ATLANTIC POWER CORP
Form S-4
May 18, 2012

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As filed with the Securities and Exchange Commission on May 18, 2012

Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-4

**REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933**

ATLANTIC POWER CORPORATION

(Exact name of registrant issuer as specified in its charter)

See Table of Registrant Guarantors for information regarding additional Registrants

British Columbia, Canada	**4900**	**55-0886410**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

**200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400**
(Address, including zip code, and telephone number, including area code, of registrants' principal executive offices)

**Barry E. Welch
President and Chief Executive Officer
Atlantic Power Corporation
200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400**
(Name, address, including zip code, and telephone number, including area code, of agent for service)

With a copy to:

**James P. Barri, Esq.
Goodwin Procter LLP
Exchange Place
Boston, Massachusetts 02109
(617) 570-1105**

**Approximate date of commencement of proposed sale of the securities to the public:
As soon as practicable after the effective date of this registration statement.**

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box: o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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

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

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issuer Tender Offer)	o
Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer)	o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	**Amount to be Registered**	**Proposed Maximum Offering Price per Security(1)**	**Proposed maximum Aggregate Offering Price(1)**	**Amount of Registration Fee**
9% Senior Notes Due 2018	$460,000,000(2)	100%	$460,000,000	$52,716
Guarantees of 9% Senior Notes Due 2018				(3)
Guarantee of Atlantic Power Limited Partnership's Guarantee of 9% Senior Notes Due 2018 by Curtis Palmer LLC				(3)

(1) Estimated solely for purposes of determining the registration fee pursuant to Section 457(f)(2) under the Securities Act.

(2) Represents the aggregate principal amount of the 9% Senior Notes due 2018 issued by Atlantic Power Corporation.

(3) Pursuant to Rule 457(n), no additional registration fee is payable with respect to the note guarantees.

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment that specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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TABLE OF REGISTRANT GUARANTORS

Exact Name of Registrant Guarantor as Specified in its Charter(1)	State of Incorporation or Organization	Primary Standard Industrial Classification Code Number	I.R.S. Employer Identification Number
Atlantic Auburndale LLC	Delaware	4900	N/A
Atlantic Cadillac Holdings, LLC	Delaware	4900	27-4273066
Atlantic Idaho Wind C, LLC	Delaware	4900	45-1605034
Atlantic Idaho Wind Holdings, LLC	Delaware	4900	27-3399080
Atlantic Oklahoma Wind, LLC	Delaware	4900	45-4407008
Atlantic Piedmont Holdings, LLC	Delaware	4900	27-3625805
Atlantic Power Generation, Inc.	Delaware	4900	68-0679361
Atlantic Power Holdings, Inc.	Delaware	4900	20-1530167
Atlantic Power Services, LLC	Delaware	4900	45-2821416
Atlantic Power Services Canada GP Inc.	Province of British Columbia, Canada	4900	N/A
Atlantic Power Services Canada LP	Province of Ontario, Canada	4900	N/A
Atlantic Power Transmission, Inc.	Delaware	4900	68-0679364
Atlantic Renewables Holdings, LLC	Delaware	4900	27-2798949
Auburndale GP, LLC	Delaware	4900	77-0605848
Aubundale LP, LLC	Delaware	4900	77-0605851
Badger Power Associates, L.P.	Delaware	4900	48-1105763
Badger Power Generation I LLC	Delaware	4900	48-1087469
Badger Power Generation II LLC	Delaware	4900	48-1087468
Baker Lake Hydro LLC	Delaware	4900	43-1531993
Atlantic Power Limited Partnership (formerly named Capital Power Income L.P.)	Province of Ontario, Canada	4900	N/A
Atlantic Power GP Inc. (formerly named CPI Income Services Ltd.)	Province of British Columbia, Canada	4900	N/A
Atlantic Power (US) GP (formerly named CPI Power (US) GP)	Delaware	4900	26-0413906
Curtis Palmer LLC	Delaware	4900	98-0421370
Dade Investment, L.P.	Delaware	4900	22-3392923
Epsilon Power Funding, LLC	Delaware	4900	04-3559960
Harbor Capital Holdings, LLC	Delaware	4900	27-2798899
Lake Cogen Ltd.	Florida	4900	22-3392919
Lake Investment, L.P.	Delaware	4900	22-3392922
NCP Dade Power LLC	Delaware	4900	33-0505981
NCP Gem LLC	Delaware	4900	33-0505980
NCP Lake Power LLC	Delaware	4900	33-0505977
NCP Pasco LLC	Delaware	4900	33-0505992
Olympia Hydro LLC	Delaware	4900	43-1532005
Orlando Power Generation I LLC	Delaware	4900	48-1120961
Orlando Power Generation II LLC	Delaware	4900	48-1120963
Pasco Cogen, Ltd.	Florida	4900	59-3100509
Teton East Coast Generation LLC	Delaware	4900	22-2579015
Teton New Lake, LLC	Delaware	4900	90-0181311
Teton Operating Services, LLC	Delaware	4900	N/A
Teton Power Funding, LLC	Delaware	4900	42-1620123
Teton Selkirk LLC	Delaware	4900	22-3340768

(1) The address and phone number of each Registrant Guarantor is as follows:

c/o Atlantic Power Corporation

200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400

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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED MAY 18, 2012

PROSPECTUS

Atlantic Power Corporation

Exchange Offer for
Up to $460,000,000 Principal Amount Outstanding
of 9% Senior Notes due 2018
for a Like Principal Amount of
Registered 9% Senior Notes due 2018

Offer for outstanding 9% Senior Notes due 2018 in the aggregate principal amount of $460,000,000 (which we refer to as the "**Old Notes**") in exchange for up to $460,000,000 in aggregate principal amount of 9% Senior Notes due 2018 that have been registered under the Securities Act of 1933, as amended (the "**Securities Act**") (which we refer to as the "**Exchange Notes**" and, together with the Old Notes, the "**notes**").

Terms of the Exchange Offer

- Expires 5:00 p.m., New York City time, , 2012, unless extended.
- You may withdraw tendered outstanding Old Notes any time before the expiration or termination of the exchange offer.
- The exchange offer is subject to customary conditions that may be waived by us.
- We will not receive any proceeds from the exchange offer.
- The exchange of Old Notes for the Exchange Notes should not be a taxable exchange for U.S. federal income tax purposes. See "Certain U.S. Federal Income Tax Considerations."
- All Old Notes that are validly tendered and not validly withdrawn prior to the expiration of the exchange offer will be exchanged for the Exchange Notes.

Terms of the Exchange Notes:

The Exchange Notes will mature on November 15, 2018. The Exchange Notes will pay interest semi-annually in cash in arrears on May 15 and November 15 of each year, beginning on November 15, 2012.

Subject to release as described in the indenture governing the notes and below in "Description of Exchange Notes," the Exchange Notes will be guaranteed, jointly and severally, on an unsecured basis, by all of our wholly owned U.S. and Canadian subsidiaries that guarantee our secured revolving credit facility, and the guarantee of the Exchange Notes by Atlantic Power Limited Partnership (the "**Partnership**") will be guaranteed by Curtis Palmer LLC.

The Exchange Notes and the related guarantees will rank effectively junior to all secured indebtedness to the extent of the value of the collateral securing such debt, pari passu with all existing and future senior unsecured indebtedness and senior to all existing and future indebtedness that by its terms is expressly subordinated to the Exchange Notes.

We may redeem the Exchange Notes in whole or in part from time to time. See "Description of Exchange Notes."

Upon a change of control, we must give holders the opportunity to sell their Exchange Notes to us at 101% of their principal amount plus accrued and unpaid interest, if any.

The terms of the Exchange Notes are identical to those of the outstanding Old Notes, except the transfer restrictions, registration rights and additional interest provisions relating to the Old Notes do not apply to the Exchange Notes.

For a discussion of the specific risks that you should consider before tendering your Old Notes in the exchange offer, see "Risk Factors" beginning on page 12 of this prospectus.

No public market exists for the outstanding Old Notes. We do not intend to list the Exchange Notes on any securities exchange and, therefore, no active public market is anticipated for the Exchange Notes.

Each broker-dealer that receives Exchange Notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Notes. A broker-dealer who acquired Old Notes as a result of market making or other trading activities may use this exchange offer prospectus, as supplemented or amended from time to time, in connection with any resales of the Exchange Notes.

Neither the Securities and Exchange Commission (the "SEC") nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2012.

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Each broker-dealer that receives Exchange Notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Notes. By so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. A broker-dealer who acquired Old Notes as a result of market making or other trading activities may use this prospectus, as supplemented or amended from time to time, in connection with any resales of the Exchange Notes. We have agreed that, for a period of up to 90 days after the closing of the exchange offer, we will use our commercially reasonable efforts make this prospectus available for use in connection with any such resale. See "Plan of Distribution."

You should rely only on the information contained in this prospectus. We have not authorized anyone to provide you with information different from that contained in this prospectus. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy securities other than those specifically offered hereby or an offer to sell any securities offered hereby in any jurisdiction where, or to any person whom, it is unlawful to make such offer or solicitation. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of the Exchange Notes.

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As used in this prospectus, the terms "Atlantic Power," the "Company," "we," "our" and "us" refer to Atlantic Power Corporation, together with those entities owned or controlled by Atlantic Power Corporation, unless the context indicates otherwise. Unless otherwise noted, all references to "C$" and "Canadian dollars" are to the lawful currency of Canada and all references to "$," "US$" and "U.S. dollars" are to the lawful currency of the United States. This prospectus includes our trademarks and other trade names identified herein. All other trademarks and trade names appearing in this prospectus are the property of their respective holders.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements within the meaning of the *Private Securities Litigation Reform Act of 1995* with respect to the financial condition, results of operations, business strategies, operating efficiencies, synergies, revenue enhancements, competitive positions, plans and objectives of management and growth opportunities of Atlantic Power Corporation. Statements in this prospectus that are not historical facts are hereby identified as forward-looking statements for the purpose of the safe harbor provided by Section 27A of the Securities Act and Section 21E of the Exchange Act and forward-looking information within the meaning defined under applicable Canadian securities legislation (collectively, "**forward-looking statements**").

These forward-looking statements relate to, among other things, the expected benefits of the Canadian Hills project, such as accretion, the ability to pay increased dividends, enhanced cash flow, growth potential, liquidity and access to capital, market profile and financial strength, the position of the combined company and the expected timing of the commencement of commercial operations (if at all).

Forward-looking statements can generally be identified by the use of words such as "should," "intend," "may," "expect," "believe," "anticipate," "estimate," "continue," "plan," "project," "will," "could," "would," "target," "potential" and other similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, such statements involve risks and uncertainties, and undue reliance should not be placed on such statements. Certain material factors or assumptions are applied in making forward-looking statements, including, but not limited to, factors and assumptions regarding the items outlined above. Actual results may differ materially from those expressed or implied in such statements. Important factors that could cause actual results to differ materially from these expectations include, among other things:

- the amount of distributions expected to be received from our projects;
- the impact of legislative, regulatory, competitive and technological changes; and
- other risk factors relating to us and the power industry, as detailed from time to time in our filings with the SEC and the Canadian Securities Administrators (the "**CSA**").

You are cautioned that any forward-looking statement speaks only as of the date of this prospectus. We undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

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ENFORCEABILITY OF CIVIL LIABILITIES

We are incorporated under the laws of Canada, and certain of the guarantors are organized under the laws of various Canadian jurisdictions. Certain of our and the guarantors' directors, as well as certain of the experts named in this prospectus, are residents of Canada, and all or a portion of their respective assets are located outside the United States. We and the guarantors have agreed, in accordance with the terms of the indenture under which the Exchange Notes will be issued, to accept service of process in any suit, action or proceeding with respect to the indenture, the notes (including Exchange Notes) or the guarantees (including registered guarantees exchanged for the guarantees of the Old Notes) brought in any federal or state court located in the Borough of Manhattan, in the City of New York, by an agent designated for such purpose, and to submit to the jurisdiction of such courts in connection with such suits, actions or proceedings. However, it may be difficult for holders of the notes to effect service within the United States upon directors and experts who are not residents of the United States or to realize in the United States upon judgments of courts of the United States predicated upon civil liability under U.S. federal or state securities laws or other laws of the United States. There is doubt as to the enforceability in Canada against us, the Canadian guarantors or against our or the guarantors' directors and the experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of courts of the United States, of liabilities predicated solely upon U.S. federal or state securities laws.

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SUMMARY

This summary highlights information contained in this prospectus. It is not complete and does not contain all of the information that you should consider before participating in the exchange offer. You should read the following summary together with the more detailed information regarding our company, the Exchange Notes and the financial statements and notes thereto appearing elsewhere in this prospectus.

Our Business

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("**PPA**s"), which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 megawatts (or "**MW**") in which our aggregate ownership interest is approximately 2,141 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada and a 500-kilovolt 84-mile electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. We also own a majority interest in Rollcast Energy, a biomass power plant developer in North Carolina, and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC ("**PERH**"). Twenty-three of our projects are wholly owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2012 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects under steam sales agreements to industrial and commercial purchasers. The transmission system rights we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is not an effective pass-through of fuel costs, we attempt to mitigate a significant portion of the market price risk of fuel purchases through the use of hedging strategies.

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

Recent Developments

Acquisition of Canadian Hills Wind Power Development Project

On January 31, 2012, we acquired a 51% interest in Canadian Hills, a 300 MW wind power development project located near El Reno, Oklahoma, 20 miles west of Oklahoma City. On March 30, 2012, concurrent with the closing of a construction financing facility for Canadian Hills, we completed the acquisition of an additional 48% interest, bringing our total interest in the project to 99%. Canadian Hills was developed by Apex Wind Energy Holdings, LLC ("**Apex**"), which will retain a 1%

interest in the project. The project, which is expected to deploy Mitsubishi 2.4 MW MWT102 and REpower 2.05 MW MM92 wind turbines, has long-term power purchase agreements for 100% of its output with Southwestern Electric Power Company, Oklahoma Municipal Power Authority and Grand River Dam Authority. Apex earned a development fee and will manage construction of the project, and, upon commencement of operations, currently expected in November 2012, we will oversee operations and be the asset manager.

Upon commencement of commercial operations, Canadian Hills is expected to generate enough clean, renewable energy to power the equivalent of over 100,000 homes. The investment is expected to increase our average remaining power purchase agreement life from 8.3 years to 9.9 years and increase the wind segment of our net generating capacity from 3% to 15%, while reducing the gas segment from 77% to 68%.

Construction and development costs for Canadian Hills are being initially funded with the proceeds of a $310 million non-recourse, project-level construction financing facility, which includes a $290 million construction loan and a $20 million five-year letter of credit facility. Construction under the terms of a fixed-price, balance of plant contract began in April 2012, with total cost for the project expected to be approximately $470 million. In connection with the closing of the construction financing facility, we committed to invest approximately $180 million in equity (net of financing costs) to cover the balance of the construction and development costs, expected to be drawn following disbursement of the construction loan. The construction loan is expected to be repaid with tax equity investments by institutional investors at the time the project commences commercial operations. We have received an approximately $360 million bridge facility commitment from Morgan Stanley to provide flexibility in the timing of the tax equity investment and our own equity commitment in the project.

PERH Interest Sale

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

Path 15

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

DuPont Litigation

In December 2008, the Chambers project, which is accounted for under the equity method of accounting, filed suit against DuPont de Nemours & Company ("DuPont") for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, the Chambers project received a favorable ruling from the court on its summary judgment motion as to liability. The court's decision included a description of the pricing methodology that is consistent with the project's position. On April 25, 2012, the court issued its written opinion which ordered DuPont to pay Chambers a total of approximately $15.7 million. This amount represents DuPont's

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electricity underpayments from January 2003 through June 2009, and interest through July 22, 2011. The court also ordered that from July 1, 2009 going forward, the pricing methodology should be calculated in accordance with the court's prior ruling on summary judgment. DuPont has until June 9, 2012 to file an appeal. The amount of such underpayments including interest is estimated at approximately $10.6 million.

Potential Offering of Common Shares and Convertible Debentures

We have filed registration statements related to the public offering of $125.0 million of our common shares and $125.0 million in aggregate principal amount of convertible unsecured subordinated debentures, which are anticipated to be convertible into our common shares at the option of the holder thereof. We cannot assure you that we will launch either offering, or even if we do, that we will consummate either offering.

Corporate Information

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, Canada V6C 2G8 and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116, telephone number (617) 977-2400. Our website is www.atlanticpower.com. Information contained on our website is not part of this prospectus.

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The Exchange Offer

On November 4, 2011, Atlantic Power (the "**Issuer**") sold, through a private placement exempt from the registration requirements of the Securities Act $460,000,000 principal amount of 9% Senior Notes due 2018 (the "**Old Notes**"), all of which are eligible to be exchanged for notes which have been registered under the Securities Act (the "**Exchange Notes**"). The Old Notes and the Exchange Notes are referred to together as the "**notes**."

Simultaneously with the private placement, we entered into a registration rights agreement with the initial purchasers of the Old Notes (the "**Registration Rights Agreement**"). Under the Registration Rights Agreement, we agreed to cause a registration statement relating to substantially identical notes, which will be issued in exchange for the Old Notes, to be filed with the Securities and Exchange Commission (the "**SEC**") and to use our commercially reasonable efforts to complete the exchange offer within 270 days following the date on which we issued the Old Notes. You may exchange your Old Notes for Exchange Notes in this exchange offer. You should read the discussion under the headings " The Exchange Notes," "The Exchange Offer" and "Description of Exchange Notes" for further information regarding the Exchange Notes.

Securities to be Exchanged	Up to $460,000,000 principal amount of 9% Senior Notes due 2018.
The Exchange Offer; Securities Act Registration	We are offering to exchange the Old Notes for an equal principal amount of the Exchange Notes. Old Notes may be exchanged only in denominations of $2,000 of principal amount and any integral multiple of $1,000 in excess thereof. The exchange offer is being made pursuant to the Registration Rights Agreement, which grants the initial purchasers and any subsequent holders of the Old Notes certain exchange and registration rights. This exchange offer is intended to satisfy those exchange and registration rights with respect to the Old Notes. After the exchange offer is complete and except for our obligations to file a shelf registration statement under the circumstances described below, you will no longer be entitled to any exchange or registration rights with respect to Old Notes. You may tender your outstanding Old Notes for Exchange Notes by following the procedures described under the heading "The Exchange Offer."
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on , 2012, or a later date and time to which the Issuer may extend it.
Withdrawal Rights	You may withdraw your tender of the Old Notes at any time prior to the expiration date of the exchange offer. Any Old Notes not accepted by us for exchange for any reason will be returned to you at our expense promptly after the expiration or termination of the exchange offer.

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Conditions to the Exchange Offer	The exchange offer is subject to customary conditions, some of which we may waive. We intend to conduct the exchange offer in accordance with the provisions of the Registration Rights Agreement and the applicable requirements of the Securities Act, the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), and the rules and regulations of the SEC. For more information, see "The Exchange Offer Conditions to the Exchange Offer."
Procedures for Tendering Old Notes Through Brokers and Banks	Since the Old Notes are represented by global book-entry notes, the Depositary Trust Company ("**DTC**"), as depositary, or its nominee is treated as the registered holder of the Old Notes and will be the only entity that can tender your Old Notes for Exchange Notes. To tender your outstanding Old Notes, you must instruct the institution where you keep your Old Notes to tender your Old Notes on your behalf so that they are received on or prior to the expiration of this exchange offer. By tendering your Old Notes you will be deemed to have acknowledged and agreed to be bound by the terms set forth under "The Exchange Offer." Your outstanding Old Notes must be tendered in denominations of $2,000 of principal amount and any integral multiple of $1,000 in excess thereof. In order for your tender to be considered valid, the exchange agent must receive a confirmation of book-entry transfer of your outstanding Old Notes into the exchange agent's account at DTC, under the procedure described in this prospectus under the heading "The Exchange Offer," on or before 5:00 p.m., New York City time, on the expiration date of the exchange offer. See "The Exchange Offer" for more information regarding the procedures for tendering Old Notes.

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Effect of Not Tendering Old Notes	If you do not tender your Old Notes or if you do tender them but they are not accepted by us, your Old Notes will continue to be subject to the existing restrictions upon transfer. Except for our obligation to file a shelf registration statement under the circumstances described below, we will have no further obligation to provide for the registration under the Securities Act of Old Notes. If your outstanding Old Notes are not tendered and accepted in the exchange offer, it may become more difficult for you to sell or transfer your outstanding Old Notes.
Resale of the Exchange Notes	Under existing interpretations by the staff of the SEC as set forth in no-action letters issued to unrelated third parties and referenced below, we believe that the Exchange Notes issued in the exchange offer in exchange for Old Notes may be offered for resale, resold and otherwise transferred by you without compliance with the registration and prospectus delivery provisions of the Securities Act, if you: are not an "affiliate" of ours within the meaning of Rule 405 of the Securities Act; are acquiring the Exchange Notes in the ordinary course of business; and have no arrangement or understanding with any person to participate in a distribution of the Exchange Notes. In addition, each participating broker-dealer that receives Exchange Notes for its own account pursuant to the exchange offer in exchange for Old Notes that were acquired as a result of market-making or other trading activity must also acknowledge that it will deliver a prospectus in connection with any resale of the Exchange Notes. For more information, see "Plan of Distribution." Any holder of Old Notes, including any broker-dealer, who: is our affiliate, does not acquire the Exchange Notes in the ordinary course of its business, or tenders in the exchange offer with the intention to participate, or for the purpose of participating, in a distribution of Exchange Notes,

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	cannot rely on the position of the staff of the SEC expressed in *Exxon Capital Holdings Corporation, Morgan Stanley & Co., Incorporated* or similar no-action letters and, in the absence of an applicable exemption, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with the resale of the Exchange Notes or it may incur liability under the Securities Act. We will not be responsible for, or indemnify against, any such liability.
Minimum Condition	The exchange offer is not conditioned on any minimum aggregate principal amount of Old Notes being tendered for exchange.
Appraisal or Dissenters' Rights	Holders of the Old Notes do not have any appraisal or dissenters' rights in connection with the exchange offer.
Certain Federal Income Tax Considerations	Your exchange of Old Notes for Exchange Notes to be issued in the exchange offer will not be a taxable event for U.S. or Canadian federal income tax purposes. See "Certain U.S. Federal Income Tax Considerations" and "Certain Canadian Federal Income Tax Considerations" for a summary of U.S. and Canadian federal tax consequences associated with the exchange of Old Notes for Exchange Notes and the ownership and disposition of those Exchange Notes.
Use of Proceeds	We will not receive any proceeds from the issuance of Exchange Notes pursuant to the exchange offer.
Exchange Agent	Wilmington Trust, National Association is serving as the exchange agent in connection with the exchange offer. The address and telephone number of the exchange agent are set forth under the heading "The Exchange Offer Exchange Agent."
Shelf Registration Statement	The Registration Rights Agreement requires that we file a shelf registration statement, in addition to or in lieu of conducting the exchange offer, in the event that: (a) we are not permitted to file the exchange offer registration statement or to consummate the exchange offer due to a change in law or SEC policy; or (b) for any reason, we do not consummate the exchange offer within 270 days following the date on which we issued the Old Notes; or (c) any of the initial purchasers party to the Registration Rights Agreement notifies us that it holds Old Notes that are or were ineligible to be exchanged in the exchange offer.

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The Exchange Notes

The summary below describes the principal terms of the Exchange Notes. Certain of the terms and conditions described below are subject to important limitations and exceptions. The terms of the Exchange Notes are identical to the terms of the Old Notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the Old Notes do not apply to the Exchange Notes. The "Description of Exchange Notes" section of this prospectus contains a more detailed description of the terms and conditions of the Exchange Notes. References to "we," "us" and "our" refer only to Atlantic Power and not to any of its subsidiaries or any other entity.

Issuer	Atlantic Power
Securities Offered	$460,000,000 principal amount of 9% Senior Notes due 2018.
Maturity	November 15, 2018.
Interest	Interest on the Exchange Notes will accrue from the date of the original issuance of the Old Notes or from the date of the last payment of interest on the Old Notes, whichever is later. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months. We will not pay interest on Old Notes tendered and accepted for exchange.
Interest Rate	Interest will accrue at a rate of 9% per annum.
Interest Payment Dates	Each May 15 and November 15, beginning on November 15, 2012.

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Ranking	The Exchange Notes will be our and the guarantors' general senior unsecured obligations, will rank equal in right of payment with all of such entities' existing and future senior indebtedness, including the Old Notes and borrowings under our secured revolving credit facility, and will rank senior in right of payment to all of such entities' existing and future subordinated indebtedness; however, the Exchange Notes will be effectively subordinated to all of our and the guarantors' secured indebtedness to the extent of the value of the collateral securing such indebtedness. The Exchange Notes will also be structurally subordinated to the indebtedness and other obligations of our subsidiaries that do not guarantee the Exchange Notes with respect to the assets of such entities. See Note 24 to our consolidated audited financial statements and Note 13 to our quarterly financial statements (unaudited), each of which is included elsewhere in this prospectus, for financial information related to our guarantor and non-guarantor subsidiaries.
Guarantees	Subject to release as described in the indenture governing the notes and below in "Description of Exchange Notes," the Exchange Notes will be guaranteed, jointly and severally, on an unsecured basis, by all of our wholly owned U.S. and Canadian subsidiaries that guarantee our secured revolving credit facility, and the Partnership's guarantee of the Exchange Notes will be guaranteed by Curtis Palmer LLC See "Description of Exchange Notes Guarantees."

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Optional Redemption	On or after November 15, 2014, we may redeem all or a part of the notes at the redemption prices set forth under "Description of Exchange Notes Optional Redemption," plus accrued and unpaid interest, if any, to the applicable redemption date. In addition, at any time prior to November 15, 2014, we may, on one or more occasions, redeem some or all of the notes at any time at a redemption price equal to 100% of the principal amount of the notes redeemed, plus a "make-whole" premium together with accrued and unpaid interest, if any, to the applicable redemption date. On or prior to November 15, 2014, we may also redeem up to 35% of the aggregate principal amount of notes, using the proceeds of certain equity offerings at a redemption price of 109% of the principal amount thereof, plus accrued and unpaid interest, if any, to the applicable redemption date. We may make that redemption only if, after the redemption, at least 65% of the aggregate principal amount of the notes remains outstanding and the redemption occurs within 90 days of the closing of the equity offering. See "Description of Exchange Notes Optional Redemption."
Change of Control	Upon a Change of Control Triggering Event (as defined under "Description of Exchange Notes"), we will be required to make an offer to purchase the notes. The purchase price will equal 101% of the principal amount of the notes on the date of purchase plus accrued and unpaid interest, if any, to the repurchase date.
Certain Covenants	The indenture governing the notes (including the Exchange Notes) contains covenants that, among other things, limit our ability to:
	incur debt or issue disqualified stock;
	incur secured debt;
	pay dividends and make distributions;
	enter into sale and leaseback transactions;
	merge, amalgamate or otherwise sell all or substantially all of our assets; and
	provide guarantees.

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	You should read "Description of Exchange Notes Certain Covenants of Atlantic Power" in this prospectus for a description of these covenants each of which contains important exceptions and carveouts.
Absence of a Public Market for the Exchange Notes	The Exchange Notes are a new issue of securities with no established public market. We do not intend to apply for listing of the Exchange Notes on any securities exchange.

You should refer to the section titled "Risk Factors" on page 12 of this prospectus for a description of some of the risks you should consider before tendering your Old Notes for Exchange Notes.

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RISK FACTORS

Before you decide to participate in the exchange offer, you should be aware that an investment in the Exchange Notes involves various risks and uncertainties, including those described below. You should carefully consider the risks and uncertainties described below with all of the other information that is included in this prospectus. If any of these risks actually occur, our business, financial position or results of operations could be materially adversely affected, and you could lose all or part of your investment.

Risks Related to Our Business and Our Projects

Our revenue may be reduced upon the expiration or termination of our power purchase agreements.

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. See "Business Our Organization and Segments" for details about our projects' PPAs and related expiration dates. In addition, these PPAs may be subject to termination prior to expiration in certain circumstances, including default by the project. When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced significantly. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

Our projects depend on their electricity, thermal energy and transmission services customers.

Each of our projects rely on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. The largest customers of our power generation projects, including projects recorded under the equity method of accounting, are Public Service Company of Colorado ("**PSCo**"), Progress Energy Florida, Inc. ("**PEF**"), Ontario Electricity Financial Corp. ("**OEFC**") and Equistar Chemicals ("**Equistar**"), which purchased approximately 17%, 15%, 9% and 8%, respectively, of the net electric generation capacity of our projects for the year ended December 31, 2011. Our results of operations are highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their obligations or make required payments.

Certain of our projects are exposed to fluctuations in the price of electricity.

Those of our projects operating with no PPA or PPAs based on spot market pricing for some or all of their output will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term PPAs expire or terminate, the relevant project will be required to either negotiate a new PPA or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time.

Currently, our most significant exposure to market power prices is at the Selkirk, Morris and Chambers projects. At Chambers, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is economical to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. At Morris, the facility can sell approximately 100MW above Equistar's demand into the grid at market prices. If market prices do not justify the increased generation the project has no requirement to sell power in excess of the Equistar demand. At Selkirk, approximately 23% of the capacity of the facility is not contracted and is sold at market prices or not sold at all if market prices do not support the profitable operation of that portion of the facility.

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Our projects may not operate as planned.

The ability of our projects to meet availability requirements and generate the required amount of power to be sold to customers under the PPAs are primary determinants of the amount of cash that will be distributed from the projects to us. There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, or force majeure events among other things, which could adversely affect revenues and cash flow. To the extent that our projects' equipment requires more frequent and/or longer than forecasted down times for maintenance and repair, or suffers disruptions of plant availability and power generation for other reasons, our results of operations may be adversely affected.

In general, our power generation projects transmit electric power to the transmission grid for purchase under the PPAs through a single step up transformer. As a result, the transformer represents a single point of vulnerability and may exhibit no abnormal behavior in advance of a catastrophic failure that could cause a temporary shutdown of the facility until a replacement transformer can be found or manufactured.

If the reason for a shutdown is outside of the control of the operator, a power generation project may be able to make a force majeure claim for temporary relief of its obligations under the project contracts such as the PPA, fuel supply, steam sales agreement, or otherwise mitigate impacts through business interruption insurance policies, maintenance and debt service reserves. If successful, such insurance claims may prevent a default or reduce monetary losses under such contracts. However, a force majeure claim may be challenged by the contract counterparty and, to the extent the challenge is successful, the outage may still have a materially adverse effect on the project.

We provide letters of credit under our $300 million senior secured revolving credit facility for contractual credit support at some of our projects. If the projects fail to perform under the related project-level agreements, the letters of credit could be drawn and we would be required to reimburse our senior lenders for the amounts drawn.

Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects.

The amount of energy generated at the projects is highly dependent on suppliers under certain fuel supply agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or an inability or failure by any supplier to meet its contractual commitments may adversely affect our results.

Upon the expiration or termination of existing fuel supply agreements, we or our project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. We may not be able to renegotiate these agreements or enter into new agreements on similar terms. Furthermore, there can be no assurance as to availability of the supply or pricing of fuel under new arrangements, and it can be very difficult to accurately predict the future prices of fuel.

Revenues earned by our projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable or predictable prices. To the extent possible, the projects attempt to match fuel cost setting mechanisms in supply agreements to energy payment formulas in the PPA. To the extent that fuel costs are not matched well to PPA energy payments, increases in fuel costs may adversely affect the profitability of the projects, if not otherwise hedged. For example, a portion of the required natural gas at our Auburndale project and all of the natural gas required at our Lake project is purchased at market prices, but the projects' PPAs that expire in 2013 do not effectively pass through changes in natural gas prices.

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Revenues from windpower projects are highly dependent on suitable wind and associated weather conditions.

We own interests in two windpower projects. The energy and revenues generated at a wind energy project are highly dependent on climatic conditions, particularly wind conditions, which are variable and difficult to predict. Turbines will only operate within certain wind speed ranges that vary by turbine model and manufacturer, and there is no assurance that the wind resource at any given project site will fall within such specifications.

We base our investment decisions with respect to each wind energy project on the findings of wind studies conducted on-site before starting construction. However, actual climatic conditions at a project site, particularly wind conditions, may not conform to the findings of these wind studies, and, therefore, our wind energy projects may not meet anticipated production levels, which could adversely affect our forecasted profitability.

Insurance may not be sufficient to cover all losses.

Our business involves significant operating hazards related to the generation of electricity. While we believe that the projects' insurance coverage addresses all material insurable risks, provides coverage that is similar to what would be maintained by a prudent owner/operator of similar facilities, and are subject to deductibles, limits and exclusions which are customary or reasonable given the cost of procuring insurance, current operating conditions and insurance market conditions, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving our assets or operations of our projects. Any losses in excess of those covered by insurance, which may include a significant judgment against any project or project operator, the loss of a significant permit or other approval or the imposition of a significant fine or penalty, could have a material adverse effect on our business, financial condition and future prospects and could adversely affect dividends to our shareholders.

Our operations are subject to the provisions of various energy laws and regulations.

Generally, in the United States, our projects are subject to regulation by the Federal Energy Regulatory Commission ("**FERC**") regarding the terms and conditions of wholesale service and rates, as well as by state regulators regarding the prudency of utilities entering into PPAs entered into by qualifying facility projects and the siting of the generation facilities. The majority of our generation is sold by qualifying facility projects under PPAs that required approval by state authorities.

In August 2005, the Energy Policy Act of 2005 was enacted, which removed certain regulatory constraints on investment in utility power producers. The Energy Policy Act of 2005 also limited the requirement that electric utilities buy electricity from qualifying facilities in certain markets that have certain competitive characteristics, potentially making it more difficult for our current and future projects to negotiate favorable PPAs with these utilities. Finally, the Energy Policy Act of 2005 amended and expanded the reach of the FERC's merger approval authority.

If any project that is a qualifying facility were to lose its status as a qualifying facility, then such project may no longer be entitled to exemption from provisions of the Public Utility Holding Company Act of 2005 or from provisions of the Federal Power Act and state law and regulations. Such project may be able to obtain exempt wholesale generator status to maintain its exemption from the provisions of the Public Utility Holding Company Act of 2005; however, our projects may not be able to obtain such exemptions. Loss of qualifying facility status could trigger defaults under covenants to maintain that status in the PPAs and project-level debt agreements, and if not cured within allowed cure periods, could result in termination of agreements, penalties or acceleration of indebtedness under such agreements.

The Energy Policy Act of 2005 provides incentives for various forms of electric generation technologies, which may subsidize our competitors. In addition, pursuant to the Energy Policy Act of 2005, the FERC selected an electric reliability organization to impose mandatory reliability rules and standards. Among other things, the FERC's rules implementing these provisions allow such reliability organizations to impose sanctions on generators that violate their new reliability rules.

The introductions of new laws, or other future regulatory developments, may have a material adverse impact on our business, operations or financial condition.

Generally, in Canada, our projects are subject to energy regulation primarily by the relevant provincial authorities.

Risks with respect to the two Canadian provinces where we currently have projects are addressed further below.

(i) British Columbia

The government of British Columbia has a number of specific statutes and regulations that govern our projects in that province. The statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

British Columbia Hydro and Power Authority ("**BC Hydro**") is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers. Two of our three British Columbia projects currently sell all of their electricity to BC Hydro, and the third project sells substantially all of its electricity to BC Hydro. Therefore, changes to BC Hydro's energy procurement policies and financial difficulties of or regulatory intervention in respect of BC Hydro could impact the market for electricity generated by our British Columbia projects. This risk is mitigated in part because, in general, BC Hydro is currently limited by regulation to undertaking efficiency improvements at its existing facilities and only undertaking development of new generation with the approval of the British Columbia Utilities Commission. There is a risk that the regulatory regime could adversely affect the amount of power that BC Hydro purchases from our projects and the competitive environment or the price at which BC Hydro is willing to purchase power from our British Columbia projects.

The British Columbia Utilities Commission to some extent regulates independent power producers. While the British Columbia Utilities Commission is nominally independent of the government, its chair and commissioners are effectively appointed by the provincial cabinet. All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by British Columbia Utilities Commission as being "in the public interest." The British Columbia Utilities Commission may hold a hearing in this regard. Furthermore, the British Columbia Utilities Commission may impose conditions to be contained in agreements entered into by public utilities for electricity.

(ii) Ontario

The government of Ontario has a number of specific statutes and regulations that govern our projects in that province. The statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

In Ontario, the Ontario Energy Board is an administrative tribunal with authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects. No person is permitted to generate electricity in Ontario without a license from the Ontario Energy Board. While all of our Ontario projects are currently licensed, the Ontario Energy Board has the authority to effectively modify the licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the Ontario Energy Board can result in fines.

While the Ontario Energy Board provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the Ontario Energy Board, and the Ontario Energy Board is required to implement such policy directives. Thus, the Ontario Energy Board's regulation of our projects is subject to potential political interference, to a degree.

A number of other regulators and quasi-governmental entities play a role, including the Independent Electricity System Operator, Hydro One, the Electrical Safety Authority, OEFC and the Ontario Power Authority. All these agencies may affect our projects.

Furthermore, on April 18, 2012, the Ontario government announced that it intended to merge the Independent Electricity System Operator and the Ontario Power Authority. The mandate of the new, merged agency would be to establish market rules to benefit consumers, align contracts and create an electricity system that is more responsive to changing conditions. The government's proposed legislation has not yet been tabled in the legislature. If and when this merger occurs, it may affect our Ontario projects.

Future FERC rate determinations could negatively impact Path 15's cash flows.

The stability of Path 15's cash flows will continue to be subject to the risk of the FERC's adjusting the expected formulation of revenues as a result of its rate review every three years and the participation therein by interveners who may argue for lower rates. Such a rate review commenced in February 2011. The cost-of-service methodology currently applied by the FERC is well established and transparent; however, certain inputs in the FERC's determination of rates are subject to its discretion, including its response to protests from interveners in such rate cases, which include return on equity and the recovery of certain extraordinary expenses. Unfavorable decisions on these matters could adversely affect the cash flow, financial position and results of operations of us and Path 15, and could adversely affect our cash available for dividends.

Noncompliance with federal reliability standards may subject us and our projects to penalties.

Our operations are subject to the regulations of NERC, a self-regulatory non-governmental organization which has statutory responsibility to regulate bulk power system users and generation and transmission owners and operators. NERC groups the users, owners, and operators of the bulk power system into 17 categories, known as functional entities e.g., Generator Owner, Generator Operator, Purchasing-Selling Entity, etc. according to the tasks they perform. The NERC Compliance Registry lists the entities responsible for complying with the mandatory reliability standards and the FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity found to be in noncompliance. Violations may be discovered through self-certification, compliance audits, spot checking, self-reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submittals, exception reporting, and complaints. The penalty that might be imposed for violating the requirements of the standards is a function of the Violation Risk Factor. Penalties for the most severe violations can reach as high as $1 million per violation, per day, and our projects could be exposed to these penalties if violations occur.

Our projects are subject to significant environmental and other regulations.

Our projects are subject to numerous and significant federal, state, provincial and local laws, including statutes, regulations, by-laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers' health and safety matters. Our facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, penalties and property damage. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters. We have implemented environmental, health and safety management programs designed to continuously improve environmental, health and safety performance.

The Clean Air Act of 1963, as amended, and related regulations and programs of the U.S. Environmental Protection Agency (the "**EPA**") extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds by power plants. Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the EPA promulgated the final Cross-State Air Pollution Rule ("**CSAPR**") which replaces the Clean Air Interstate Rule ("**CAIR**") and requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through more aggressive state-by-state emissions limits for nitrogen oxides and sulfur dioxide. The first phase of compliance was to begin on January 1, 2012 and the second (and more restrictive) phase would begin on January 1, 2014. On December 30, 2011, the U.S. Court of Appeals stayed CSAPR pending hearings in the second quarter of 2012. The court could issue a final decision on the merits of CSAPR in the summer or early fall of 2012. In the interim, the regulations of the CAIR remain in place. Compliance with the new rule, when implanted, may have a material adverse impact on our business, operations or financial condition.

The EPA proposed new mercury and air toxics emissions standards for power plants on May 3, 2011 and issued a final rule on December 16, 2011. Meeting these new standards at our coal-fired facility may have a material adverse impact on our business, operations or financial condition.

The Resource Conservation and Recovery Act of 1976, as amended, has historically exempted fossil fuel combustion wastes from hazardous waste regulation. However, in June 2010 the EPA proposed two alternative sets of regulations governing coal ash. One set of proposed regulations would designate coal ash as "special waste" and bring ash impoundments at coal-fired power plants under federal regulations governing hazardous solid waste under Subtitle C of the Resource Conservation and Recovery Act. Another set of proposed regulations would regulate coal ash as a non-hazardous solid waste. If the EPA determines to regulate coal ash as a hazardous waste, our 40% owned coal-fired facility may be subject to increased compliance obligations and costs associated that may have a material adverse impact on our business, operations or financial condition.

Significant costs may be incurred for either capital expenditures or the purchase of allowances under any or all of these programs to keep the projects compliant with environmental laws and regulations. The projects' PPAs do not allow for the pass through of emissions allowance or emission reduction capital expenditure costs, with the exception of Pasco. However, the Selkirk project has such a PPA without pass-through, yet participated in a settlement with New York utilities, IPPs and the state in which any required RGGI costs shall nonetheless be reimbursed to the IPPs. If it is not economical to make those expenditures it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

Our projects have obtained environmental permits and other approvals that are required for their operations. Compliance with applicable environmental laws, regulations, permits and approvals and material future changes to them could materially impact our businesses. Although we believe the operations of the projects are currently in material compliance with applicable environmental laws,

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licenses, permits and other authorizations required for the operation of the projects, and although there are environmental monitoring and reporting systems in place with respect to all the projects, there is no guarantee that more stringent laws will not be imposed, that there will not be more stringent enforcement of applicable laws or that such systems may not fail, which may result in material expenditures. Failure by the projects to comply with any environmental, health or safety requirements, or increases in the cost of such compliance, including as a result of unanticipated liabilities or expenditures for investigation, assessment, remediation or prevention, could result in additional expense, capital expenditures, restrictions and delays in the projects' activities, the extent of which cannot be predicted.

Ongoing public concerns about emissions of CO_2 and other greenhouse gases have resulted in the enactment of, and proposals for, laws and regulations at the federal, state and regional levels, some of which do or could apply to some of our project operations. For example, the multi-state CO_2 cap-and-trade program, known as the Regional Greenhouse Gas Initiative, applies to our fossil fuel facilities in the Northeast region. The Regional Greenhouse Gas Initiative program went into effect on January 1, 2009. CO_2 allowances are now a tradable commodity.

California, British Columbia and Ontario are part of the Western Climate Initiative, which is developing a regional cap-and-trade program to reduce greenhouse gas emissions in the region to 15% below 2005 levels by 2020.

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws are more commonly known as AB 32 and SB 1368. Under AB 32 (the Global Warming Solutions Act), the California Air Resources Board ("**CARB**") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector). In order to do so, it must adopt regulations for the mandatory reporting and verification of greenhouse gas emissions and to reduce state-wide emissions of greenhouse gases to 1990 levels by 2020. On October 20, 2011, the CARB adopted rules whose first phase will take full effect on January 1, 2013. Starting that date, electricity generators and certain other facilities will be subject to an allowance for greenhouse gas emissions. Allowances will be allocated by both formulas set by the CARB and auctions. Legal challenges to the program are underway and additional challenges are anticipated.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "**CPUC**") and the CARB establish greenhouse gas emission performance standards and implement regulations for power purchase agreements for a term of five or more years entered into prospectively by publicly-owned electric utilities. The legislation directs the California Energy Commission to establish the performance standard as one not exceeding the rate of greenhouse gas emitted per megawatt-hour associated with combined-cycle, gas turbine baseload generation, such as our North Island project.

In addition to the regional initiatives, legislation for the reduction of greenhouse gases has been introduced at the federal level and if passed, may eventually override the regional efforts with a national cap and trade program. To date, however, federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have not been adopted into law. Separately, the EPA has taken several recent actions for the regulation of greenhouse gas emissions.

The EPA's actions include its finding of "endangerment" to public health and welfare from greenhouse gases, its issuance in September 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule which requires large sources, including power plants, to monitor and report greenhouse gas emissions to the EPA annually starting in 2011, and its publication in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, which took effect in 2011 and requires large industrial facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases. Proposed EPA regulations to

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impose greenhouse gas new source performance standards for electricity utility stream generating units are anticipated in 2012.

The implementation of existing CO_2 and other greenhouse gas legislation or regulation, the introduction of new regulation, or other future regulatory developments may subject us to increased compliance obligations and costs that could have a material adverse impact on our business, operations or financial condition.

All of our generating facilities complied with the March 31, 2011 requirement to submit 40 CFR Part 98 Mandatory Greenhouse Gas reporting for the emission of eligible site generated greenhouse gases in 2010. This is a national requirement and stands as a start in developing a baseline for greenhouse gases emissions at a national level.

Increasing competition could adversely affect our performance and the performance of our projects.

The power generation industry is characterized by intense competition, and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for power sales agreements, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. Increasing competition among participants in the power generation industry may adversely affect our performance and the performance of our projects.

We have limited control over management decisions at certain projects.

In a number of cases, our projects are not wholly-owned by us or we have contracted for their operations and maintenance, and in some cases we have limited control over the operation of the projects. Although we generally prefer to acquire projects where we have control, we may make acquisitions in non-control situations to the extent that we consider it advantageous to do so and consistent with regulatory requirements and restrictions, including the Investment Company Act of 1940. Third-party operators (such as Caithness, PPMS and Western) operate many of the projects. As such, we must rely on the technical and management expertise of these third-party operators, although typically we are represented on a management or operating committee if we do not own 100% of a project. To the extent that such third-party operators do not fulfill their obligations to manage the operations of the projects or are not effective in doing so, the amount of cash available to pay dividends may be adversely affected.

We may face significant competition for acquisitions and may not successfully integrate acquisitions.

Our business plan includes growth through identifying suitable acquisition opportunities, pursuing such opportunities, consummating acquisitions and effectively integrating them with our business. We may be unable to identify attractive acquisition candidates in the power industry in the future, and we may not be able to make acquisitions on an accretive basis or be sure that acquisitions will be successfully integrated into our existing operations, any of which could negatively impact our ability to continue paying dividends in the future at current rates.

Although electricity demand is expected to grow, creating the need for more generation, and the U.S. power industry is continuing to undergo consolidation and may offer attractive acquisition opportunities, we are likely to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments.

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Any acquisition or investment may involve potential risks, including an increase in indebtedness, the inability to successfully integrate operations, the potential disruption of our ongoing business, the diversion of management's attention from other business concerns and the possibility that we pay more than the acquired company or interest is worth. There may also be liabilities that we fail to discover, or are unable to discover, in our due diligence prior to the consummation of an acquisition, and we may not be indemnified for some or all these liabilities. In addition, our funding requirements associated with acquisitions and integration costs may reduce the funds available to us to make dividend payments.

Our equity interests in certain of projects may be subject to transfer restrictions.

The partnership or other agreements governing some of the projects may limit a partner's ability to sell its interest. Specifically, these agreements may prohibit any sale, pledge, transfer, assignment or other conveyance of the interest in a project without the consent of the other partners. In some cases, other partners may have rights of first offer or rights of first refusal in the event of a proposed sale or transfer of our interest. These restrictions may limit or prevent us from managing our interests in these projects in the manner we see fit, and may have an adverse effect on our ability to sell our interests in these projects at the prices we desire.

The projects are exposed to risks inherent in the use of derivative instruments.

We and the projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. In the future, the project operators could recognize financial losses on these arrangements as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. If actively quoted market prices and pricing information from external sources are not available, the valuation of these contracts would involve judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income (as calculated in accordance with GAAP) that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. As a result, we may be unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual income (as calculated in accordance with GAAP).

If the values of these financial contracts change in a manner that we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our financial condition, results of operations and cash flows. We have executed natural gas swaps to reduce our risks to changes in the market price of natural gas, which is the fuel consumed at many of our projects. Due to declining natural gas prices, we have incurred losses on these natural gas swaps. We execute these swaps only for the purpose of managing risks and not for speculative trading.

Construction projects are subject to construction risk.

In any construction project, there is a risk that circumstances occur which prevent the timely completion of a project, cause construction costs to exceed the level budgeted, or result in operating performance standards not being met. In the event a power project does not achieve commercial operation by its expected date, the project may be subject to increased construction costs associated with the continuing accrual of interest on the project's construction loan, which customarily matures at the start of commercial operation and converts to a term loan. A delay in completion of construction may also impact a project under its PPA which may include penalty provisions for a delay in commercial operation date or in situations of extreme delay, termination of the PPA.

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Construction cost overruns which exceed the project's construction contingency amount may require that the project owner infuse additional funds in order to complete construction.

At the completion of construction, the power project may not meet its expected operating performance levels. Adverse circumstances may impact the design, construction, and commissioning of the project that could result in reduced output, increased heat rate or excessive air emissions.

The Piedmont project commenced construction in November 2010 and is expected to be completed in late 2012. A delay in completion could result in the delay and/or loss of the proceeds from the 1603 grant.

Our Canadian Hills project is subject to construction risk.

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

In the event Canadian Hills does not begin commercial operations by its expected date, the project may be subject to increased construction costs associated with the continuing accrual of interest on the project's construction loan, which matures at the start of commercial operation. A delay in completion of construction may also impact a project under its PPA which may include penalty provisions for a delay in commercial operation date or in situations of extreme delay, termination of the PPA. To the extent actual construction costs of the project exceed estimates, we will have to contribute additional funds in order to complete construction. We have entered into contracts with our turbine suppliers and balance of plant contractor which contain terms and conditions (e.g. liquidated damages provisions) designed to mitigate those risks.

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

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

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

Pursuant to the terms of the Canadian Hills' construction financing facility, we have agreed to make equity contributions in aggregate amount of $180 million to Canadian Hills to finance the project construction and development costs in excess of the borrowings available under the financing facility.

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While we do not need to begin making our equity contributions until the construction loan facility is drawn down in full, we are required thereafter to make our equity contributions as necessary to meet construction draws as they occur. The precise required timing and amount of the draws depends upon the progress of the project construction, which will be subject to a variety of contingencies, many of which will be beyond our control.

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

Certain employees are subject to collective bargaining.

A number of our plant employees, one plant in British Columbia and four plants in Ontario are subject to collective bargaining agreements. These agreements expire periodically and we may not be able to renew them without a labor disruption or without agreeing to significant increases in labor costs.

Our Pension Plan may require future contributions.

Certain of our employees in Canada are participants in a defined benefit pension plans that we sponsor. As of December 31, 2011, the unfunded pension liability on our pension plan was approximately $2.2 million. The amount of future contributions to our defined benefit plan will depend upon asset returns and a number of other factors and, as a result, the amounts we will be required to contribute in the future may vary. Cash contributions to the plan will reduce the cash available for our business.

Risks Related to Our Structure

Distribution of available cash may restrict our potential growth.

A payout of a significant portion of our operating cash flow may make additional capital and operating expenditures dependent on increased cash flow or additional financing in the future. Lack of these funds could limit our future growth and cash flow. In addition, we may be precluded from pursuing otherwise attractive acquisitions or investments if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund the acquisition or investment.

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A downgrade in Atlantic Power's or the Partnership's credit ratings or any deterioration in their credit quality could negatively affect our ability to access capital and our ability to hedge and could trigger termination rights under certain contracts.

A downgrade in Atlantic Power's or the Partnership's credit ratings or deterioration in their credit quality could adversely affect our ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities and/or trigger termination rights or enhanced disclosure requirements under certain contracts to which Atlantic or the Partnership is a party. Any downgrade of Atlantic's or the Partnership's corporate credit rating could cause counterparties to require us to post letters of credit or other additional collateral, make cash prepayments, obtain a guarantee agreement or provide other security, all of which would expose us to additional costs and/or could adversely affect our ability to comply with covenants or other obligations under any of our revolving credit facility, convertible debentures or unsecured notes or any other financing arrangements, borrowings or indebtedness (or could constitute an event of default under any such financing arrangements, borrowings or indebtedness that we may be unable to cure), any of which could have a material adverse effect on our business, results of operations and financial condition.

We are subject to Canadian tax.

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes, and dividends paid by us are generally subject to Canadian withholding tax if paid to a shareholder that is not a resident of Canada. We completed our initial public offering on the TSX in November 2004. At the time of the initial public offering, our public security was an Income Participating Security ("**IPS**"). Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. In the fourth quarter of 2009, we converted to a traditional common share company through a shareholder approved plan of arrangement in which each IPS was exchanged for one of our new common shares. Our new common shares were listed and posted for trading on the TSX commencing on December 2, 2009 and trade under the symbol "ATP," and the former IPSs, which traded under the symbol "ATP.UN," were delisted at that time. In connection with our conversion from an IPS structure to a traditional common share structure and the related reorganization of our organizational structure, we received a note from our primary U.S. holding company (the "**Intercompany Note**"). We are required to include, in computing our taxable income, interest on the Intercompany Note.

On November 5, 2011, we acquired directly and indirectly, all of the outstanding limited partnership units of the Partnership pursuant to a court-approved plan of arrangement. We are required to include the income or loss from the Partnership in our taxable income. We expect that our existing tax attributes initially will be available to offset the income inclusions noted herein such that they will not result in an immediate material increase to our liability for Canadian taxes. However, once we fully utilize our existing tax attributes (or if, for any reason, these attributes were not available to us), our Canadian tax liability would materially increase. Although we intend to explore potential opportunities in the future to preserve the tax efficiency of our structure, no assurances can be given that our Canadian tax liability will not materially increase at that time.

Our prior and current structure may be subject to additional U.S. federal income tax liability.

Under our prior IPS structure, we treated the subordinated notes as debt for U.S. federal income tax purposes. Accordingly, we deducted the interest payments on the subordinated notes and reduced our net taxable income treated as "effectively connected income" for U.S. federal income tax purposes. Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 35%, plus state and local taxes), and one of our U.S. holding companies will claim interest deductions with respect to the Intercompany Note in computing its income for U.S. federal income tax purposes. The Partnership

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acquisition added another U.S. holding company to our structure. This holding company owns the U.S. operating assets of the Partnership. This group currently has certain intercompany financing arrangements (the "**Partnership Financing Arrangements**") in place. We claim interest deductions in the U.S. with respect to the Partnership Financing Arrangements. To the extent any interest expense under the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding companies will increase, which could materially affect the after-tax cash available to distribute to us.

While we received advice from our U.S. tax counsel, based on certain representations by us and our U.S. holding companies and determinations made by our independent advisors, as applicable, that the subordinated notes and the Intercompany Note should be treated as debt for U.S. federal income tax purposes, and the Partnership has received advice from its U.S. accountants, based on certain representations by its holding companies, that the payments on the Partnership Financing Arrangements should be deductible for U.S. federal income tax purposes, it is possible that the Internal Revenue Service ("**IRS**") could successfully challenge these positions and assert that any of these arrangements be treated as equity rather than debt for U.S. federal income tax purposes or that the interest on such arrangements are otherwise not deductible. In this case, the otherwise deductible interest would be treated as non-deductible distributions and, in the case of the Intercompany Note and the Partnership Financing Arrangements, may be subject to U.S. withholding tax to the extent our U.S. holding company had current or accumulated earnings and profits. The determination of debt or equity treatment for U.S. federal income tax purposes is based on an analysis of the facts and circumstances. There is no clear statutory definition of debt for U.S. federal income tax purposes, and its characterization is governed by principles developed in case law, which analyzes numerous factors that are intended to identify the nature of the purported creditor's interest in the borrower.

Furthermore, not all courts have applied this analysis in the same manner, and some courts have placed more emphasis on certain factors than other courts have. To the extent it were ultimately determined that our interest expense on the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements were disallowed, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect the after-tax cash available to us to distribute. Alternatively, the IRS could argue that the interest on the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements exceeded or exceeds an arm's length rate, in which case only the portion of the interest expense that does not exceed an arm's length rate may be deductible and, in the remainder may be subject to U.S. withholding tax to the extent our U.S. holding companies had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on these debt instruments was and is, as applicable, commercially reasonable in the circumstances, but the advice is not binding on the IRS.

Furthermore, our U.S. holding companies' deductions attributable to the interest expense on the Intercompany Note and/or certain of the Partnership Financing Arrangements may be limited by the amount by which its net interest expense (the interest paid by our U.S. holding company on all debt, including the Intercompany Note and the Partnership Financing Arrangements, less its interest income) exceeds 50% of their adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. Moreover, proposed legislation has been introduced, though not enacted, several times in recent years that would further limit the 50% of adjusted taxable income cap described above to 25% of adjusted taxable income, although recent proposals in the Fiscal Year Budget for 2010 would only apply the revised rules to certain foreign corporations that were expatriated. Furthermore, if our U.S. holding companies do not make regular interest payments as required under these debt agreements, other limitations on the deductibility of interest under U.S. federal income tax laws could apply to defer and/or eliminate all or a portion of the interest deduction that our U.S. holding company would otherwise be entitled to. Finally, the

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applicability of recent changes to the U.S.-Canada Income Tax Treaty to the structure associated with certain of the Partnership Financing Arrangements may result in distributions from the Partnership's U.S. group to its Canadian parent being subject to a 30% rate of withholding tax instead of the 5% rate that would otherwise have applied.

Our U.S. holding companies have existing net operating loss carryforwards that we can utilize to offset future taxable income. While we expect these losses will be available to us as a future benefit, in the event that they are successfully challenged by the IRS or subject to future limitations, our ability to realize these benefits may be limited. A reduction in our net operating losses, or a limitation on our ability to use such losses, may result in a material increase in our future income tax liability. Our U.S. Holding companies include the Partnership's U.S. Holding company, Atlantic Power (US) GP, which has net operating loss carryforwards attributable to tax years prior to our acquisition. It is anticipated that these net operating loss carryforwards will be available to offset future taxable income of Atlantic Power (US) GP; however, their use may be subject to an annual limitation. While we expect these losses will be available to us as a future benefit, in the event that they are successfully challenged by the IRS or subject to additional future limitations, our ability to realize these benefits may be limited. A reduction in our net operating losses, or additional limitations on our ability to use such losses, may result in a material increase in our future income tax liability.

Risks Related to the Acquisition of the Partnership

The failure to integrate successfully the businesses of Atlantic Power and the Partnership in the expected timeframe would adversely affect the combined company's future result.

The success of our acquisition of the Partnership, which was completed in the fourth quarter of 2011, will depend, in large part, on our ability to realize the anticipated benefits, including modest cost savings, from combining the businesses of Atlantic Power and the Partnership. To realize these anticipated benefits, the businesses of Atlantic Power and the Partnership must be successfully integrated. This integration will be complex and time-consuming. The failure to integrate successfully and to manage successfully the challenges presented by the integration process may result in the combined company not fully achieving the anticipated benefits of the Plan of Arrangement.

Potential difficulties that may be encountered in the continuing integration process include the following:

- challenges associated with managing the larger, more complex, combined business;
- conforming standards, controls, procedures and policies, business cultures and compensation structures between the entities;
- integrating personnel from the two entities while maintaining focus on developing, producing and delivering consistent, high quality services;
- consolidating corporate and administrative infrastructures;
- coordinating geographically dispersed organizations;
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions;
- performance shortfalls at one or both of the entities as a result of the diversion of management's attention caused integrating the entities' operations; and
- the ability of the combined company to deliver on its strategy going forward.

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If goodwill or other intangible assets that we record in connection with the acquisition become impaired, we could have to take significant charges against earnings.

In connection with the accounting for the acquisition, we have recorded a significant amount of goodwill and other intangible assets. Under U.S. GAAP, we must assess, at least annually and potentially more frequently, whether the value of goodwill and other indefinite-lived intangible assets have been impaired. Amortizing intangible assets will be assessed for impairment in the event of an impairment indicator. Any reduction or impairment of the value of goodwill or other intangible assets will result in a charge against earnings, which could materially adversely affect our results of operations and shareholders' equity in future periods.

Our success depends in part on our ability to retain, motivate and recruit executives and other key employees, and failure to do so could negatively affect us.

Our success depends in part on our ability to retain, recruit and motivate key employees. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Employees of both Atlantic Power and the Partnership may experience uncertainty about their future role with the combined company even after, strategies with regard to the combined company are announced or executed. The potential distractions may adversely affect our ability to attract, motivate and retain executives and other key employees and keep them focused on applicable strategies and goals. A failure to retain and motivate executives and other key employees could have an adverse impact on our business.

Atlantic Power Preferred Equity Ltd. (formerly named CPI Preferred Equity Ltd.) is subject to Canadian tax, as is Atlantic Power's income from the Partnership.

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes. See "Risks Related to Our Structure We are subject to Canadian tax." We are required to include in computing our taxable income any income earned by the Partnership. In addition, Atlantic Power Preferred Equity Ltd., a subsidiary of the Partnership, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes. Atlantic Power Preferred Equity Ltd. is liable to pay its applicable Canadian taxes.

Risks Relating to the Exchange Offer

You may not be able to sell your Old Notes if you do not exchange them for Exchange Notes in the exchange offer.

If you do not exchange your Old Notes for Exchange Notes in the exchange offer, your Old Notes will continue to be subject to restrictions on transfer. In general, you may not offer, sell or otherwise transfer the Old Notes in the United States unless they are:

- registered under the Securities Act;
- offered or sold pursuant to an exemption from the Securities Act and applicable state securities laws; or
- offered or sold in a transaction not subject to the Securities Act and applicable state securities laws.

The Issuers and the guarantors do not currently anticipate that they will register the Old Notes under the Securities Act and, except for limited instances, they will not be under any obligation to do so under the Registration Rights Agreement or otherwise.

Your ability to sell your Old Notes may be significantly more limited and the price at which you may be able to sell your Old Notes may be significantly lower if you do not exchange them for Exchange Notes in the exchange offer.

To the extent that the Old Notes are tendered and accepted for exchange in the exchange offer, the trading market for the Old Notes that remain outstanding may be significantly more limited. As a result, the liquidity of the Old Notes not tendered and accepted for exchange could be adversely affected. The extent of the market for Old Notes and the availability of price quotations would depend on a number of factors, including the number of holders of Old Notes remaining outstanding and the interest of securities firms in maintaining a market in the Old Notes. An issue of securities with a similar outstanding market value available for trading, which is called the "float," may command a lower price than would be comparable to an issue of securities with a greater float. As a result, the market price for the Old Notes that are not exchanged in the exchange offer may be affected adversely to the extent that the Old Notes exchanged in the exchange offer reduce the float. The reduced float also may make the trading price of the Old Notes that are not exchanged more volatile.

You must comply with the exchange offer procedures in order to receive new, freely tradable Exchange Notes.

Delivery of Exchange Notes in exchange for Old Notes tendered and accepted for exchange pursuant to the exchange offer will be made only after timely receipt by the exchange agent of book-entry transfer of Old Notes into the exchange agent's account at DTC, as depositary, including an Agent's Message (as defined in "The Exchange Offer Procedures for Tendering Old Notes Through Brokers and Banks"). We are not required to notify you of defects or irregularities in tenders of Old Notes for exchange. Old Notes that are not tendered or that are tendered but we do not accept for exchange will, following consummation of the exchange offer, continue to be subject to the existing transfer restrictions under the Securities Act and, upon consummation of the exchange offer, certain registration and other rights under the Registration Rights Agreement will terminate. See "The Exchange Offer Procedures for Tendering Old Notes Through Brokers and Banks" and "The Exchange Offer Consequences of Failure to Exchange."

Some holders who exchange their Old Notes may be deemed to be underwriters, and these holders will be required to comply with the registration and prospectus delivery requirements in connection with any resale transaction.

If you exchange your Old Notes in the exchange offer for the purpose of participating in a distribution of the Exchange Notes, you may be deemed to have received restricted securities and, if so, will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

Risks Relating to our Indebtedness and the Exchange Notes

If you fail to exchange your Original Notes, they will continue to be restricted securities and may become less liquid.

Original Notes that you do not tender or we do not accept will, following the exchange offer, continue to be restricted securities, and you may not offer to sell them except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities law. We will issue New Notes in exchange for the Original Notes pursuant to the exchange offer only following the satisfaction of the procedures and conditions set forth in "The Exchange Offer Procedures for Tendering." These procedures and conditions include timely receipt by the exchange agent of such Original Notes (or a confirmation of book-entry transfer) and of a properly completed and duly executed letter of transmittal (or an agent's message from The Depository Trust Company).

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Because we anticipate that most holders of Original Notes will elect to exchange their Original Notes, we expect that the liquidity of the market for any Original Notes remaining after the completion of the exchange offer will be substantially limited. Any Original Notes tendered and exchanged in the exchange offer will reduce the aggregate principal amount of the Original Notes outstanding. Following the exchange offer, if you do not tender your Original Notes you generally will not have any further registration rights, and your Original Notes will continue to be subject to certain transfer restrictions. Accordingly, the liquidity of the market for the Original Notes could be adversely affected.

We have a substantial amount of indebtedness, which may adversely affect our cash flow, financial condition, results of operations and ability to fulfill our obligations under the notes.

As of March 31, 2012, our total indebtedness was approximately $1.9 billion, including $577.8 million of secured indebtedness. Our substantial indebtedness can have important consequences for you and significant effects on our business, including:

- increasing our vulnerability to adverse economic, industry or competitive developments;
- requiring a substantial portion of cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- making it more difficult for us to satisfy our financial obligations, including with respect to the notes;
- restricting us from making strategic acquisitions or causing us to make non-strategic divestitures;
- limiting our ability to obtain additional financing for working capital, capital expenditures, product development, debt service requirements and general corporate or other purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business or the industry in which we operate; and
- placing us at a competitive disadvantage compared to our competitors who are less highly leveraged and who therefore, may be able to take advantage of opportunities that our leverage prevents us from exploiting.

Despite our existing indebtedness, we may still incur more debt, which could exacerbate the risks described above.

We may be able to incur substantial additional indebtedness in the future. Although covenants contained in the indenture governing the notes and the credit agreement governing our senior secured revolving credit facility limit our ability to incur certain additional indebtedness, these restrictions are subject to qualifications and exceptions, and the indebtedness incurred in compliance with these restrictions could be substantial. While the senior secured revolving credit facility limits new unsecured indebtedness by requiring compliance with certain financial covenants both before and after incurring such indebtedness, the indenture governing the notes only requires that we meet a specified pro forma ratio of earnings to fixed charges or have availability under a basket or carveout prior to incurring additional unsecured indebtedness. To the extent we incur additional indebtedness, the risks associated with our leverage described above, including our possible inability to service our debt, including the notes, would increase.

Servicing our debt will require a significant amount of cash, and our ability to generate sufficient cash depends on many factors, some of which are beyond our control.

Our ability to make payments on and refinance our debt and to fund capital expenditures depends on our ability to generate cash flow in the future. To some extent, our ability to generate future cash flow is subject to general economic, financial, competitive and other factors that are beyond our control. We cannot assure you that:

- our business will generate sufficient cash flow from operations;
- we will continue to realize the cost savings, revenue growth and operating improvements that resulted from the execution of our long-term strategic plan; or
- future sources of funding will be available to us in amounts sufficient to enable us to fund our liquidity needs.

In addition, the ability to borrow funds under our senior secured revolving credit facility in the future will depend on our satisfying certain borrowing conditions in the agreement governing such facilities. We cannot assure you that our business will generate cash flow from operations or that future borrowings will be available to us under our senior secured revolving credit facility in an amount sufficient to enable us to pay our debt or to fund other liquidity needs. We also may experience difficulties repatriating cash from our foreign subsidiaries due to law, regulation or contracts which could further constrain our liquidity. If we cannot fund our liquidity needs, we will have to take actions such as reducing or delaying capital expenditures, marketing efforts, strategic acquisitions, investments and alliances, selling assets, restructuring or refinancing our debt, including the notes, or seeking additional equity capital. We cannot assure you that any of these remedies could, if necessary, be effected on commercially reasonable or favorable terms, or at all, or that they would permit us to meet our scheduled debt service obligations. Any inability to generate sufficient cash flow or refinance our debt on favorable terms could have a material adverse effect on our financial condition. In addition, if we incur additional debt, the risks associated with our substantial leverage, including the risk that we will be unable to service our debt or generate enough cash flow to fund our liquidity needs, could intensify.

Covenant restrictions under our senior secured revolving credit facility and the indenture governing our notes may limit our ability to operate our business.

The agreement governing our senior secured revolving credit facility and the indenture governing the notes contain covenants that may restrict our ability to, among other things, borrow money, make capital expenditures and certain distributions on our equity, enter into sale and lease back transactions and effect a consolidation, merge or dispose of all or substantially all of our assets. Although the covenants in the senior secured revolving credit facility and the indenture governing the notes are subject to various exceptions, we cannot assure you that these covenants will not adversely affect our ability to finance future operations or capital needs or to engage in other activities that may be in our best interest. In addition, covenants in the indentures governing the debt securities of the Partnership and certain of its subsidiaries may limit our ability to operate our business. In addition, our new credit facility requires us to maintain a specified financial ratio and satisfy certain financial condition tests, which may require that we take action to reduce our debt or to act in a manner contrary to our business objectives. A breach of any of these covenants could result in a default under our senior secured revolving credit facility and the indenture governing the notes. If an event of default under our senior secured revolving credit facility occurs, the lenders thereunder could elect to declare all amounts outstanding thereunder, together with accrued interest, to be immediately due and payable. In addition, our senior secured revolving credit facility will be secured by first priority security interests on certain of our real and personal property and pledges of the capital stock of certain of our subsidiaries. If we are unable to pay all amounts declared due and payable in the event of a default, the lenders could foreclose on these assets. See "Management's Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources" and "Description of Exchange Notes" for additional information.

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The restrictive covenants in the indenture governing the notes may be less protective than those typically found in covenant packages for non-investment grade debt securities.

Although the notes contain restrictive covenants, these covenants are less protective than is customary for non-investment grade debt securities and are subject to a number of important exceptions and qualifications. For example, the indenture does not limit our ability to make asset sales, enter into transactions with affiliates, prepay subordinated debt or make investments. See "Description of Exchange Notes" for a more detailed description of the covenants that will be in the indenture governing the notes.

The notes and the guarantees are unsecured and effectively subordinated to our and the guarantors' existing and future secured indebtedness, to the extent of the value of the assets securing such indebtedness, and the indebtedness of our subsidiaries that do not guarantee the notes.

The notes and the guarantees are our senior unsecured obligations ranking effectively junior in right of payment to all of our existing and future secured indebtedness and that of each guarantor, including indebtedness under our senior secured revolving credit facility to the extent of the value of the assets securing such indebtedness. Additionally, the indenture governing the notes permit us to incur additional secured indebtedness in the future. In the event that we or a guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, holders of our and our guarantor's secured indebtedness will be entitled to be paid in full from our assets or the assets of the guarantor, as applicable, securing such indebtedness before any payment may be made with respect to the notes or the affected guarantees. Holders of the notes will participate ratably with all holders of our senior unsecured indebtedness, and potentially with all of our other general creditors, based upon the respective amounts owed to each holder or creditor, in our remaining assets. As of March 31, 2012, the notes and the guarantees were effectively subordinated to approximately $577.8 million of senior secured indebtedness.

You will not have any claim as a creditor against the subsidiaries that are not guarantors of the notes, and the indebtedness and other liabilities, including trade payables, whether secured or unsecured, of non-guarantor subsidiaries will be effectively senior to any claim you may have against these non-guarantor subsidiaries relating to the notes. In the event of a bankruptcy, liquidation, reorganization or other winding up of our non-guarantor subsidiaries, holders of their indebtedness and their trade creditors will generally be entitled to payment of their claims from the assets of those non-guarantor subsidiaries before any assets are made available for distribution to us. See "Description of Exchange Notes General" for additional information.

We may not have the ability to raise the funds necessary to finance the offer to purchase required by the indenture governing the notes upon a change of control triggering event.

Upon certain kinds of changes of control coupled with a ratings downgrade by two ratings agencies in connection therewith, we are required to offer to purchase all outstanding notes at 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase. Any such change of control might also constitute a change of control as defined in our then-existing credit facility and thereby become an event of default under that facility. Therefore, upon the occurrence of such a change of control, the lenders under our then-existing credit facility would have the right to accelerate their loans and we would be required to prepay all outstanding obligations under the then-existing credit facility, as applicable, before the notes could be repurchased. We cannot assure you that we will have available funds sufficient to pay the change of control triggering event purchase price for any or all of the notes that might be delivered by holders of the notes seeking to accept the change of control triggering event offer. See "Description of Exchange Notes Repurchase of Notes Upon a Change of Control" and "Management's Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources" for additional information.

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Canadian bankruptcy and insolvency laws may impair the trustees' ability to enforce remedies under the notes.

The rights of the trustees who represent the holders of the notes to enforce remedies could be restricted or delayed by the restructuring provisions of applicable Canadian federal bankruptcy, insolvency and other restructuring legislation if the benefit of such legislation is sought with respect to us. For example, both the *Bankruptcy and Insolvency Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada) contain provisions enabling an insolvent person to obtain a stay of proceedings against its creditors and to file a proposal to be voted on by the various classes of its affected creditors. A restructuring proposal, if accepted by the requisite majorities of each affected class of creditors, and if approved by the relevant Canadian court, would be binding on all creditors within each affected class, including those creditors who do not vote to accept the proposal. Moreover, this legislation, in certain instances, permits the insolvent debtor to retain possession and administration of its property, subject to court oversight, even though it may be in default under the applicable debt instrument, during the period that the stay against proceedings remains in place.

The powers of the court under the *Bankruptcy and Insolvency Act* (Canada), and particularly under the *Companies' Creditors Arrangement Act* (Canada), have been interpreted and exercised broadly so as to protect a restructuring entity from actions taken by creditors and other parties. Accordingly, we cannot predict whether payments under the notes would be made during any proceedings in bankruptcy, insolvency or other restructuring, whether or when a trustee could exercise its rights under the applicable indenture governing the notes or whether and to what extent holders of the notes would be compensated for any delays in payment, if any, of principal, interest and costs, including the fees and disbursements of the respective trustees.

U.S. federal and state statutes allow courts, under specific circumstances, to avoid the notes and guarantees thereof, and to require holders of the notes to return payments received in respect thereof.

Our creditors and the creditors of the guarantors of the notes could challenge the issuance of the notes or the guarantors' issuance of their guarantees, respectively, as fraudulent conveyances or on other grounds. Under U.S. federal bankruptcy law and similar provisions of state fraudulent transfer laws, the issuance of notes and the delivery of the guarantees could be avoided (that is, cancelled) as fraudulent transfers if a court determined that the issuer, at the time it issued the notes, or a guarantor, at the time it issued its guarantee:

- issued the notes or guarantee, as the case may be, with the intent to hinder, delay or defraud its existing or future creditors; or
- received less than reasonably equivalent value or did not receive fair consideration for the delivery of the notes or the guarantee, as the case may be, and if the issuer or guarantor:
  - was insolvent or rendered insolvent at the time it issued the notes or issued the guarantee;
  - was engaged in a business or transaction for which the issuer's or guarantor's remaining assets constituted unreasonably small capital; or
  - intended to incur, or believed that it would incur, debts beyond its ability to pay such debts generally as they mature.

If the notes or guarantees were avoided or limited under fraudulent transfer or other laws, any claim you may make against the issuer or the guarantors for amounts payable on the notes would be unenforceable to the extent of such avoidance or limitation. Moreover, the court could order you to return any payments previously made by the issuer or the guarantors.

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The measures of insolvency for purposes of these fraudulent transfer laws will vary depending upon the law applied in any proceeding to determine whether a fraudulent transfer has occurred. Generally, however, a party would be considered insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the sum of its property, at a fair valuation;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

We cannot be certain what standard a court would apply in making these determinations or, regardless of the standard, that a court would not avoid the notes or guarantees.

Canadian federal and provincial laws allow courts, under certain circumstances, to void guarantees and require the holders of notes to return payments received from guarantors.

If creditors initiated a lawsuit or we or a guarantor became subject to Canadian bankruptcy, insolvency, liquidation, reorganization or similar proceedings, payments made to the holders of notes may be required to be returned or the guarantees may be avoided or set aside under Canadian federal or provincial legislation if it is judicially determined that, among other things:

- at the time of the payment or of the making of the guarantee, the payor or guarantor, as the case may be, was insolvent and the payment or guarantee had the effect of or was given with a view to giving a preference to, or conferred a fraudulent or unjust preference on, the recipient or another guarantor;
- the payment or making of the guarantee was intended to defeat, hinder, delay or defraud creditors; or
- the payment or making of the guarantee was oppressive to creditors.

The measures of insolvency for purposes of these preference and impeachable transaction laws will vary depending upon the law applied in any such proceeding and upon the valuation assumptions and methodology applied by the court. Generally, however, a party would be considered insolvent if:

- it is unable to meet its obligations as they generally become due;
- it has ceased meeting its current obligations in the ordinary course of business as they generally become due; and
- the aggregate of its property is not, at a fair valuation, sufficient, or, if disposed at a fairly conducted sale under legal process, would not be sufficient to enable payment of all its liabilities, due and accruing due.

As it relates to the guarantees, on the basis of historical financial information, recent operating history and other factors (including rights of contribution against other guarantors), we believe that none of the guarantors will be rendered insolvent by giving effect to such guarantor's guarantee.

We cannot assure you, however, as to what standard a court would apply in making the relevant determinations or that a court would agree with our conclusions in this regard. The guarantees could be subject to the claim that, since the guarantees were given for our benefit, and only indirectly for the benefit of the guarantors, the obligations of the guarantors were incurred for less than reasonably equivalent value or fair consideration.

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An active trading market may not develop for the notes, which may hinder your ability to liquidate your investment.

The Exchange Notes are a new issue of securities and there is no established trading market for them, or for the Old Notes. We do not intend to apply for listing of the notes on any national securities exchange or seek the admission of the notes for quotation through any automated inter-dealer quotation system. As a result, an active trading market for the notes may not develop or be sustained. If an active trading market for the notes fails to develop or be sustained, the trading price of the notes could be adversely affected.

We also cannot assure you that you will be able to sell your notes at a particular time or at all, or that the prices that you receive when you sell them will be favorable. If no active trading market develops, you may not be able to resell your notes at their fair market value, or at all. The liquidity of, and trading market for, the notes may also be adversely affected by, among other things:

- prevailing interest rates;
- our operating performance and financial condition;
- the interest of securities dealers in making a market;
- the market for similar securities.

Historically, the market of non-investment grade debt like the notes has been subject to disruptions that have caused substantial market price fluctuations in the price of securities that are similar to the notes. Therefore, even if a trading market for the notes develops, it may be subject to disruptions and price volatility.

Because the Old Notes were issued with OID for U.S. federal income tax purposes, holders that participate in the Exchange Offer must continue to report OID.

Because the stated principal amount of the Old Notes exceeded their issue price by more than a de minimis amount, the Old Notes were treated as issued with OID for U.S. federal income tax purposes. A holder of Exchange Notes subject to U.S. federal income taxation generally will be required to continue to include the OID in gross income (as ordinary income) in the manner as if the Old Notes had not been exchanged. See "Certain U.S. Federal Income Tax Considerations."

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EXCHANGE RATE INFORMATION

The following table sets forth, for each period indicated, the high and low exchange rates for one U.S. dollar, expressed in Canadian dollars, the average of such exchange rates on the last day of each month during such period and the exchange rate at the end of such period, based on the noon buying rate as quoted by the Bank of Canada. On May 17, 2012, the noon buying rate was $1.00 = C$1.0164.

	Three Months Ended March 31,		Twelve Months Ended December 31,				
	2012	2011	2011	2010	2009	2008	2007
High	C$ 1.0272	C$ 1.0022	C$ 1.0604	C$ 1.0778	C$ 1.3000	C$ 1.2969	C$ 1.1853
Low	C$ 0.9849	C$ 0.9686	C$ 0.9449	C$ 0.9946	C$ 1.0292	C$ 0.9719	C$ 0.9170
Average	C$ 1.0011	C$ 0.9855	C$ 0.9891	C$ 1.0299	C$ 1.1420	C$ 1.0660	C$ 1.0748
Period End	C$ 0.9991	C$ 0.9718	C$ 1.0170	C$ 0.9946	C$ 1.0466	C$ 1.2246	C$ 0.9881

Source: Bank of Canada

THE EXCHANGE OFFER

Purpose of the Exchange Offer

The Old Notes were originally issued and sold on November 4, 2011. In connection with the original issuance and sale of the Old Notes, we entered into the Registration Rights Agreement pursuant to which we agreed, for the benefit of the holders of the Old Notes, at our cost, to use our commercially reasonable efforts:

- to file with the SEC an exchange offer registration statement pursuant to which we and the guarantors will offer, in exchange for the Old Notes, new notes identical in all material respects to, and evidencing the same indebtedness as, the Old Notes (but will not contain terms with respect to transfer restrictions or provide for the additional interest described below); and

- to cause the exchange offer registration statement to be declared effective under the Securities Act and exchange offer to be consummated by the 270th day following the date on which we issued the Old Notes (the "**Consummation Deadline**").

Under existing interpretations by the staff of the SEC as set forth in no-action letters issued to unrelated third parties and referenced below, we believe that the Exchange Notes issued in the exchange offer in exchange for the Old Notes may be offered for resale, resold and otherwise transferred by any exchange noteholder without compliance with the registration and prospectus delivery provisions of the Securities Act, if:

- such holder is not an "affiliate" of ours within the meaning of Rule 405 of the Securities Act;

- such Exchange Notes are acquired in the ordinary course of the holder's business; and

- such holder has no arrangement or understanding with any person to participate in a distribution (within the meaning of the Securities Act) of the Exchange Notes.

Any holder who tenders in the exchange offer with the intention of participating in any manner in a distribution of the Exchange Notes:

- cannot rely on the position of the staff of the SEC set forth in *Exxon Capital Holdings Corporation, Morgan Stanley & Co., Incorporated* or similar no-action letters; and

- in the absence of an applicable exemption, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a resale of the Exchange Notes or it may incur liability under the Securities Act. We will not be responsible for, or indemnify against, any such liability.

If, as stated above, a holder cannot rely on the position of the staff of the SEC set forth in *Exxon Capital Holdings Corporation, Morgan Stanley & Co., Incorporated* or similar no-action letters, any effective registration statement used in connection with a secondary resale transaction must contain the selling security holder information required by Item 507 of Regulation S-K under the Securities Act.

We do not intend to seek our own interpretation regarding the exchange offer, and we cannot assure you that the staff of the SEC would make a similar determination with respect to the Exchange Notes as it has in other interpretations to third parties.

This prospectus may be used for an offer to resell, for the resale or for other retransfer of Exchange Notes only as specifically set forth in this prospectus. With regard to broker-dealers, only broker-dealers that acquired the Old Notes for its own account as a result of market-making activities or other trading activities may participate in the exchange offer. Each broker-dealer that receives Exchange Notes for its own account in exchange for Old Notes, where such Old Notes were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of the Exchange Notes.

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Please read the section entitled "Plan of Distribution" for more details regarding these procedures for the transfer of Exchange Notes. We have agreed, for a period of 180 days after the registration statement (of which this prospectus is a part) is declared effective, to make this prospectus available to any broker-dealer for use in connection with any resale of the Exchange Notes.

In order to participate in the exchange offer, each holder of Old Notes that wishes to exchange Old Notes for Exchange Notes in the exchange offer will be required to make the representations described below under "Representations."

Shelf Registration Statement

In the event that:

- we determine that consummation of the exchange offer would violate any applicable law or applicable interpretations of the SEC; or
- for any reason, we do not consummate the exchange offer by the Consummation Deadline; or
- we received a written request (a "**Shelf Request**") from any "initial purchaser" of the Old Notes representing that it holds Old Notes that are or were ineligible to be exchanged in the exchange offer,

then we will use our commercially reasonable efforts to cause to be filed as promptly as practicable after such determination, date or Shelf Request, as the case may be, a shelf registration statement providing for the sale of all Old Notes by the holders thereof and to have such shelf registration statement become effective. We have agreed to use our commercially reasonable efforts to keep any such shelf registration statement continuously effective until the securities cease to be Registrable Securities (as defined in the Registration Rights Agreement).

Additional Interest

If (1) the exchange offer is not completed on or prior to the Consummation Deadline, (2) the shelf registration statement, if required, has not become effective on or prior to the dates specified in the Registration Rights Agreement, or (3) the Shelf Registration Statement, if required, has become effective but thereafter, subject to certain exceptions, ceases to be effective or usable in connection with resales of any notes registered under the shelf registration statement during the periods specified in the Registration Rights Agreement, then we will be in default under the Registration Rights Agreement (a "**Registration Default**"). If a Registration Default occurs, the interest rate on the Registrable Securities will be increased by (1) 0.25% per annum for the first 90-day period beginning on the day immediately following such Registration Default and (2) an additional 0.25% per annum with respect to each subsequent 90-day period, in each case until the earlier of the date such Registration Default ends and November 4, 2012, up to a maximum increase of 0.50% per annum. If at any time more than one Registration Default has occurred and is continuing, then, until the next date that there is no Registration Default, the increase in interest rate will apply as if there occurred a single Registration Default that begins on the date that the earliest such Registration Default occurred and ends on such next date that there is no Registration Default. When we have cured all of the Registration Defaults or as of the November 4, 2012, the interest rate on the Registrable Securities will revert immediately to the original level.

The exchange offer is intended to satisfy our exchange offer obligations under the Registration Rights Agreement. The notes will not have rights to additional interest as set forth above upon the consummation of the exchange offer.

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Terms of the Exchange Offer

We are offering to exchange up to $460 million aggregate principal amount of the Exchange Notes, the issuance of which has been registered under the Securities Act, for an equal principal amount of the Old Notes. Upon the terms and subject to the conditions set forth in this prospectus, we will accept any and all Old Notes validly tendered and not withdrawn prior to 5:00 p.m., New York City time, on the expiration date of the exchange offer. We will issue $1,000 principal amount of Exchange Notes in exchange for each $1,000 principal amount of Exchange Notes accepted in the exchange offer. Holders may tender some or all of their Old Notes pursuant to the exchange offer. However, Old Notes may be tendered only in denominations of $2,000 of principal amount and any integral multiple of $1,000 in excess thereof.

The form and terms of the Exchange Notes are the same as the form and terms of the Old Notes except that the Old Notes have been registered under the Securities Act and will not have transfer restrictions or contain the additional interest provisions of the Old Notes. The Exchange Notes will evidence the same debt as the Old Notes and will be issued under and entitled to the benefits of the indenture. Consequently, the Old Notes and the Exchange Notes will be treated as a single class of debt securities under the indenture.

As of the date of this prospectus, Old Notes representing $460 million in aggregate principal amount were outstanding, and there was one registered holder, CEDE & Co., as nominee of DTC. This prospectus is being sent to all registered holders of the Old Notes.

The exchange offer is not conditioned on any minimum aggregate principal amount of Old Notes being tendered for exchange.

We intend to conduct the exchange offer in accordance with the applicable requirements of the Exchange Act and the rules and regulations of the SEC. We will be deemed to have accepted for exchange properly tendered Old Notes when we have given oral or written notice of the acceptance to the exchange agent. The exchange agent will act as agent for the tendering holders for the purposes of receiving the Exchange Notes from us and delivering the Exchange Notes to such holders.

Old Notes that are not tendered for exchange in the exchange offer or that are tendered but we do not accept for exchange will remain outstanding and continue to accrue interest and will continue to be entitled to the rights and benefits such holders have under the indenture relating to the Old Notes. The Old Notes that are not exchanged will continue to be subject to the existing transfer restrictions under the Securities Act and, upon consummation of the exchange offer, certain registration and other rights under the Registration Rights Agreement will terminate. Holders of the Old Notes do not have any appraisal or dissenters' rights in connection with the exchange offer.

Holders who tender Old Notes in the exchange offer will not be required to pay brokerage commissions or fees or transfer taxes with respect to the exchange of Old Notes pursuant to the exchange offer. We will pay all charges and expenses, other than transfer taxes in certain circumstances, in connection with the exchange offer. See " Fees and Expenses" and " Transfer Taxes" below.

Expiration Date; Extensions; Amendments

The exchange offer will remain open for at least 20 business days. The term "**expiration date**" will mean 5:00 p.m., New York City time, on , 2012, unless we, in our sole discretion, extend the exchange offer, in which case the term "**expiration date**" will mean the latest date and time to which the exchange offer is extended.

In order to extend the exchange offer, we will notify the exchange agent orally to be promptly confirmed in writing or in writing of any extension. We will notify in writing by press release or other

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public announcement the registered holders of Old Notes of the extension no later than 9:00 a.m., New York City time, on the business day after the previously scheduled expiration date.

We reserve the right, in our sole discretion:

- to delay accepting any Old Notes, to extend the exchange offer or, if any of the conditions to the exchange offer set forth below under " Conditions to the Exchange Offer" have not been satisfied, to terminate the exchange offer, by giving oral or written notice of such delay, extension or termination to the exchange agent; or

- to amend the terms of the exchange offer in any manner.

Any delay in acceptance, extension, termination or amendment will be followed as promptly as practicable by written notice to the registered holders by a press release or other public announcement. If we amend the exchange offer in a manner that we determine to constitute a material change in the exchange offer, we will promptly disclose such amendment in a manner reasonably calculated to inform the holders of Old Notes of such amendment, and we will extend the exchange offer period, if necessary, so that at least five business days remain in the exchange offer following notice of the material change. If we terminate an exchange offer as provided in this prospectus before accepting any Old Notes for exchange or if we amend the terms of the exchange offer in a manner that constitutes a fundamental change in the information set forth in the registration statement of which this prospectus forms a part, we will promptly file a post-effective amendment to the registration statement of which this prospectus forms a part. In addition, we will in all event comply with our obligation to exchange promptly all Old Notes properly tendered and accepted for exchange in the exchange offer.

Procedures for Tendering Old Notes Through Brokers and Banks

Since the Old Notes are represented by global book-entry notes, DTC, as depositary, or its nominee is treated as the registered holder of the Old Notes and will be the only entity that can tender your Old Notes for Exchange Notes. Therefore, to tender Old Notes subject to this exchange offer and to obtain Exchange Notes, you must instruct the institution where you keep your Old Notes to tender your Old Notes on your behalf so that they are received on or prior to the expiration of this exchange offer.

To tender your Old Notes in the exchange offer, you must:

- comply with DTC's Automated Tender Offer Program ("**ATOP**") procedures described below; and

- the exchange agent must receive a timely confirmation of a book-entry transfer of the Old Notes into its account at DTC through ATOP pursuant to the procedure for book-entry transfer described below, along with a properly transmitted Agent's Message (defined below), before the expiration date.

IF YOU WISH TO ACCEPT THIS EXCHANGE OFFER, PLEASE INSTRUCT YOUR BROKER OR ACCOUNT REPRESENTATIVE IN TIME FOR YOUR OLD NOTES TO BE TENDERED BEFORE THE 5:00 P.M. (NEW YORK CITY TIME) DEADLINE ON , 2012.

In order to accept this exchange offer on behalf of a holder of Old Notes you must submit or cause your DTC participant to submit an Agent's Message as described below.

The exchange agent, on our behalf, will seek to establish an ATOP account with respect to the outstanding Old Notes at DTC promptly after the delivery of this prospectus. Any financial institution that is a DTC participant, including your broker or bank, may make book-entry tender of outstanding Old Notes by causing the book-entry transfer of such Old Notes into our ATOP account in accordance with DTC's procedures for such transfers. Concurrently with the delivery of Old Notes, an Agent's

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Message in connection with such book-entry transfer must be transmitted by DTC to, and received by, the exchange agent on or prior to 5:00 p.m., New York City Time on the expiration date. The confirmation of a book entry transfer into the ATOP account as described above is referred to herein as a "**Book-Entry Confirmation**."

The term "**Agent's Message**" means a message transmitted by the DTC participants to DTC, and thereafter transmitted by DTC to the exchange agent, forming a part of the Book-Entry Confirmation which states that DTC has received an express acknowledgment from the participant in DTC described in such Agent's Message stating that such participant and beneficial holder agree to be bound by the terms of this exchange offer, including the letter of transmittal, and that the agreement may be enforced against such participant.

Each Agent's Message must include the following information:

- Name of the beneficial owner tendering such Old Notes;

- Account number of the beneficial owner tendering such Old Notes;

- Principal amount of Old Notes tendered by such beneficial owner; and

- A confirmation that the beneficial holder of the Old Notes tendered has made the representations for our benefit set forth under " Representations" below.

BY SENDING AN AGENT'S MESSAGE THE DTC PARTICIPANT IS DEEMED TO HAVE CERTIFIED THAT THE BENEFICIAL HOLDER FOR WHOM NOTES ARE BEING TENDERED HAS BEEN PROVIDED WITH A COPY OF THIS PROSPECTUS AND AGREES TO BE BOUND BY THE TERMS OF THIS EXCHANGE OFFER, INCLUDING THE LETTER OF TRANSMITTAL.

The delivery of Old Notes through DTC, and any transmission of an Agent's Message through ATOP, is at the election and risk of the person tendering Old Notes. We will ask the exchange agent to instruct DTC to promptly return those Old Notes, if any, that were tendered through ATOP but were not accepted by us, to the DTC participant that tendered such Old Notes on behalf of holders of the Old Notes.

When you tender your outstanding Old Notes and we accept them, the tender will be a binding agreement between you and us as described in this prospectus. By using the ATOP procedures to exchange Old Notes, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by its terms, and you will be deemed to have made the acknowledgements and the representations and warranties it contains, just as if you had signed it.

We will decide all questions about the validity, form, eligibility, time of receipt, acceptance and withdrawal of tendered Old Notes, and our reasonable determination will be final and binding on you. We reserve the absolute right to: (1) reject any and all tenders of any particular Old Note not properly tendered; (2) refuse to accept any Old Note if, in our reasonable judgment or the judgment of our counsel, the acceptance would be unlawful; and (3) waive any defects or irregularities or conditions of the exchange offer as to any particular Old Notes before the expiration of the offer, other than those dependent upon the receipt of necessary government approvals. Our interpretation of the terms and conditions of the exchange offer will be final and binding on all parties. You must cure any defects or irregularities in connection with tenders of Old Notes as we will reasonably determine. Neither us, the exchange agent nor any other person will incur any liability for failure to notify you of any defect or irregularity with respect to your tender of Old Notes. If we waive any terms or conditions pursuant to (3) above with respect to a noteholder, we will extend the same waiver to all noteholders with respect to that term or condition being waived.

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Representations

To participate in the exchange offer, each holder of Old Notes that wishes to exchange Old Notes for Exchange Notes in the exchange offer will be required to make the following representations:

it has full corporate (or similar) power and authority to tender, exchange, assign and transfer the Old Notes and to acquire the Exchange Notes;

when the Old Notes are accepted for exchange, the Issuers will acquire good and unencumbered title to the tendered Old Notes, free and clear of all liens, restrictions, charges and encumbrances and not subject to any adverse claim; and

if such holder is a broker-dealer that will receive Exchange Notes for its own account in exchange for Old Notes that were acquired as a result of market-making or other trading activities, then such holder will comply with the applicable provisions of the Securities Act with respect to any resale of the Exchange Notes. See "Plan of Distribution."

Broker-dealers who cannot make the representations in item (3) of the paragraph above cannot use this exchange offer prospectus in connection with resales of the Exchange Notes issued in the exchange offer.

Each holder of Old Notes that wishes to exchange Old Notes for Exchange Notes in the exchange offer and any beneficial owner of those Old Notes also will be required to make the following representations:

neither the holder nor any beneficial owner of the Old Notes is an "affiliate" (as defined in Rule 405 under the Securities Act) of the Issuers;

neither the holder nor any beneficial owner of the Old Notes is engaged in or intends to engage in, and has no arrangement or understanding with any person to participate in, a distribution (within the meaning of the Securities Act) of the Exchange Notes;

any Exchange Notes to be acquired by the holder and any beneficial owner of the Old Notes pursuant to the exchange offer will be acquired in the ordinary course of business of the person receiving such Exchange Notes; and

the holder is not acting on behalf of any person who could not truthfully make the foregoing representations.

BY TENDERING YOUR OLD NOTES YOU ARE DEEMED TO HAVE MADE THESE REPRESENTATIONS.

If you are our "affiliate," as defined under Rule 405 of the Securities Act, if you are a broker-dealer who acquired your Old Notes in the initial offering and not as a result of market-making or trading activities, or if you are engaged in or intend to engage in or have an arrangement or understanding with any person to participate in a distribution of Exchange Notes acquired in the exchange offer, you or that person:

cannot rely on the position of the staff of the SEC set forth in *Exxon Capital Holdings Corporation, Morgan Stanley & Co., Incorporated* or similar no-action letters; and

in the absence of an applicable exemption, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a resale of the Exchange Notes.

Acceptance of Outstanding Old Notes for Exchange; Delivery of Exchange Notes

We will accept validly tendered Old Notes when the conditions to the exchange offer have been satisfied or we have waived them. We will have accepted your validly tendered Old Notes when we

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have given oral to be promptly confirmed in writing or written notice to the exchange agent. The exchange agent will act as agent for the tendering holders for the purpose of receiving the Exchange Notes from us. If we do not accept any tendered Old Notes for exchange by book-entry transfer because of an invalid tender or other valid reason, we will credit the Old Notes to an account maintained with DTC promptly after the exchange offer terminates or expires.

THE AGENT'S MESSAGE MUST BE TRANSMITTED TO THE EXCHANGE AGENT ON OR BEFORE 5:00 P.M., NEW YORK CITY TIME, ON THE EXPIRATION DATE.

No Guaranteed Delivery

There are no guaranteed delivery procedures provided for by us in conjunction with the exchange offer. Holders of Old Notes must timely tender their Old Notes in accordance with the procedures set forth herein.

Withdrawal Rights

You may withdraw your tender of outstanding notes at any time before 5:00 p.m., New York City time, on the expiration date.

For a withdrawal to be effective, you should contact your bank or broker where your Old Notes are held and have them send an ATOP notice of withdrawal so that it is received by the exchange agent before 5:00 p.m., New York City time, on the expiration date. Such notice of withdrawal must:

- specify the name of the person that tendered the Old Notes to be withdrawn;
- identify the Old Notes to be withdrawn, including the CUSIP number and principal amount at maturity of the Old Notes;
- specify the name and number of an account at the DTC to which your withdrawn Old Notes can be credited.

We will decide all questions as to the validity, form and eligibility of the notices and our determination will be final and binding on all parties. Any tendered Old Notes that you withdraw will not be considered to have been validly tendered. We will promptly return any outstanding Old Notes that have been tendered but not exchanged, or credit them to the DTC account. You may re-tender properly withdrawn Old Notes by following one of the procedures described above before the expiration date.

Conditions to the Exchange Offer

Notwithstanding any other provision of the exchange offer, we are not required to accept for exchange, or to issue Exchange Notes in exchange for, any Old Notes and may terminate or amend the exchange offer if, at any time before the acceptance of Old Notes for exchange, (1) we determine that the exchange offer violates applicable law, any applicable interpretation of the staff of the SEC or any order of any governmental agency or court of competent jurisdiction, (2) any action or proceeding has been instituted or threatened in any court or before any governmental agency with respect to the exchange offer which, in our judgment, might impair our ability to proceed with the exchange offer or have a material adverse effect on us, or (3) we determine that there has been a material change in our business or financial affairs which, in our judgment, would materially impair our ability to consummate the exchange offer.

The foregoing conditions are for our sole benefit and may be asserted by us regardless of the circumstances giving rise to any such condition. The failure of any of the foregoing conditions other than those conditions dependent upon the receipt of necessary government approvals, may be waived by us, in whole or in part, at any time and from time to time at prior to the expiration date, at our sole discretion. Our failure to exercise any of the foregoing rights at any time will not be deemed a waiver of any such right and each such right will be deemed an ongoing right which may be asserted at any time and from time to time.

In addition, we will not accept for exchange any Old Notes tendered, and no Exchange Notes will be issued in exchange for any Old Notes, if at such time any stop order will be threatened or in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture governing the notes under the Trust Indenture Act of 1939, as amended. In any such event we are required to use our commercially reasonable efforts to promptly obtain the withdrawal of any stop order.

Exchange Agent

We have appointed Wilmington Trust, National Association as the exchange agent for the exchange offer. You should direct questions, requests for assistance, and requests for additional copies of this prospectus and the letter of transmittal to the exchange agent addressed as follows:

Wilmington Trust, National Association

	By Regular, Registered or Certified Mail, By Overnight Courier or By Hand:	
By Facsimile: (302) 636-4139 Attention: Sam Hamed	Corporate Capital Markets Rodney Square North 1100 North Market Street Wilmington, Delaware 19890-1626 Attention: Sam Hamed	*Confirm by Telephone:* (302) 636-6181

Delivery to an address other than set forth above will not constitute a valid delivery.

Fees and Expenses

The principal solicitation is being made through DTC by Wilmington Trust, National Association as exchange agent. We will pay the exchange agent customary fees for its services, reimburse the exchange agent for its reasonable out-of-pocket expenses incurred in connection with the provisions of these services and pay other registration expenses, including registration and filing fees and expenses, fees and expenses of compliance with federal securities and state securities or blue sky securities laws, printing expenses, messenger and delivery services and telephone, fees and disbursements to our counsel, application and filing fees and any fees and disbursements to our independent certified public accountants. We will not make any payment to brokers, dealers, or others soliciting acceptances of the exchange offer except for reimbursement of mailing expenses.

Additional solicitations may be made by telephone, facsimile or in person by our and our affiliates' officers employees and by persons so engaged by the exchange agent.

Accounting Treatment

The Exchange Notes will be recorded at the same carrying value as the existing Old Notes, as reflected in our accounting records on the date of exchange. Accordingly, we will recognize no gain or loss for accounting purposes. The expenses of the exchange offer will be capitalized and expensed over the term of the Exchange Notes.

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Transfer Taxes

If you tender outstanding Old Notes for exchange you will not be obligated to pay any transfer taxes. However, if you instruct us to register Exchange Notes in the name of, or request that your Old Notes not tendered or not accepted in the exchange offer be returned to, a person other than the registered tendering holder, you will be responsible for paying any transfer tax owed.

OID Reporting.

Because the stated principal amount of the Old Notes exceeded their issue price by more than a de minimis amount, the Old Notes were treated as issued with OID for U.S. federal income tax purposes. A holder of Exchange Notes subject to U.S. federal income taxation generally will be required to continue to include the OID in gross income (as ordinary income) in the manner as if the Old Notes had not been exchanged. See "Certain U.S. Federal Income Tax Considerations."

Consequences of Failure to Exchange

If you do not tender your outstanding Old Notes, you will not have any further registration rights, except for the rights described in the Registration Rights Agreement and described above, and your Old Notes will continue to be subject to the provisions of the indenture governing the notes regarding transfer and exchange of the Old Notes and the restrictions on transfer of the Old Notes imposed by the Securities Act and states securities law when we complete the exchange offer. These transfer restrictions are required because the Old Notes were issued under an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. Accordingly, if you do not tender your Old Notes in the exchange offer, your ability to sell your Old Notes could be adversely affected. Once we have completed the exchange offer, holders who have not tendered notes will not continue to be entitled to any additional interest that the indenture governing the notes provides for if we do not complete the exchange offer.

Other

Participation in the exchange offer is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial, tax, legal and other advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered Old Notes in the open market or in privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any Old Notes that are not tendered in the exchange offer or to file a shelf registration statement to permit resales of any untendered Old Notes.

USE OF PROCEEDS

This exchange offer is intended to satisfy our obligations under the Registration Rights Agreement. We will not receive any proceeds from the issuance of the Exchange Notes. In consideration for issuing the Exchange Notes, we will receive, in exchange, an equal number of Old Notes in like principal amount. The form and terms of the Exchange Notes are identical to the form and terms of the Old Notes, except as otherwise described under the heading "The Exchange Offer Terms of the Exchange Offer." The Old Notes properly tendered and exchanged for Exchange Notes will be retired and cancelled. Accordingly, issuance of the Exchange Notes will not result in any change in our capitalization. We have agreed to bear the expense of the exchange offer.

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratios of earnings to fixed charges for the periods indicated calculated on the basis of the U.S. GAAP financial statements included in this prospectus. For this purpose, "**earnings**" consists of earnings from continuing operations and distributed income of equity investees, excluding income taxes, non-controlling interests share in earnings and fixed charges, other than capitalized interest, and "**fixed charges**" consists of project-level interest expense and corporate level interest expense.

	Year Ended December 31,					Three Months Ended March 31,
	2011	**2010**	**2009**	**2008**	**2007**	**2012**
Ratio of Earnings to Fixed Charges	(1)	2.08x	(1)	2.24x	1.58x	(1)

(1) For purposes of computing this ratio of earnings to fixed charges, fixed charges consist of project-level interest expense and corporate level interest expense. Earnings consist of earnings from continuing operations and distributed income of equity investees, excluding income taxes, non-controlling interests share in earnings and fixed charges, other than capitalized interest. Earnings were insufficient to cover fixed charges by $43.9 and $54.2 million, for the years ended December 31, 2011 and 2009, respectively, and $55.5 million for the three months ended March 31, 2012.

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DESCRIPTION OF ACQUISITION OF THE PARTNERSHIP

On November 5, 2011, Atlantic Power completed the acquisition of all the outstanding limited partnership interests of the Partnership pursuant to the terms and conditions of the Arrangement Agreement, dated June 20, 2011, as amended by Amendment No. 1, dated July 15, 2011 (the "**Arrangement Agreement**"), by and among the Atlantic Power, the Partnership, CPI Income Services Ltd., the general partner of the Partnership, and CPI Investments Inc., a unitholder of the Partnership that is owned by EPCOR Utilities Inc. and Capital Power Corporation. The transactions contemplated by the Arrangement Agreement were effected through a court-approved plan of arrangement under the Canada Business Corporations Act (the "**Plan of Arrangement**"). The Plan of Arrangement was approved by the unitholders of the Partnership, and the issuance of Atlantic Power's common shares to the Partnership unitholders pursuant to the Plan of Arrangement was approved by Atlantic Power's shareholders, at respective special meetings held on November 1, 2011. A Final Order approving the Plan of Arrangement was entered by the Court of Queen's Bench of Alberta, Judicial District of Calgary, on November 1, 2011.

Under the terms of the Plan of Arrangement, the Partnership unitholders exchanged each of their limited partnership units for, at their election, Cdn$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections were subject to proration if total cash elections exceeded approximately Cdn$506.5 million and all share elections were subject to proration if total share elections exceeded approximately 31.5 million Atlantic Power common shares. At closing, Atlantic Power paid Cdn$506,531,834 in cash and issued 31,500,215 of its common shares in exchange for the Partnership units.

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UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS

On November 5, 2011, we completed the direct and indirect acquisition of all the outstanding limited partnership interests of the Partnership pursuant to the Plan of Arrangement. The following unaudited pro forma condensed combined consolidated statement of operations (which we refer to as the pro forma statement of operations) combines the historical consolidated statements of operations of Atlantic Power and the Partnership to illustrate the effect of the Plan of Arrangement. An unaudited pro forma condensed combined consolidated balance sheet is not presented herein as the Plan of Arrangement was effected prior to, and is reflected in, the audited consolidated balance sheet of Atlantic Power appearing elsewhere in this prospectus.

The pro forma statement of operations and accompanying notes should be read in conjunction with:

- audited consolidated financial statements of Atlantic Power for the year ended December 31, 2011 and the notes relating thereto, appearing elsewhere in this prospectus; and

- audited consolidated financial statements of the Partnership for the year ended December 31, 2010 and the notes relating thereto, and the unaudited consolidated financial statements of the Partnership for the nine months ended September 30, 2011 and the notes relating thereto, appearing elsewhere in this prospectus.

The pro forma statement of operations is based on (i) the audited consolidated statement of operations of Atlantic Power for the year ended December 31, 2011 and the notes relating thereto, and (ii) the unaudited consolidated statement of operations of the Partnership for the period from January 1, 2011 to November 5, 2011. The historical consolidated statements of operations have been adjusted in the pro forma statement of operations to give effect to pro forma events that are (1) directly attributable to the Plan of Arrangement, (2) factually supportable and (3) expected to have a continuing impact on the combined results. The pro forma statement of operations for the year ended December 31, 2011 gives effect to the Plan of Arrangement as if it occurred on January 1, 2011.

As described in the accompanying notes, the pro forma statement of operations has been prepared using the acquisition method of accounting under existing United States generally accepted accounting principles, or GAAP, and the regulations of the SEC. Atlantic Power has been treated as the acquirer in the transaction for accounting purposes. Accordingly, the pro forma financial information is preliminary and has been made solely for the purpose of providing this unaudited pro forma condensed combined consolidated statement of operations. Differences between these preliminary estimates and the final acquisition accounting will occur and these differences could have a material impact on the pro forma financial information presented and the combined company's future results of operations and financial position.

The pro forma statement of operations has been presented for informational purposes only and is not necessarily indicative of what the combined company's results of operations and financial position would have been had the transaction been completed on the dates indicated. In addition, the pro forma statement of operations does not purport to project the future results of operations or financial position of the combined company.

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ATLANTIC POWER CORPORATION AND ATLANTIC POWER LIMITED PARTNERSHIP

UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2011

(IN THOUSANDS, EXCEPT PER SHARE DATA)

	Atlantic Power Historical (Audited)(a)	Partnership Historical (Unaudited)(a)(b)(1)	Pro Forma Adjustments(c)	Pro Forma Combined
Project revenue:	$ 284,895	$ 409,267	$	$ 694,162
Project expenses:				
Fuel	93,993	170,704		264,697
Project operations and maintenance	56,832	73,406		130,238
Depreciation and amortization	63,638	73,236	26,875(d)	163,750
	214,463	317,346	26,875	558,684
Project other income (expenses):				
Change in fair value of derivative instruments	(22,776)	1,043		(21,733)
Equity in earnings of unconsolidated affiliates	6,356			6,356
Interest expense, net	(20,053)			(20,053)
Other expense, net	20			20
	(36,453)	1,043		(35,410)
Project income	33,979	92,965	(26,875)	100,068
Administrative and other expenses (income):				
Administration	38,108	45,375		83,483
Interest expense, net	25,998	34,668	37,145(e)	97,811
Other expense, net				
Foreign exchange gain	13,838	10,077		23,915
	77,944	90,121	37,145	205,210
Income (loss) from operations before income taxes	(43,965)	2,844	(64,020)	(105,141)
Income tax expense	(8,324)	(2,669)	(24,328)(f)	(35,321)
Net income (loss)	(35,641)	5,513	(39,693)	(69,821)
Net income (loss) attributable to noncontrolling interest	2,767	10,770		13,537
Net income (loss) attributable to Atlantic Power Corporation	$ (38,408)	$ (5,527)	$ (39,693)	$ (83,358)
EPS-Basic	$ (0.50)	(0.10)	(0.13)	$ (0.73)
EPS-Diluted	$ (0.50)	(0.10)	(0.13)	$ (0.73)

(1) The Partnership historical results are recorded in Canadian dollars and are in accordance with IFRS. See Note 5(b) and (c) for an explanation of the conversion to U.S. dollars and U.S. GAAP.

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Statement of Operations, which are an integral part of this statement.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME, LP

NOTES TO THE UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS

Note 1. Description of the Transaction

On November 5, 2011, we completed the direct and indirect acquisition of all of the outstanding limited partnership units of Capital Power Income, L.P. (renamed Atlantic Power Limited Partnership on February 1, 2012, the "**Partnership**") pursuant to the terms and conditions of an Arrangement Agreement, dated June 20, 2011, as amended by Amendment No. 1, dated July 15, 2011 (the "**Arrangement Agreement**"), by and among us, the Partnership, CPI Income Services, Ltd., the general partner of the Partnership and CPI Investments, Inc., a unitholder of the Partnership that was then owned by EPCOR Utilities Inc. and Capital Power Corporation. The transactions contemplated by the Arrangement Agreement were effected through a court-approved plan of arrangement under the Canada Business Corporations Act (the "**Plan of Arrangement**"). The Plan of Arrangement was approved by the unitholders of the Partnership, and the issuance of our common shares to the Partnership unitholders pursuant to the Plan of Arrangement was approved by our shareholders, at respective special meetings held on November 1, 2011. A Final Order approving the Plan of Arrangement was granted by the Court of Queen's Bench of Alberta on November 1, 2011.

Under the terms of the Plan of Arrangement, the Partnership unitholders were permitted to exchange each of their Partnership units for, at their election, Cdn$19.40 in cash or 1.3 of our common shares. All cash elections were subject to proration if total cash elections exceed approximately Cdn$506.5 million and all share elections were subject to proration if total share elections exceed approximately 31.5 million of our common shares.

Pursuant to the Plan of Arrangement, the Partnership sold its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, for approximately Cdn$121.4 million which equated to approximately Cdn$2.15 per unit of the Partnership. In addition, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and the Partnership and certain subsidiaries of the Partnership were terminated (or assigned to us) in consideration of a payment of Cdn$10.0 million. Atlantic Power and its subsidiaries assumed the management of the Partnership upon closing and entered into a transitional services agreement with Capital Power Corporation for a term of six to twelve months following closing to facilitate and support the integration of the Partnership into Atlantic Power.

Note 2. Basis of Pro Forma Presentation

The pro forma statement of operations was derived from historical consolidated statements of operations of Atlantic Power and the Partnership. Certain reclassifications have been made to the historical statement of operations of the Partnership to conform with Atlantic Power's presentation. This resulted in income statement adjustments to operating revenues, operating expenses, other income and deductions.

The historical consolidated statements of operations have been adjusted in the pro forma statement of operations to give effect to pro forma events that are (1) directly attributable to the transaction, (2) factually supportable, and (3) expected to have a continuing impact on the combined results. The following matters have not been reflected in the pro forma statement of operations as they do not meet the aforementioned criteria.

- Cost savings (or associated costs to achieve such savings) from operating efficiencies, synergies or other restructuring that could result from the transaction with the Partnership. The timing and effect of actions associated with integration are currently uncertain.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME, LP

NOTES TO THE UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS (Continued)

Note 2. Basis of Pro Forma Presentation (Continued)

The pro forma statement of operations was prepared using the acquisition method of accounting under GAAP and the regulations of the SEC. Atlantic Power has been treated as the acquirer in the transaction for accounting purposes. Acquisition accounting requires, among other things, that most assets acquired and liabilities assumed be recognized at fair value as of the acquisition date. In addition, acquisition accounting establishes that the consideration transferred be measured at the closing date of the transaction at the then-current market price. Since acquisition accounting is dependent upon certain valuations and other studies that have yet to commence or progress to a stage where there is sufficient information for a definitive measurement, the pro forma statement of operations is preliminary and has been prepared solely for the purpose of providing unaudited pro forma condensed combined consolidated financial information. Differences between these preliminary estimates and the final acquisition accounting will occur and these differences could have a material impact on the accompanying pro forma statement of operations and the combined company's future results of operations and financial position. The pro forma statement of operations has been presented for informational purposes only and is not necessarily indicative of what the combined company's results of operations would have been had the transaction been completed on the date indicated. In addition, the pro forma statement of operations does not purport to project the future results of operations or financial position of the combined company.

Note 3. Significant Accounting Policies

Based upon Atlantic Power's initial review of the Partnership's summary of significant accounting policies, as disclosed in the Partnership's consolidated historical financial statements elsewhere in this Prospectus, as well as on preliminary discussions with the Partnership's management, the pro forma condensed combined consolidated statement of operations assumes there will be certain adjustments necessary to conform the Partnership's accounting policies under International Financial Reporting Standards ("**IFRS**") to Atlantic Power's accounting policies under U.S. GAAP. Upon completion of the transaction and a more comprehensive comparison and assessment, differences may be identified that would necessitate changes to the Partnership's future accounting policies and such changes could result in material differences in future reported results of operations and financial position for the Partnership as compared to historically reported amounts.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME, LP

NOTES TO THE UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS (Continued)

Note 4. Estimated Purchase Price and Preliminary Purchase Price Allocations

Our acquisition of the Partnership is accounted for under the acquisition method of accounting as of the transaction closing date. The purchase price allocation for the business combination is estimated as follows (in thousands):

Fair value of consideration transferred:		
Cash	$	601,766
Equity		407,424
Total purchase price	$	1,009,190
Preliminary purchase price allocation		
Working capital	$	37,951
Property, plant and equipment		1,024,015
Intangibles		554,679
Other long-term assets		224,295
Long-term debt		(621,551)
Other long-term liabilities		(155,489)
Deferred tax liability		(164,539)
Total identifiable net assets		899,361
Preferred shares		(221,304)
Goodwill		331,133
Total purchase price		1,009,190
Less cash acquired		(22,683)
Cash paid, net of cash acquired	$	986,507

The purchase price was computed using the Partnership's outstanding units as of June 30, 2011, adjusted for the exchange ratio at November 4, 2011. The purchase price reflects the market value of our common shares issued in connection with the transaction based on the closing price of our common shares on the Toronto Stock Exchange on November 4, 2011.

Note 5. Pro Forma Adjustments to Statement of Operations

The pro forma adjustments included in the pro forma statement of operations are as follows:

(a) *Atlantic Power and the Partnership historical presentation* Based on the amounts reported in the consolidated statements of operations of Atlantic Power for the year ended December 31, 2011 and the consolidated statements of operations of the Partnership for the period from January 1, 2011 to November 5, 2011. Certain financial statement line items included in the Partnership's historical presentation have been reclassified to corresponding line items included in Atlantic Power's historical presentation. These reclassifications had no impact on the historical operating income or net income from continuing operations reported by the Partnership.

(b) *The Partnership conversion to U.S. dollars* Based on the amounts reported in the historical consolidated statement of operations of the Partnership for the period from January 1, 2011 to November 5, 2011. The amounts have been converted from Canadian dollars to U.S.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME, LP

NOTES TO THE UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS (Continued)

Note 5. Pro Forma Adjustments to Statement of Operations (Continued)

dollars using average exchange rates for the applicable periods. The adjustments to revenues and expenses were not material to the Partnership's consolidated income statement.

(c) *The Partnership conversion to U.S. GAAP* Based on the amounts reported in the consolidated statement of operations of the Partnership for the period from January 1, 2011 to November 5, 2011. Certain financial statement line items included in the Partnership's historical presentation have been reclassified or adjusted to conform to U.S. GAAP presentation. For the period from January 1, 2011 to November 5, 2011, the Partnership statements conform to the IFRS. The adjustments to revenues and expenses were not material to the Partnership's consolidated income statement.

(d) *Power Purchase Agreements and Plants* The pro forma statement of operations includes pro forma adjustments to reflect the increase in expense resulting from the amortization of the valuation adjustment related to the Partnership's intangibles and the depreciation of the plants.

(e) *Debt and Equity issuance* The pro forma statement of operations includes pro forma adjustments to reflect the net incremental interest expense resulting from Atlantic Power's issuance of 9% Senior Notes due 2018, the proceeds of which were used to partially fund the cash portion of the purchase price, and amortization of deferred financing costs of $36.0 million and $1.1 million, respectively, for the year ended December 31, 2011.

(f) *Income Tax Benefit* For purposes of the unaudited pro forma condensed combined consolidated statement of operations, tax benefits are provided at the Canadian enacted statutory rate of 25%. This rate does not reflect Atlantic Power's effective tax rate, which includes other tax items, such as non-deductible items, as well as other tax charges or benefits, and does not take into account any historical or possible future tax events that may impact the combined company.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL INFORMATION FOR ATLANTIC POWER

The following table presents selected historical consolidated financial information for Atlantic Power. The annual historical information as of December 31, 2011 and 2010 and for the years ended, December 31, 2011, 2010 and 2009 has been derived from the audited consolidated financial statements appearing elsewhere in this prospectus. The annual historical information as of December 31, 2009, 2008 and 2007 and for the years ended December 31, 2008 and 2007 has been derived from audited consolidated financial statements not appearing in this prospectus. The historical information as of, and for the three-month periods ended March 31, 2012 and 2011 has been derived from the unaudited consolidated financial statements appearing elsewhere in this prospectus. Data for all periods have been prepared under U.S. GAAP. You should read the following selected consolidated financial data together with Atlantic Power's consolidated financial statements and the notes thereto and the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this prospectus.

(in thousands of U.S. dollars, except per share/subordinated note data and as otherwise stated)	Year Ended December 31,					Three Months Ended March 31,	
	2011	2010	2009	2008	2007	2012(a)	2011(a)
Project revenue	$ 284,895	$ 195,256	$ 179,517	$ 173,812	$ 113,257	$ 167,610	$ 53,665
Project income	33,979	41,879	48,415	41,006	70,118	(24,650)	14,869
Net (loss) income attributable to Atlantic Power Corporation	(38,408)	(3,752)	(38,486)	48,101	(30,596)	(42,292)	6,136
Basic earnings (loss) per share	$ (0.50)	$ (0.06)	$ (0.63)	$ 0.78	$ (0.50)	$ (0.37)	$ 0.09
Basic earnings (loss) per share, C$(b)	$ (0.49)	$ (0.06)	$ (0.72)	$ 0.84	$ (0.53)	$ (0.37)	$ 0.09
Diluted earnings (loss) per share(c)	$ (0.50)	$ (0.06)	$ (0.63)	$ 0.73	$ (0.50)	$ (0.37)	$ 0.09
Diluted earnings (loss) per share, C$(b)(c)	$ (0.49)	$ (0.06)	$ (0.72)	$ 0.78	$ (0.53)	$ (0.37)	$ 0.09
Distribution per subordinated note(d)	$	$	$ 0.51	$ 0.60	$ 0.59	$	$
Dividend declared per common share	$ 1.11	$ 1.06	$ 0.46	$ 0.40	$ 0.40	$ 0.29	$ 0.27
Total assets	$ 3,248,427	$ 1,013,012	$ 869,576	$ 907,995	$ 880,751	$ 3,475,710	$ 1,007,801
Total long-term liabilities	$ 1,940,192	$ 518,273	$ 402,212	$ 654,499	$ 715,923	$ 1,940,073	$ 504,492

(a) Unaudited.

(b) The C$ amounts were converted using the average exchange rates for the applicable reporting periods.

(c) Diluted earnings (loss) per share is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long term incentive plan. Because we reported a loss during the years ended December 31, 2011, 2010, 2009, and 2007 and for the three-month period ended March 31, 2012, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive. Please see the notes to our historical consolidated financial statements appearing elsewhere in this prospectus for information relating to the number of shares used in calculating basic and diluted earnings per share for the periods presented.

(d) At the time of our initial public offering, our publicly traded security was an income participating security, or an "**IPS**," each of which was comprised of one common share and C$5.767 principal amount of 11% subordinated notes due 2016. On November 27, 2009, we converted from the IPS structure to a traditional common share structure. In connection with the conversion, each IPS was exchanged for one new common share.

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BUSINESS

Overview

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("**PPA**s"), which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 megawatts (or "**MW**") in which our aggregate ownership interest is approximately 2,141 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada and a 500-kilovolt 84-mile electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. We also own a majority interest in Rollcast Energy Inc. ("**Rollcast**"), a biomass power plant developer in North Carolina, and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC ("**PERH**"). Twenty-three of our projects are wholly owned subsidiaries.

The following map shows the location of our currently-owned projects, including joint venture interests, across the United States and Canada:

	Project Name	Location	Fuel Type	Total MW	Ownership Interest	Net MW
1	Auburndale	Auburndale FL	Natural Gas	155	100%	155
2	Badger Creek	Bakersfield CA	Natural Gas	46	50%	23
3	Cadillac	Cadillac MI	Biomass	40	100%	40
4	Calstock	Hearst ON	Biomass	35	100%	35

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	Project Name	Location	Fuel Type	Total MW	Ownership Interest	Net MW
5	Canadian Hills	El Reno OK	Wind	298	99%	295
6	Chambers	Carney's Point NJ	Coal	263	40%	105
7	Curtis Palmer	Corinth NY	Hydro	60	100%	60
8	Delta Person	Albuquerque NM	Natural Gas	132	40%	53
9	Frederickson	Tacoma WA	Natural Gas	250	50%	125
10	Greeley	Greeley CO	Natural Gas	72	100%	72
11	Gregory	Corpus Cristi TX	Natural Gas	400	17%	68
12	Idaho Wind	Twin Falls ID	Wind	183	28%	50
13	Kapuskasing	Kapuskasing ON	Natural Gas	40	100%	40
14	Kenilworth	Kenilworth NJ	Natural Gas	30	100%	30
15	Koma Kulshan	Concrete WA	Hydro	13	50%	6
16	Lake	Umatilla FL	Natural Gas	121	100%	121
17	Mamquam	Squamish BC	Hydro	50	100%	50
18	Manchief	Brush CO	Natural Gas	300	100%	300
19	Moresby Lake	Moresby Island BC	Hydro	6	100%	6
20	Morris	Morris IL	Natural Gas	177	100%	177
21	Naval Station	San Diego CA	Natural Gas	47	100%	47
22	Naval Training Ctr	San Diego CA	Natural Gas	25	100%	25
23	Nipigon	Nipigon ON	Natural Gas	40	100%	40
24	North Bay	North Bay ON	Natural Gas	40	100%	40
25	North Island	San Diego CA	Natural Gas	40	100%	40
26	Orlando	Orlando FL	Natural Gas	129	50%	65
27	Oxnard	Oxnard CA	Natural Gas	49	100%	49
28	Pasco	Tampa FL	Natural Gas	121	100%	121
29	Path 15	California	Transmission	NA	100%	NA
30	PERH	Illinois	NA	NA	14%	NA
31	Piedmont	Barnsville GA	Biomass	53	98%	53
32	Rockland	American Falls ID	Wind	80	30%	24
33	Rollcast	Charlottesville NC	NA	NA	60%	NA
34	Selkirk	Bethlehem NY	Natural Gas	345	18%	64
35	Tunis	Tunis ON	Natural Gas	43	100%	43
36	Williams Lake	Williams Lake BC	Biomass	66	100%	66

The following charts show, based on MW, the diversification of our portfolio by geography, reporting segment and fuel type:

We sell the capacity and energy from our power generation projects under PPAs with a number of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2012 to 2037, we receive payments for electric energy delivered to our customers (known as energy payments), in addition to payments for electric generating capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. The transmission system rights ("**TSRs**") associated with our power transmission project entitles us to payments indirectly from the utilities that make use of the transmission line.

Our power generation projects generally have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements corresponds to the term of the relevant PPAs. Many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is no pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies.

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

History of Our Company

Atlantic Power Corporation is a corporation continued under the laws of British Columbia, Canada, which was incorporated in 2004. We used the proceeds from our IPO on the Toronto Exchange in November 2004 to acquire a 58% interest in Atlantic Power Holdings, LLC (now Atlantic Power Holdings, Inc., which we refer to herein as "**Atlantic Holdings**") from two private equity funds managed by ArcLight Capital Partners, LLC ("**ArcLight**") and from Caithness. Until December 31, 2009, we were externally managed under an agreement with Atlantic Power Management, LLC, an affiliate of ArcLight. We agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement, satisfied by a payment of $6 million on the termination date of December 31, 2009, and additional payments of $5 million, $3 million and $1 million on the first, second and third anniversaries of the termination date, respectively. In connection with the termination of the management agreement, we hired all of the then-current employees of Atlantic Power Management, LLC and entered into employment agreements with its three officers.

At the time of our initial public offering, our publicly traded security was an Income Participating Security ("**IPS**"), each of which was comprised of one common share and a subordinated note. In November 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure in which each IPS was 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 common shares trade on the Toronto Stock Exchange ("**TSX**") under the symbol "ATP" and began trading on the New York Stock Exchange ("**NYSE**") under the symbol "AT" on July 23, 2010.

On November 5, 2011, we directly and indirectly acquired all of the issued and outstanding limited partnership units of Capital Power Income L.P., which was renamed Atlantic Power Limited Partnership (the "**Partnership**") on February 1, 2012, in exchange for Cdn$506.5 million in cash and 31.5 million of our common shares. The Partnership's portfolio consisted of 19 wholly-owned power generation assets located in both Canada and the United States, a 50.15% interest in a power generation asset in the state of Washington, and a 14.3% common ownership interest in PERH. At the acquisition date, the transaction increased the net generating capacity of our projects by 143% from 871 MW to approximately 2,116 MW. We did not purchase two of the Partnership's assets located in North Carolina. We remain headquartered in Boston, Massachusetts and added offices in Chicago, Illinois; Toronto, Ontario; and Richmond and Vancouver, British Columbia. Additionally, the Capital Power

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Corporation employees that operated and maintained the Partnership assets and most of those who provided management support of operations, accounting, finance, and human resources became employees of Atlantic Power.

As part of our integration efforts in conjunction with our acquisition of the Partnership, we have fully integrated the accounting and administration of the Canadian plants from the previous Capital Power Corporation accounting group into our Chicago office. Additionally, we have reviewed our existing policies and procedures and incorporated the changes necessary for a larger, more complex organization.

Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, 02116 USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Additionally, we make available on our website, our Canadian securities filings.

Our Competitive Strengths

We believe we distinguish ourselves from other independent power producers through the following competitive strengths:

Diversified projects. Our power generation projects have an aggregate gross electric generation capacity of approximately 3,397 MW, and our net ownership interest in these projects is approximately 2,141 MW. These projects are diversified by fuel type, electricity and steam customers, and geography. The majority are located in the deregulated and more liquid electricity markets of California, the U.S. Mid-Atlantic and New York. We also have a power transmission project, known as the Path 15 project, that is regulated by the Federal Energy Regulatory Commission ("**FERC**"). Additionally, we have a 53 MW biomass project under construction in Georgia and an approximately 300 MW wind project under construction in Oklahoma.

Experienced management team. Our management team has a depth of experience in commercial power operations and maintenance, project development, asset management, mergers and acquisitions, capital raising and financial controls. Our network of industry contacts and our reputation allow us to access proprietary acquisition opportunities on a regular basis.

Stability of project cash flow. Many of our power generation projects currently in operation have been in operation for over ten years. Cash flows from each project are generally supported by PPAs with investment-grade utilities and other creditworthy counterparties. We believe that each project's combination of PPAs, fuel supply agreements and/or commodity hedges help stabilize operating margins.

Access to capital. Our shares are publicly traded on the NYSE and the TSX. We have a history of successfully raising capital through public offerings of equity and debt securities in Canada and the U.S., issuing public convertible debentures in Canada and bonds in the United States. We have also issued securities by way of private placement in the U.S. and Canada. In addition, we have used non-recourse project-level financing as a source of capital. Project-level financing can be attractive as it typically has a lower cost than equity, is non-recourse to Atlantic Power and amortizes over the term of the project's PPA. Having significant experience in accessing all of these markets provides flexibility such that we can pursue transactions in the most cost-effective market at the time capital is needed.

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Strong in-house operations team complemented by leading third-party operators. We operate and maintain 17 of our power generation projects, which represent 44% of our portfolio's generating capacity, and the remaining 14 generation projects are operated by third-parties, who are recognized leaders in the independent power business. Affiliates of Caithness, CEM and PPMS operate projects representing approximately 19%, 14% and 8%, respectively, of the net electric generation capacity of our power generation projects. No other operator is responsible for the operation of projects representing more than 3% of the net electric generation capacity of our power generation projects.

Strong customer base. Our customers are generally large utilities and other parties with investment-grade credit ratings. The largest customers of our power generation projects, including projects recorded under the equity method of accounting, are Public Service Company of Colorado ("**PSCo**"), Progress Energy Florida, Inc. ("**PEF**") and Ontario Electricity Financial Corp. ("**OEFC**"), which purchase approximately 17%, 15% and 9%, respectively, of the net electric generation capacity of our projects. No other electric customer purchases more than 6% of the net electric generation capacity of our power generation projects.

Our Objectives and Business Strategies

Our corporate strategy is to increase the value of the company through accretive acquisitions in North American markets while generating stable, contracted cash flows from our existing assets to sustain our dividend payout to shareholders. In order to achieve these objectives, we intend to focus on enhancing the operating and financial performance of our current projects and pursuing additional accretive acquisitions primarily in the electric power industry in the United States and Canada.

Organic growth

Since the time of our initial public offering on the TSX in late 2004, we have twice acquired the interest of another partner in one of our existing projects and will continue to look for additional such opportunities. We intend to enhance the operation and financial performance of our projects through:

- achievement of improved operating efficiencies, output, reliability and reduced operation and maintenance costs through the upgrade or enhancement of existing equipment or plant configurations;
- optimization of commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, operations and maintenance agreements and hedge agreements; and
- expansion of existing projects.

Extending PPAs following their expiration

PPAs in our portfolio have expiration dates ranging from 2012 to 2037. In each case, we plan for expirations by evaluating various options in the market. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, "reverse" requests for proposals by the projects to likely bilateral counterparties, arrangements with creditworthy energy trading firms for tolling agreements, full service PPAs or the use of derivatives to lock in value. We do not assume that revenues or operating margins under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested, and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs.

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Acquisition and investment strategy

We believe that new electricity generation will continue to be required in the United States and Canada as a result of growth in electricity demand, transmission constraints and the retirement of older generation projects due to obsolescence or environmental concerns. In addition, Renewable Portfolio Standards in over 31 states as well as renewables initiatives in several provinces have greatly facilitated attractive PPAs and financial returns for significant renewable project opportunities. While we are not greenfield developers ourselves, we work with experienced development companies to acquire pipelines of late stage development investment opportunities. There is also a very active secondary market for the purchase and sale of existing projects.

We intend to expand our operations by making accretive acquisitions with a focus on power generation, transmission and related facilities in the United States and Canada. We may also invest in other forms of energy-related projects, utility projects and infrastructure projects, as well as make additional investments in development stage projects or companies where the prospects for creating long-term predictable cash flows are attractive. In 2010, we purchased a 60% interest in Rollcast, a biomass developer out of North Carolina with a pipeline of development projects, in which we have the option but not the obligation to invest capital. We continue to assess development companies with strong late-stage development projects, and believe that there are opportunities in the market to enter into joint ventures with strong development teams.

Our management has significant experience in the independent power industry and we believe that our experience, reputation and industry relationships will continue to provide us with enhanced access to future acquisition opportunities on a proprietary basis.

Asset Management

Our asset management strategy is to ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures, if required, to provide for their safety, efficiency, availability and longevity. We also proactively look for opportunities to optimize power, fuel supply and other agreements to deliver strong and predictable financial performance. In conjunction with our acquisition of the 18 Partnership assets, the personnel that operated and maintained the assets became employees of Atlantic Power. The staff at each of the facilities has extensive experience in managing, operating and maintaining the assets. Personnel at Capital Power Corporation regional offices that provided support in operations management, environmental health and safety, and human resources also joined Atlantic Power. In combination with the existing staff of Atlantic Power, we have a dedicated and experienced operations and commercial management organization that is well regarded in the energy industry.

For operations and maintenance services at the 14 projects in our portfolio which we do not operate, we partner with recognized leaders in the independent power business. Most of our third-party operated projects are managed by Caithness, CEM, PPMS and, in the case of Path 15, Western, a U.S. Federal power agency. On a case-by-case basis, these third-party operators may provide: (i) day-to-day project-level management, such as operations and maintenance and asset management; (ii) partnership level management, such as insurance renewals and annual budgets; and (iii) partnership level management, such as acting as limited partner. In some cases these project managers or the project partnerships may subcontract with other firms experienced in project operations, such as General Electric, to provide for day-to-day plant operations. In addition, employees of Atlantic Power with significant experience managing similar assets are involved in all significant decisions with the objective of proactively identifying value-creating opportunities such as contract renewals or restructurings, asset-level refinancings, add-on acquisitions, divestitures and participation at partnership meetings.

Caithness is one of the largest privately-held independent power producers in the United States. For over 25 years Caithness has been actively engaged in the development, acquisition and management of independent power facilities for its own account as well as in venture arrangements with other entities. Caithness operates our Auburndale, Lake and Pasco projects and provides asset management services for our Orlando, Selkirk and Badger Creek projects.

Colorado Energy Management ("**CEM**") is an energy infrastructure management company specializing in operations and maintenance, asset management and construction management for independent power producers and investors. With over 25 years of experience in operations and maintenance management, CEM focuses on revenue growth through continuous operational improvement and advanced maintenance concepts. Clients of CEM include independent power producers, municipalities and plant developers. CEM operates our Manchief facility.

Power Plant Management Services is a management services company focused on providing senior level energy industry expertise to the independent power market. Founded in 2006, PPMS provides management services to a large portfolio of solid fuel and gas-fired generating stations including our Selkirk and Chambers facilities. Previously, Cogentrix provided services to these facilities.

Western owns and maintains the Path 15 transmission line. Western transmits and delivers hydroelectric power and related services within a 15-state region of the central and western United States. They are one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. Western's transmission system carries electricity from 57 power plants. Together, these plants have an operating capacity of approximately 8,785 MW.

Our Organization and Segments

The following tables outline by segment our portfolio of power generating and transmission assets in operation and under construction as of May 2, 2012, including our interest in each facility. We believe our portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

As a result of the Partnership acquisition we revised our reportable business segments during the fourth quarter of 2011. The new operating segments are Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. Our financial results for the years ended December 31, 2010 and 2009 and the three months ended March 31, 2011 have been presented to reflect these changes in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss. Un-allocated Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel.

The sections below provide descriptions of our projects by segment. See Note 19 to the Consolidated Audited Financial Statements of Atlantic Power Corporation for information on revenue from external customers, Project Adjusted EBITDA (a non-GAAP measure) and total assets by segment.

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Northeast Segment

Project Name	Location (State)	Type	Total MW	Economic Interest(%)(1)	Net MW(2)	Primary Electric Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Cadillac	Michigan	Biomass	40	100.00	40	Consumers Energy	2028	BBB-
Chambers	New Jersey	Coal	262	40.00	105	ACE(3)	2024	BBB+
Kenilworth	New Jersey	Natural Gas	30	100.00	30	Merck & Co.	2012(4)	AA
Curtis Palmer	New York	Hydro	60	100.00	60	Niagara Mohawk Power Corporation	2027	A-
Selkirk	New York	Natural Gas	345	17.70(5)	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Calstock	Ontario	Biomass	35	100.00	35	Ontario Electricity Financial Corp	2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100.00	40	Ontario Electricity Financial Corp	2017	AA-
Nipigon	Ontario	Natural Gas	40	100.00	40	Ontario Electricity Financial Corp	2022	AA-
North Bay	Ontario	Natural Gas	40	100.00	40	Ontario Electricity Financial Corp	2017	AA-
Tunis	Ontario	Natural Gas	43	100.00	43	Ontario Electricity Financial Corp	2014	AA-

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

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

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

(4) Contract expires July 31, 2012. Contract extension negotiations are ongoing.

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

Cadillac

The Cadillac project is a 39.6 MW biomass power generation facility located in north central Michigan approximately 200 miles north of Detroit. The facility, which achieved commercial operation in 1993, was acquired by Atlantic Power in December 2010, from ArcLight Energy Partners Fund II and Olympus Power, LLC.

Cadillac sells up to 34 MW of its capacity and energy under a PPA with Consumers Energy Company ("**Consumers**") which expires in 2028, with the remaining output sold into the spot market. In 2007, Cadillac entered into a Reduced Dispatch Agreement with Consumers under which the project shares in the economic benefit when Consumers reduces the dispatch level of the project to a specified minimum during periods in which Consumers can purchase replacement power in the wholesale market at a price that is less than Cadillac's variable cost of production.

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The project consumes approximately 360,000 tons per year of biomass fuel sourced under numerous short-term supply contracts from approximately 30 local suppliers. Cadillac is managed by Rollcast and has an operations and maintenance agreement with DPS.

Cadillac had non-recourse debt outstanding of $38.8 million at December 31, 2011, which fully amortizes through 2025. In addition there are notes in the aggregate amount of approximately $1.4 million with Beaver Michigan Associates, LP, a party involved in the early development of the project, due April 15, 2012. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Chambers

The Chambers project is a 262 MW pulverized coal-fired cogeneration facility located at the E.I. du Pont Nemours and Company ("**DuPont**") Chambers Works chemical complex near Carney's Point, New Jersey. The project sells steam and electricity, and achieved commercial operation in 1994. We have a 40% ownership interest in the Chambers project, with the remainder owned by an affiliate of Energy Investors Funds.

Chambers sells electricity to ACE under two separate power purchase agreements: a "Base PPA" and a power sales agreement ("**PSA**"). Under the Base PPA, which expires in 2024, ACE has agreed to purchase 184 MW of capacity and has dispatch rights for energy of up to approximately 180 MW with a minimum dispatch level of 46 MW. Energy generated at Chambers in excess of amounts delivered to ACE under the Base PPA and to DuPont, is sold to ACE under the PSA. Under this agreement, energy that ACE does not find economically attractive at the Base PPA's energy rate, but which may be cost effective to sell into the spot market, may be self-scheduled by the project to capture additional profits. The PSA includes a provision under which Chambers shares a portion of the margin on electricity sales with ACE. The PSA originally expired in July 2010 and we entered into subsequent replacement agreements on an annual basis in 2010 and 2011. The current PSA will expire in December 2012.

Steam and electricity is sold to DuPont under an energy services agreement ("**ESA**") that expires in 2024. In December 2008, Chambers filed a lawsuit against DuPont for breach of the ESA related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, Chambers received a favorable ruling from the court on its summary judgment motion as to liability. In November 2011, the suit went to trial as to damages and in April 2012, the court awarded damages to Chambers in excess of $15.7 million with additional damage awards to be determined upon invoicing by Chambers. The additional damages are estimated at approximately $10.6 million.

Chambers financed the construction of the project with a combination of term debt due 2014 and New Jersey Economic Development Authority bonds due 2021. Both debt facilities are nonrecourse to us. In February 2012 Chambers failed one of its debt covenants and subsequently received a waiver from the creditors on February 24, 2012. Our 40% share of the total debt outstanding at the Chambers project as of December 31, 2011 was $64.1 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Kenilworth

The Kenilworth project is a 30MW dual-fueled natural gas-fired combined cycle cogeneration facility located in Kenilworth, New Jersey adjacent to a pharmaceutical research and manufacturing facility owned by subsidiary of Merck & Co. Inc. ("**Merck**"). The facility also has the capability of burning No. 2 distillate fuel oil. We indirectly own 100% of the project. Kenilworth sells electricity and steam to the facility under an ESA that expires in July 2012. Under the ESA, Merck pays for electricity at an energy rate that escalates annually. Excess generation above the Merck load is sold into the spot market. The price of steam under the ESA is based on the delivered cost of fuel to Merck's auxiliary boilers. Merck is able to request long-term purchase strategies to minimize the monthly volatility of natural gas prices.

The natural gas supply is purchased from PPL Energy Plus LLC and is priced at monthly index prices similar to the rates used in calculating the steam price under the ESA. We are currently in negotiations with Merck regarding extension of the ESA.

Curtis Palmer

The 60 MW Curtis Palmer facility consists of two run-of-river hydroelectric generating facilities located on the Hudson River near Corinth, New York that commenced commercial operation in 1913 and were re-powered in 1986. We indirectly own 100% of the project. All power generated by the facility is sold to Niagara Mohawk Power Corporation ("**Niagara**") under a PPA that expires at the earlier of 2027 or the delivery to Niagara of a cumulative 10,000 GWh of electricity. The PPA sets out 11 different energy pricing blocks for electricity sold to Niagara, with the applicable rate to be paid at any given time being dependent upon the cumulative generation that has been delivered to Niagara. Over the remaining term of the PPA, the energy rate increases by $10/MWh with each additional 1,000 GWh of electricity delivered. Under certain circumstances, Niagara has the ability to relocate, rearrange, retire or abandon its transmission system which would potentially give rise to material future capital cost outlays by Curtis Palmer to maintain its interconnection.

As of December 31, 2011, the Curtis Palmer project had $190 million aggregate principal amount of 5.90% senior unsecured notes due July 2014. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" for additional details.

Selkirk

The Selkirk project is a 345 MW dual-fueled, combined-cycle cogeneration plant located in the Town of Bethlehem in Albany County, New York, which commenced commercial operation in 1994. The project site is situated adjacent to a Saudi Arabia Basic Industries Corporation ("**SABIC**") plastics manufacturing plant, which also purchases steam from the project. Selkirk consists of two units: Unit I (79 MW), which currently sells electricity into the New York merchant market and Unit II (265 MW) which sells electricity to Consolidated Edison Company of New York, Inc. ("**ConEd**"). We own an approximate 18.5% interest in the Selkirk project. The other partners include affiliates of Energy Investors Funds, The McNair Group, and Osaka Gas Energy America Corporation.

Selkirk sells the output from Unit I into the New York merchant market, and the output of Unit II to ConEd under a PPA that expires in 2014, subject to a 10-year extension at the option of ConEd under certain conditions. The Unit II PPA provides for a capacity payment, a fuel payment, an operations and maintenance payment, and a payment for transmission costs from the project to ConEd. The capacity payment, a portion of the fuel payment, a portion of the operations and maintenance payment, and the transmission payment are paid on the basis of plant availability.

The project sells steam to the SABIC plant under an agreement that expires in 2014, under which SABIC is not charged for steam in an amount up to a specified level during each hour in which the SABIC plant is in production. For steam in excess of the specified amount, SABIC pays the project a variable price. SABIC is required to purchase the minimum thermal output necessary for Selkirk to maintain its qualifying facility ("**QF**") status.

Selkirk purchases natural gas for Unit I at spot market prices under a contract with Coral Energy Canada Inc. expiring in 2012. Selkirk is in the process of engaging a third party to provide fuel

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management and procurement services post 2012. The gas supply arrangements for Unit II are with Imperial Oil Resources Limited, EnCana Corporation and Canadian Forest Oil Limited, which expire in 2014.

The Selkirk project has 8.98% first mortgage bonds outstanding which are non-recourse to us and which fully amortize over the remaining term of the PPA . Our proportionate share of the mortgage bonds was $5.8 million as of December 31, 2011. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Calstock

Calstock is a 35 MW generating facility that uses enhanced combined cycle generation and biomass to produce electricity. The plant is located near Hearst, Ontario, adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 2000. We indirectly own 100% of the project and also provide operations and management services. Calstock utilizes a biomass boiler and a steam turbine, in conjunction with waste heat from the nearby TransCanada Mainline compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2020. Calstock burns wood waste obtained under short-term contracts from three local sawmills: Tembec, Inc., Lecours Lumber Company Limited and Columbia Forest Products, Inc. Although the supply of wood waste and related transportation services are contracted, the suppliers have no obligation to provide fuel in the event they scale back or shut down operations. Pursuant to a Certificate of Approval ("**CoA**") from the Ministry of Environment, Calstock successfully completed a test burn of railroad rail ties in November 2009. The project has applied for a permanent CoA amendment from the Ministry of Environment, which if approved, would permit the burning of rail ties up to approximately 20% of the Calstock facility's fuel requirement.

Under a long-term waste heat agreement with TransCanada, Calstock is provided on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

Kapuskasing

The Kapuskasing facility is a gas-fired 40 MW facility that uses enhanced combined cycle generation to produce electricity. The facility is located near Kapuskasing, Ontario adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1997. We indirectly own 100% of the project and also provide operations and management services. The facility utilizes a gas turbine driven generator and a steam turbine, in conjunction with waste heat from the nearby TransCanada Mainline compressor station to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2017. Natural gas is procured under a long-term gas supply agreement with TransCanada Power Marketing expiring in 2017. The gas supply is transported to the plant under a firm transportation agreement with TransCanada Pipelines expiring in 2016. Under a long-term waste heat agreement with TransCanada, Kapuskasing is provided on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

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Nipigon

The Nipigon facility is a gas-fired 40 MW plant that uses enhanced combined cycle generation to produce electricity. Nipigon is located in Nipigon, Ontario, adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1992. We indirectly own 100% of the project and also provide operations and management services. Nipigon utilizes a gas-fired combustion turbine and a steam turbine, in conjunction with waste heat from the nearby TransCanada compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2012, but extends automatically to 2022 upon satisfying certain conditions related to a replacement gas supply. Natural gas is procured under long-term gas supply agreements with NAL Oil and Gas Trust and Petrobank Energy that expire in 2012. We have obtained a replacement long-term gas supply agreement for Nipigon that meets the extension requirements under the PPA. In April 2012, the OEFC acknowledged extension of the PPA to 2022. Nipigon's fuel supply is transported under a long-haul agreement with TransCanada which transports gas from Nipigon's suppliers in Alberta to the plant. The fuel transportation agreement expires in 2012 and will be renewed as part of the replacement gas supply agreement. Under a long-term waste heat agreement with TransCanada, Nipigon is provided on an as-available basis all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

North Bay

North Bay is a gas-fired 40 MW facility that uses enhanced combined cycle cogeneration to produce electricity. We indirectly own 100% of the project and also provide operations and management services. North Bay is located in North Bay, Ontario adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1989. North Bay utilizes a gas-fired combustion turbine and a steam turbine, in conjunction with waste heat from the nearby TransCanada compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2017. Natural gas is procured under a long-term gas supply agreement with TransCanada Power Marketing expiring in 2017. Gas is transported to the plant under a transportation agreement with TransCanada that expires in 2016. Under a long-term waste heat agreement with TransCanada, North Bay is provided, on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

Tunis

Tunis is a 43 MW facility that uses enhanced combined cycle cogeneration to produce electricity. We indirectly own 100% of the project and also provide operations and management services. The facility is located in Tunis, Ontario adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1995. Tunis utilizes a gas-fired combustion turbine and a steam turbine, in conjunction with waste heat from the nearby TransCanada compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2014. Natural gas is procured under a combination of spot purchases and short-term contracts. Tunis has gas transportation agreements with TransCanada, expiring in 2014, to ship gas to the plant. Under a long-term waste heat agreement with TransCanada, Tunis is provided, on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

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Southeast Segment

Project Name	Location (State)	Type	Total MW	Economic Interest	Net MW	Primary Electric Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00	121	Tampa Electric Co.	2018	BBB+
Orlando	Florida	Natural Gas	129	50.00	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District(1)	2013	AA-(2)
Piedmont(3)	Georgia	Biomass	54	98.00	53	Georgia Power	2032	A

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

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

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

Auburndale

The Auburndale project is a 155 MW dual fueled, combined-cycle, cogeneration plant located in Pope County, Florida, which commenced commercial operations in 1994. We indirectly own 100% of the Auburndale project, which was acquired in 2008 from ArcLight Energy Partners Fund I, L.P. and Calpine Corporation. The capacity and energy from the project is sold to PEF under three PPAs expiring at the end of 2013. Steam is sold to Florida Distillers Company and the Cutrale Citrus Juices USA. The Florida Distillers steam agreement is renewed annually and the Cutrale Citrus Juices agreement expires in 2013. Auburndale is operated and maintained by an affiliate of Caithness. The project also has a maintenance agreement in place with Siemens Energy, Inc. for the long-term supply of certain parts, repair services and outage services related to the gas turbine, which expires in 2013.

Each of Auburndale's PPAs expires at the end of 2013. Under the largest of the PPAs, Auburndale sells 114 MW of capacity and energy to PEF. In addition, 17 MW of capacity is sold under two identical 8.5 MW agreements with PEF. Electricity revenues from the three PPAs consist of capacity payments based on a fixed schedule of prices and energy payments. The capacity payments are dependent on Auburndale maintaining a minimum on peak capacity factor. Auburndale entered into an agreement with Tampa Electric Company ("**TECO**") to transmit electric energy from the project to PEF. Under the agreement, which expires in 2024, Auburndale's cost for these services is based on a contractual formula derived from TECO's cost of providing such services.

Auburndale obtains the majority of its natural gas requirements through a gas supply agreement with El Paso Merchant Energy, LP, that expires in June 2012. We are in the process of obtaining a replacement gas supply that will extend to the expiry of the PPA in 2013.

As of December 31, 2011, the Auburndale project had an $11.9 million 5.10% term loan, which is due in 2013. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Lake

Lake is a 121 MW dual-fueled, combined-cycle, cogeneration facility located in Umatilla, Florida, that began commercial operation in 1993. We indirectly own 100% of the Lake project. Capacity and electric energy is sold to PEF under a PPA expiring in July 2013. Steam is sold to Citrus World, Inc. for use at its adjacent citrus processing facility, and is also used to make distilled water in the projects distillation units that is sold to various parties. The Lake facility does not have any debt outstanding.

Revenues under the PPA consist of a fixed capacity payment and an energy payment. The capacity payment is based on Lake maintaining a specified capacity factor during on-peak hours (11 hours daily). Energy payments are comprised of several components including a fuel component based on the

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cost of coal consumed at two PEF owned coal-fired generating stations and a component intended to recover operations and maintenance costs. The project sells steam to Citrus World under an agreement that expires in 2013.

Natural gas requirements for the facility are provided by Iberdrola Renewables, Inc. and TECO Gas Services, Inc. under contracts that expire in 2013. Natural gas is transported to the project from supply points in Texas, Louisiana and Mississippi under contracts with Peoples Gas System, Inc.

Lake is operated and maintained by an affiliate of Caithness. The facility also has a long-term services agreement and a lease engine agreement in place with General Electric ("**GE**") to provide for planned and unplanned maintenance on Lake's two gas turbines, and to provide temporary replacement gas turbines when Lake's turbines are removed for major maintenance.

Pasco

The Pasco project is a 121 MW dual-fuel, combined-cycle, cogeneration facility located in Dade City, Florida which began commercial operation in 1993. Upon the expiration of Pasco's original PPA with PEF in 2008, the facility entered into a replacement tolling agreement with TECO that expires in 2018. Under the terms of the tolling agreement, TECO is responsible for the fuel supply and is financially responsible for fuel transportation to Pasco. We indirectly own 100% of the Pasco project.

Revenues under the tolling agreement with TECO consist of capacity payments, startup charges, variable payments based on the amount of electricity generated, and heat rate bonus payments based on the actual efficiency of the plant versus a contractual efficiency.

Pasco is operated and maintained by an affiliate of Caithness. The project also has a long-term services agreement and a lease engine agreement in place with GE.

Orlando

The Orlando project, a 129 MW natural gas-fired, combined-cycle, cogeneration facility located near Orlando Florida, commenced commercial operation in 1993. We indirectly own a 50% interest in the project and Northern Star Generation, LLC ("**Northern Star**") owns the remaining 50% interest. Orlando sells all of its electricity to PEF and Reedy Creek Improvement District ("**Reedy Creek**") under long-term PPAs. Orlando also sells chilled water produced using steam from the project to a subsidiary of Air Products and Chemicals.

Capacity and energy up to 79.2 MW is sold to PEF under a PPA that expires in 2023, under which Orlando receives a monthly capacity payment based on achieving a specified on-peak capacity factor, and an energy payment based on the total amount of electric energy delivered to PEF. In 2009, PEF provided notice to Orlando that the committed capacity under its PPA would be increased to 115 MW upon expiration of the Reedy Creek PPA in 2013, upon meeting certain criteria. Capacity and energy is also sold to Reedy Creek, a municipal district serving the Walt Disney World complex, under a PPA that expires in 2013. Orlando receives a monthly capacity payment based on the actual average on-peak capacity factor of the facility and a monthly energy payment based on the total amount of electric energy delivered to Reedy Creek. In 2009, Orlando executed an agreement with Rainbow Energy Marketing Corporation ("**Rainbow**") to market up to 15 MW of energy at spot market rates subject to the profitability of such sales. The agreement with Rainbow can be terminated by either party upon 30 days notice.

Under an agreement with a subsidiary of Air Products and Chemicals, Orlando supplies chilled water produced using steam from the project to its cryogenic air separation facility. Due to reduced demand for chilled water at the Air Products and Chemicals facility, Orlando procured and installed water distiller units in 2009 and entered into contracts to provide the distilled water to unaffiliated third parties to ensure maintenance of its QF status.

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Natural gas is purchased from an affiliate of Northern Star under an agreement that expires in 2013. Other affiliates of Northern Star entered into agreements with Florida Gas Transmission for the delivery of natural gas to Orlando. The project is operated and maintained by an affiliate of Northern Star under an operations and maintenance services agreement that expires in 2023. In 1997, Orlando also entered into a long-term maintenance agreement with Alstom Power Inc. for the long-term supply of hot gas path turbine parts.

Piedmont

The Piedmont project is a 53.5 MW biomass-fired, electric generating facility under construction in Barnesville, Georgia, approximately 60 miles Southeast of Atlanta. The project was developed by our 60% owned subsidiary Rollcast. We have a 98% ownership interest in Piedmont.

Piedmont will sell 100% of its output to Georgia Power Company under a 20-year PPA and has executed two long-term biomass fuel supply contracts under pricing terms that largely track the energy payment under the PPA. Zachary Industrial ("**ZHI**") is constructing the facility under a turn-key engineering procurement and construction contract. Notice to proceed was authorized in October 2010 and commercial operation is expected in late 2012. Total project costs of approximately $207 million were financed in part with an $82 million construction loan, which will convert to a five-year term loan upon commercial operation, a $51 million bridge loan and approximately $75 million of equity contributed by us. The bridge loan will be repaid from the proceeds of a federal stimulus grant, which is expected to be received two months after achieving commercial operation. We expect to refinance the term loan over a longer period.

Operations and management services will be provided under a five-year agreement with DPS. DPS will be paid its actual direct operating costs plus an annual fee. Piedmont has also executed a management services agreement with Rollcast for the provision of administrative and asset management services.

Northwest Segment

Project Name	Location (State)	Type	Total MW	Economic Interest	Net MW	Primary Electric Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Mamquam	British Columbia	Hydro	50	100.00	50	British Columbia Hydro and Power Authority	2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00	6	British Columbia Hydro and Power Authority	2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00	66	British Columbia Hydro and Power Authority	2018	AAA
Idaho Wind	Idaho	Wind	183	27.56	50	Idaho Power Co.	2030	BBB
Rockland	Idaho	Wind	80	30.00	24	Idaho Power Co.	2036	BBB
Frederickson	Washington	Natural Gas	250	50.15	125	Benton Co. PUD, Grays Harbor PUD, Franklin Co. PUD	2022	A
Koma Kulshan	Washington	Hydro	13	49.80	6	Puget Sound Energy	2037	BBB

Mamquam

Mamquam station is a wholly-owned 50 MW run-of-river hydroelectric generating plant located on the Mamquam River in British Columbia. The plant achieved commercial operation in 1996. We indirectly own 100% of Mamquam and also provide operations and management services. All of the output of the station is sold to British Columbia Hydro and Power Authority ("**BC Hydro**") under a long-term PPA which expires in 2027. BC Hydro has the option, exercisable in 2021 and every five years thereafter, to either purchase the Mamquam facility or extend the PPA. The energy rate under the PPA consists of a fixed energy component, an operations and maintenance component (adjusted annually for inflation), and a reimbursable cost component which covers expenses such as property taxes, water and land-use fees, as well as insurance premiums.

Moresby Lake

Moresby Lake is a 6 MW reservoir-based, hydroelectric generating station located on the island of Haida Gwaii off the coast of northern British Columbia. The project achieved commercial operation in 1990. We indirectly own 100% of Moresby Lake and also provide operations and management services. Substantially all of the output of the facility is sold to BC Hydro under a long-term PPA expiring in 2022. The energy rate payable by BC Hydro consists of a fixed energy rate adjusted annually for inflation. Approximately 1% of the station's generation is sold to NAV Canada and the Department of Fisheries and Oceans (Canada) under long-term PPAs.

Williams Lake

The Williams Lake power plant is a wholly-owned 66 MW biomass fired generating facility located in Williams Lake, British Columbia, that achieved commercial operation in 1993. Power is sold to BC Hydro under a PPA with the initial term expiring in 2018. BC Hydro has an option to extend the agreement by up to 10 years, on the basis of two five-year term extensions. The Williams Lake plant is operated and maintained by one of our affiliates.

The PPA contains two pricing tranches: a firm energy tranche, representing approximately 82% of the total energy produced; and a surplus energy tranche, representing approximately 18% of total energy produced. The firm energy tranche pricing consists of a fixed energy component, an operations and maintenance component (adjusted annually for average weekly earnings in British Columbia), and a reimbursable cost component. The surplus energy tranche pricing is adjusted annually for changes in the Dow Jones California Oregon Border index. However, surplus energy can be sold to a third party if a higher price is available. In 2010, the surplus energy was sold to a third party at a higher price than under the PPA. In 2011, the price of surplus energy was determined through negotiations with BC Hydro at a rate higher than what the PPA would have provided.

Williams Lake is fueled by locally purchased wood waste under six fuel supply agreements: five expiring in 2018 and one expiring in 2014. The facility also obtains wood waste from several periodic suppliers on an as-available and as-needed basis. The PPA with BC Hydro provides for the recovery of approximately 82% of the cost of fuel, thereby largely protecting the plant from the impact of increased fuel costs.

Idaho Wind

The Idaho Wind project is a 183 MW wind power project comprised of 11 wind farms located near Twin Falls, Idaho. Construction of the project began in June 2010 and it commenced commercial operation in January 2011. The Idaho Wind project is owned by Idaho Wind Partners 1, LLC ("**Idaho Wind**"), in which we own a 27.6% interest. We acquired our ownership interest in July 2010. The other owners are affiliates of GE Energy Financial Services, Reunion Power, and Exergy Development Group, the original project developer. Electricity is sold to Idaho Power Company under 11 PPAs expiring in 2030.

The project was financed in part by a consortium of lenders with a $221 million project-level credit facility that closed in October 2010. The credit facility is composed of two tranches, which are a $139 million construction loan that converted to a 17-year term loan following commercial operation, and an $83 million cash grant facility that was repaid with federal grant proceeds after completion of construction in early 2011. The remaining costs of the project of approximately $200 million were funded with a combination of owners' equity and member loans from affiliates of Atlantic Power and GE Energy Financial Services. The member loans were fully repaid in 2011. Idaho Wind's project

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financing includes credit support for the facility's obligations under the PPAs in the form of approximately $20 million of letters of credit.

Under the terms of the PPAs, Idaho Power purchases all of the electricity at fixed prices. The price paid for electricity can be reduced in the event the wind farms do not maintain a minimum level of availability or underperform relative to monthly nominations under the PPA.

An operations support agreement is in place with GE that provides for ongoing monitoring of the performance of the wind turbines as well as planned and unplanned maintenance. Idaho Wind also has a balance of plant maintenance contract with Caribou Construction to maintain the projects' substations and other equipment not associated with the wind turbines. Day-to-day operations and maintenance is provided by an affiliate of Reunion Power under a management services agreement.

Our proportionate share of the Idaho Wind project's non-recourse debt was $50.9 million as of December 31, 2011, which fully amortizes by and has a final maturity in 2027. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Rockland

Rockland Wind Project LLC ("**Rockland**") owns an 80 MW wind power generating facility located near American Falls, Idaho, which commenced commercial operation in December 2011. We acquired a 30% ownership interest in Rockland in December 2011. Rockland's other owners include Ridgeline Energy, LLC, the project developer, and an affiliate of Diamond Generating Corporation. Electricity is sold to Idaho Power Company under a 25-year fixed-price PPA expiring in 2036.

The Rockland project utilizes wind turbines manufactured by Vestas Wind Systems ("**Vestas**"), which also provides an availability guarantee. Vestas provides long-term turbine operations and maintenance services to the project under a 10-year service agreement. enXco, an established provider of renewable energy development and operations and management services, is under contract to provide administrative services, plant maintenance and maintenance of the transmission lines and collection systems.

The project was project financed in March 2011 with Bank of Tokyo Mitsubishi, Sumitomo and Mizuho. The facility consisted of an $87.0 million construction loan, a $45.0 million Section 1603 cash grant bridge loan and a $5.0 million letter of credit facility. At term conversion, the construction loan converted to an $87.0 million, 15-year term loan. The term loan is fully swapped for the life of the loan at a LIBOR equivalent of 4.02%. Debt service is paid semi-annually as are distributions.

Our proportionate share of the Rockland project's debt was $39.3 million as of December 31, 2011, which is due 2031.

Frederickson

The Frederickson facility is a 250 MW combined cycle gas-fired generating facility that commenced commercial operation in 2002. The facility, located near Tacoma, Washington, also has 20 MW of duct firing capability. We indirectly own a 50.15% interest in the project. Our share of the output of the facility, approximately 125 MW, is sold to three different Washington State Public Utility Districts ("**PUDs**") under PPAs expiring in 2022. The Frederickson plant is operated and maintained by one of our affiliates.

Under each of the PPAs, Frederickson provides generating capacity and associated energy to each of the PUDs in exchange for a capacity charge, a fixed operations and maintenance charge, a variable operations and maintenance charge and a fuel charge. The PUDs supply their proportionate share of natural gas to Frederickson at a specific delivery point. Frederickson is responsible for obtaining firm transportation from such delivery point to the facility. The facility is responsible for any fixed and variable cost increases above those recoverable under the PPAs, other than costs resulting from the effects of material changes to environmental and tax laws. The remainder of the ownership interest in Frederickson, approximately 49.85%, is held by Puget Sound Energy, Inc. ("**PSE**"). The portion of Frederickson's output allocable to PSE under its ownership interest is used by PSE to meet the needs of a portion of its electrical customers.

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Koma Kulshan

The Koma Kulshan project is a 13 MW run-of-river hydroelectric generating facility located on the slopes of Mount Baker, approximately 80 miles north of Seattle, Washington. Koma Kulshan commenced commercial operations in 1990. The project has a PPA with PSE that expires in 2037. We have a 49.75% economic interest in Koma Kulshan. The other partners include Mt. Baker Corporation and Covanta Energy Corporation ("**Covanta**"). Operations and maintenance of the facility is performed under an agreement with Covanta, which expires in 2012 and is renewed annually.

Southwest Segment

Project Name	Location (State)	Type	Total MW	Economic Interest	Net MW	Primary Electric Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2013(1)	BBB+
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	2019	A
Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	2019	A
North Island	California	Natural Gas	40	100.00%	40	San Diego Gas & Electric	2019	A
Oxnard	California	Natural Gas	49	100.00%	49	Southern California Edison	2020	BBB+
Path 15	California	Transmission	N/A	100.00%	N/A	California Utilities via CAISO(2)	N/A(3)	BBB+ to A(4)
Greeley	Colorado	Natural Gas	72	100.00%	72	Public Service Company of Colorado	2013	A-
Manchief	Colorado	Natural Gas	300	100.00%	300	Public Service Company of Colorado	2022	A-
Morris	Illinois	Natural Gas	177	100.00%	77	Equistar Chemicals, LP	2023	BB-
					100	Merchant		N/A
Delta-Person	New Mexico	Natural Gas	132	40.00%	53	Public Service Company of New Mexico	2020	BB
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing and Trading	2013	AA
					9	Sherwin Alumina	2020	N/R
Canadian Hills	Oklahoma	Wind	300	99.0%	200	Southwestern Electric Power	2032	BBB
					49	Oklahoma Municipal Power Authority	2037	N/R
					48	Grand River Dam Authority	2032	N/R
PERH(5)	Illinois				14.30%			

(1) Entered into a one-year interim agreement in February 2012.

(2)

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

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

(4) Largest payers of transmission access charges supporting Path 15's annual revenue requirement are Pacific Gas & Electric (BBB+), Southern California Edison (BBB+) and San Diego Gas & Electric (A). The California

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Independent System Operator imposes minimum credit quality requirements for any participants rated A or better unless collateral is posted per the California Independent System Operator imposed schedule.

(5)

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("**PERC**"), whereby PERC will purchase our 14.3% common ownership interests in PERH. Completion of the transaction is subject to PERC obtaining financing and is expected to occur in the second quarter of 2012.

Badger Creek

The Badger Creek facility is a 46 MW simple-cycle, gas-fired cogeneration facility that commenced commercial operation in 1991. We own a 50% interest in the project. A private equity fund managed by ArcLight owns the remaining 50% interest. The output of the facility is sold to PG&E under a PPA that expires in April 2013, at which time a transition PPA will become effective ("**Transition PPA**"). The Transition PPA expires in June 2015 and is pursuant to the "Qualifying Facility and Combined Heat and Power Program Settlement Agreement" ("**Settlement Agreement")** under a proceeding at the California Public Utilities Commission achieved in November 2011. The Settlement Agreement, among other QF facilities, California's major investor-owned utilities, and numerous consumer and independent power producer groups, resolves numerous outstanding QF disputes and provides for an orderly transition from the existing QF program in California to a new QF/Combined Heat and Power program.

Under the PPA and Transition PPA, Badger provides capacity and associated energy to PG&E in exchange for a capacity charge, and an energy charge based on defined heat rates. Gas is supplied by J.P. Morgan Ventures Energy Corporation. Consolidated Asset Management Services, an affiliate of ArcLight, provides administrative services and operations and maintenance services.

Naval Station

The Naval Station Facility is a wholly-owned 47 MW cogeneration facility that supplies steam to the US Navy's San Diego Naval Station located in San Diego, California. The facility began commercial operation in 1989 and is operated and maintained by an affiliate of ours. The Naval Station plant supplies electricity to San Diego Gas & Electric Company ("**SDG&E**") pursuant to a long-term PPA, which expires in 2019. The steam agreement expires in 2018. Fuel is supplied by JP Morgan under a monthly indexed pricing agreement which links the gas price used in the PPA energy payments with similar components in the Navy steam contract to minimize the exposure to gas price volatility.

Naval Training Center

The Naval Training Center facility is a wholly-owned nominal 25 MW, dual-fuel cogeneration facility located at the U.S. Marine Corps Recruit Depot (and former Naval Training Center) in San Diego, California. The facility began commercial operation in 1989 and is operated and maintained by an affiliate of ours.

The Naval Training Center facility supplies electricity to SDG&E pursuant to a long-term PPA, which expires in 2019. A portion of the facility's output is sold to SDG&E under a Standard Offer contract with an indefinite term. The Naval Training Center facility also sells steam to the U.S. Marine Corps under an agreement that expires in 2018. Fuel is supplied by J.P. Morgan under a monthly indexed pricing agreement that links the gas price used in the PPA energy payments with similar components in the Navy steam contract to minimize the exposure to gas price volatility.

North Island

The North Island facility is a wholly-owned 40 MW cogeneration facility that serves the US Navy's North Island Naval Air Station on Coronado Island located in San Diego, California. The facility began commercial operation in 1989 and is operated and maintained by an affiliate of ours. The North Island plant supplies electricity to SDG&E pursuant to a long term PPA that expires in 2019. The facility also

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provides electricity and steam to the Navy for building heat and to service docked ships, and for the aircraft re-work facility. The steam agreement expires in 2018. Fuel is supplied by JP Morgan under a monthly indexed pricing agreement that links the gas price used in the PPA energy payments with similar components in the Navy steam contract to minimize the exposure to gas price volatility.

Oxnard

The Oxnard plant is a wholly-owned 49 MW peaker facility located in Oxnard, California, that achieved commercial operations in 1990. Electrical output from the facility is sold to Southern California Edison Company ("**SCE**") under a PPA expiring in 2020.

Oxnard uses steam in its absorption refrigeration plant to provide refrigeration services to Boskovich Farms, Inc. ("**Boskovich**") at no charge; thereby maintaining the facility's QF status. The original energy services agreement with Boskovich expired in 2005 and refrigeration services are currently being provided on a month-to-month agreement. Boskovich is an integrated vegetable and fruit grower, processor, and refrigerated/frozen food storage company.

Path 15

Path 15 consists of our ownership of 72% of the transmission system rights associated with the Path 15 transmission project, an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in central California. The Path 15 project commenced commercial operation in 2004 and facilitates the movement of power from the Pacific Northwest to southern California in the summer months and from generators in southern California to northern California in the winter months. The transmission system rights entitle us to receive an annual revenue requirement that is regulated by the FERC which established a 30-year regulatory life for the project. The annual revenue requirement is established in a triennial rate case proceeding before the FERC. Such a rate case proceeding is currently underway.

In February 2011, we filed our triennial rate application with the FERC to establish Path 15's revenue requirement for the 2011-2013 period. We engaged in a formal settlement process with FERC staff and three parties that challenged certain aspects of how Path 15 determined the rates in its filing. After exchanges of information and direct discussions, we concluded that a fair and equitable settlement between the parties was not achievable through the settlement process and therefore in September 2011, we ended settlement discussions and pursued resolution of the issues through the formal hearing process at FERC. This step was similarly taken in the prior rate case, which ultimately concluded in a settlement among the parties.

In September 2011, FERC appointed a presiding judge in Path 15's rate case hearing proceeding. Under the judge's order establishing the procedural schedule for the case, the discovery period was set for October 2011 through April 2012. In February 2011, we filed a rate application with FERC to establish Path 15's revenue requirement at $30.3 million for the 2011-2013 period. On March 7, 2012, Path 15 filed a formal settlement agreement establishing a revenue requirement at $28.8 million with the Administrative Law Judge for her review and certification to FERC for approval. All of the parties in the rate case either support or do not oppose the settlement agreement. Path 15 expects an order approving the settlement from FERC during the second quarter of 2012. During the pendency of the rate case, we continue to collect the rates we filed as permitted under the initial FERC order it received in April 2011. Those rates are subject to refund, including interest, back to October 2011 based on a final disposition of the proceeding. We believe that the resolution of this matter will not have a material impact on our financial position or results of operations.

The Path 15 project and right of way is owned and operated by Western, a US Federal power agency that operates and maintains approximately 17,000 miles of transmission lines. The project is not subject to the same operating risks of a power plant or the volatility that may arise from changes in the price of electricity or fuel.

Three of our wholly-owned subsidiaries have incurred nonrecourse debt relating to our interest in Path 15. Total debt outstanding at Path 15 as of December 31, 2011 was $145.9 million, which is required to fully amortize over their remaining terms through 2028. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Greeley

The Greeley facility is a 72 MW combined cycle, gas-fired cogeneration facility located near Greeley, Colorado. Greeley commenced commercial operation in 1988 and is operated and maintained by one of our affiliates. We indirectly own 100% of the project. The electrical output of the facility is sold to PSCo under a PPA expiring in 2013 that provides for the payment of a monthly capacity and energy payment to Greeley. Steam is sold to the University of Northern Colorado ("**UNC**") under a thermal sales agreement ("**TSA**"), which also expires in 2013. Under the TSA, the Greeley facility is obligated to sell steam to UNC only as steam is generated during the production of electrical energy for sale to PSCo. The steam is priced such that UNC receives a discount versus its avoided natural gas-fired boiler costs. The natural gas supply for Greeley is obtained on the spot market.

Manchief

The Manchief facility is a 300 MW simple-cycle, gas-fired generating plant located in Brush, Colorado. We indirectly own 100% of Manchief. The project achieved commercial operation in 2000 and sells its output to PSCo under a PPA expiring in 2022. The current expiry date of the PPA is a result of a ten-year extension agreed to with PSCo in 2006. Under the PPA, Manchief receives capacity payments and energy payments. The capacity payment is based on the plant's actual net generating capacity available in any given hour up to 301.8 MW. Energy payments are based on the actual electrical energy dispatched by PSCo and consist of tolling fees, start-up fees, heat rate adjustment payments (payable either to or by Manchief) and natural gas transportation charges. PSCo is responsible for providing gas supply to Manchief.

The project and PSCo have entered into an option agreement under which PSCo has the right, in the eighth year of the PPA extension term, to acquire the Manchief facility for $56.5 million. If PSCo exercises its purchase option, we would receive a fixed purchase price, as specified in the option agreement.

Manchief is operated and maintained by CEM pursuant to a ten year O&M agreement.

Morris

Morris is a wholly-owned 177 MW combined cycle natural gas-fired cogeneration facility located adjacent to the Equistar Chemicals, LP ("**Equistar**") manufacturing facility in Morris, Illinois. We indirectly own 100% of Morris which operates and maintains the facility. The plant sells electricity and steam to Equistar under an energy supply agreement ("**ESA**") that expires in 2023, and additional electricity into the PJM merchant market. The facility achieved commercial operation in 1998.

Under the ESA, Equistar pays a tiered energy rate based on the amount of energy consumed up to a maximum of 77 MW. Equistar also pays capacity payments consisting of a non-escalating fixed fee and a variable fee. The steam price under the ESA is based on a tiered pricing schedule calculated as a function of the delivered price of fuel to Equistar. The ESA provides for the renegotiation of the steam pricing if steam demand falls below a set range for a stipulated period of time. Equistar has the right to purchase Morris at fair market value at the end of 2013, 2018 and 2023.

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The facility purchases natural gas under a long-term agreement with Tenaska Power Services Company ("**Tenaska**") that expires in 2016. Under the supply agreement, gas pricing is indexed to the Chicago City Gate delivery point. Additionally, Tenaska provides power market trading services through a year-to-year agreement.

PERH

We hold 14.3% of the common ownership interests in PERH. The remaining interest in PERH is held by Primary Energy Recycling Corporation ("**PERC**"), a public company listed on the Toronto Stock Exchange. PERH owns 100% of Primary Energy Operations, LLC, which in turn owns, through its subsidiaries, four wholly-owned recycled energy projects and a 50% interest in a pulverized coal facility.

Pursuant to a long-term management agreement with PERC (the "**PERC Management Agreement**"), a subsidiary of Atlantic Power provides management and administrative services to PERH and its subsidiaries and, if and to the extent requested by PERC, provides certain administrative services. The initial term of the PERC Management Agreement expires in 2025. In consideration for providing the management and administrative services, we receive a base annual management fee.

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

Delta-Person

The Delta-Person project, a 132 MW natural gas-fired peaking facility located near Albuquerque, New Mexico, commenced commercial operation in 2000. We own a 40% interest in Delta-Person and affiliates of Olympus Power, LLC, John Hancock Mutual Life Insurance Company, and ArcLight own the remaining interests. Delta-Person sells all of its electrical output to PNM (formerly Public Service of New Mexico) under a PPA that expires in 2020. The development and construction of the project was financed with two non-recourse term loans expiring in 2017 and 2019, both of which fully amortize over their remaining terms. Our share of the total debt outstanding at Delta-Person as of December 31, 2011 was $9.4 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

The PPA provides for payments from PNM for energy, capacity, house load and other applicable charges. In order to receive its full capacity payments, the Delta-Person project must maintain a minimum availability level. Fuel is provided to the project by an affiliate of PNM. The project's fuel costs are reimbursed by PNM under the PPA.

Olympus Power provides asset management services, which include operational and contractual oversight of the facility and other administrative services. A contractual services agreement in place with GE provides for major maintenance services the cost of which are passed through to PNM under the PPA.

Gregory

The Gregory project is a 400 MW natural gas-fired, combined cycle cogeneration facility located near Corpus Christi, Texas which commenced commercial operation in 2000. Our ownership interest in Gregory is approximately 17%. The other owners include affiliates of John Hancock Life Insurance Company and Rockland Capital. Gregory sells approximately 345 MW of electricity to Fortis Energy Marketing and Trading GP ("**Fortis**"), up to 33 MW of energy to Sherwin Alumina Company

("**Sherwin**") and the remainder in the spot market. The project is located on a site adjacent to the Sherwin alumina production facility, which also serves as Gregory's steam customer. The development and construction of the Gregory project was financed, in part, with a non-recourse loan that matures in 2017 and amortizes over its remaining term. Our share of the total debt outstanding at the Gregory project as of December 31, 2011 was $12.6 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-Level Debt" for additional details.

Electricity is sold to Fortis under a PPA that expires in December 2013. Fortis pays Gregory a capacity payment based on a fixed rate, and an energy payment based on a natural gas price index and a contract heat rate. Sales to Fortis consist of two tranches: a must run block that corresponds to the project's minimum energy output needed to satisfy Sherwin's electricity and steam requirements, and a dispatchable block that can be scheduled at the option of Fortis.

Steam is sold to Sherwin under an agreement that expires in 2020. Under the steam agreement, Gregory is the exclusive source of steam to the Sherwin alumina plant up to a specified maximum amount.

Gregory purchases natural gas under various short-term and long-term agreements. The project has the option of procuring 100% of its gas requirements from Kinder Morgan Tejas Pipeline, LP, under a market-based gas supply agreement that expires in 2012. Gregory is in discussion to obtain a replacement gas supply agreement that will extend to the expiry of the PPA in 2013.

DPS is responsible for the operation and maintenance of the project under an agreement that terminates in 2015. Tenaska provides energy management services such to the project. Tenaska optimizes Gregory's operation in the ancillary services market of the Electric Reliability Council of Texas, purchases gas for operations, provides scheduling services, provides back-office support and serves as Gregory's retail energy provider and qualified scheduling entity.

Power Industry Overview

Historically, the North American electricity industry was characterized by vertically-integrated monopolies. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers.

In the independent power generation sector, electricity is generated from a number of energy sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. According to the North American Electric Reliability Council's Long-Term Reliability Assessment, published in November 2011, summer peak demand within the United States in the ten-year period from 2011 through 2020 is projected to increase approximately 1.1%, while winter peak demand in Canada is projected to increase 1.0%.

The non-utility power generation industry

Our 31 power generation projects are non-utility electric generating facilities that operate in the North American electric power generation industry. The electric power industry is one of the largest industries in the United States, generating retail electricity sales of approximately $369 billion in 2010, based on information published by the Energy Information Administration in November 2011. A growing portion of the power produced in the United States and Canada is generated by non-utility generators. According to the Energy Information Administration, there were approximately 5,708 independent power producers representing approximately 408 GW or 42% of capacity in 2009, the most recent year for which data are available. Independent power producers sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

Industry Regulation

Overview

In the United States, the trend towards restructuring the electric power industry and the introduction of competition in electricity generation began with the passage and implementation of the Public Utility Regulatory Policies Act of 1978, as amended ("**PURPA**"). Among other things, PURPA, as implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided cost. The FERC defines avoided cost as the incremental cost to a utility of energy or capacity which, but for the purchase from QFs, the utility would itself generate or purchase from another source. This requirement was modified in 2005, as discussed below. PURPA also provided exemptible relief from typical utility state regulatory oversight and reporting requirements.

Electric transmission assets, such as our Path 15 project, are generally regulated by the FERC on a traditional cost-of-service rate base methodology. This approach allows a transmission company to establish a revenue requirement that provides an opportunity to recover operating costs, depreciation and amortization, and a return on capital. The revenue requirement and calculation methodology is reviewed by the FERC in periodic rate cases. As determined by the FERC, all prudently incurred operating and maintenance costs, capital expenditures, debt costs and a return on equity may be collected in rates charged.

Our Canadian projects are subject to regulation by Canadian governmental agencies. In addition to U.S. environmental regulation, our facilities and operations are subject to laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, access to transmission, and the geographical location, zoning, land use and operation of a facility.

In Canada, electricity generation is subject primarily to provincial regulation. Our projects in British Columbia are thus subject to different regulatory regimes from our projects in Ontario.

Regulation generating projects

(i) United States

Ten of our power generating projects are Qualifying Facilities under PURPA and related FERC regulations. The Delta-Person and Pasco projects are exempt wholesale generators ("**EWGs**") under the Public Utility Holding Company Act of 2005, as amended ("**PUHCA**") and are therefore exempt from regulations under PUHCA. The generating projects with QF status and which are currently party to a power purchase agreement with a utility or have been granted authority to charge market-based rates are exempt from FERC rate-making authority. The FERC has granted seven of the projects the authority to charge market-based rates based primarily on a finding that the projects lack market power. The projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities.

A QF falls into one or both of two primary classes, both of which would facilitate one of PURPA's goals to more efficiently use fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind,

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solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only. With the exception of QFs, generation, transmission and distribution of electricity remained largely owned by vertically integrated electric utilities until the enactment of the Energy Policy Act of 1992 (the "**EP Act of 1992**") and subsequent orders in 1996, along with electric industry restructuring initiated at the state level. Among other things, the EP Act of 1992 enhanced the FERC's power to order open access to power transmission systems, contributing to significant growth in the independent power generation industry.

In August 2005, the Energy Policy Act of 2005 (the "**EP Act of 2005**") was enacted, which removed certain regulatory constraints on investment in utility power producers. The EP Act of 2005 also limited the requirement from PURPA that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. Finally, the EP Act of 2005 amended and expanded the reach of the FERC's corporate merger approval authority under Section 203 of the Federal Power Act.

All of our projects are subject to reliability standards developed and enforced by the North American Electric Reliability Corporation ("**NERC**"). NERC is a self-regulatory non-governmental organization which has statutory responsibility to regulate bulk power system users, generation and transmission owners and operators through the adoption and enforcement of standards for fair, ethical and efficient practices.

In March 2007, the FERC issued an order approving mandatory reliability standards proposed by NERC in response to the August 2003 northeastern U.S. blackouts. As a result, users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Manager of Operational and Regulatory Compliance to oversee compliance with liability standards and an outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

(ii) British Columbia, Canada

The vast majority of British Columbia's power is generated or procured by BC Hydro. BC Hydro is one of the largest electric utilities in Canada. BC Hydro is owned by the Province of British Columbia and is regulated by the British Columbia Utilities Commission ("**BCUC**").

BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers.

The BCUC to some extent regulates independent power producers. While the BCUC is nominally independent of the government, its chair and commissioners are effectively appointed by the provincial cabinet. All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by BCUC as being "in the public interest." The BCUC may hold a hearing in this regard. Furthermore, the BCUC may impose conditions to be contained in agreements entered into by public utilities for electricity.

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The BCUC has adopted the NERC standards as being applicable to, among others, all generators of electricity in British Columbia, including independent power producers. However, the BCUC has adopted a number of other standards, including the Western Electricity Coordinating Council ("**WECC**") standards. As a practical matter, WECC typically administers standards compliance on the BCUC's behalf.

In 2010, the *Clean Energy Act* became law in British Columbia. This Act states, among other things, that British Columbia aims to accelerate and expand development of clean and renewable energy sources within the Province of British Columbia to achieve energy self-sufficiency, economic development and job creation as well as the reduction of greenhouse gas emissions. This Act also explicitly states that British Columbia will encourage the use of waste heat, biogas and biomass to reduce waste. This Act is consistent with the British Columbia Government Energy Plan, introduced in 2009, which favors clean and renewable energy sources such as hydroelectric, wind and wood waste electricity generation.

Other provincial regulators in BC having authority over independent power producers include the British Columbia Safety Authority, the Ministry of Environment and the Integrated Land Management Bureau.

(iii) Ontario, Canada

In Ontario, the Ontario Energy Board ("**OEB**") is an administrative tribunal with authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects. No person is permitted to generate electricity in Ontario without a license from the OEB.

The OEB has the authority to effectively modify licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the licence or other irregularities in the relationship with the OEB can result in fines. While the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives.

A number of other regulators and quasi-governmental entities play a role in electricity regulation in Ontario, including the Independent Electricity System Operator ("**IESO**"), Hydro One, the Electrical Safety Authority (**"ESA**"), OEFC and the Ontario Power Authority ("**OPA**").

The IESO is responsible for administering the wholesale electricity market and controlling Ontario's transmission grid. The IESO is a non-profit corporation whose directors are appointed by the government of Ontario. The IESO's "Market Rules" form the regulatory framework for the operation of Ontario's transmission grid and electricity market. The Market Rules require, among other things, that generators meet certain equipment and performance standards and certain system reliability obligations. The IESO may enforce the Market Rules by imposing financial penalties. The IESO may also terminate, suspend or restrict participatory rights.

In November 2006, the IESO entered into a memorandum of understanding with NERC, in which it recognized NERC as the "electricity reliability organization" in Ontario. In addition, the IESO has also entered into a similar MOU with the Northeast Power Coordinating Council (the "**NPCC**"). IESO is accountable to NERC and NPCC for compliance with NERC and NPCC reliability standards. While IESO may impose Ontario-specific reliability standards, such standards must be consistent with, and at least as stringent as, NERC's and NPCC's standards.

The OPA was established in 2005 to, among other things, procure new electricity generation. As a result, the OPA enters into electricity generation contracts with electricity generators in Ontario from time to time. Although we are not presently party to any such contracts, we may seek to enter into such contracts if and when the opportunity arises.

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On April 18, 2012, the Ontario government announced its intention to merge the OPA and the IESO. The government intends to introduce legislation that would, if passed, create a single new agency. The mandate of the new, merged agency would be to establish market rules to benefit consumers, align contracts and create an electricity system that is more responsive to changing conditions. The government has not yet tabled the proposed legislation in the legislature.

Most of the operating assets of the entity formerly known as Ontario Hydro were transferred, in or around 1998, to Hydro One, IESO and a third company called Ontario Power Generation Inc. The remaining assets and liabilities were kept in OEFC. Once all of OEFC's debts (approximately $27.1 billion as of March 2011) have been retired, it will be wound up and its assets and liabilities will be transferred directly to the Government of Ontario.

The *Green Energy Act* became law in Ontario in 2009 renewable electricity generation technologies, including via a feed-in tariff program. This Act states that the Government of Ontario is, among other things, committed to fostering the growth of renewable energy projects, to removing barriers to and promoting opportunities for renewable energy projects and to promoting a green economy.

Regulation transmission project

The revenues received by the Path 15 project are regulated by the FERC through a rate review process every three years that sets an annual revenue requirement. Our filed revenue requirements are subject to review by the FERC staff as well other parties prior to their approval. Differences between our filed revenue requirements and those determined by FERC staff or interveners are subject to a formal settlement process or in the circumstance that settlement cannot be achieved, litigation.

Carbon emissions

In the United States, government policy addressing carbon emissions had gained momentum over the last two years, but more recently has slowed at the federal level. Beginning in 2009, the Regional Greenhouse Gas Initiative was established in ten Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for CO_2 emissions. These states have varied implementation plans and schedules. The two states where we have project interests, New York and New Jersey, also provide cost mitigation for independent power projects with certain types of power contracts. At the end of 2011, New Jersey withdrew from the RGGI program. Other states and regions in the United Sates are developing similar regulations and it is possible that federal climate legislation will be established in the future.

Federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have been introduced in both the U.S. House and Senate. Separately, the EPA has taken several recent actions to potentially regulate CO_2 emissions.

Additionally, more than half of the U.S. states and most Canadian provinces have set mandates requiring certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass. In order to meet CO_2 reduction goals, changes in the generation fuel mix are forecasted to include a reduction in existing coal resources, higher reliance on nuclear, natural gas, and renewable energy resources and an increase in demand-side resources. Investments in new or upgraded transmission lines will be required to move increasing renewable generation from more remote locations to load centers.

Competition

The power generation industry is characterized by intense competition, and we compete with utilities, industrial companies and other independent power producers. In recent years, there has been increasing competition among generators in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. In addition, many states and regions have aggressive Demand Side Management programs designed to reduce current load and future local growth.

The U.S. power industry is continuing to undergo consolidation which may provide attractive acquisition and investment opportunities, although we believe that we will continue to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms.

We compete for acquisition opportunities with numerous private equity funds, infrastructure funds, Canadian and U.S. independent power firms, utility genco subsidiaries and other strategic and financial players. Our competitive advantages include our competitive access to capital, experienced management team, diversified projects and stability of project cash flow.

Employees

As of February 24, 2012, we had 277 employees, 168 in the U.S. and 109 in Canada. 68 of our Canadian employees are covered by two collective bargaining agreements. During 2011, we did not experience any labor stoppages or labor disputes at any of our facilities.

Legal Proceedings

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

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview of Our Business

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("**PPA**s"), which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 megawatts (or "**MW**") in which our aggregate ownership interest is approximately 2,141 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada and a 500-kilovolt 84-mile electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. We also own a majority interest in Rollcast Energy, a biomass power plant developer in North Carolina, and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC ("**PERH**"). Twenty-three of our projects are wholly owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2012 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects under steam sales agreements to industrial and commercial purchasers. The transmission system rights we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is not an effective pass-through of fuel costs, we attempt to mitigate a significant portion of the market price risk of fuel purchases through the use of hedging strategies.

We revised our reportable business segments during the fourth quarter of 2011 upon completion of the Partnership acquisition. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Our financial results for the years ended December 31, 2010 and 2009 and three months ended March 31, 2011 have been presented to reflect these changes in our operating segments. We revised our segments to align with changes in management's resource allocation and performance assessment in making decisions regarding our operations. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss.

Current Trends in Our Business

Macroeconomic impacts

The recession caused significant decreases in both peak electricity demand and consumption that varied by region, although as always, summer and winter peak demand will also be greatly influenced by weather. This has had the effect of delaying projected increases in capacity requirements to varying degrees by region. Typically, electricity demand makes a strong recovery to pre-recession levels along with the economic recovery and the projected delays in capacity needs tend to revert to some extent as well, depending on the pace of the recovery. The reduced electricity peak demand and consumption during a recession tends to impact base load (plants that typically operate at all times) and peaking plants (those that only operate in periods of very high demand) more than mid-merit plants (those that operate for a portion of most days, but not at night or in other lower demand periods). During recessionary periods, base load plants may be called on for lower levels of off-peak generation and peaking plants may be called on less frequently as a function of their efficiency and the overall peak demand level. The actual financial impacts on particular plants depend on whether contractual provisions, such as minimum load levels and/or significant capacity payments, partially mitigate the impact of reduced demand. One other recession related industry impact was an easing of commodity costs, whose previous escalation had greatly increased new plant construction costs. The economic recovery has moved prices higher again for copper, steel and other inputs, with labor costs a function of regional power plant and general construction activity levels, which in some locations includes increased renewable project construction.

Increased renewable power projects

The combination of federal stimulus and other tax provisions in the U.S. and Canada, state renewable portfolio standards and state or regional CO_2/greenhouse gases reduction programs has provided powerful incentives to build new renewable power capacity. One simple impact of this trend is the offsetting reduction in new fossil-fired generation, with the following exception, because significant renewable capacity is being built as intermittent resources (e.g., wind and solar) there will be an increased need by system operators to have more "firming resources." These are units that can be started quickly or idle at low levels in order to be available to compensate for sudden decreases in output from the solar or wind projects. These firming resources are generally natural gas-fired generators or, in more limited locations, pumped storage or reservoir-based hydro resources. The second significant impact of increased renewable projects is the increased need for new transmission lines to move power from renewable resources in typically more remote locations, to the more highly populated electricity load centers. This transmission requirement will require significant capital and tends to encounter a long and risky development, siting and regulatory process.

Increased shale gas resources

The substantial additions of economically viable shale gas reserves and increasing production levels have put strong downward pressure on natural gas prices in both the spot and forward markets. One impact of the reduced prices is that gas-fired generators have displaced some generation from base load coal plants, particularly in the southeast U.S. Lower natural gas prices also have compressed, and in some cases turned negative, the "spark spread," which is the industry term for the profit margin between spot market fuel and power prices. Reduced spark spreads directly impact the profitability of plants selling power into the spot market with no contract, which are referred to as merchant plants.

The lower power prices can have an adverse impact on development of new renewable projects whose owners are attempting to negotiate power purchase agreements at favorable levels to support the financing and construction of the projects. The expectation of reduced future volatility of gas prices due to increased supply has reinforced a growing expectation of the role of natural gas as a "bridging fuel," helping from a carbon policy perspective to bridge the desired U.S. transition to both cleaner fuels and more commercially viable carbon removal and sequestration technologies.

Credit markets

Weak and volatile credit markets over the past three years reduced the number of lenders providing power project financing, as well as the size and length of loans, resulting in higher costs for such financing. This reduces the number of new power projects that could be feasibly financed and built. Credit market conditions for project-lending have generally improved, but are still weaker than pre-recession levels. However, base lending rates such as LIBOR have stayed quite low by historical

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standards, somewhat compensating for the increased interest rate spreads demanded by lenders. Corporate-level credit markets experienced similar adverse impacts, which impeded the ability of many development companies to obtain financing for new power projects.

Factors That May Influence Our Results

Our primary objective is to generate consistent levels of cash flow to support dividends to our shareholders, which we refer to as "Cash Available for Distribution." Because we believe that our shareholders are primarily focused on income and secondarily on capital appreciation, we provide supplementary cash flow-based non-GAAP information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and discuss our results in terms of these non-GAAP measures, in addition to analysis of our results on a GAAP basis. See "Supplementary Non-GAAP Financial Information" below for additional details.

The primary components of our financial results are (i) the financial performance of our projects, (ii) non-cash unrealized gains and losses associated with derivative instruments and (iii) interest expense and foreign exchange impacts on corporate-level debt. We have recorded net losses in four of the past five years, primarily as a result of non-cash losses associated with items (ii) and (iii) above, which are described in more detail in the following paragraphs.

Financial performance of our projects

The operating performance of our projects supports cash distributions that are made to us after all operating, maintenance, capital expenditures and debt service requirements are satisfied at the project-level. Our projects are able to generate Cash Available for Distribution because they generally receive revenues from long-term contracts that provide relatively stable cash flows. Risks to the stability of these distributions include the following:

- While approximately 46% of our power generation revenue in 2011 was related to contractual capacity payments, commodity prices do influence our variable revenues and the cost of fuel. Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel prices. For example, a portion of the natural gas required for projects in our Southeast segment is purchased at spot market prices but not effectively passed through in their PPAs. Our Orlando project should benefit from switching to market prices for natural gas when its fuel contract expires in 2013 since the contract prices are above current and projected spot prices. We have executed a hedging strategy to partially mitigate this risk. See "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging program at our Southeast segment projects. Our most significant exposure to market power prices exists at the Selkirk, Chambers and Morris projects. At Chambers, our utility customer has the right to sell a portion of the plant's output to the spot power market if it is economical to do so, and the Chambers project shares in the profits from those sales. With low demand for electricity the utility reduces its dispatch to minimum contracted levels during off-peak hours. At Selkirk, approximately 23% of the capacity of the facility is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of that portion of the facility. Additionally at Morris, approximately 56% of the facility's capacity is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of the facility. When revenue or fuel contracts at our projects expire, we may not be able to sell power or procure fuel under new arrangements that provide the same level or stability of project cash flows. In particular, the power agreements for our Kenilworth facility expires in 2012 and our Lake, Auburndale and Greeley projects expire in 2013. We expect these projects to continue operating under new PPAs and generating Cash Available for Distribution after their existing

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power contracts expire, but at significantly lower levels. The degree of the expected decline in Cash Available for Distribution is subject to market conditions when we execute new power agreements for these projects and is difficult to estimate at this time. These projects will be free of debt when their PPAs expire, which provides us with some flexibility to pursue the most economic type of contract without restrictions that might be imposed by project-level debt.

Some of our projects have non-recourse project-level debt that can restrict the ability of the project to make cash distributions. The project-level debt agreements typically contain cash flow coverage ratio tests that restrict the project's cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. The Selkirk, Gregory and Delta-Person projects and Epsilon Power Partners, the holding company for our ownership in the Chambers project, are currently not meeting their cash flow coverage ratio tests and they are restricted from making cash distributions. We expect to resume receiving distributions from Selkirk in 2012, Gregory and Delta-Person in 2014 and Epsilon Power Partners in 2013. See the "Liquidity and Capital Resources Project-Level Debt" for additional details.

Non-cash gains and losses on derivatives instruments

In the ordinary course of our business, we execute natural gas swap contracts to manage our exposure to fluctuations in commodity prices, forward foreign currency contracts to manage our exposure to fluctuations in foreign exchange rates and interest rate swaps to manage our exposure to changes in interest rates on variable rate project-level debt. Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. See "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our derivative instruments.

Interest expense and other costs associated with debt

Interest expense relates to both non-recourse project-level debt and corporate-level debt. Our convertible debentures and long-term corporate level debt are denominated in Canadian dollars. These debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt.

Critical Accounting Policies and Estimates

Accounting standards require information be included 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, the valuation of shares associated with our Long-Term Incentive Plan and the fair value of derivatives.

For a summary of our significant accounting policies, see Note 2 to the Consolidated Audited Financial Statements of Atlantic Power Corporation and Note 1 to the Quarterly Financial Statements of Atlantic Power Corporation. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others; these policies are discussed below.

Acquired assets

When we acquire a business, a portion of the purchase price is typically allocated to identifiable assets, such as property, plant and equipment, power purchase agreements or fuel supply agreements. Fair value of these assets is determined primarily using the income approach, which requires us to project future cash flows and apply an appropriate discount rate. We amortize tangible and intangible assets with finite lives over their expected useful lives. Our estimates are based upon assumptions believed to be reasonable, but which are inherently uncertain and unpredictable. Assumptions may be incomplete or inaccurate, and unanticipated events and circumstances may occur. Incorrect estimates could result in future impairment charges, and those charges could be material to our results of operations.

Impairment of long-lived assets and equity investments

Long-lived assets, which include property, plant and equipment, transmission system rights and other intangible assets and liabilities 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 calculate 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.

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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 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.

Goodwill

At December 31, 2011, we reported goodwill of $343.6 million, consisting of $331.1 million resulting from the November 5, 2011 acquisition of the Partnership, $9.0 million associated with the Path 15 project in the Southwest segment and $3.5 million that is associated with the step-up acquisition of Rollcast in March 2010 in Un-allocated Corporate segment. See Note 3, *Acquisitions and divestments* to the Consolidated Audited Financial Statements of Atlantic Power Corporation for further discussion.

We apply an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available and whether segment management regularly reviews the operating results of those components. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary, our goodwill will be impaired at that time.

We did not perform an annual impairment assessment for goodwill recorded resulting from the Partnership acquisition as no changes occurred that would impact the fair value attributed during the purchase price allocation performed at the acquisition date.

We performed our annual goodwill impairment assessment as of December 31, 2011, for Path 15 and Rollcast which are at the operating segment levels. We determined the fair value of these reporting units using an income approach. Significant inputs to the determination of fair value were as follows:

Path 15 We applied a discounted cash flow methodology to the project's long-term budget. This approach is consistent with that used to determine fair value in prior years. The cash flows in the budget are based on our estimated allowable future recoveries by the FERC for transmission revenue.

Rollcast We applied a discounted cash flow methodology to Rollcast's long-term budget. This approach is consistent with that used to determine fair value in prior years. The cash flows in the budget are based on our estimated future cash flows from projects currently in development and expected to be placed into service or sold.

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If fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, we estimated the fair value of Path 15 to exceed its carrying value by approximately 16% and the fair value of Rollcast to exceed its carrying value by approximately 414% at December 31, 2011.

Our estimate of fair value under the income approach described above is affected primarily by assumptions about the results of future rate cases and the ability of Rollcast to develop future biomass projects. Our estimates for Path 15 are based on prior rate case settlements. Estimating allowed recoveries from a regulatory agency contains significant uncertainty. If the results of future cases are not consistent with past results, our goodwill may become impaired, which would result in a non-cash charge, not to exceed $9.0 million. If Rollcast is unable to complete development of its budgeted projects our goodwill may become impaired, which would result in a non-cash charge, not to exceed $3.5 million.

Fair value of derivatives

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and 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 values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk-free interest rate. We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties.

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.

Long-term incentive plan

The officers and certain other employees of Atlantic Power are eligible to participate in the LTIP that was implemented in 2007. In the second quarter of 2010, the Board of Directors approved an

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amendment to the LTIP and the amended plan was approved by our shareholders on June 29, 2010. The amended LTIP became 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 officers' 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, for officers, if we do not meet certain 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 the fair value of the award at each balance sheet date for notional units accounted for as liability awards. The 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 accrued monthly as incremental 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 and after 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 amended LTIP is limited to 1,350,000. 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.

Recent Accounting Developments

Adopted

On January 1, 2012, we adopted changes issued by the FASB to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. The adoption of these changes had no impact on our consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements; the option to present components of other comprehensive income as part of the statement of changes in shareholders' equity was eliminated. The items that must be reported in other comprehensive income

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or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We elected to present the two-statement option. Other than the change in presentation, the adoption of these changes had no impact on our consolidated financial statements.

In September 2011, the FASB issued changes to the testing of goodwill for impairment. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, go directly to the two-step quantitative impairment test. These changes become effective for any goodwill impairment test performed on January 1, 2012 or later. We early adopted these changes for our annual review of goodwill in the fourth quarter of 2011. These changes did not have an impact on the consolidated financial statements.

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

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. These changes are reflected in Note 3, *Acquisitions and divestments*.

Issued

In May 2011, the FASB issued changes to conform existing guidance regarding fair value measurement and disclosure between US GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. These changes become effective on January 1, 2012. These changes will not have an impact on the consolidated financial statements.

In June 2011, the FASB issued changes to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements; the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity was eliminated. The items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We will adopt these changes on January 1, 2012. Other than the change in presentation, these changes will not have an impact on the consolidated financial statements.

Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2011, 2010 and 2009 and the three months ended March 31, 2012 and 2011.

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The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year ended December 31,			Three months ended March 31,	
	2011	2010	2009	2012	2011
	(in thousands of U.S. dollars)				
Project revenue					
Northeast	$ 58,201	$ 596	$	$ 66,926	$ 4,547
Southeast	160,911	163,205	148,517	41,751	41,426
Northwest	8,982			15,300	
Southwest	55,501	30,318	31,000	42,696	7,644
Unallocated Corporate and Other	1,300	1,137		937	48
	284,895	195,256	179,517	167,610	53,665
Project expenses					
Northeast	44,477	443		47,177	3,695
Southeast	120,024	124,755	117,484	30,167	31,735
Northwest	9,414			13,947	
Southwest	36,598	10,570	11,565	34,418	3,047
Unallocated Corporate and Other	3,950	1,409		4,358	542
	214,463	137,177	129,049	130,067	39,019
Project other income (expense)					
Northeast	(2,785)	6,841	2,596	(57,794)	(1,084)
Southeast	(22,189)	(13,754)	6,307	129	3,397
Northwest	(430)	326	458	557	57
Southwest	(11,245)	(9,761)	(11,147)	(5,061)	(2,146)
Unallocated Corporate and Other	196	148	(267)	(24)	(1)
	(36,453)	(16,200)	(2,053)	(62,193)	223
Total project income					
Northeast	10,939	6,994	2,596	(38,045)	(232)
Southeast	18,698	24,696	37,340	11,713	13,088
Northwest	(862)	326	458	1,910	57
Southwest	7,658	9,987	8,288	3,217	2,451
Unallocated Corporate and Other	(2,454)	(124)	(267)	(3,445)	(495)
	33,979	41,879	48,415	(24,650)	14,869
Administrative and other expenses					
Administration	38,108	16,149	26,028	7,833	4,054
Interest, net	25,998	11,701	55,698	22,036	3,968
Foreign exchange loss (gain)	13,838	(1,014)	20,506	986	(658)
Other (income) expense, net		(26)	362		
Total administrative and other expenses	77,944	26,810	102,594	30,855	7,364
Income (loss) from operations before income taxes	(43,965)	15,069	(54,179)	(55,505)	7,505
Income tax expense (benefit)	(8,324)	18,924	(15,693)	(16,291)	1,523
Net (loss) income	(35,641)	(3,855)	(38,486)	(39,214)	5,982
Net loss attributable to noncontrolling interest	(480)	(103)		(161)	(154)
Preferred share dividends of a subsidiary company	3,247			3,239	
Net (loss) income attributable to Atlantic Power Corporation	$ (38,408)	$ (3,752)	$ (38,486)	$ (42,292)	$ 6,136

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Consolidated Overview

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. The consolidated results of operations are discussed below by reportable segment. The consolidated results of operation include the results of operation from the Partnership beginning on the acquisition date of November 5, 2011.

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

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Quantitative and Qualitative Disclosures About Market Risk" for additional information); (2) the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations; and (3) the related deferred income tax expense (benefit) associated with these non-cash items.

Cash available for distribution was $59.8 million and $16.6 million for the three months ended March 31, 2012 and 2011, respectively. Cash available for distribution was $82.2 million, $65.5 million and $66.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. See "Cash Available for Distribution" for additional information.

Income (loss) from operations before income taxes for the three months ended March 31, 2012 and 2011 was $(55.5) million and $7.5 million, respectively. Income (loss) from operations before income taxes for the years ended December 31, 2011, 2010 and 2009 was $(44.0) million, $15.1 million and $(54.2) million, respectively. See "Segment Analysis" below for additional information.

Segment Analysis

Northeast

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

	Year ended December 31,			Three months ended March 31,	
Northeast	**2011**	**2010**	**2009**	**2012**	**2011**
Project Income	$ 10,939	$ 6,994	$ 2,596	$ (38,045)	$ (232)

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

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

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

These decreases were partially offset by:

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

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project income for 2011 increased $3.9 million or 56% from 2010 primarily due to:

- increased project income of $2.8 million at Cadillac which was acquired in December 2010;
- increased project income of $3.0 million at Selkirk attributable to higher capacity revenues resulting from the recognition of previously deferred revenues; and
- project income from the newly acquired Curtis Palmer project of $3.6 million and Tunis project of $1.7 million.

These increases were partially offset by:

- decreased project income of $6.3 million at Chambers primarily attributable to increased operations and maintenance costs incurred in connection with a forced outage during July 2011, lower dispatch compared to 2010 and $3.2 million non-cash adjustment to the project's asset retirement obligation;
- lower project income of $1.4 million at Onondaga Renewables which recorded a $1.5 million asset impairment; and
- elimination of project income at Rumford which was sold in 2010 of $1.2 million.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project income for 2010 increased $4.4 million or 169% from 2009 primarily due to:

- increased project income of $6.4 million at Chambers due to lower maintenance costs in 2010 compared to 2009, which included a planned steam turbine overhaul, higher dispatch during a warmer summer in 2010 compared to 2009 and a $1.2 million non-cash change in fair value of derivative instruments associated with its interest rate swaps; and
- increased project income of $3.1 million at Rumford primarily due to a $1.5 million pre-tax gain on the sale of our equity investment in the project.

These increases were partially offset by:

- decreased project income of $1.9 million at Topsham due to a $2.0 million pre-tax long-lived impairment charge; and
- decreased project income of $3.2 million at Selkirk primarily attributable to a $2.1 million non-cash change in the fair value of a natural gas contract that is recorded at fair value and lower operations and maintenance expenses.

Southeast

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

Year ended December 31,	Three months ended March 31,

Southeast	2011	2010	2009	2012	2011
Project Income	$ 18,698	$ 24,696	$ 37,340	$ 11,713	$ 13,088

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

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

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

These decreases were partially offset by:

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project income for 2011 decreased $6.0 million or 24% from 2010 primarily due to:

- decreased project income of $14.9 million at Piedmont due to non-cash change in the fair value of the interest rate swaps related to the project's non-recourse construction financing;
- decreased project income of $3.5 million at Orlando primarily due to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher operations and maintenance expenses resulting from a planned major gas turbine overhaul; and
- lower project income of $2.4 million at Pasco due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs on the generator and boiler during 2011.

These decreases were partially offset by:

- increased project income of $7.9 million at Lake primarily attributable to a decrease of $7.0 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as lower fuel expenses attributable to lower prices on natural gas swaps; and
- increased project income of $6.7 million at Auburndale primarily attributable to $2.4 million increased revenue from annual contractual escalation of capacity payments, the decrease of $2.1 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher dispatch in 2011.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project income for 2010 decreased $12.6 million or 34% from 2009 primarily due to:

- decreased project income of $6.3 million at Auburndale due to increase in charge associated with non-cash change in fair value of derivative instruments associated with its natural gas swaps; and

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decreased project income of $13.1 million due to the absence of Mid-Georgia during 2010. The Mid-Georgia project was sold in the fourth quarter of 2009.

These decreases were partially offset by:

increased project income of $3.4 million at Lake due to earnings favorable off-peak dispatch during the summer months as well as annual escalation of capacity payments; and

increased project income of $3.3 million at Piedmont due to non-cash change in the fair value of the interest rate swaps related to the project's non-recourse construction financing.

Northwest

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

	Year ended December 31,			Three months ended March 31,	
Northwest	**2011**	**2010**	**2009**	**2012**	**2011**
Project Income	$ (862)	$ 326	$ 458	$ 1,910	$ 57

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

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

project income of $0.8 million from the newly acquired Mamquam project;

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

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project income for 2011 decreased $1.2 million or 364% from 2010 primarily due to a $1.6 million project loss at Idaho Wind which became operational in 2011. This was offset by $0.4 million of project income from the newly acquired Frederickson project.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project income in the Northwest segment for the year ended December 31, 2010 did not change significantly from 2009.

Southwest

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

	Year ended December 31,			Three months ended March 31,	
Southwest	**2011**	**2010**	**2009**	**2012**	**2011**
Project Income	$ 7,658	$ 9,987	$ 8,288	$ 3,217	$ 2,451

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

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

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

This increase was partially offset by:

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project income for 2011 decreased $2.3 million or 23% from 2010 primarily due to:

- decreased project income of $1.6 million at Gregory attributable to higher gas prices due to a favorable gas hedge that expired at the end of 2010;

- decreased project income of $0.7 million at Badger due to lower capacity payments under a new one-year interim power purchase agreement beginning in April 2011; and

- project loss of $1.6 million from the newly acquired Oxnard project.

These decreases were partially offset by project income of $1.5 million from the newly acquired Manchief project.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project income for 2010 increased $1.7 million or 20% from 2009 primarily due to the absence of losses from the Stockton project. The Stockton project, which had $2.5 million in losses in 2009, was sold in the fourth quarter of 2009.

Un-allocated Corporate

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

	Year ended December 31,			Three months ended March 31,	
	2011	2010	2009	2012	2011
Un-Allocated Corporate					
Project loss	$ (2,454)	$ (124)	$ (267)	$ (3,445)	$ (495)
Administration	38,108	16,149	26,028	7,833	4,054
Interest, net	25,998	11,701	55,698	22,036	3,968
Foreign exchange loss (gain)	13,838	(1,014)	20,506	986	(658)
Other (income) expense, net		(26)	362		
Total administrative and other expenses	$ 77,944	$ 26,810	$ 102,594	$ 30,855	$ 7,364
Income tax expense (benefit)	$ (8,324)	$ 18,924	$ (15,693)	$ (16,291)	$ 1,523

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

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

- increased administration expense of $3.8 million primarily due to the costs of administration subsequent to the acquisition of the Partnership;
- increased interest expenses of $18.1 million primarily due to issuance of the Senior Notes in the fourth quarter of 2011 as well as debt assumed in our acquisition of the Partnership; and
- increased foreign exchange loss of $1.6 million primarily due to a $12.6 million increase in unrealized loss on foreign exchange forward contracts and a $1.6 million decrease in unrealized losses in the revaluation of instruments denominated in Canadian dollars offset by a $9.4 million increase in realized gains on foreign exchange contract settlements. The U.S. dollar to Canadian dollar exchange rate decreased by 1.9% in the three months ended March 31, 2012 compared to a decrease of 2.5% in the comparable 2011 period.

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Total administrative and other expenses for 2011 increased $51.1 million or 191% from 2010 primarily due to:

- increased administration expense of $21.7 million primarily due to costs incurred related to the acquisition of the Partnership;
- increased interest expenses of $14.3 million primarily due to issuance of the Senior Notes in the fourth quarter of 2011 as well as debt assumed in our acquisition of the Partnership; and
- increased foreign exchange loss of $14.9 million primarily due to a $17.8 million increase in unrealized losses on foreign exchange forward contracts and an $11.8 million increase in realized losses on foreign exchange contract settlements, offset by a $14.7 million unrealized gain in the revaluation of instruments denominated in Canadian dollars. The U.S. dollar to Canadian dollar exchange rate increased by 2.3% in 2011 compared to a decrease of 5.7% in 2010.

Income tax benefit for 2011 was $8.3 million. The difference between the actual tax benefit of $8.3 million and the expected income tax benefit, based on the Canadian enacted statutory rate of 26.5%, of $11.7 million for the year ended December 31, 2011 is primarily due to a $9.4 million increase in the valuation allowance offset by a benefit of $5.6 million related to different tax rates for operating projects in the United States. The income tax expense for 2010 was $18.9 million. The difference between the actual tax expense of $18.9 million and the expected income tax expense, based on the Canadian enacted statutory rate of 28.5%, of $4.3 million for the year ended December 31, 2010 is primarily due to a $12.3 million increase in the valuation allowance and a $1.5 million additional tax expense related to different tax rates for operating projects in the United States.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Total administrative and other expenses for 2010 decreased $75.8 million or 74% from 2009 primarily due to:

- decreased management fees of $14.1 million due to a non-cash charge associated with the termination of the management agreements at the end of 2009. Effective December 31, 2009,

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Atlantic Power Management, LLC no longer provides management and administrative services for our company; and

decreased interest expenses of $44.0 million due to extinguishment of the subordinated notes that were outstanding and converted to common stock at the end of 2009. In November 2009, we completed our common share conversion, which resulted in the extinguishment of Cdn$347.8 million ($327.7 million) principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

These decreases were partially offset by increased foreign exchanges loss (gain) of $21.5 million due to a decrease in the exchange rate from U.S. dollar to Canadian dollar. The exchange rate decreased by 5.7% in 2010 compared to a decrease of 15.9% in 2009.

Income tax expense for 2010 was $18.9 million. The difference between the actual tax expense of $18.9 million and the expected income tax expense, based on the Canadian enacted statutory rate of 28.5%, of $4.3 million for the year ended December 31, 2010 is primarily due to a $12.3 million increase in the valuation allowance and a $1.5 million additional tax expense related to different tax rates for operating projects in the United States. The income tax benefit for 2009 was $15.7 million. The difference between the actual tax benefit of $15.7 million and the expected income tax benefit, based on the Canadian enacted statutory rate of 30.0%, of $16.2 million for the year ended December 31, 2009 is primarily due to a $22.0 million increase in the valuation allowance offset by recording a $13.2 million deferred tax benefit related to the expected benefit of utilizing a portion of our Canadian net operating losses in 2010 and a $5.4 million additional tax benefit related to different tax rates for operating projects in the United States.

Supplementary Non-GAAP Financial Information

The key measure we use to evaluate the results of our business is Cash Available for Distribution. Cash Available for Distribution is not a measure recognized under GAAP, does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. We believe Cash Available for Distribution is a relevant supplemental measure of our ability to pay dividends to our shareholders. A reconciliation of net cash provided by operating activities to Cash Available for Distribution is set out below under "Cash Available for Distribution." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

The primary factor influencing Cash Available for Distribution is cash distributions received from the projects. These distributions received are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service and capital expenditures, dividends paid on preferred shares of a subsidiary company and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use unaudited Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is set out below by segment under "Project Adjusted EBITDA." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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

	Year ended December 31,			Three months ended March 31,	
	2011	2010	2009	2012	2011
Project Adjusted EBITDA by segment					
Northeast	$ 59,299	$ 36,030	$ 32,435	$ 42,398	$ 7,488
Southeast	79,445	78,245	75,265	21,674	19,588
Northwest	11,363	736	822	13,439	866
Southwest	37,717	37,867	35,891	18,764	8,501
Un-allocated corporate	(2,546)	(294)	(234)	(3,424)	(450)
Total	185,278	152,584	144,179	92,851	35,993
Reconciliation to project income					
Depreciation and amortization	95,564	65,791	67,643	49,945	17,437
Interest expense, net	27,990	23,628	31,511	8,868	6,240
Change in the fair value of derivative instruments	25,334	17,643	5,047	58,422	(2,784)
Other (income) expense	2,411	3,643	(8,437)	266	231
Project income	$ 33,979	$ 41,879	$ 48,415	$ (24,650)	$ 14,869

Northeast

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

	Year ended December 31,			Three months ended March 31,	
Northeast	**2011**	**2010**	**2009**	**2012**	**2011**
Project Adjusted EBITDA	$ 59,299	$ 36,030	$ 32,435	$ 42,398	$ 7,488

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

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

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project adjusted EBITDA for 2011 increased $23.3 million or 65% from 2010 primarily due to:

- increased EBITDA of $8.7 million at Cadillac which was acquired in December 2010;

increased EBITDA of $1.6 million at Selkirk attributable to higher energy and capacity revenues resulting from the recognition of previously deferred revenue;

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EBITDA of $8.2 million at the newly acquired Curtis Palmer project;

EBITDA of $2.8 million at the newly acquired Tunis project; and

EBITDA of $1.9 million at the newly acquired North Bay project.

These increases were partially offset by:

decreased EBITDA of $2.8 million at Chambers attributable to lower dispatch and increased operations and maintenance costs incurred in connection with a forced outage during July 2011 compared to 2010; and

decreased EBITDA of $1.9 million at Topsham which was sold during the second quarter of 2011 and generated no EBITDA during 2011.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project adjusted EBITDA for 2010 increased $3.6 million or 11% from 2009 primarily due to increased EBITDA of $5.7 million at Chambers due to lower operations and maintenance costs in 2010 as compared to 2009, which had a planned steam turbine generator overhaul outage, as well as higher generation due to better market prices on the ACE PPA; offset by

decreased EBITDA of $2.6 million due to the absence of Rumford EBITDA as the project was sold in the fourth quarter of 2010 and generated no EBITDA during 2010.

Southeast

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

	Year ended December 31,			Three months ended March 31,	
Southeast	**2011**	**2010**	**2009**	**2012**	**2011**
Project Adjusted EBITDA	$ 79,445	$ 78,245	$ 75,265	$ 21,674	$ 19,588

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

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

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project adjusted EBITDA for 2011 increased $1.2 million or 2% from 2010 primarily due to increased EBITDA of $4.0 million at Auburndale due to higher dispatch and increased capacity payments under contractual escalation of the PPA.

This increase was partially offset by:

decreased EBITDA of $2.4 million at Pasco due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs on the generator and boiler during 2011; and

decreased EBITDA of $1.2 million at Orlando due to higher operations and maintenance expenses resulting from a planned major gas turbine overhaul.

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Year ended December 31, 2010 compared with Year ended December 31, 2009

Project adjusted EBITDA for 2010 increased $3.0 million or 4% from 2009 primarily due to:

- increased EBITDA of $6.1 million at Lake due to earnings from favorable off-peak dispatch during the summer months of 2010 and increased contractual capacity payments under the project's PPA; and

- increased EBITDA of $1.4 million at Pasco primarily attributable to a maintenance outage during the year ended December 31, 2009.

These increases were partially offset by:

- decreased EBITDA of $1.0 million at Auburndale due to higher maintenance costs in 2010 and a longer scheduled down-time during a planned outage; and

- decreased EBITDA of $2.5 million at Mid-Georgia. Mid-Georgia was sold in the fourth quarter of 2009.

Northwest

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

	Year ended December 31,			Three months ended March 31,	
Northwest	**2011**	**2010**	**2009**	**2012**	**2011**
Project Adjusted EBITDA	$ 11,363	$ 736	$ 822	$ 13,439	$ 866

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

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

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

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

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project adjusted EBITDA for 2011 increased $10.6 million or greater than 100% from 2010 primarily due to:

- increased EBITDA of $4.4 million at Idaho Wind which became operational in the first quarter of 2011;

- EBITDA of $2.7 million from newly acquired Williams Lake project; and

- EBITDA of $2.1 million from the newly acquired Frederickson project.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project adjusted EBITDA in the Northwest segment for the year ended December 31, 2010 did not change significantly from 2009.

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Southwest

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

	Year ended December 31,			Three months ended March 31,	
Southwest	**2011**	**2010**	**2009**	**2012**	**2011**
Project Adjusted EBITDA	$ 37,717	$ 37,867	$ 35,891	$ 18,764	$ 8,501

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

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

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

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

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

These increases were partially offset by:

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project adjusted EBITDA for 2011 decreased less than 1% from 2010 primarily due to:

- decreased EBITDA of $2.4 million at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement beginning in April 2011; and

- decreased EBITDA of $2.9 million at Gregory attributable to higher gas prices due to a favorable gas hedge that expired at the end of 2010.

These decreases were partially offset by:

- EBITDA of $3.6 million from the newly acquired Manchief project.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Project adjusted EBITDA for 2010 increased $2.0 million or 6% from 2009 primarily due to:

- increased EBITDA of $1.0 million at Stockton. In 2009, Stockton had an EBITDA loss of $1.0 million and was sold in the fourth quarter of 2009; and

- increased EBITDA of $1.0 million at Path 15 due to lower operations and maintenance expenses.

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Generation and Availability

	Year ended December 31,			Three months ended March 31,	
	2011	**2010**	**2009**	**2012**	**2011**
Aggregate power generation (Net MWh)					
Northeast	1,207,961	784,683	786,039	665,193	207,640
Southeast	1,770,800	1,935,649	1,848,751	459,272	430,325
Northwest	338,678	21,418	18,087	248,048	22,991
Southwest	877,338	643,811	819,354	580,392	158,385
Total	4,194,777	3,385,562	3,472,231	1,952,905	819,341
Weighted average availability					
Northeast	93.0%	92.6%	87.9%	98.6%	80.5%
Southeast	98.3%	95.7%	98.4%	98.5%	99.3%
Northwest	99.7%	98.8%	99.8%	93.2%	97.7%
Southwest	96.5%	96.9%	92.8%	93.2%	94.6%
Total	96.5%	95.3%	95.1%	96.3%	93.8%

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

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

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

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

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

This increase was partially offset by:

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

Year ended December 31, 2011 compared with Year ended December 31, 2010

Aggregate power generation for 2011 increased 23.9% from 2010 primarily due to:

- increased generation in the Northeast segment primarily due to 314,211 MWh from newly acquired Partnership projects;

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increased generation in the Northwest segment primarily due to 198,821 MWh from newly acquired Partnership projects as well as generation from Idaho Wind which became operational in the first quarter of 2011; and

increased generation in the Southwest segment primarily due to 340,498 MWh from newly acquired Partnership projects.

These increases were partially offset by:

decreased generation in the Southeast segment attributable to the Lake project that dispatched during off-peak hours due to favorable market conditions in 2010 and not in 2011 as well as scheduled major maintenance at the Orlando project during 2011.

Year ended December 31, 2010 compared with Year ended December 31, 2009

Aggregate power generation for 2010 decreased 2.5% from 2009 primarily due to:

decreased generation in the Southwest segment from the absence of the Stockton project which was sold in 2009.

This decrease was partially offset by:

increased generation in the Southeast segment due primarily to increased generation at Lake associated with dispatch during off-peak hours due to favorable market conditions.

Consolidated Cash Flows

At March 31, 2012, cash and cash equivalents increased $46.0 million from December 31, 2011 to $106.6 million. The increase in cash and cash equivalents was primarily due to $66.4 million provided by operating activities and $150.1 million of cash provided by financing activities, offset by and $170.6 million of cash used in investing activities.

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

At December 31, 2011, cash and cash equivalents increased $15.2 million from December 31, 2010 to $60.7 million. The increase in cash and cash equivalents was due to $55.9 million provided by operating activities and $641.2 million of cash provided by financing activities offset by $682.0 million of cash used for investing activities.

At December 31, 2010, cash and cash equivalents decreased $4.4 million from December 31, 2009 to $45.5 million. The decrease in cash and cash equivalents was due to $147.0 million used in investing activities offset by $87.0 million provided by operating activities and $55.7 million of cash provided by financing activities.

	Year ended December 31,			Three months ended March 31,	
	2011	**2010**	**2009**	**2012**	**2011**
Net cash provided by operating activities	$ 55,935	$ 86,953	$ 50,449	$ 66,492	$ 20,347
Net cash (used in) provided by investing activities	(682,008)	(146,997)	24,958	(170,615)	(18,115)
Net cash (used in) provided by financing activities	641,227	55,691	(62,884)	150,081	(19,471)

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Operating Activities

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

Cash flows from operating activities increased by $46.1 million for the three months ended March 31, 2012 over the comparable period in 2011. The change from the prior year is primarily attributable to the increases in Project adjusted EBITDA noted above.

Cash flow from operating activities decreased by $31.0 million for the year ended December 31, 2011 over the comparable period in 2010. The change from the prior year is primarily attributable to approximately $33.0 million in transaction expenses related to the Partnership acquisition during 2011 and the timing of the five Ontario projects in the Northeast segment November receivables received in early January of approximately $15.0 million. These decreases were offset by an increase of approximately $12.0 million of earnings and distributions from our equity investment projects.

Cash flow from operating activities increased by $36.5 million for the year ended December 31, 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 November 2009, which eliminated Cdn$347.8 million ($327.7 million) of outstanding subordinated notes, as well as higher net cash tax refunds of $8.0 million. The positive change in operating cash flow attributable to the reduced interest expense was partially offset by a $5.8 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.

Investing Activities

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

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

Cash flows used in investing activities for the year ended December 31, 2011 were $682.0 million compared to cash flows used in investing activities of $147.0 million for the year ended December 31, 2010. The change is due to the $579.1 million cash paid for the Partnership acquisition net of cash acquired. We also invested $118.1 million in 2011 for the construction-in-progress for our Piedmont biomass project.

Cash flows used in investing activities for the year ended December 31, 2010 were $147.0 million compared to cash flows provided by investing activities of $25.0 million for the year ended December 31, 2009. We acquired a 27.6% equity interest in Idaho Wind for $38.9 million and

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approximately $3.1 million in transaction costs. In addition, we loaned $22.8 million to Idaho Wind to temporarily fund a portion of construction costs at the project. We acquired 100% interest of Cadillac Renewable Energy for $36.6 million and assumed $43.1 million in non-recourse project-level debt. We invested $47.7 million for the construction-in-progress for our Piedmont biomass project.

Financing Activities

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

Cash provided by financing activities for the year ended December 31, 2011 resulted in a net inflow of $641.2 million compared to a net inflow of $55.7 million for the same period in 2010. The change from the prior year is primarily attributable to $438.0 million in net proceeds from our issuance of Senior Notes in November 2011 and $155.4 million in net proceeds from our equity offering in October 2011 to fund a portion of the cash portion of the Partnership acquisition. In 2011, we also received proceeds of $100.8 million of project-level debt related to our Piedmont biomass construction project and borrowed $58.0 million from our credit facility. This was offset by a $20.0 million increase in dividends paid.

Cash provided by financing activities for the year ended December 31, 2010 resulted in a net inflow of $55.7 million compared to a net outflow of $62.9 million for the same period in 2009. The change from the prior year is primarily attributable to $72.8 million in net proceeds from our equity offering and $74.6 million in net proceeds from the issuance of convertible debentures, offset by a $40.0 million increase in dividends paid and a $6.1 million increase in project-level debt payments. We completed our common share conversion in November 2009. As a result, Cdn$347.8 million ($327.7 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 year ended December 31, 2009.

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 received the same monthly cash distributions of Cdn$1.094 per year in the form of a dividend on the new common shares. The dividend was increased to Cdn$1.15 in November 2011.

The payout ratio associated with the dividend was 55% and 114% for the three months ended March 31, 2012 and 2011, respectively. The payout ratio for the three months ended March 31, 2012 was positively impacted by an increase in working capital associated with the Ontario plants acquired in the Partnership acquisition as well as reducing our combined foreign currency forward positions as a result of the acquisition. Due to the timing of numerous working capital adjustments and the cash payments associated with our corporate level interest payments, our payout ratio will fluctuate from quarter to quarter. For example, the interest payments on the $460 million Senior Notes are due semi-annually (May and November) and will impact our payout ratios in the second and fourth quarters.

The payout ratio was 105%, 100% and 88% for the years ended December 31, 2011, 2010 and 2009, respectively. The payout ratio of 105% for the year ended December 31, 2011 is close to the range we had expected prior to the acquisition of the Partnership and includes approximately two

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months of combined results. The increase in the payout ratios from 2009 through 2011 was anticipated. We expect a material decline in the 2012 payout ratio due to a number of factors including:

- a full year's impact of the Partnership acquisition;
- increases in cash flow from our legacy portfolio of projects such as Selkirk whose project level debt will be repaid by mid-year 2012 and Chambers where we expect a resolution of the dispute with the host over electrical pricing;
- a one-time realized gain from the termination of foreign currency forwards based on combined entities' aggregate position; and
- the lower final termination payment from our prior management agreement with an Arclight affiliate.

The table below presents our calculation of cash available for distribution for the years ended December 31, 2011, 2010 and 2009 and the three months ended March 31, 2012 and 2011:

	Year ended December 31,			Three months ended March 31,	
(unaudited)					
(in thousands of U.S. dollars, except as otherwise stated)	**2011**	**2010**	**2009**	**2012**	**2011**
Cash flows from operating activities	$ 55,935	$ 86,953	$ 50,449	$ 66,492	$ 20,347
Project-Level Debt repayments	(21,589)	(18,882)	(12,744)	(2,725)	(3,400)
Interest on IPS portion of subordinated notes(1)			30,639		
Purchases of property, plant and equipment(2)	(2,035)	(2,549)	(2,016)	(716)	(338)
Transaction costs(3)	33,402				
Dividends on preferred shares of a subsidiary company	(3,247)			(3,239)	
Realized foreign currency losses on hedges associated with the Partnership transaction	16,492				
Cash Available for Distribution(5)	78,958	65,522	66,328	59,812	16,609
Interest on subordinated notes			30,639		
Dividends on common shares	86,357	65,648	27,988	32,780	18,992
Total dividends declared to shareholders	$ 86,357	$ 65,648	$ 58,627	$ 32,780	$ 18,992
Payout ratio	109%	100%	88%	55%	114%
Expressed in Cdn$					
Cash Available for Distribution	78,149	67,540	75,673	59,882	16,407
Total dividends declared to shareholders	85,437	67,914	66,325	32,667	18,623

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

(2) Excludes construction-in-progress costs related to our Piedmont biomass project and Canadian Hills wind project.

(3) Represents costs incurred associated with the Partnership acquisition.

(4) Represents realized foreign currency losses associated with foreign exchange forwards entered into in order to hedge a portion of the foreign currency exchange risks associated with the closing of the Partnership acquisition.

(5) Cash Available for Distribution is not a recognized measure under GAAP and does not have any standardized meaning prescribed by GAAP. Therefore, this measure may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information" above.

Liquidity and Capital Resources

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. A significant portion of the cash received from project distributions is used to pay dividends to our shareholders and interest on our outstanding convertible debentures, Senior Notes and other corporate level debt. We may fund future acquisitions with a combination of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non-recourse operating level debt.

We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due.

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

Capital and Major Maintenance Expenditures

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. Ongoing capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $30 million in 2012 in our project portfolio in the form of capital expenditures and major maintenance expenses. As explained above, this investment is generally paid at the project level. One of the benefits of our diverse fleet is that plant overhauls and other major expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations allow us to predict major maintenance events and balance the funds necessary for these expenditures over time. Future capital expenditures and major maintenance expenses may exceed the level in 2012 as a result of the timing of more infrequent events such as steam turbine overhauls, and gas turbine and hydroelectric turbine upgrades.

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

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

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

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

Senior Credit Facility

On November 4, 2011, we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $200.0 million of which may be utilized for letters of credit. Borrowings under the facility are available in U.S. dollars and Canadian dollars and bear interest at a variable rate equal to the U.S. Prime Rate, the London Interbank Offered Rate, or the Canadian Prime Rate, as applicable plus an applicable margin of between 0.75% and 3.00% that varies based on our corporate credit rating. The credit facility matures on November 4, 2015.

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

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

Notes of Atlantic Power Corporation

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

Notes of the Partnership

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

Notes of Atlantic Power (US) GP

Atlantic Power (US) GP, an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership, has outstanding $150.0 million aggregate principal amount of 5.87%

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

Notes of Curtis Palmer LLC

Curtis Palmer LLC has outstanding $190.0 million aggregate principal amount of 5.90% senior unsecured notes, due July 2014 (the "Curtis Palmer Notes"). Interest on the Curtis Palmer Notes is payable semi-annually at 5.90%. Pursuant to the terms of the Curtis Palmer Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Curtis Palmer Notes are guaranteed by the Partnership.

Convertible Debentures

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

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

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

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Preferred Shares Issued by a Subsidiary Company

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

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares are redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%.

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

Project-Level Debt

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at March 31, 2012 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-Level Debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. As of December 31, 2011, the covenants at the Selkirk, Gregory, Delta-Person and at Epsilon Power Partners are temporarily preventing those projects from making cash distributions to us. We expect to resume receiving distributions from Selkirk in 2012, Gregory and Delta-Person in 2014 and Epsilon Power Partners in 2013. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. For the year ended December 31, 2012, we have contributed approximately $0.48 million to Epsilon Power Partners for debt service payments on the holding company debt but do not anticipate any additional required contributions to Epsilon. In February 2012 Chambers failed one of its debt covenants and subsequently received a waiver from the creditors on February 24, 2012.

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

	Range of Interest Rates	Total Remaining Principal Repayments	2012	2013	2014	2015	2016	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 34,608	$ 1,125	$ 3,000	$ 5,000	$ 5,750	$ 6,000	$ 13,733
Piedmont(1)	3.80% - 5.20%	108,863		55,357	4,789	4,772	3,690	40,255
Canadian Hills(2)	3.30%	176,149	176,149					
Path 15	7.90% - 9.00%	145,880	8,667	9,402	8,065	8,749	9,487	101,510
Auburndale	5.10%	10,150	5,250	4,900				
Cadillac	6.40% - 8.00%	39,631	1,800	2,400	2,000	3,891	2,500	27,040
Curtis Palmer(3)	5.90%	190,000			190,000			
Total Consolidated Projects		705,281	192,991	75,059	209,854	23,162	21,677	182,538
Equity Method Projects:								
Chambers	1.70% - 7.60%	61,127	9,200	10,783	5,780	5,213	5,447	24,704
Delta-Person	1.90%	8,883	703	1,300	1,394	1,495	1,604	2,387
Selkirk	9.00%	5,845	5,845					
Gregory	2.40% - 7.70%	12,115	1,346	2,007	2,170	2,268	2,448	1,876
Rockland	6.40%	26,105	434	368	445	529	583	23,746
Idaho Wind	3.10% - 6.60%	50,365	1,529	2,198	2,364	2,554	2,511	39,209
Total Equity Method Projects		164,440	19,057	16,656	12,153	12,059	12,593	91,922
Total Project-Level Debt		$ 869,721	$ 212,048	$ 91,715	$ 222,007	$ 35,221	$ 34,270	$ 274,460

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

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

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

Restricted Cash

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

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Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations as of December 31, 2011 (in thousands of U.S. dollars):

	Less than 1 year	1 - 3 Years	3 - 5 Years	Thereafter	Total
Long-term debt including estimated interest(1)	$ 192,911	$ 655,128	$ 1,085,009	$ 652,485	$ 2,585,533
Operating leases	1,149	1,965	1,037	907	5,058
Operations and maintenance commitments	5,592	3,790	772	2,541	12,695
Fuel purchase and transportation obligations	67,712	189,966	80,961	51,777	390,416
Construction obligations	22,618				22,618
Interconnection obligations	3,510	8,455	7,831	14,413	34,209
Other liabilities	3,118	3,118	2,700	898	9,834
Total contractual obligations	296,610	862,422	1,178,310	723,021	3,060,363

(1) Debt represents our consolidated share of project long-term debt and corporate-level debt. The amount presented excludes the net unamortized purchase price adjustment of $10.6 million related to the fair value of debt assumed in the Path 15 acquisition. Project debt is non-recourse to us and is generally amortized during the term of the respective revenue generating contracts of the projects. The range of interest rates on long-term consolidated project debt at December 31, 2011 was 3.80% to 9.00%.

(2) The natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2012 to 2017.

Off-Balance Sheet Arrangements

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

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QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas and coal prices. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by passing through changes in fuel prices to the buyer of the energy.

The Tunis project is exposed to changes in natural gas prices under a combination of spot purchases and short-term contracts expiring in 2014. In 2012, projected cash distributions at Tunis would change by approximately $2.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of natural gas volumes used by the project.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In the third quarter of 2010, we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

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

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

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

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

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

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

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

Foreign Currency Exchange Risk

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars but we pay dividends to shareholders and interest on corporate-level long-term debt and on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 85% of our expected dividend, long-term debt and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At March 31, 2012, the forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$123.0 million at an average exchange rate of Cdn$1.127 per U.S. dollar. It is our intention to periodically consider extending or terminating the length of these forward contracts.

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

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counter-party's credit risk. Changes in the fair value of the

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

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

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

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of March 31, 2012:

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

Interest Rate Risk

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 83% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

We have executed an interest rate swap at our consolidated Auburndale project to economically fix a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

We have an interest rate swap at our consolidated Cadillac project to economically fix a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt. The interest rate swap expires on June 30, 2025.

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements are not designated as hedges and changes in their fair market value are recorded in the statements of operations. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other

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comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income. Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings until the expected transaction occurs.

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

MANAGEMENT AND BOARD OF DIRECTORS

This section reflects information with respect to the directors and executive officers of Atlantic Power.

The following table sets forth the names, ages and positions of the persons who serve as the directors of Atlantic Power.

Name	Age	Positions
Irving Gerstein	71	Director
Kenneth Hartwick	49	Director
John McNeil(1)	70	Director
R. Foster Duncan	58	Director
Holli Ladhani	41	Director
Barry Welch	54	Director, President and Chief Executive Officer

Irving R. Gerstein, C.M., O.Ont: The Honourable Irving R. Gerstein has been a Director since October 2004. Senator Gerstein is a Member of the Order of Canada and a Member of the Order of Ontario, and was appointed to the Senate of Canada in December 2008. He is a retired executive, and is currently a director of Medical Facilities Corporation and Student Transportation Inc., and previously served as a director of other public companies including Economic Investment Trust Limited, CTV Inc., Traders Group Limited, Guaranty Trust Company of Canada, Confederation Life Insurance Company and Scott's Hospitality Inc., and as an officer and director of Peoples Jewellers Limited. Senator Gerstein is an honorary director of Mount Sinai Hospital (Toronto), having previously served as Chairman of the Board, Chairman Emeritus and a director over a period of 25 years, and is currently a member of its Research Committee. Senator Gerstein earned his BSc in Economics from the University of Pennsylvania (Wharton School of Finance and Commerce). Mr. Gerstein's substantial experience on the boards of numerous other public companies and his prior experience as an executive of a substantial public company make him a valued advisor and highly qualified to serve as chairman of our Board of Directors and as chairman of our Nominating and Corporate Governance Committee.

Ken Hartwick, C.A.: Mr. Hartwick has been a Director since October 2004. Ken Hartwick has over 13 years of management experience in the energy sector, and more than 20 years' experience in the financial sector. Mr. Hartwick's experience in the energy industry spans several markets having played an integral role as an executive officer for Just Energy Group Inc. since April 2004, helping launch their businesses in Alberta, British Columbia, Indiana, Texas, Georgia, Manitoba, Ontario, Québec, Saskatchewan, California, Illinois, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio and Pennsylvania. He currently serves as the President and CEO for, and is a director on the board of Just Energy, an integrated retailer of commodity products. Mr. Hartwick has served as President and CEO for Just Energy Group Inc. since June 2008, as President from 2006 until June 2008, and as Chief Financial Officer from April 2004 to 2006. Mr. Hartwick understands the issues facing the electricity industry through his previous role as Chief Financial Officer of one of the largest distribution companies in North America, Hydro One Inc., where he gained increasing executive-level responsibility throughout his career, and provided strategic direction as Ontario transitions towards a competitive energy marketplace. Mr. Hartwick earned his Honours of Business Administration from Trent University, Peterborough, Ontario. Mr. Hartwick's substantial experience in the energy industry and financial sector make him a valued advisor and highly qualified to serve as a member of our Board of Directors and as chairman of our Audit and Compensation Committees.

John McNeil: Mr. McNeil has been a Director since October 2004. Mr. McNeil is President of BDR NorthAmerica Inc., an energy consulting company based in Toronto, Ontario. Prior to his appointment at BDR NorthAmerica Inc. in 2000, Mr. McNeil was Managing Director Investment Banking with Scotia Capital Inc. from 1996 to 1999. Previously, he was a Senior Vice-President and

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Director of Scotia McLeod Inc. from 1991 to 1995. Mr. McNeil has extensive expertise in the areas of asset management models, capitalization, mergers and acquisitions, business and enterprise valuations, capital markets and market ratings and has worked extensively throughout North America and Europe. Mr. McNeil specializes in the electric power sector and his major focus in recent years has been in the field of corporate and enterprise unbundling and reconstitution resulting from the restructuring of the electricity sector in North America. Mr. McNeil earned a B.A. (Honors) from Queens University, a Bachelor of Laws from the University of Toronto and a Master of Business Administration from the University of British Columbia. Mr. McNeil's extensive experience in the financial and capital markets sectors, as well as his expertise in the electric power sector, make him a valued advisor and highly qualified to serve as a member of our Board of Directors.

R. Foster Duncan: Mr. Duncan has been a Director of Atlantic Power since June 2010. He has more than 30 years of senior corporate, investment banking, and private equity experience. Mr. Duncan joined SAIL Capital Partners, LLC in April 2011 as Managing Partner of SAIL Sustainable Partners, LLC. Prior to joining SAIL, he was a Managing Director at Advantage Capital Partners with senior management responsibility for the firm's energy related portfolio. From 2005 through 2009, Mr. Duncan was Managing Member of KD Capital L.L.C., an affiliate of Kohlberg Kravis Roberts & Co. ("**KKR**"), which he and KKR formed. Mr. Duncan was located in KKR's offices and worked exclusively with KKR and its portfolio companies in connection with creating value and investing in the energy, utility, natural resources, and infrastructure sectors. Previously, Mr. Duncan was Executive Vice President and CFO of Cinergy Corp., Chairman of Cinergy's Investment Committee and CEO and President of Cinergy's Commercial Business Unit. Mr. Duncan is active with the Edison Electric Institute, serves as a member of the Wall Street Advisory Group, and is the past Chairman of the Finance Executive Advisory Committee. He has also held senior management positions at LG&E Energy Corp. and Freeport-McMoRan Copper & Gold and Howard, Weil, Labouisse, Friedrichs Inc. He graduated with Distinction from the University of Virginia and later received his MBA degree from the A.B. Freeman Graduate School of Business at Tulane University. Mr. Duncan is on the Board of Directors of Essential Power, LLC in Iselin, New Jersey, and Xtreme Power Inc. in Austin, Texas. He also serves on the Board of Advisors of GridPoint, Inc. in Arlington, Virginia. Mr. Duncan is active in a number of civic organizations including the Board of Directors of the Eye, Ear, Nose and Throat Hospital Foundation in New Orleans, the Board of Trustees of Cincinnati Country Day School and in Charlottesville, Virginia the National Advisory Board of the University of Virginia Jefferson Scholars Program. Mr. Duncan's extensive experience as a senior executive in the electric utility industry, as well as his experience in the private equity sector, make him a valued advisor and highly qualified to serve on our Board of Directors.

Holli Ladhani: Ms. Ladhani has been a Director of Atlantic Power since June, 2010. She currently serves as the Chief Financial Officer of Rockwater Energy Solutions. Houston-based Rockwater provides fluids management and environmental solutions to the energy industry in North America to uniquely address the special fluid and environmental-related challenges associates with modern day unconventional and conventional oil and gas resource development. Rockwater is controlled by SCF Partners, a private equity investor since 1989 that provides equity capital and strategic growth assistance to build energy service and equipment companies that operate throughout the world. Prior to joining SCF Partners in March, 2011, Ms. Ladhani served in a number of positions with Dynegy Inc., a provider of wholesale power, capacity and ancillary services in multiple regions of the United States, most recently as Executive Vice President and Chief Financial Officer. In November 2011, subsequent to Ms. Ladhani's departure, two Dynegy subsidiaries of which Ms. Ladhani had formerly been an officer filed for bankruptcy protection. Prior to joining Dynegy, Ms. Ladhani was a Senior Manager-Audit with PricewaterhouseCoopers LLP, where she supervised teams that provided audit services to large public companies in the oil and gas industry. A Certified Public Accountant, Ladhani received a bachelor's of science from Baylor University and a master's of business administration from Rice University. She serves on the board of His Grace Foundation, which supports

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children who undergo bone marrow transplants. Ms. Ladhani's extensive experience as a senior executive in the independent power industry, as well as her financial and accounting background, make her a valued advisor and highly qualified to serve on our Board of Directors.

Barry Welch: Mr. Welch has been our President and Chief Executive Officer since October 2004 (until December 31, 2009, through the Manager) and a Director since June 2007. Prior to joining Atlantic Power, Mr. Welch was the Senior Vice President and co-head of the Bond & Corporate Finance Group of John Hancock Financial Services ("**John Hancock**"), Boston, Massachusetts, from 2000 to 2004. Mr. Welch served on several committees at John Hancock, including its Pension Investment Advisory Committee and Investment Operating Committee. Mr. Welch was Chairman of John Hancock's Bond Investment Committee and reported monthly on investment portfolio, strategy and activity to the Committee of Finance of John Hancock's board of directors. Mr. Welch also led the development and approval of John Hancock's involvement with ArcLight Capital Partners and served as a member of ArcLight Energy Partners Fund I's Investment Committee. During his time at John Hancock, Mr. Welch headed the Bond and Corporate Finance Group's Power and Energy investment team. From 1989 to 2004, he was involved directly or oversaw $25 billion of investments in more than 1,000 utility, project finance and oil and gas transactions. Prior to joining John Hancock, Mr. Welch spent more than three years as a developer of power projects at Thermo Electron Corporation's Energy Systems Division (later known as Thermo Ecotek). There, he was involved in greenfield development of natural gas, wood and waste-to-energy projects, as well as asset management roles for operating plants. Mr. Welch earned a Bachelors of Science in Mechanical and Aerospace Engineering from Princeton University, and a Masters of Business Administration from Boston College. Mr. Welch serves on the board of directors of the Walker Home and School in Needham, Massachusetts. Mr. Welch's extensive experience in energy investment and related activities in the financial sector, as well as his in-depth knowledge of our company through his position as President and Chief Executive Officer, make him highly qualified to serve as a member of our Board of Directors.

The following table sets forth the names, ages and positions of Atlantic Power 's principal executive officer, interim principal financial officer, former principal financial officer, three other most highly compensated officer and non-officer employees, collectively referred to as the "**named executive officers**":

Name	Age	Position
Barry Welch	54	Director, President and Chief Executive Officer
Lisa Donahue	47	Interim Chief Financial Officer
Patrick Welch*	44	Former Chief Financial Officer
Paul Rapisarda	58	Executive Vice President Commercial Development
William Daniels	53	Vice President Operations East
John J. Hulburt	45	Corporate Controller

* Patrick Welch resigned on June 10, 2011.

Lisa Donahue: Ms. Donahue has been our interim Chief Financial Officer since July 2011. Ms. Donahue is a Managing Director of AlixPartners, LLP and has been performing various consulting projects on behalf of AlixPartners for the last 13 years. Ms. Donahue has extensive experience working with independent power and other energy related companies.

Paul Rapisarda: Mr. Rapisarda joined Atlantic Power in 2008. He is currently Executive Vice President Commercial Development, with primary responsibility for the company's operating portfolio, including asset management and commercial relationships, as well as its growth initiatives. Prior to joining Atlantic Power, Mr. Rapisarda spent more than 25 years working in energy, utility and

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independent power investment banking. From 2001 to early 2008 he was a Principal with Compass Advisors, a boutique M&A advisory firm in New York, where he was involved in numerous strategic advisory, restructuring and principal transactions in the energy and power sectors. Prior to Compass Advisors, Mr. Rapisarda held senior positions at Schroders, Merrill Lynch and BT Securities. Prior to that he was a Managing Director and Co-Head, Utilities and Structured Finance, at Drexel Burnham Lambert. While at Drexel, he also worked with the firm's chief financial officer in making tax-oriented investments on the firm's behalf. Mr. Rapisarda worked on a broad range of capital markets and advisory transactions including substantial experience in cross-border and emerging markets. He earned his Bachelors degree from Amherst College and his MBA from Harvard Business School.

William Daniels: Mr. Daniels has been with Atlantic Power since March 2007. He is currently Vice President Operations East. Mr. Daniels has 26 years of experience in oil and gas exploration, independent power development, project finance and asset management. Prior to joining Atlantic Power, from January 2006 to February 2007, Mr. Daniels was Director, Asset Management at American National Power. He has held various positions in asset management and project finance at Calpine Corp. (March 2001 to January 2006), Edison Mission Energy, Citizens Power, J. Makowski Company and the Toronto-Dominion Bank. Prior to receiving his MBA, he worked with Mitchell Energy Corp. as an exploration geologist. Mr. Daniels earned a Bachelor of Science degree in Geology from the University of Rochester, a Master of Science in Geology from the Ohio State University, and an MBA from Columbia University Business School.

John J. Hulburt: Mr. Hulburt has been the Corporate Controller of Atlantic Power since June 2008. Mr. Hulburt has 17 years of experience in the accounting industry. Before joining Atlantic Power, from February 2007 to June 2008, Mr. Hulburt was Controller of GreatPoint Energy, Inc. headquartered in Cambridge, Massachusetts. GreatPoint Energy is a technology-driven natural resources company and the developer of a proprietary, highly-efficient catalytic process, known as hydromethanation. Mr. Hulburt was responsible for all accounting, budgeting and financial reporting for GreatPoint Energy. Prior to that he was the Chief Financial Officer at Datawatch Corporation (December 2004 to January 2007) in Chelmsford, Massachusetts, and the Chief Financial Officer at Bruker Daltonics in Billerica, Massachusetts (April 2000 to June 2004). Datawatch and Bruker Daltonics were publicly listed Companies on the NASDAQ Exchange. He was responsible for all accounting, budgeting, SEC and financial reporting for Datawatch and Bruker Daltonics. Prior to Bruker Daltonics, Mr. Hulburt was an Audit Manager in the Hi-Technology and Manufacturing Practice of Ernst & Young LLP, where he served several major Hi-Tech and Manufacturing clients. He earned his Bachelor's degree from the Merrimack College and is a Certified Public Accountant.

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EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

Until December 31, 2009, we were managed through a management services agreement with Atlantic Power Management, LLC, which is referred to herein as the "**Manager**," which was owned by two private equity funds managed by ArcLight Capital Partners, LLC. As such, we did not have any executive officers or other employees and all of the persons listed in this Information Circular and Proxy Statement as "named executive officers" were employed by the Manager. Effective December 31, 2009, the management services agreement was terminated and all of the employees of the Manager became our employees. In addition, Barry Welch, Patrick Welch and Paul Rapisarda entered into executive employment agreements with Atlantic Power in connection with the termination of the management services agreement.

The following Compensation Discussion and Analysis ("**CD&A**") describes our compensation policies and practices as they relate to our executive officers identified in the Summary Compensation Table below (the "**named executive officers**").

2011 Achievements and Highlights

Acquired the Partnership on November 5, 2011 for a total enterprise value of approximately $1.8 billion, roughly doubling our enterprise value and market capitalization;

added 18 generation projects and increased our net generating capacity by 143% to 2,116 MW, significantly decreasing its dependence on any individual project's performance;

diversified our portfolio by adding plants in new regions of the United States and eight Canadian plants in Ontario and British Columbia and enhancing growth projects for those regions;

established Atlantic Power as the owner operator for approximately 50% of its projects;

retained 100% of Partnership's operations personnel, increasing our employee count to 277, and adding offices in Toronto, Vancouver, Chicago and San Diego;

acquired a 30% interest in Rockland Wind, an 80 MW wind farm in American Falls, Idaho in December 2011, bringing our total net generating capacity to 2,140 MW;

continued construction of 53MW Piedmont biomass facility on schedule and on budget;

met our guidance for cash generated by projects, exceeding the Board approved 2011 budget; and

substantially met the Board approved 2011 goals and objectives.

Aggregate power generation in MWh's for 2011 increased approximately 24% from the previous year primarily due to increased generation from the newly acquired Partnership projects. Weighted average availability of Atlantic Power's projects also increased by 1.3% to 96.5% for the year ended 2011 vs. 2010.

Project revenue was 46% higher than in 2010.

Cash available for distribution was 21% higher than in 2010.

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Executive Compensation Objectives

Compensation plays an important role in achieving short and long-term business objectives that ultimately drives business success in alignment with long-term shareholder goals. The objectives of our compensation program are to:

- attract and retain highly qualified executive officers with a history of proven success;
- align the interests of the executive officers with Shareholders' interests and with the execution of our business strategy;
- establish performance goals that, if met by us, are expected to improve long-term shareholder value; and
- tie compensation to performance with respect to those goals and provide meaningful rewards for achieving them.

Our compensation program is designed to provide competitive rewards for services and incentive for its senior management team to implement both short-term and long-term strategies aimed at increasing shareholder value and aligning the interests of senior management with those of the Shareholders.

Our compensation program has been established in order to compete with remuneration practices of companies similar to us and those which represent potential competition for our executive officers and other employees. In this respect, we identify remuneration practices and remuneration levels of companies that are likely to compete for its employees. In designing the compensation program, the Board of Directors focuses on remaining competitive in the market with respect to total compensation for each of the executive officers. However, the Board of Directors does review each element of compensation for market competitiveness and it may weigh a particular element more heavily based on the executive officer's role.

2011 Say on Pay Vote

At our Annual Meeting of Shareholders held on June 24, 2011, 91.47% of the votes cast on the say-on-pay proposal regarding the executive compensation of our named executive officers identified in our 2011 Information Circular and Proxy Statement were voted in favor of the proposal. The Compensation Committee believes this strong level of support affirms Shareholders' support of our approach to executive compensation. The Compensation Committee will continue to consider the outcome of our annual 'say-on-pay' votes when making future compensation decision for the named executive officers.

Elements of Executive Compensation

The compensation of each named executive officer includes a base salary, cash bonus and eligibility for awards under the long-term incentive plan. All compensation decisions for named executive officers are made by the Compensation Committee of the Board of Directors. The Compensation Committee periodically utilizes the services of Hugessen, an independent compensation consultant, to assist it in reviewing its compensation structure. Hugessen does not provide any other services to us.

Named Executive Officers in 2011

Our named executive officers in 2011 include Barry E. Welch, our President and Chief Executive Officer, Paul H. Rapisarda, our Executive Vice President Commercial Development, William B. Daniels, our Vice President Operations East and John J. Hulburt, our Corporate Controller. We also

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appointed Lisa Donahue to serve as interim Chief Financial Officer on July 12, 2011 as Patrick J. Welch, our former Chief Financial Officer, resigned on June 10, 2011.

Base salary

The base salaries for the named executive officers for 2011 were based on a review by the Compensation Committee. This review is based on the level of responsibility, the experience level attained by the relevant named executive officer, competitive salaries for similar positions in the market, and his or her personal contribution to our operating and financial performance with a goal to ensure that the base salaries are appropriate and competitive. On the basis of this review by the Board of Directors, Barry Welch's salary was increased from $535,000 to $575,000, Patrick Welch's salary was increased from $259,500 to $310,000, and Paul Rapisarda's salary was increased from $257,500 to $310,000. Lisa Donahue, our interim Chief Financial Officer, serves as an Managing Director of AlixPartners, LLP, with whom we have entered into an agreement for management services relating to fees for Ms. Donahue's services. Accordingly, Ms. Donahue's compensation is not determined by the Compensation Committee.

Barry Welch. Prior to December 31, 2009, Barry Welch was the President and Chief Executive Officer of the Manager. Beginning in 2010, Mr. Welch became our President and Chief Executive Officer. For the year ended December 31, 2011, Mr. Welch received a base salary of $575,000 and an annual bonus of $700,000.

Mr. Welch's base salary was historically established by the Manager, but reviewed by our independent directors as part of the annual approval of the Manager's budget, based on his responsibilities, his execution of our strategic business plan, whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was unchanged for 2010 and increased by $40,000 for 2011. For 2012, the Compensation Committee approved an increase in Mr. Welch's salary by $125,000 based on a review of peer company data following the Partnership acquisition as well as his accomplishments in achieving our goals and objectives and his critical role in executing our strategy.

Patrick Welch. Prior to December 31, 2009, Patrick Welch was the Chief Financial Officer and Corporate Secretary of the Manager. Beginning in 2010, Mr. Welch became our Chief Financial Officer and Corporate Secretary and he resigned from such office on June 10, 2011. For the portion of the year ended December 31, 2011 prior to his resignation, Mr. Welch received a base salary of $141,900 and an annual bonus of $260,000.

Mr. Welch's base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. Mr. Welch's salary was unchanged for 2010 and increased by $50,500 for 2011.

Paul Rapisarda. Prior to December 31, 2009, Paul Rapisarda was the Managing Director, Asset Management and Acquisitions of the Manager. Beginning in 2011, Mr. Rapisarda became our Executive Vice President Commercial Development. For the year ended December 31, 2011, Mr. Rapisarda received a base salary of $310,000 and an annual bonus of $260,000.

Mr. Rapisarda's base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was unchanged in 2010 and was increased by $52,500 in 2011. For 2012, the Compensation Committee approved an increase in Mr. Rapisarda's salary by $115,000 based on a review of peer company data following the Partnership acquisition as well as his accomplishments in achieving our goals and objectives and his critical role in executing our strategy.

William Daniels. Prior to December 31, 2009, William Daniels was the Director, Asset Management of the Manager. Beginning in 2011, Mr. Daniels became our Vice President Operations East. For the year ended December 31, 2011, Mr. Daniels received a base salary of $190,000 and an annual bonus of $175,750. In March 2011, Mr. Daniels received a grant of 10,836 notional shares under the amended LTIP with an estimated total fair market value of $129,503 as at the date of grant.

Mr. Daniels' base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was unchanged for 2010 and was increased by $5,000 in 2011. Mr. Daniels base salary was increased by $5,000 for 2012.

John Hulburt. Prior to December 31, 2009, John Hulburt was the Corporate Controller of the Manager. Beginning in 2010, Mr. Hulburt became our Corporate Controller. For the year ended December 31, 2011, Mr. Hulburt received a base salary of $188,000 and an annual bonus of $90,000. In March 2011, Mr. Hulburt received a grant of 9,187 notional shares under the amended LTIP with an estimated total fair market value of $109,795 as at the date of grant.

Mr. Hulburt's base salary was historically established by the Manager, but reviewed by our independent Directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was increased by $5,000 in 2011. Mr. Hulburt's salary was increased by $4,500 for 2012.

Annual cash bonus (non-equity incentive plan compensation)

Annual cash bonus awards for William Daniels and John Hulburt are discretionary, and generally based on whether or not duties have been performed well based on the relevant named executive officer's success in contributing to our operating and financial performance, including achieving annual goals and objectives approved by the Board. The annual goals and objectives are established at the company level and are broadly based on (i) company growth strategy through acquisitions and organic growth; (ii) operating performance of existing assets; (iii) accounting and finance; (iv) investor relations; and (v) risk management and administrative functions.

In 2011, William Daniels made significant contributions to Atlantic Power achieving its goals and objectives pertaining to operating, safety and financial performance of existing projects as well as to the successful acquisition and integration of the Partnership. In 2011, John Hulburt made significant contributions to Atlantic Power achieving its goals and objectives pertaining to timely issuances of financial statements and other required disclosures and meeting Sarbanes Oxley 404 requirements for internal control over financial reporting with no significant deficiencies or material weaknesses identified in management or external audit testing.

In the case of Barry Welch, Patrick Welch and Paul Rapisarda, for each of the three years 2009 through 2011 per the terms of their respective employment contracts there are three components: (i) pursuant to arrangements entered into at the time of the internalization of the Manager in December 2009, a portion of the annual cash bonus, identified as "Bonus" in the Summary Compensation Table on page 47, is fixed based on the average amount in 2007 and 2008 of the portion of their bonuses that were paid by the Manager and not reimbursed by us in such years; (ii) a second component is based on our total shareholder return compared to a group of our peer companies. For this portion, which is included in the column identified as "Non-equity incentive plan compensation" in the Summary Compensation Table on page 47, a scale establishes a minimum of zero and a maximum

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of 110% of a target amount equal to $300,000, $130,000 and $130,000 for Barry Welch, Patrick Welch and Paul Rapisarda, respectively. Relative performance at greater than the 10th percentile of the peer group is required to earn the minimum award and at greater than the 85th percentile of the peer group in order to earn the maximum award; and (iii) a discretionary component from zero to a maximum of 20% of the target in (ii) above, which is also included in the column identified as "Non-equity incentive plan compensation" in the Summary Compensation Table on page 47, is based on the Board's assessment of the senior officers' performance in contributing to achievement of our approved goals and objectives. Specifically in 2011, the Directors based these assessments on for Barry Welch, his contributions to the achievement of goals related to our growth strategy, operating and financial performance, risk management and investor relations and for Paul Rapisarda, his contributions to the achievement of goals related to our growth strategy and operating performance of existing assets. In 2011, Barry Welch, Patrick Welch and Paul Rapisarda received for the portion of their bonus compensation based on 2010 relative total shareholder return 80% of their target amounts, and each also received the maximum 20% of such target based on the Board's assessment of the senior officers' performance.

Total shareholder return refers to the rate of return that a shareholder would earn on an investment in common shares (or, prior to the conversion of IPSs to common shares, IPSs) assuming the investment was held for the entire year and that monthly dividends were reinvested. For 2011, the Compensation Committee included the following companies in the peer group (the "**2011 Peer Group**") for the purpose of determining our relative total shareholder return performance:

- Boralex, Inc.;
- Brookfield Renewable Power Fund;
- Capital Power Income LP;
- Northland Power Income Fund;
- Macquarie Power and Infrastructure Income Fund;
- Innergex Power Income Fund;
- Algonquin Power & Utilities Corp.;
- Maxim Power Corp.;
- 50 U.S.-listed master limited partnerships in the Alerian Index; and(1)
- 22 utilities in the S&P 400 Utility Index(1)

In 2011, our total shareholder performance return ("**TSR**") of 6.6% was at the 43rd percentile of our peer group, as calculated by IPREO.

While this TSR would result in a 2012 TSR bonus of $150,000 for Barry Welch and $65,000 for Paul Rapisarda and a total 2012 bonus of $610,000 and $221,000, respectively for them, the Compensation Committee elected to exercise its discretion and recommend one-time additional bonus payments of $140,000 for Barry Welch and $79,000 for Paul Rapisarda. This was based on recognizing their achievements related to assessing, financing and closing the transformative acquisition and beginning the successful integration of the Partnership. The Compensation Committee took into account the value to Atlantic Power of the acquisition and the strong TSR performance after absorbing the impact of the issuance of substantial additional Common Shares in October and November in connection with the acquisition. The Compensation Committee also made one-time LTIP awards to Mr. Welch and Mr. Rapisarda of 15,000 and 12,000 notional shares on March 1, 2012, respectively.

(1) In 2011, the Compensation Committee approved an expanded peer group to include the first eight in the group above as well as the companies included in the two indices.

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Annual cash bonus awards for William Daniels and John Hulburt are discretionary, and generally based on whether or not duties have been performed well based on the relevant named executive officer's success in contributing to our operating and financial performance, including achieving annual goals and objectives approved by the Board. The annual goals and objectives are established at the company level and are broadly based on (i) company growth strategy through acquisitions and organic growth; (ii) operating performance of existing assets; (iii) investor relations; and (iv) risk management and administrative functions.

Annual Bonuses

For the annual bonus paid in 2011 based on the 2010 performance year, Barry Welch's bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus had been paid for the prior two years, or $400,000. The other portion of Mr. Welch's bonus was determined based on the sum of $240,000 determined by our 2010 total shareholder return performance relative to our peer group and a maximum $60,000 based on the independent directors' assessment of his performance against annually approved goals and objectives.

For the 2011 performance year, Barry Welch's annual cash bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus that had been paid for the prior two years, or $400,000. The other portion of Mr. Welch's bonus was determined based on the sum of $150,000 determined by our 2011 total shareholder return performance relative to our peer group and a maximum of $60,000 based on the independent directors' assessment of his performance against annually approved goals and objectives. Including the one-time additional bonus of $140,000 described above, Mr. Welch's total cash bonus for the 2011 performance year was $750,000.

Our former Chief Financial Officer, Patrick Welch's 2011 bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus had been paid for the prior two years, or $130,000. The other portion of Mr. Welch's bonus was determined based on the sum of $104,000 determined by our 2011 total shareholder return performance relative to our peer group and a maximum $26,000 based on the independent directors' assessment of his performance against annually approved goals and objectives. He resigned from Atlantic Power on June 10, 2011.

Our interim Chief Financial Officer, Lisa Donahue, did not receive an annual bonus from us for the 2011 performance year as fees for her services are subject to our agreement with AlixPartners, LLP.

For the annual bonus paid in 2011 based on the 2010 performance year, Mr. Rapisarda's bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus had been paid for the prior two years, or $130,000. The other portion of Mr. Rapisarda's bonus was determined based on the sum of $104,000 determined by our 2011 total shareholder return performance relative to our peer group and a maximum $26,000 based on the independent directors' assessment of his performance against annually approved goals and objectives.

For the 2011 performance year, Mr. Rapisarda's annual cash bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus had been paid for the prior two years, or $130,000. The other portion of Mr. Rapisarda's bonus was determined based on the sum of $65,000 determined by our 2011 total shareholder return performance relative to our peer group and a maximum of $26,000 based on the independent directors' assessment of his performance against annually approved goals and objectives. Including the one-time additional bonus of $79,000 described above, Mr. Rapisarda's total cash bonus for the 2011 performance year was $300,000.

Mr. Daniels' 2011 annual bonus was $175,750 which was recommended by the senior executive officers based on his contributions to achieving approved goals and objectives relating to operating and financial performance of our existing projects, and his assistance with the Partnership acquisition and

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approved by the Compensation Committee. For the 2011 performance year, Mr. Daniels' total cash bonus was $176,000.

Mr. Hulburt's 2011 annual bonus was $90,000 which was recommended by the senior executive officers based on his contributions to achieving approved goals and objectives related to finance, accounting and internal controls, and approved by the Compensation Committee. For the 2011 performance year, Mr. Hulburt's total cash bonus was $94,000.

Short Term Incentive Plan ("**STIP**")

Under the senior officers' employment agreements a three-year STIP structure was in place since the prior management agreement was terminated in December 2009. The cash bonuses paid in January 2012 were the last ones to be determined under that framework so the Compensation Committee developed and approved a new methodology. The new framework will be applicable to performance year 2012 and beyond. Senior officers' performance will be evaluated utilizing the following four components:

	CEO	CFO	EVP Commercial Development
1. Performance of Existing Portfolio	20%	30%	30%
a. Project Adjusted EBITDA vs. Board approved budget			
b. Cash flow from projects vs. guidance			
c. Approved commercial and operating goals			
d. Environmental Health & Safety			
2. Growth	30%	20%	30%
a. Capital committed vs. goal			
b. Building acquisition pipeline			
c. Demonstrable synergies and integration			
3. Financial & Risk Management	20%	30%	20%
a. Effective capital raises			
b. Broadening investor base			
c. Approved risk management objectives			
d. Expanded analyst coverage and strengthened credit rating			
4. Discretionary	30%	20%	20%
a. Leadership and strategic planning			
b. Hiring, mentoring, development and succession planning			
c. Commitment, energy level and creativity			
d. Overall effectiveness individually and on senior officer team			
Target ranges for STIP as percentages of base salaries	75 - 150%	50 - 100%	50 - 100%

Long Term Incentive Plan ("**LTIP**")

Our named executive officers and other employees are eligible to participate in the LTIP as determined by the Board of Directors. The purpose of the LTIP is to align the interests of named executive officers with those of the Shareholders and to assist in attracting, retaining and motivating our key employees by making a significant portion of their incentive compensation directly dependent upon the achievement of critical strategic, financial and operational objectives that are critical to ongoing growth and increasing our long-term value, as well as providing an opportunity to increase their share ownership over time. The LTIP is designed to help achieve short-term compensation

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objectives by setting yearly performance targets that trigger various levels of grants and also to achieve longer term objectives and assist in retention through the use of both a three-year vesting period and possible forfeiture of awards if certain levels of performance are not achieved during each grant's vesting period.

The following description applies to our initial LTIP, approved by Shareholders in June 2006 and amended in June 2008. For each performance period (being, generally, a period of one calendar year commencing on January 1 of each year), the independent directors establish LTIP award percentages that will determine the amount (based on a percentage of base salary) that each participant is entitled to receive under the LTIP if certain levels of target project cash flow for the performance period are achieved. Project cash flow is based on cash flows generated by our projects less management fees, administrative expenses, corporate interest, taxes and any other adjustments determined by the independent directors, which discretion is exercised narrowly and may reflect either increases or decreases to project cash flow performance. LTIP awards for each performance period are determined by the independent directors based on our actual cash flow compared to the target projected cash flow. In making this determination, the independent directors have discretion to consider other factors, related to our performance. If certain levels of target project cash flow are achieved as determined by the independent directors, the named executive officer will be eligible to receive a number of notional units (including fractional units) to be calculated by dividing an incentive amount (based on the LTIP award percentages and the named executive officer's base salary) by the market price per IPS. The market price per IPS is defined in the LTIP as the weighted average closing price of IPSs on the TSX for the five days immediately preceding the applicable day. Notional units are meant to track the investment performance of IPSs, including IPS market prices and distributions. Any notional units granted to a participant in respect of a performance period will be credited to a notional unit account for each participant on the determination date for such performance period. Each notional unit is entitled to receive distributions equal to the distributions on an IPS, to be credited in the form of additional notional units immediately following any distribution on the IPSs. Subsequent to our conversion to a common share structure in December 2009, all references to "IPS" in the LTIP were changed to "Common Shares" and all references to distributions on IPSs were changed to dividends on common shares. In addition, from 2010 onward, the discretion with respect to the determination of awards rests with the Board of Directors, rather than independent directors.

For grants under the LTIP, one-third of the notional units in a participant's notional unit account for a performance period vest on the 13-month anniversary following the determination date for such performance period, 50% of the notional units remaining in a participant's notional unit account for a performance period vest on the second anniversary date of the determination date for such performance period, and all remaining notional units in a participant's notional unit account for a performance period vest on the third anniversary of the determination date for such performance period.

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On the applicable vesting date for notional units held in a participant's notional unit account, we redeem such vested notional units as follows: (i) one-third by lump sum cash payment (generally intended to be withheld toward payment of taxes that will be owed due to the vesting), and (ii) the remaining two-thirds by an exchange for common shares. Notwithstanding the foregoing, a named executive officer may elect to redeem such notional units for 100% common shares upon prior written notice of such election. All issuances of common shares on redemption of notional units under the LTIP are subject to compliance with applicable securities laws. In addition, the Board of Directors has the discretion to redeem notional units 100% with cash and has exercised this discretion for all notional units vested since the inception of the LTIP through 2010, except for those that have vested in the notional unit accounts of our senior officers. This was due to constraints with regard to U.S. securities laws, which are no longer relevant since the company has registered with the SEC and listed on the NYSE, so all listings in 2011 and beyond should follow the vesting approach in (i) and (ii) above for all employees.

If the net cash flows (as determined by the Board of Directors) achieved in a performance period are less than 80% of the target project cash flow previously approved by the Board of Directors for that performance period, all notional units having a vesting date in the next performance period will be cancelled, will no longer be redeemable for common shares and the executive officers will forfeit all rights, title and interest with respect to such notional units, unless otherwise expressly determined by the Board of Directors, as administrators of the LTIP.

The aggregate number of Common Shares that may be issued under the LTIP upon the redemption of notional units is 1,000,000 Common Shares, which represents 0.9% of the issued and outstanding Common Shares, subject to increase or decrease by reason of amalgamation, rights offerings, reclassifications, consolidations or subdivisions, or as may otherwise be permitted by applicable law and the TSX. The total number of notional units granted under the LTIP is 485,781, which represents 0.4% of the issued and outstanding Common Shares. The total number of Common Shares issuable under actual grants is 485,781,which represents 0.4% of the issued and outstanding Common Shares.

Except with the approval of shareholders, no notional shares may be granted where such grant could result, at any time, in:

(a) the number of Common Shares reserved for issuance to participants pursuant to the redemption of notional shares together with any other common share compensation arrangement exceeding 10% of Common Shares then issued and outstanding;

(b) the number of Common Shares issuable to insider participants, at any time under the LTIP pursuant to the redemption of notional shares and any other common share compensation arrangements, exceeding 10% of Common Shares then issued and outstanding; or

(c) the number of Common Shares issued to insider participants, within any one-year period, under the LTIP pursuant to the redemption of notional shares and any other common share compensation arrangements, exceeding 10% of Common Shares then issued and outstanding.

The Board of Directors may terminate, modify or amend the LTIP, without securityholder approval, at any time in such manner and to such extent as they deem advisable, subject to applicable corporate, securities and tax law requirements and the requirements of the TSX, provided that any such action may not adversely affect any rights already acquired under the LTIP to such date. The amendments that may be made by the independent directors to the LTIP include, without limitation, the vesting and redemption dates for notional units and the persons who may qualify as "Eligible Persons" under the LTIP provided that any change to the "Eligible Persons" does not have the potential of broadening or increasing insider participation. A participant may not assign or transfer any right or interest in the LTIP. All unvested notional units are forfeited by a participant on the date he or

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she ceases to be employed by Atlantic Power or its subsidiaries, except in the case of death, disability, retirement or change of control (in certain circumstances, as described below). If the employment of a participant is terminated in connection with the death, retirement or upon a change of control (in the case of a change of control, where termination is by the participant for good reason or by Atlantic Power without cause) prior to the applicable vesting date, all notional units credited to the participant's notional unit account will vest or be deemed to have vested effective the date immediately prior to the date of such termination of the participant's employment. If the employment of a participant is terminated due to the disability of the participant prior to the applicable vesting date, all notional units credited to the participant's notional unit account will vest on the vesting date as if the participant continued to be actively employed until the applicable vesting date.

2010 LTIP Amendments

In 2009, Hugessen was retained to assist the Board in assessing our existing LTIP and proposing several design changes. The purpose of the LTIP changes was to further align the interests of our officers and employees with Shareholders and to assist in attracting, retaining and motivating our key employees.

In early 2010, the Board of Directors approved amendments to the LTIP. The amendments did not impact grants for the 2009 performance year or unvested notional shares related to grants made prior to the 2010 amendments. The amended LTIP became effective for grants beginning with the 2010 performance year and was approved by the Shareholders at the annual general meeting held on June 29, 2010.

Under the amended LTIP, the notional shares granted to plan participants have the same characteristics as the notional shares under the old LTIP. However, the number of notional shares granted is currently based, for senior executives, entirely on our total shareholder return compared to the group of peer companies included in the 2011 Peer Group and, for employees that are not senior executives, performance measurement is weighted 1/3rd based on our total shareholder return compared to a the 2011 Peer Group, and 2/3rd based on the achievement of a simplified net project cash flow measure. In addition, vesting of notional shares for senior executives occurs on a three-year cliff basis as opposed to ratable vesting over three years under the old LTIP. Pursuant to each senior executive's employment agreement, each senior executive receives a grant at the beginning of each three-year performance period in an amount equal to his base salary. The grant vests at the end of the three-year performance period in an amount ranging from 0% up to a maximum of 150% of the sum of units initially granted plus dividend equivalent rights received during the performance period. In addition, on May 14, 2010, each senior executive received a grant equal to one-third of his base salary (the "2010 Transition Award") and a grant equal to two-thirds of his base salary (the "2011 Transition Award"). The 2010 Transition Awards vested on March 31, 2011 in an amount equal to 125% of the sum of the initial grant plus dividend equivalent rights received during the vesting period, based on our total shareholder return in 2010 compared to the 2011 Peer Group. The 2011 Transition Awards vested on February 28, 2012 in an amount equal to 109% of the sum of the initial grant, plus dividend equivalent rights received during the vesting period, based on our total shareholder return during 2010 and 2011 compared to the 2011 Peer Group. The Compensation Committee considered the senior officers' contributions to the Partnership and, consistent with their approach to the 2011 performance year STIP award, elected to use their discretion to make a one-time special award of 15,000 and 12,000 units to Barry Welch and Paul Rapisarda respectively. These units and associated dividend equivalent rights will vest ratably over three years. Named executive officers other than senior executives are eligible for an annual award under the LTIP ranging from 0% to 100% of their annual base salary.

2011 LTIP Amendments

Effective as of November 5, 2011, being the closing date for our acquisition of the Partnership, the Board of Directors and the Compensation Committee approved certain amendments to the LTIP in the

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form of a fourth amended and restated LTIP to provide for participation by certain designated employees who performed functions related to the Partnership's business ("New Employees") who became our employees following the closing of the acquisition and certain other updates and clarifying amendments to the LTIP. Shareholder approval of these amendments was not required under the terms of the LTIP. The description below is qualified in its entirety by the text of the fourth amended and restated LTIP available on SEDAR at www.sedar.com.

The amendments related to the acquisition included revisions to certain defined terms to appropriately reflect that participants in the LTIP may be employees of our subsidiaries and located in Canada and to provide the administrators of the LTIP with increased flexibility in the administration of the LTIP by granting them authority to (i) adopt rules and regulations for implementing the LTIP; (ii) determine when notional shares will be granted to eligible persons, the vesting period for each grant of notional shares and whether any adjustment(s) (performance-related or otherwise) will apply prior to vesting of any notional shares granted; (iii) adjust the size of any previously-approved pool for awards available for allocation among LTIP participants who are not officers and the membership of such non-officer group; (iv) interpret and construe the provisions of the LTIP; (v) alter or adjust any provision that is expressly provided in the LTIP in circumstances so as to operate the LTIP as objectively as possible; (vi) subject to regulatory requirements, make exceptions to the LTIP in circumstances which they determine to be exceptional; (vii) impose certain conditions at the date of grant for any notional shares, which would have to be met for an LTIP participant to be entitled to redeem notional shares granted; and (viii) make amendments to the LTIP in accordance with the amendment provisions contained therein. The peer group applied in determining potential performance adjustments to certain awards under the LTIP has been changed from a scheduled list to a group of entities determined by the administrators from time to time in their sole discretion.

The Board of Directors also approved certain updates and clarifying amendments, including an update to the definition of "Insider Participant" to reflect the current TSX definition of "insider", and clarifying that notional shares held by non-officer participants vest in respect of one-third of such notional shares after each of the first three anniversaries of the date that the Board of Directors approves our audited financial statements for a given fiscal year of Atlantic Power.

In connection with the November 5, 2011 amendments, the Board of Directors approved certain grants of notional shares under the LTIP to the New Employees in an aggregate dollar amount of Cdn$830,680 to replace similar equity compensation such New Employees had been entitled prior to employment by Atlantic Power upon closing of the acquisition. The terms of these grants are as follows: (i) the number of notional shares to be credited to the notional share account for each New Employee was determined by dividing the portion of the aggregate dollar amount allocated to such New Employee by the Market Price per Common Share (as defined in the LTIP) on November 5, 2011; (ii) the notional shares credited to each New Employee's notional share account on November 5, 2011 vest in respect of one-third of such notional shares after each of the first three anniversaries of the Financial Statement Approval Date (as defined in the LTIP) for our fiscal year 2011 with no performance-related adjustments; and (iii) other than the foregoing, the notional shares credited to the New Employee's notional share account are subject to the terms and conditions of the LTIP treating each New Employee as a Non-Officer Group Participant (as defined in the LTIP).

2011 LTIP Awards

On March 31, 2011, Barry Welch received a grant of 38,134 notional shares under the amended LTIP for the 2011-2013 performance period. In accordance with the LTIP, the LTIP award for the 2011-2013 performance year for all senior officers was set at 100% of their base salary. Vesting of this award after three years will be based on the 2011-2013 relative TSR performance.

On March 31, 2011, Patrick Welch received a grant of 20,559 notional shares under the amended LTIP for the 2011-2013 performance period. In accordance with the LTIP, the LTIP award for the

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2011-2013 performance year for all senior officers was set at 100% of their base salary. Patrick Welch forfeited these and all other unvested national shares upon his resignation on June 10, 2011.

On March 31, 2011, Mr. Rapisarda received a grant of 20,559 notional shares under the amended LTIP for the 2011-2013 performance period. In accordance with the LTIP, the LTIP award for the 2011-2013 performance year for all senior officers was set at 100% of their base salary. Vesting of this award after three years will be based on the 2011-2013 relative TSR performance.

LTIP awards to Mr. Daniels are based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors and to Atlantic Power achieving relative total shareholder return performance, as well as progress in successfully executing our strategic plan and goals and objectives, which are approved by the Compensation Committee each year. Vesting of this award occurs rateably over the three-year period immediately following the LTIP award. Based on our actual cash flow compared to the project cash flow levels, and the actual relative total shareholder return performance, Mr. Daniels' LTIP award in 2011 was set at 68% of base salary and was granted by the Board of Directors on March 31, 2011.

LTIP awards to Mr. Hulburt are based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors and to Atlantic Power achieving relative total shareholder return performance, as well as progress in successfully executing our strategic plan and goals and objectives, which are approved by our Compensation Committee each year. Vesting of this award occurs rateably over the three-year period immediately following the LTIP award. Based on our actual cash flow compared to the project cash flow levels, and the actual relative total shareholder return performance, Mr. Hulburt's LTIP award for the 2010 performance year was set at 58% of base salary and was granted by the Board of Directors on March 31, 2011.

On February 29, 2012 Barry Welch and Paul Rapisarda received annual grants with a value equal to their 2012 salaries of $700,000 and $425,000 respectively.

2012 LTIP Amendments

In 2012, the Compensation Committee reviewed the LTIP for our senior officers and considered changes in light of both changes to the scale and complexity of Atlantic Power as well as input about plans for similar companies, especially those in the U.S. which is the relevant market for our senior officers. Based on this review, the Compensation Committee approved certain changes to the LTIP for 2012. Under the revised LTIP, total shareholder return will be replaced as the exclusive measure of performance for our senior officers with a combined measure based on project adjusted EBITDA per share, free cash flow, growth cash flow and relative total shareholder return. In determining the total score under the revised LTIP for a fiscal year, each of these four metrics will be given an equal 25% weighting and the combined score will serve as a guideline for the Compensation Committee in determining a senior officer's LTIP award. The Compensation Committee will have discretion to adjust a senior officer's LTIP award based on the long term progress of Atlantic Power or other factors determined relevant by the Compensation Committee. Awards under the revised LTIP will be made annually based on the performance over the applicable fiscal year and will vest as to one third over each of the three years following the year of the award. The quantum of awards under the revised LTIP will range from zero to a cap of $2.8 million for the CEO and $1.5 million for the EVP CFO and EVP Commerical Development. For 2012, the midpoint targets for each of the four performance measures have been set as follows: (1) project adjusted EBITDA per share $2.98 to $3.03; (2) free cash flow $140.3 million to $143.1 million; (3) growth cash flow $18.5 million to $21.7 million; and (4) relative total shareholder return 56^{th} to 65^{th} percentile. If each of these target ranges were achieved in 2012, the recommended award for our CEO would be $1.5 million and for our CFO and our Executive Vice President Commercial Development would be $750,000.

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Employment Agreements

In connection with the termination of the management services agreement with the Manager on December 31, 2009, we entered into employment agreements with each of Barry Welch, Patrick Welch and Paul Rapisarda, who were previously employees of the Manager. (The employment agreement with Mr. Patrick Welch has been terminated in connection with his resignation.) To assist in the structuring and negotiation of the employment contracts, our independent directors employed Hugessen to review and advise on their terms to ensure that the employment agreements were consistent with best practices in the marketplace. We believe that the consideration of a change in control transaction will create uncertainty regarding the continued employment of our senior executive officers. This uncertainty results from the fact that many change in control transactions result in significant organizational changes, particularly at the senior executive level. In order to encourage our executive officers to focus on seeking the best return for our Shareholders and to remain employed with Atlantic Power during an important time when their prospects for continued employment following a change in control transaction are often uncertain, we have agreed in the employment agreements to provide for severance benefits in the event the officer's employment is terminated under certain circumstances in connection with a change in control of Atlantic Power. In exchange for such severance protection, each executive officer agreed to certain non-competition and non-solicitation limitations following certain termination events.

For a description of the employment agreement change in control benefits provided to Barry Welch and Paul Rapisarda, see the sections of this Information Circular and Proxy Statement titled "Employment Contracts" and "Termination and Change in Control Benefits."

401(k) matching contributions

We also make annual matching contributions to each named executive officer's 401(k) plan account based upon a predetermined formula. The purpose of the matching contributions is to supplement the named executive officer's personal savings toward future retirement as we have no other pension plan for them. The matching for the named executive officers is a dollar-for-dollar match with the employee's 401(k) contribution, up to the maximum allowed by Internal Revenue Service ("**IRS**") regulations. The IRS maximum contribution in 2011 was $16,500 for participants under age 50 and $22,000 for participants 50 and over.

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Summary Compensation Table

The following table sets forth a summary of salary and other annual compensation paid for 2011, 2010 and 2009 to each named executive officer (in US$).

Name and principal position	Year	Salary	Bonus(1)	Stock awards(2)	Non-equity incentive plan compensation	All other compensation(3)	Total Compensation
Barry E. Welch	2011	575,000	400,000	575,170	350,000	22,000	1,922,170
Director, President and	2010	535,000	400,000	1,587,088	300,000	22,000	2,844,088
Chief Executive Officer	2009	535,000	400,000	472,500	300,000	22,000	1,729,500
Lisa Donahue(4)	2011	603,000					603,000
Interim Chief Financial Officer							
Patrick J. Welch(5)	2011	141,910		310,088		16,500	468,498
Former Chief Financial Officer	2010	259,500	130,000	769,798	130,000	16,500	1,305,798
and Corporate Secretary	2009	259,000	130,000	226,800	130,000	16,500	762,300
Paul H. Rapisarda	2011	310,000	130,000	310,088	170,000	22,000	942,088
Executive Vice President	2010	257,500	130,000	763,873	130,000	22,000	1,303,373
Commercial Development	2009	257,500	130,000	225,000	130,000	22,000	764,500
William B. Daniels	2011	190,000		129,503	176,000	22,000	517,503
Vice President	2010	185,000		129,524	175,750	22,000	512,274
Operations East	2009	185,000		110,500	166,500	22,000	484,000
John J. Hulburt	2011	188,000		109,795	94,000	16,500	408,295
Corporate Controller	2010	183,000		108,015	90,000	16,500	397,515
	2009	180,000		87,500	80,000	12,601	360,101

(1) Represents the fixed portion of annual cash bonus for 2009 through 2011 payable per the terms of each executive officer's employment contract executed in connection with the management internalization in December 2009.

(2) The amounts shown under "Stock awards" reflect the grant date fair value of notional shares granted during the year under the terms of the LTIP and are calculated in accordance with FASB ASC Topic 718. The assumptions used in determining the grant date fair value of these awards are described in Note 14 to the Consolidated Audited Financial Statements of Atlantic Power Corporation contained in our Annual Report on Form 10-K for the year ended December 31, 2011. A portion of the awards granted to senior officers in 2011 contains a performance condition. Assuming the highest level of performance is achieved, the total fair value of awards for 2011 would be $862,754 for Barry Welch and $465,133 for Paul Rapisarda. The amounts shown do not include dividend equivalent rights that accrued on notional units.

(3) Amounts represent company matching contributions to the 401(k) plan accounts of each executive officer.

(4) Ms. Donahue, a managing director of AlixPartners, has served as our interim Chief Financial Officer since July 2011. Ms Donahue's services as Chief Financial Officer were provided pursuant to an agreement with AlixPartners. We are unable to determine the amount received by Ms. Donahue in connection with her services to us in 2011, as we did not compensate Ms. Donahue directly; rather, Ms. Donahue was compensated independently pursuant to separate arrangements between her and AlixPartners. Under our agreement with AlixPartners, we incurred

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$603,000 in 2011 for Ms. Donahue's services. The agreement with AlixPartners and the total amount incurred by us in 2011 under this agreement, is described at " Employment Contracts" and " Certain Relationships and Related Transactions".

(5)
Patrick Welch resigned from Atlantic Power on June 10, 2011.

Following are plan-based awards during the year ended December 31, 2011 for each named executive officer.

		Estimated future payouts under non-equity incentive plan awards			Estimated future payouts under equity incentive plan awards(1)			
Name	**Grant date**	**Minimum (US$)**	**Target (US$)**	**Maximum (US$)**	**Minimum (#)**	**Target (#)**	**Maximum (#)**	**Grant date fair value of LTIP awards (US$)(2)**
Barry E. Welch	N/A	525,000	700,000	1,050,000				
	3/31/11					N/A	57,201	575,170
Lisa Donahue(3)	N/A		N/A	N/A				
						N/A	N/A	N/A
Paul H. Rapisarda	N/A	212,500	318,750	425,000				
	3/31/11					N/A	30,839	310,088
William B. Daniels	N/A		146,250	195,000				
	3/31/11				10,836	10,836	10,836	129,503
John J. Hulburt	N/A		77,000	96,250				
	3/31/11				9,187	9,187	9,187	109,795

(1)
The amounts shown for William Daniels and John Hulburt represent the fixed number of notional units granted for the 2010 performance year that was approved by the Board of Directors. The amounts shown for Barry Welch and Paul Rapisarda represent grants under the amended LTIP, which are subject to a performance-based vesting condition. Amounts shown do not include dividend equivalent rights that accrue on notional shares.

(2)
Amounts are calculated in accordance with FASB ASC Topic 718.

(3)
As Managing Director of AlixPartners, Ms. Donahue is not eligible to participate in grants of plan-based awards.

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Outstanding Share-Based Awards

The following table sets forth, for each named executive officer, all share-based awards outstanding under the terms of the LTIP as of December 31, 2011:

Name	Number of shares or notional units that have not vested(1)(2)	Market or pay-out value of share-based awards that have not vested (US$)(2)	Equity Incentive Plan Awards: Number of unearned shares or notional shares that have not vested(1)(2)	Equity Incentive Plan Awards: Market or payout value of unearned shares or notional shares that have not vested(2)
Barry E. Welch	193,187	2,762,574	125,833	1,799,412
Lisa Donahue(3)				
Paul H. Rapisarda	95,139	1,360,488	62,900	899,470
William B. Daniels	27,484	393,021		
John J. Hulburt	22,736	325,125		

(1) Notional shares granted under the LTIP vest in accordance with the amended plan over a period of up to a maximum of three years.

(2) This amount includes notional shares credited under the LTIP to the notional share account of the named executive officer for monthly dividends through December 31, 2011.

(3) Lisa Donahue has acted as Interim CFO since July 2011, but is not an employee and therefore is not eligible for awards under LTIP.

Stock Vested

The following table sets forth, for each named executive officer, the value of all share-based incentive plan awards vested during the year ended December 31, 2011:

Name	Number of shares acquired on vesting	Value realized on vesting (US$)
Barry E. Welch	97,363	1,468,234
Lisa Donahue	N/A	N/A
Patrick J. Welch	46,909	707,388
Paul H. Rapisarda	37,441	564,610
William B. Daniels	16,760	252,741
John J. Hulburt	9,215	138,962

Equity Compensation Plan Information

The following table provides information as of December 31, 2011 regarding the LTIP, the only equity compensation plan of Atlantic Power or its subsidiaries.

	Equity Compensation Plan Information	
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)	Number of securities remaining available for future issuance under equity compensation plan(1)(2)
Equity compensation plans approved by security holders:	485,781	590,314

(1)

Assumes that the participants elect to receive 100% Common Shares upon redemption. This amount does not include future credits to the notional share accounts of participants related to monthly dividends paid on the Common Shares.

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(2) The maximum aggregate number of Common Shares that may be issued under the original LTIP and the amended LTIP upon redemption of notional shares is 1,000,000 shares.

Employment Contracts

Each of Barry Welch (President and Chief Executive Officer) and Paul Rapisarda (Executive Vice President Commercial Development) are parties to employment agreements with Atlantic Power. Each of the employment agreements provides the respective officer with the following: (i) an initial annual base salary, which is subject to annual review; (ii) eligibility for a performance-based annual cash bonus; (iii) eligibility to participate in the LTIP; and (iv) certain other customary employee benefits. Under the employment agreements, the annual base salary is evaluated each calendar year and for 2011 for Barry Welch and Paul Rapisarda was $575,000 and $310,000, respectively. The guaranteed portion of cash bonuses for 2011 for Barry Welch and Paul Rapisarda were $400,000 and $130,000, respectively.

Effective July 12, 2011, we entered into an arrangement with AlixPartners to provide various accounting and financial consulting services. Pursuant to the arrangement, we announced the appointment of Lisa Donahue of AlixPartners as interim Chief Financial Officer and engaged other consultants from AlixPartners, the services of each of whom are billed by AlixPartners.

Termination and Change of Control Benefits

Each named senior executive officer's employment agreement provides that if the respective officer is terminated without cause within 90 days preceding or one year after a change in control or if he resigns within that time period because certain further triggering events have occurred including a constructive dismissal, reduction in salary or benefits, relocation, change in position of employment or reporting relationships, or our breach of the employment agreement, then the following are paid or provided under the employment agreement: (i) his salary and bonus pro-rated through the termination date; (ii) a termination payment equal to three times the average (in the case of Barry Welch) or one times the average (in the case of Paul Rapisarda), during the last two years, of the sum of the respective officer's: (a) base salary, (b) annual cash bonus, and (c) the most recent matching contribution to his 401(k) plan; (iii) immediate vesting of all previous awards under the LTIP which had not yet vested; (iv) continuation of all employee benefits for a period of two years (in the case of Barry Welch) or one year (in the case of Paul Rapisarda) following termination; and (v) costs of outplacement services customary for senior executives at the respective officer's level for a period of 12 months following termination with the cost capped at $25,000. The Compensation Committee has approved an amendment to Paul Rapisarda's employment agreement to provide that his termination payment as described in (ii) of the preceding sentence will be two times the average, during the last two years, of the sum of Mr. Rapisarda's (a) base salary, (b) annual cash bonus, and (c) the most recent matching contribution to his 401(k) plan. The employment agreements also contain non-competition and non-solicitation limitations on each of the officers following certain termination events. The non-competition restrictions apply for a period of one year or one month (in the case of Barry Welch) or a period of one month or six months (in the case of Paul Rapisarda) following termination depending on the circumstances of the termination and the non-solicitation restrictions apply for a period of two years (in the case of Barry Welch) or one year (in the case of Paul Rapisarda) following the date of termination.

In each senior executive officer's employment agreement, the term "Change in Control" means the occurrence of any of the following events: (i) the sale, lease or transfer to any person or group, in one or a series of related transactions, of our assets, directly or indirectly, which assets generated more than 50% of our cash flow in a 12-month period ended on the last day of the most recent fiscal quarter to any person or group; (ii) the adoption of a plan related to our liquidation or dissolution; (iii) the acquisition by any person or group of a direct or indirect interest in more than 50% of our common

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shares or voting power; (iv) our merger or consolidation with another person with the effect that immediately after such transaction Shareholders immediately prior to such transaction hold, directly or indirectly, less than 50% of the voting control over the person surviving such merger or consolidation; or (v) we enter into any agreement providing for any of the foregoing; or the date which is 90 days prior to a definitive announcement of any of the foregoing whichever is earlier, and the transaction contemplated thereby is ultimately consummated.

If Barry Welch or Paul Rapisarda is terminated for cause, then he will be entitled to all vested benefits under all incentive compensation or other plans in accordance with the terms and conditions of such plan, however he will not be entitled to the payments or benefits listed in items (i) through (v) in the second preceding paragraph above, except as may be required by applicable law. "Cause" is defined in each employment agreement as "a termination by reason of the Corporation's good faith determination that the executive (i) engaged in willful misconduct in the performance of his duties, (ii) breached a fiduciary duty to the Corporation for personal profit to himself, (iii) after determination by a court of competent jurisdiction, willfully violated any law, rule or regulation of a governmental authority with jurisdiction over the executive or the Corporation at the time and place of such violation (other than traffic violation or similar offenses) or any final cease and desist order of a court or other tribunal of competent jurisdiction, or (iv) materially and willfully breached this Agreement. No act, or failure to act, on the executive's part shall be considered "willful" unless he has acted, or failed to act, with an absence of good faith and without a reasonable belief that this action or failure to act was in the best interest of the Corporation."

The following table provides, for each of the foregoing senior executive officers, an estimate of the payments payable by us, assuming a termination for any reason other than cause, including the occurrence of the triggering events described above. The amounts shown assume that such termination was effective as of December 31, 2011 and thus only include amounts earned through such time and are estimates of the amounts that would be paid out to the executives upon their termination. The actual amounts to be paid out can only be determined at the time of each such officer's separation from Atlantic Power.

Name	Type of payment	Termination payment(1) (US$)	2011 Pro-rata bonus (US$)	Vesting of stock based compensation (US$)	Employee benefits (US$)	Total (US$)
Barry E. Welch	Termination without cause or in connection with change of control	3,966,000	700,000	2,762,574	74,860	7,503,434
Paul H. Rapisarda	Termination without cause or in connection with change of control	585,250	260,000	1,360,488	49,930	2,255,668

(1) Includes three times the average (in the case of Barry Welch) or one times the average (in the case of Paul Rapisarda), during the last two years, of the sum of the respective officer's: (a) base salary, (b) annual Bonus, and (c) the most recent matching contribution to his 401(k) plan.

Compensation Risk Assessment

We have reviewed our compensation policies and practices for all employees and concluded that any risks arising from our policies and programs are not reasonably likely to have a material adverse effect on Atlantic Power. We believe that the mix and design of the elements of executive compensation do not encourage management to assume excessive risks. The corporation reviewed the

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elements of executive compensation to determine whether any portion of executive compensation encouraged excessive risk taking and concluded:

- allocation of compensation between cash compensation and long-term equity compensation, combined with the vesting schedule under LTIP, discourages short-term risk taking;

- approach of goal setting, setting of targets with payouts at multiple levels of performance, capping the amount of our incentive payouts, and evaluation of performance results assist in mitigating excessive risk-taking;

- compensation decisions include subjective considerations, which limit the influence of formulae or objective factors on excessive risk taking; and

- business does not face the same level of risks associated with compensation for employees at financial services firms (traders and instruments with a high degree of risk).

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DIRECTOR COMPENSATION

Director Fees

Each independent director is entitled to receive an annual retainer of $50,000, plus $10,000 of value in deferred share unit ("**DSU**") and $1,500 per meeting attended in person or $750 per meeting attended by phone. The Chairman, chair of the Audit Committee and Compensation Committee receive an additional $25,000, 15,000 and 10,000 per year respectively. Directors are reimbursed for out-of-pocket expenses for attending meetings. Directors also participate in the insurance and indemnification arrangements described below.

Equity Ownership Guideline

On April 24, 2007, the Board of Directors adopted an equity ownership guideline for independent Directors. The guideline provides that by April 24, 2010 (for existing independent directors) or within three years of their initial election (for new independent directors), each independent director should own equity securities of Atlantic Power (which will include notional shares issued under the deferred share unit plan described below), representing an investment by each independent director of three times their current annual retainer.

Deferred Share Unit Plan

On April 24, 2007, the Board of Directors established a deferred share unit plan ("**DSU Plan**") for Directors. Under the DSU Plan, each non-management Director is entitled to elect to have fees paid to them by Atlantic Power for their services as directors contributed to the DSU Plan. All fees contributed to the DSU Plan are credited to such director in the form of notional shares representing the current market price of our common shares at the time of contribution. For so long as the participant continues to serve on the Board of Directors, dividends accrue on the notional shares consistent with amounts declared by the Board of Directors on our common shares and additional notional shares representing the dividends are credited to the participant's notional share account. Notional shares credited to the participant's notional share account may be redeemed only when a participant no longer serves on the Board of Directors for any reason or upon a reorganization of Atlantic Power.

The following table describes director compensation for non-management directors for the year ended December 31, 2011. Directors who are also officers of Atlantic Power are not entitled to any compensation for their services as a director.

Name	Fees earned or paid in cash (US$)	Stock awards (US$)*	Total compensation (US$)
Irving R. Gerstein	84,500		84,500
Kenneth M. Hartwick	47,250	47,250(1)	94,500
John A. McNeil	80,500		80,500
Holli Ladhani	36,250	36,250(2)	72,500
R. Foster Duncan	80,500		80,500

* Reflects the grant date fair value of DSUs awarded in 2011 determined in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation Stock Compensation.

(1) Mr. Hartwick has elected to defer 50% of his 2011 fees in the DSU Plan.

(2) Ms. Ladhani has elected to defer 50% of her 2011 fees in the DSU Plan.

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COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

During 2011, Messrs. Gerstein, Hartwick, McNeil and Duncan and Ms. Ladhani served as members of the Compensation Committee of the Board of Directors of Atlantic Power.

Mr. Barry Welch was involved in making recommendations to the Compensation Committee regarding compensation for the other two senior executives, and all three senior executives were involved in making recommendations regarding compensation of the other two named executive officers. During 2011, none of the executive officers of Atlantic Power has served as: (i) a member of the compensation committee (or other committee of the board of directors performing equivalent functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on the Compensation Committee of Atlantic Power; (ii) a director of another entity, one of whose executive officers served on the Board of Directors of Atlantic Power; or (iii) a member of the compensation committee (or other committee of the board of directors performing equivalent functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on the Board of Directors of Atlantic Power.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Effective July 12, 2011, we entered into an arrangement with AlixPartners to provide various accounting and financial consulting services. Pursuant to the arrangement, we announced the appointment of Lisa Donahue of AlixPartners as interim Chief Financial Officer and engaged other consultants from AlixPartners, the services of each of whom are billed by AlixPartners. Ms. Donahue is a Managing Director of AlixPartners. We are unable to determine the amount received by Ms. Donahue in connection with her services to us in 2011, as we did not compensate Ms. Donahue directly; rather, Ms. Donahue was compensated independently pursuant to separate arrangements between her and AlixPartners. Under our agreement with AlixPartners, we incurred $1,065,312 in the aggregate in 2011, including $603,000 for Ms. Donahue's services.

POLICIES AND PROCEDURES FOR REVIEW OF TRANSACTIONS WITH RELATED PERSONS

The Board of Directors has adopted written policies and procedures with respect to related party transactions and will review and approve all relationships and transactions in which Atlantic Power and any of the its Directors, director nominees and executive officers and their immediate family members, as well as holders of more than 5% of any class of its voting securities and their family members, have a direct or indirect material interest. In approving or rejecting such proposed relationships and transactions, the Board shall consider the relevant facts and circumstances available and deemed relevant to this determination. The Nominating and Governance Committee is responsible under its charter for monitoring compliance with the Code of Business Conduct and Ethics.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information regarding the beneficial ownership of Common Shares of Atlantic Power as of April 27, 2012 with respect to:

each person (including any "group" of persons as that term is used in Section 13(d)(3) of the Exchange Act) who is known to us to be the beneficial owner of more than 5% of the outstanding Common Shares (none as of April 27, 2012);

each of our Directors;

each of our named executive officers; and

all of our Directors and executive officers as a group.

The address of each beneficial owner listed in the following table is c/o Atlantic Power Corporation, 200 Clarendon Street, Floor 25, Boston, MA 02116.

Except as otherwise indicated in the footnotes to the following table, we believe, based on the information provided to us, that the persons named in the following table have sole voting and investment power with respect to the shares they beneficially own, subject to applicable community property laws.

Name of beneficial owner	Number of Common Shares beneficially owned	Percentage of Common Shares beneficially owned(1)
Directors and named executive officers		
Irving R. Gerstein	10,579(2)	*
Kenneth M. Hartwick	63,676(2)	*
John A. McNeil	12,679(2)	*
R. Foster Duncan	2,612(2)	*
Holli Ladhani	4,967(2)	*
Barry E. Welch	454,004(3)	*
Patrick J. Welch(4)	89,205	*
Lisa J. Donahue		*
Paul H. Rapisarda	164,058(3)	*
William B. Daniels	22,255(3)	*
John J. Hulburt	24,701(3)	*
All directors and executive officers as a group (10 persons)(5)	759,531	*

* Less than l%.

(1) The applicable percentage ownership is based on 113,680,643 common shares issued and outstanding as of April 27, 2012.

(2) Common Shares beneficially owned include units held in our deferred share unit plan of 179 for Irving R. Gerstein, 61,676 for Kenneth M. Hartwick, 179 for John A. McNeil, 1,112 for R. Foster Duncan and 4,967 for Holli Ladhani.

(3) Common Shares beneficially owned include unvested notional shares granted under our LTIP of 171,147 for Barry E. Welch, 95,407 for Paul H. Rapisarda, 21,322 for William B. Daniels and 18,701 for John J. Hulburt.

(4)
Patrick J. Welch is no longer employed by Atlantic Power. Information with respect to Patrick J. Welch's beneficial ownership is as of June 10, 2011, the date of his resignation from Atlantic Power.

(5)
Patrick J. Welch is not included in this group.

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DESCRIPTION OF EXCHANGE NOTES

The Exchange Notes are to be issued under the Indenture, dated as of November 4, 2011 (the "**Indenture**"), between Atlantic Power and Wilmington Trust, National Association, as trustee (the "**Trustee**"). The Exchange Notes will evidence the same debt as the Old Notes and the Indenture under which the Exchange Notes are to be issued is the same indenture under which the Old Notes were issued. Any Old Note that remains outstanding after the completion of the exchange offer, together with the Exchange Notes issued in connection with the exchange offer, will be treated as a single class of securities under the Indenture. As used in this "Description of Exchange Notes," except as otherwise specified or the context otherwise requires, the Old Notes, the Exchange Notes and any additional notes we may issue under the Indenture are referred to together as the "**notes**."

The following summary of certain provisions of the Indenture does not purport to be complete and is subject to, and qualified in its entirety by reference to, all of the provisions of the Indenture, including the definitions of certain terms in the Indenture, which provisions are made a part of the Indenture by reference to the Trust Indenture Act of 1939, as amended. It does not restate that agreement, and we urge you to read the Indenture in its entirety, which is available upon request to Atlantic Power at the address indicated under "Where You Can Find More Information" elsewhere in this prospectus, because it, and not this description, defines your rights as a noteholder. Copies of the Indenture are available upon request from Atlantic Power.

As used in this "Description of Exchange Notes," the terms "Atlantic Power," "we," "us," "our" or similar terms refer only to Atlantic Power Corporation, and does not include any of its subsidiaries. References to "**$**" are to U.S. dollars. The Notes are denominated in U.S. dollars and all payments on the Notes will be made in U.S. Dollars.

We may issue additional notes from time to time after this exchange offer under the Indenture ("**Additional Notes**"). The notes and any Additional Notes subsequently issued under the Indenture will be treated as a single class for all purposes under the Indenture, including waivers, amendments, redemptions and offers to purchase; provided that any additional Notes that are not fungible with the existing Notes for U.S. federal income tax purposes will have a separate CUSIP number.

General

The Notes

The Old Notes were issued in an aggregate principal amount of $460,000,000. The notes are our direct, unsecured and unsubordinated obligations and rank:

- equal in right of payment with all of our existing and future senior unsecured debt;
- effectively junior in right of payment to (a) our existing and future secured debt to the extent of the value of the assets securing such debt, including borrowings under our Senior Secured Revolving Credit Facility and our 6.50% convertible secured debentures, and (b) the debt and other liabilities (including trade payables) of our non-Guarantor subsidiaries; and
- senior in right of payment to our existing and future subordinated debt.

As of March 31, 2012:

- we had approximately $1.9 billion of total indebtedness, $577.8 million of which was secured indebtedness, and $148.3 million of subordinated indebtedness; and

In addition, as of March 31, 2012, we had $88 million of additional borrowing capacity available under our revolving credit facility.

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The Indenture permits us to incur debt subject to the covenants described under " Certain Covenants of Atlantic Power Limitations on the Incurrence of Debt and Issuance of Disqualified Stock" and " Certain Covenants of Atlantic Power Restrictions on Secured Debt."

The entire principal amount of the notes will mature and become due and payable, together with any accrued and unpaid interest thereon, on November 15, 2018. The notes are not subject to any sinking fund provision.

The Guarantees

The notes are guaranteed on a senior unsecured basis by our U.S. and Canadian Wholly Owned Domestic Subsidiaries that guarantee the Senior Secured Revolving Credit Facility and the Partnership's guarantee of the notes is guaranteed by Curtis Palmer LLC. The Guarantees of the notes are:

- general unsecured obligations of each Guarantor;
- ranked equally in right of payment with all existing and future senior debt of such Guarantor;
- ranked senior in right of payment to all existing and future subordinated debt of such Guarantor, if any; and
- ranked effectively junior to (a) secured obligations of such Guarantor to the extent of the collateral securing such obligations, including the secured guarantees by the Guarantors of our obligations under the Senior Secured Revolving Credit Facility and the secured guarantees by the Guarantors of our 6.50% convertible secured debentures and (b) the debt and liabilities of our non-Guarantor Subsidiaries.

Each Guarantor (other than Curtis Palmer LLC) jointly and severally guaranteed Atlantic Power's obligations under the notes and the Partnership's guarantee of the notes is guaranteed by Curtis Palmer LLC. The obligations of each Guarantor under its Guarantee are limited as necessary to prevent such Guarantee from constituting a fraudulent conveyance or fraudulent transfer under applicable law. See "Risk Factors Risks related to our Indebtedness and the Notes Federal and state statutes allow courts, under specific circumstances, to void the guarantees and require noteholders to return payments received from us or the guarantors."

"**Domestic Subsidiary**" means any Subsidiary of Atlantic Power that was formed under the laws of the United States, any state thereof or the District of Columbia, or the laws of Canada, any province thereof or any territory thereof or that guarantees or otherwise provides direct credit support for any indebtedness of Atlantic Power.

"**Wholly Owned**" means, with respect to (1) any Subsidiary that is a corporation, a Subsidiary all of the outstanding Capital Stock of which is owned by Atlantic Power and/or one or more Wholly Owned Subsidiaries (or a combination thereof) of Atlantic Power and (2) any other Subsidiary, a Subsidiary all of the interests of which is owned by Atlantic Power and/or one or more Wholly Owned Subsidiaries (or a combination thereof) of Atlantic Power.

Guarantors

Each Guarantor may consolidate with or merge into or sell its assets to us or another Guarantor, or with or to other persons upon the terms and conditions set forth in the Indenture. A Guarantor may not sell or otherwise dispose of all or substantially all of its assets, or consolidate with or merge with or into another person (whether or not such Guarantor is the surviving person), unless certain conditions are met. See " Certain Covenants of Atlantic Power Restrictions on Mergers, Consolidations and Sales of Assets."

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The Guarantee of a Guarantor will be deemed automatically discharged and released in accordance with the terms of the Indenture:

(1) in connection with (i) any direct or indirect sale, conveyance or other disposition of all of the capital stock or all or substantially all of the assets of that Guarantor (including by way of merger or consolidation) and (ii) the merger, amalgamation or consolidation of a Guarantor with Atlantic Power or any other Guarantor;

(2) if such Guarantor is dissolved, liquidated or wound-up in accordance with the provisions of the Indenture;

(3) if such Guarantor no longer guarantees borrowings under the Senior Secured Revolving Credit Facility;

(4) if Curtis Palmer LLC no longer guarantees the Partnership's guarantee of borrowings under the Senior Secured Revolving Credit Facility or

(5) upon any legal Defeasance of the Indenture or satisfaction and discharge of the Indenture.

Interest

The Exchange Notes will initially bear interest at 9% per annum, payable semi-annually on May 15 and November 15 of each year to the person in whose name such Note is registered at the close of business on the May 1 or November 1, as the case may be, immediately preceding the relevant interest payment date. Principal of, premium, if any, and interest on the Exchange Notes will be payable, and the Exchange Notes may be exchanged or transferred, in accordance with the terms of the Indenture. The amount of interest payable will be computed on the basis of a 360-day year of twelve 30-day months. In the event that any date on which interest is payable on the notes is not a Business Day, then payment of the interest payable on such date will be made on the next succeeding day which is a Business Day (and without any interest or other payment in respect of any such delay) with the same force and effect as if made on such date.

We will deem the right to receive any interest accrued but unpaid on the Old Notes waived by you if we accept your Old Notes for exchange. Additional interest may accrue on the notes in certain circumstances if we do not consummate the exchange offer or file the shelf registration statement, as applicable, as provided in the Registration Rights Agreement.

"Business Day" means a day other than a Saturday, Sunday or other day on which the Trustee or commercial banking institutions in New York City are authorized or required by law to close

Repurchase of Notes Upon a Change of Control Triggering Event

Upon a Change of Control Triggering Event (as defined below), each holder of the notes will have the right to require that Atlantic Power repurchase such holder's notes at a repurchase price in cash equal to 101% of the principal amount thereof plus accrued and unpaid interest, if any, to, but not including, the date of repurchase.

Certain of the events constituting a Change of Control (as defined below) under the notes will, and may in the future, also constitute an event of default under the Senior Secured Revolving Credit Facility and other of our and our subsidiaries' existing and future debt instruments. Due to the highly leveraged nature of Atlantic Power, there can be no assurance that Atlantic Power will have sufficient funds to purchase tendered notes upon a Change of Control Triggering Event.

The Change of Control provisions will not necessarily afford protection to holders, including protection against an adverse effect on the value of the notes, in the event that Atlantic Power or its

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Subsidiaries incur additional debt, whether through recapitalizations or otherwise. The Change of Control provisions will not prevent a change in the Board of Directors which is approved by the then-present members of the Board of Directors. See the definition for "Change of Control" below. With respect to a sale of assets, the phrase "all or substantially all," which appears in the definition of Change of Control, has not gained an established meaning. In interpreting this phrase, courts have made subjective determinations, considering such factors as the value of the assets conveyed and the proportion of an entity's income derived from such assets. Furthermore, this term has not been interpreted under New York law (which is the governing law of the Indenture) to represent a specific quantitative test. Accordingly, there may be uncertainty as to whether a holder can determine whether a Change of Control has occurred and can exercise any remedies such holder may have upon a Change of Control.

Within 30 days following any Change of Control Triggering Event, Atlantic Power will mail a notice to each holder of the notes with a copy to the Trustee stating:

(1) that a Change of Control Triggering Event has occurred and that such holder has the right to require Atlantic Power to repurchase such holder's notes at a repurchase price in cash equal to 101% of the principal amount thereof plus accrued and unpaid interest, if any, to, but not including, the date of repurchase (the "**Change of Control Offer**");

(2) the circumstances and relevant facts regarding such Change of Control Triggering Event (including information with respect to pro forma historical income, cash flow and capitalization after giving effect to such Change of Control Triggering Event);

(3) the repurchase date (which will be not earlier than 30 days or later than 60 days from the date such notice is mailed) (the "**Repurchase Date**");

(4) that any Note not tendered will continue to accrue interest;

(5) that any Note accepted for payment pursuant to the Change of Control Offer will cease to accrue interest after the Repurchase Date;

(6) that holders electing to have a Note purchased pursuant to a Change of Control Offer will be required to surrender the Note, with the form entitled "Option of Holder to Elect Purchase" on the reverse of the Note completed, to the paying agent at the address specified in the notice prior to the close of business on the Repurchase Date;

(7) that holders will be entitled to withdraw their election if the paying agent receives, not later than the close of business on the third Business Day (or such shorter periods as may be required by applicable law) preceding the Repurchase Date, a telegram, telex, facsimile transmission or letter setting forth the name of the holder, the principal amount of notes the holder delivered for purchase, and a statement that such holder is withdrawing his election to have such notes purchased; and

(8) that holders which elect to have their notes purchased only in part will be issued new notes in a principal amount equal to the unpurchased portion of the notes surrendered.

On the Repurchase Date, Atlantic Power will, to the extent lawful:

- accept for payment notes or portions thereof tendered pursuant to the Change of Control Offer;
- deposit with the paying agent money sufficient to pay the purchase price of all notes or portions thereof so tendered; and
- deliver or cause to be delivered to the Trustee notes so accepted together with an officer's certificate identifying the notes or portions thereof tendered to Atlantic Power.

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The paying agent will promptly deliver to the holders of the notes so accepted payment in an amount equal to the purchase price, and the Trustee shall promptly authenticate and deliver to such holders a new Note of the same series in a principal amount equal to any unpurchased portion of the Note surrendered. Atlantic Power will publicly announce the results of the Change of Control Offer on or as soon as practicable after the Repurchase Date.

Atlantic Power will comply with all applicable tender offer rules, including without limitation Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with the repurchase of the notes, in connection with a Change of Control Offer.

"**Affiliate**" means, as applied to any Person, any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such Person. For the purposes of this definition, "**control**" (including, with correlative meanings, the terms "**controlling**," "**controlled by**" and "**under common control with**") when used with respect to any Person is defined to mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities, by contract or otherwise.

"**Board of Directors**" means either the Board of Directors of Atlantic Power or (except for the purposes of clause (iii) of the definition of "**Change of Control**") any committee of such Board of Directors duly authorized to act under the Indenture.

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated, whether voting or non-voting) of, or interests in (however designated), the equity of such Person which is outstanding or issued on or after the date of the Indenture, including, without limitation, all Common Stock and Preferred Stock and partnership and joint venture interests of such Person.

"**Common Stock**" means, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated, whether voting or non-voting) of common stock of such Person which is outstanding or issued on or after the date of the Indenture, including, without limitation, all series and classes of such common stock.

"**Change of Control**" means the occurrence of one or more of the following events: (i) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, of the assets of Atlantic Power (determined on a consolidated basis) to any Person or group (as that term is used in Section 13(d)(3) of the Exchange Act) of Persons, (ii) a Person or group (as so defined) of Persons (other than any Wholly Owned Subsidiary of Atlantic Power) will have become the beneficial owner of more than 50% of the outstanding Voting Stock of Atlantic Power, or (iii) during any one-year period, individuals who at the beginning of such period constituted the Board of Directors (together with any new director whose election or nomination was approved by a majority of the directors then in office who were either directors at the beginning of such period or who were previously so approved) cease to constitute a majority of the Board of Directors.

"**Change of Control Triggering Event**" means the occurrence of a Rating Event and a Change of Control.

"**Exchange Act**" means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC promulgated thereunder.

"**Person**" means an individual, a corporation, a partnership, a limited liability company, an association, a trust or any other entity or organization, including a government or political subdivision or an agency or instrumentality thereof.

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"**Preferred Stock**" means, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated, whether voting or non-voting) of preferred or preference stock of such Person which is outstanding or issued on or after the date of the Indenture.

"**Rating Agencies**" means, with respect to any series of notes, (a) each of Moody's and S&P, and (b) if either Moody's or S&P ceases to rate the notes or fails to make a rating of the notes publicly available for reasons outside of our control, a "nationally recognized statistical rating organization" (within the meaning of Rule 15c3-1(c)(2)(vi)(F) under the Exchange Act) selected by us as a replacement Rating Agency for a former Rating Agency.

"**Rating Event**" means the rating on the notes of such series is lowered by both Rating Agencies on any day within the period commencing on the earlier of (a) the occurrence of a Change of Control and (b) public notice of the occurrence of a Change of Control or our intention to effect a Change of Control, and ending 60 days following the consummation of such Change of Control (which 60-day period will be extended so long as the rating of the notes is under publicly announced consideration for a possible downgrade by any of the Rating Agencies).

It shall be Atlantic Power's obligation to determine if a Rating Event has occurred and the Trustee shall have no obligation to determine or verify if such an event has occurred or to notify the holders is such an event has occurred.

"**Voting Stock**" means, with respect to any Person, Capital Stock of any class or kind ordinarily having the power to vote for the election of directors of such Person or other Persons performing similar functions.

Optional Redemption

Except as described below, the notes are not redeemable until November 15, 2014. On and after November 15, 2014, we may redeem the notes, in whole or in part, upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount of the notes to be redeemed) set forth below, plus accrued and unpaid interest on the notes, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date following, on or prior to such redemption date), if redeemed during the twelve-month period beginning on November 15th of the years indicated below:

Year	**Percentage**
2014	104.500%
2015	102.250%
2016 and thereafter	100.00%

Prior to November 15, 2014, we may on any one or more occasions redeem up to 35% of the original aggregate principal amount of the notes (calculated after giving effect to any issuance of Additional Notes) with the Net Cash Proceeds of one or more Equity Offerings at a redemption price equal to 109% of the aggregate principal amount thereof, plus accrued and unpaid interest, if any, to, but not including, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date following on or prior to such redemption date); *provided* that at least 65% of the original aggregate principal amount of the notes (calculated after giving effect to any issuance of Additional Notes) remains outstanding after each such redemption; *provided further* that each redemption occurs within 90 days of the date of closing of each such Equity Offering.

In addition, at any time prior to November 15, 2014, we may redeem the notes, in whole but not in part, upon not less than 30 nor more than 60 days' prior notice mailed to each holder, with a copy to the Trustee, or otherwise in accordance with the procedures of the depositary at a redemption price equal to 100% of the aggregate principal amount of the notes plus the Applicable Premium (as defined below), plus accrued and unpaid interest, if any, to, but not including, the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on an interest payment date following, on or prior to such redemption date).

If the optional redemption date is on or after an interest record date and on or before the related interest payment date, the accrued and unpaid interest, if any, will be paid to the Person in whose name the Note is registered at the close of business, on such record date, and no additional interest will be payable to holders whose notes will be subject to redemption by Atlantic Power.

In the case of any partial redemption, selection of the notes for redemption will be made by the Trustee in compliance with the requirements of the principal national securities exchange, if any, on which the notes are listed (if such listing is known to the Trustee) or, if the notes are not listed, then on a pro rata basis, by lot or by such other method as the Trustee in its sole discretion will deem to be fair and appropriate or in accordance with DTC procedures, although no Note of $2,000 in original principal amount or less will be redeemed in part. If any Note is to be redeemed in part only, the notice of redemption relating to such Note will state the portion of the principal amount thereof to be redeemed. A new Note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder thereof upon cancellation of the original Note.

Any redemption or notice may, at our discretion, be subject to one or more conditions precedent, including completion of an Equity Offering or other corporate transaction.

If Atlantic Power or any Guarantor has become obligated to pay, on the next due date on which any amount may be payable with respect to the notes, any Additional Amounts (as defined below) as a result of a change (in, or amendment to, the laws or regulations of any Relevant Taxing Jurisdiction (including a change in legislation proposed by the Minister of Finance of Canada or any similar authority that, if enacted, will be effective prior to the enactment date and that, in practice, is treated as having the force of law at the time it is proposed), or a change in, or amendment to, any official position regarding the application or interpretation thereof (including by virtue of a holding by a court of competent jurisdiction), which change or amendment is publicly announced and becomes effective after the issue date of the notes (or, where the Relevant Taxing Jurisdiction did not become a Relevant Taxing Jurisdiction until a later date, after such later date), and such obligation to pay Additional Amounts cannot be avoided by commercially reasonable measures, then Atlantic Power may, at its option, redeem the notes then outstanding, in whole but not in part, upon not less than 30 nor more than 60 days' notice (such notice to be provided not more than 90 days before the next date on which it would be obligated to pay Additional Amounts), at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of Holders of record on the relevant record date to receive interest due on an interest payment date that is on or prior to the redemption date) and any applicable Additional Amounts.

Notice of Atlantic Power's intent to redeem the notes shall not be effective until such time as it delivers to the Trustee, (1) an Officer's Certificate stating that Atlantic Power has or will become obligated to pay Additional Amounts because of an amendment to or change in law or regulation or position as described in this paragraph, and such obligation cannot be avoided by commercially reasonable measures, and (2) an opinion of independent tax counsel qualified to practice in Canada (the choice of such counsel to be subject to the prior written approval of the Trustee (such approval not to be unreasonably withheld)) to the effect that there has been such amendment or change which would entitle the Issuer to redeem the notes hereunder.

"**Applicable Premium**" means, with respect to a Note on any date of redemption, the greater of:

(1) 1.0% of the principal amount of such Note, and

(2) the excess, if any, of (a) the present value as of such date of redemption of (i) the redemption price of such Note on November 15, 2014 (such redemption price being described under "Optional Redemption") plus (ii) all required interest payments due on such Note through November 15, 2014 (excluding accrued but unpaid interest to the date of redemption), computed using a discount rate equal to the Treasury Rate as of such date of redemption plus 50 basis points, over (b) the then-outstanding principal of such Note.

The Trustee shall have no duty to calculate, or verify the calculation of, the Applicable Premium.

"**Net Cash Proceeds**" means, with respect to any issuance or sale of Capital Stock, the cash proceeds of such issuance or sale, net of attorneys' fees, accountants' fees, underwriters' or placement agents' fees, listing fees, discounts or commissions and brokerage, consultant and other fees and charges actually incurred in connection with such issuance or sale and net of taxes paid or payable as a result of such issuance or sale (after taking into account any available tax credit or deductions and any tax sharing arrangements).

"**Equity Offering**" means an offering for cash by Atlantic Power of its Capital Stock, or options, warrants or rights with respect to its Capital Stock, other than (x) offerings with respect to Atlantic Power's Capital Stock, or options, warrants or rights, registered on Form S-4 or S-8, (y) an issuance to any Subsidiary or (z) any offering of Capital Stock issued in connection with a transaction that constitutes a Change of Control.

Payment of Additional Amounts

All payments made by or on behalf of Atlantic Power under or with respect to the notes, or by or on behalf of any Guarantor under or with respect to any Guarantee, are required to be made free and clear of and without withholding or deduction for or on account of any present or future tax, duty, levy, impost, assessment or other governmental charge (including penalties, interest, additions to tax and other liabilities related thereto) (hereinafter referred to as "**Taxes**") imposed or levied by or on behalf of the government of Canada, any province or territory of Canada or any political subdivision or any authority or agency therein or thereof having power to tax, or any other jurisdiction in which Atlantic Power or any such Guarantor is organized, or is otherwise carrying on business in, or is otherwise resident for tax purposes or any jurisdiction from or through which payment is made by or on behalf of Atlantic Power or any Guarantor, or (in each case) any political subdivision or authority or agency therein or thereof having power to tax (each, a "**Relevant Taxing Jurisdiction**"), unless such Person or other applicable withholding agent is required to withhold or deduct Taxes by law or by the interpretation or administration thereof. If such Person or other withholding agent is so required to withhold or deduct any amount for or on account of Taxes imposed by a Relevant Taxing Jurisdiction from any payment made under or with respect to the notes or a Guarantee, Atlantic Power or the applicable Guarantor (each, a "**Payor**") will be required to pay such additional amounts ("**Additional Amounts**") as may be necessary so that the net amount received by a beneficial owner of notes (including Additional Amounts) after such withholding or deduction will not be less than the amount such beneficial owner of notes would have received if such Taxes (including Taxes on any Additional Amounts) had not been withheld or deducted; *provided, however,* that the foregoing obligations to pay Additional Amounts do not apply to (1) any Canadian taxes imposed on any holder or beneficial owner of notes with which the applicable Payor does not deal at arm's length (within the meaning of the *Income Tax Act* (Canada)) at the time of the payment; or (2) any Taxes that would not have been so imposed but for the existence of any present or former connection between the relevant holder or beneficial owner of notes and the Relevant Taxing Jurisdiction including, for greater certainty and without limitation, being or having been a citizen, resident or national thereof, or being or having been engaged in a trade or business therein or maintaining a permanent establishment or other physical presence in or otherwise having some connection with the Relevant Taxing Jurisdiction (other than any connection arising solely from the acquisition, ownership or disposition of such Note or a beneficial

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interest therein, the enforcement of rights under a Note or any Guarantee or the receipt of any payment in respect thereof under a Note or any Guarantee); nor will Additional Amounts be paid (a) if the payment could have been made without such deduction or withholding if the beneficiary of the payment had presented the Note for payment within 30 days after the date on which such payment or such Note became due and payable or on the date on which payment thereof is duly provided for, whichever is later (except to the extent that the holder or beneficial owner would have been entitled to Additional Amounts had the Note been presented on the last day of such 30-day period); (b) to the extent relating to Taxes imposed by reason of the holder's or beneficial owner's failure to comply with any certification, documentation or information requirement or required to provide other evidence concerning such holder's or beneficial owner's nationality, residence, identity or connection with the Relevant Taxing Jurisdiction if such compliance or information is required by law, regulation, administration practice or an applicable treaty as a precondition to exemption from, or a reduction in the rate of deduction or withholding of, such Taxes to which such Holder or beneficial owner is legally entitled; or (c) any combination of any of the above clauses (any such Tax in respect of which Additional Amounts are payable, an "**Indemnified Tax**").

The applicable Payor, if it is the applicable withholding agent, will make any required withholding or deduction and remit the full amount deducted or withheld to the Relevant Taxing Jurisdiction in accordance with applicable law. Atlantic Power will provide the Trustee (and, upon written request, any holder) with official receipts or other documentation evidencing the payment of the Taxes with respect to which Additional Amounts are paid.

If a Payor determines that it is or will become obligated to pay Additional Amounts in respect of any amount payable under or with respect to the notes or any Guarantee, at least 30 days prior to the date of payment of such amount, such Payor will deliver to the Trustee an Officer's Certificate stating the fact that Additional Amounts will be payable and the amount so payable and such other information necessary to enable the Paying Agent to pay Additional Amounts to Holders on the relevant payment date.

Whenever in the Indenture there is mentioned in any context:

(1) the payment of principal;

(2) redemption prices or purchase prices in connection with a redemption or purchase of notes;

(3) interest; or

(4) any other amount payable under or with respect to any of the notes or any Guarantee; such reference shall be deemed to include payment of Additional Amounts as described under this heading to the extent that, in such context, Additional Amounts are, were or would be payable in respect thereof.

Atlantic Power and the Guarantors will indemnify and hold harmless a holder or beneficial owner of the notes for the amount of any Indemnified Taxes (including for greater certainty Taxes payable pursuant to Regulation 803 of the Income Tax Regulations (Canada)) levied or imposed and paid by such holder or beneficial owner as a result of payments made under or with respect to the notes or any Guarantee, or with respect to any reimbursement under this clause, in all cases to the extent that no Additional Amounts have previously been paid in respect thereof.

We will pay any present or future stamp, court or documentary taxes or any other excise, property or similar Taxes, charges or levies that arise in any Relevant Taxing Jurisdiction from the execution, delivery, enforcement or registration of the notes, the Guarantees, the Indenture or any other document or instrument in relation thereof, or the receipt of any payments under or with respect to the notes or any Guarantees and we will agree to indemnify the holders or beneficial owners of notes for any such amounts (including penalties, interest, additions to tax and other liabilities related thereto) paid by such holders or beneficial owners.

The obligations described under this heading will survive any termination, defeasance or discharge of the Indenture and will apply *mutatis mutandis* to any jurisdiction, in which any successor Person to Atlantic Power or any Guarantor is organized, doing business as resident for tax purposes or any jurisdiction through which any payment is made by or on behalf of such successor Person, or any political subdivision or authority or agency therein or thereof having power to tax.

Certain Covenants of Atlantic Power

Limitations on the Incurrence of Debt and Issuance of Disqualified Stock

Atlantic Power will not, and will not permit any of the Guarantors to, directly or indirectly, create, incur, issue, assume, guarantee or otherwise become directly or indirectly liable, contingently or otherwise, with respect to (collectively, "**incur**") any indebtedness for borrowed money represented by notes, bonds, loans, debentures or similar evidences of indebtedness (other than Permitted Indebtedness) or issue any shares of Disqualified Stock unless the Fixed Charge Coverage Ratio of Atlantic Power for its most recently ended four full fiscal quarters for which internal financial statements are available immediately preceding the date on which such indebtedness is incurred or such Disqualified Stock is issued would have been at least 1.75 to 1.0 determined on a pro forma basis (including a pro forma application of the net proceeds therefrom), as if the indebtedness had been incurred or the Disqualified Stock had been issued at the beginning of such four-quarter period.

Restrictions on Secured Debt

If Atlantic Power incurs, issues, assumes or guarantees any indebtedness for borrowed money represented by notes, bonds, debentures or other similar evidences of indebtedness, secured by a mortgage, pledge or other lien on any Principal Property (as defined below) or any Capital Stock or indebtedness held directly by Atlantic Power, Atlantic Power will secure the notes equally and ratably with (or prior to) such indebtedness, so long as such indebtedness will be so secured, unless after giving effect thereto the aggregate amount of all such indebtedness so secured, together with all Attributable Debt (as defined below) in respect of sale and leaseback transactions involving Principal Properties, would not exceed 15% of the Consolidated Net Assets (as defined below) of Atlantic Power. This restriction will not apply to, and there will be excluded in computing secured indebtedness for the purpose of such restriction, indebtedness that (1) consists of (a) purchase money mortgages and construction cost mortgages existing at or incurred within 365 days of the time of acquisition or completion of such construction or commencement of full operation of such property, whichever is later, or (b) any mortgage existing on any office equipment, data processing equipment (including computer and computer peripheral equipment) or transportation equipment (including motor vehicles, aircraft and marine vessels) or (2) is secured by (a) property of or equity interests held by any Subsidiary of Atlantic Power, (b) liens on property of, or on any equity interests on or held by or debt of, any Person existing at the time such Person becomes a Subsidiary, (c) liens in favor of Atlantic Power or any Subsidiary, (d) liens in favor of United States or foreign governmental bodies to secure partial, progress, advance or other payments, (e) liens on property, shares of stock or debt existing at the time of acquisition thereof (including acquisition through merger or consolidation), (f) liens existing on the first date on which any notes issued under the Indenture are authenticated by the Trustee, (g) liens under one or more Credit Facilities for indebtedness in an aggregate principal amount not to exceed the greater of (i) $350,000,000 and (ii) 10% of Consolidated Net Assets at any time outstanding, (h) liens incurred in connection with pollution control, industrial revenue or similar financings, (i) mechanics' or materialmen's liens or any lien or charge arising by reason of pledges or deposits to secure payment of workmen's compensation or other insurance, good faith deposits in connection with tenders or leases of real estate, bids or contracts (other than contracts for the payment of money),

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deposits to secure public or statutory obligations, deposits to secure or in lieu of surety, stay or appeal bonds and deposits as security for the payment of taxes or assessments or other similar charges; (j) undetermined mortgages and charges incidental to construction or maintenance; (k) liens on deposits required by any Person with whom Atlantic Power or any Subsidiary enters into forward contracts, futures contracts, swap agreements or other commodities contracts in the ordinary course of business and in accordance with established risk management policies; and (l) any extension, renewal, refinancing or replacement of any debt secured by any liens referred to in the foregoing clauses (1)(a) through (b) and (2)(a) through (k), inclusive. As of the date of this prospectus, Atlantic Power does not own or lease any Principal Property.

"**Principal Property**" means any building, structure or other facility (together with the land on which it is erected and fixtures comprising a part thereof) used primarily for power generation, transmission or distribution directly owned or leased by Atlantic Power and having a net book value in excess of 2% of Consolidated Net Assets, except such as the principal executive officer, president and principal financial officer of Atlantic Power determine in good faith is not of material importance to the total business conducted or assets owned by Atlantic Power and its Subsidiaries, taken as a whole.

"**Consolidated Net Assets**" means the aggregate amount of assets (less reserves and other deductible items) after deducting current liabilities, as shown on the consolidated balance sheet of Atlantic Power and its Subsidiaries contained in the latest quarterly or annual report, as the case may be, furnished to the holders of notes in accordance with the provisions described in " Reports."

"**Credit Facilities**" means one or more debt facilities, including the Senior Secured Revolving Credit Facility, or other financing arrangements (including, without limitation, commercial paper facilities with banks or other institutional lenders or investors or indentures) providing for revolving credit loans, term loans, letters of credit or other long-term indebtedness, including any notes, mortgages, guarantees, collateral documents, instruments and agreements executed in connection therewith, and any amendments, supplements, modifications, extensions, renewals, restatements or refundings thereof and any indentures or credit facilities or commercial paper facilities with banks or other institutional lenders or investors that refinance any part of the loans, notes or other securities, other credit facilities or commitments thereunder, including any such refinancing facility or indenture that increases the amount borrowable thereunder or alters the maturity thereof (provided that such increase in borrowings is permitted under the Indenture) or adds Subsidiaries as additional borrowers or guarantors thereunder and whether by the same or any other agent, lender or group of lenders.

"**Attributable Debt**" means the present value (discounted at the rate of interest implicit in the terms of the lease) of the obligations for net rental payments required to be paid during the remaining term of any lease of more than 12 months.

"**Subsidiary**" means, with respect to any person, any corporation, association or other business entity of which a majority of the capital stock or other ownership interests having ordinary voting power to elect a majority of the board of directors or other persons performing similar functions are at the time directly or indirectly owned by such person.

For purposes of determining compliance with any U.S. dollar-denominated restriction on the incurrence of indebtedness, the U.S. dollar-equivalent principal amount of indebtedness denominated in a foreign currency shall be calculated based on the relevant currency exchange rate in effect on the date such indebtedness was incurred, in the case of term indebtedness, or first committed, in the case of revolving credit indebtedness; provided that if such indebtedness is incurred to refinance other indebtedness denominated in a foreign currency, and such refinancing would cause the applicable U.S. dollar-denominated restriction to be exceeded if calculated at the relevant currency exchange rate in effect on the date of such refinancing, such U.S. dollar-denominated restriction shall be deemed not to have been exceeded so long as the principal amount of such refinancing indebtedness does not exceed the principal amount of such Indebtedness being refinanced. Notwithstanding any other provision of this covenant, the maximum amount of indebtedness that Atlantic Power may Incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in the exchange rate of currencies. The principal amount of any indebtedness incurred to refinance other Indebtedness, if incurred in a different currency from the indebtedness being refinanced, shall be calculated based on the currency exchange rate applicable to the currencies in which such refinancing indebtedness is denominated that is in effect on the date of such refinancing.

Restrictions on Sale and Leasebacks

Atlantic Power may not enter into any sale and leaseback transaction involving any Principal Property, the acquisition or completion of construction and commencement of full operation of which has occurred more than one year prior thereto, whichever is later, unless (a) Atlantic Power could incur a lien on such property under the restrictions described above under "Restrictions on Secured Debt" securing indebtedness in an amount equal to the Attributable Debt with respect to the sale and leaseback transaction without equally and ratably securing the notes, (b)(1) Atlantic Power receives fair market value for the Principal Property sold as determined by the principal executive officer, president or principal financial officer of Atlantic Power and (2) Atlantic Power, within one year after such sale or transfer, applies to (i) the retirement of its indebtedness for borrowed money (including the notes) and/or (ii) the acquisition of assets that are used or useful in the business of Atlantic Power or its subsidiaries, in each case, with the Net Proceeds of the sale of the Principal Property sold and leased pursuant to such arrangement, (c) any sale and leaseback transaction involving a lease for a period, including renewals, of not more than three years, and (d) such transaction was for the sale and leasing back to Atlantic Power of any Principal Property by one of its Subsidiaries.

Notwithstanding the foregoing, Atlantic Power may effect any sale and leaseback transaction that is not excepted by clauses (a) through (d), inclusive, of the preceding paragraph; *provided* that the Attributable Debt from such sale and leaseback transaction, together with the aggregate principal amount of outstanding indebtedness secured by liens upon Principal Properties, does not exceed 10% of Atlantic Power's Consolidated Net Assets.

"**Net Proceeds**" means the aggregate cash proceeds received by Atlantic Power in respect of the sale of the Principal Property sold and leased pursuant to any sale and leaseback transaction, net of the direct costs relating to such transaction, including, without limitation, legal, accounting and investment banking fees, and sales commissions, and any relocation expenses incurred as a result of the transaction, taxes paid or payable as a result of the transaction, in each case, after taking into account any available tax credits or deductions and any tax sharing arrangements, and amounts required to be applied to the repayment of indebtedness and any reserve for adjustment in respect of the sale price of such asset or assets established in accordance with GAAP.

Limitations on Restricted Payments

Atlantic Power will not, and will not permit any of its Subsidiaries to, directly or indirectly:

(a) declare or pay any dividend or make any other payment or distribution on account of Atlantic Power or any of its Subsidiaries' Equity Interests (including, without limitation, any payment in connection with any merger or consolidation involving Atlantic Power or any of its Subsidiaries) or to the direct or indirect holders of Atlantic Power's or any of its Subsidiaries' Equity Interests in their capacity as such (other than dividends or distributions payable in Equity Interests (other than Disqualified Stock) of Atlantic Power or to Atlantic Power or a Subsidiary of Atlantic Power); or

(b) purchase, redeem or otherwise acquire or retire for value (including, without limitation, in connection with any merger or consolidation involving Atlantic Power) any Equity Interests of

Atlantic Power or any direct or indirect parent of Atlantic Power (other than any such Equity Interests owned by Atlantic Power or any Subsidiary of Atlantic Power),

(all such payments and other actions set forth in these clauses (a) and (b) above being collectively referred to as "**Restricted Payments**"), unless, at the time of and after giving effect to such Restricted Payment:

(1) no Default or Event of Default has occurred and is continuing or would occur as a consequence of such Restricted Payment; and

(2) Atlantic Power, at the time of such Restricted Payment and after giving pro forma effect thereto as if such Restricted Payment had been made at the beginning of the applicable four-quarter period, have been permitted to incur at least $1.00 of additional indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the covenant described above under the caption " Limitations on the Incurrence of Debt and Issuance of Disqualified Stock."

The preceding provisions will not prohibit:

(1) the payment of any dividend within 90 days after the date of declaration of the dividend, if at the date of declaration the dividend payment would have complied with the provisions of the Indenture;

(2) (a) the making of any Restricted Payment in exchange for, or out of the aggregate proceeds of the sale (other than to a Guarantor of Atlantic Power) of, Equity Interests of Atlantic Power (other than Disqualified Stock) or from the contribution of equity capital (unless such contribution would constitute Disqualified Stock) to Atlantic Power ("**Refunding Capital Stock**") and (b) if immediately prior to any Restricted Payment that consists of redeeming, repurchasing, retiring or otherwise acquiring Equity Interests ("**Treasury Capital Stock**"), the declaration and payment of dividends thereon was permitted under clause (6) of this paragraph, the declaration and payment of dividends on the Refunding Capital Stock in an aggregate amount per year no greater than the aggregate amount of dividends per annum that were declarable and payable on such Treasury Capital Stock immediately prior to such retirement;

(3) the payment of any dividend (or, in the case of any partnership or limited liability company, any similar distribution) by a Subsidiary of Atlantic Power to the holders of its Equity Interests on a pro rata basis;

(4) (a) the repurchase, redemption or other acquisition or retirement for value of any Equity Interests of Atlantic Power or any Subsidiary of Atlantic Power held by any current or former officer, director or employee of Atlantic Power or any of its Subsidiaries (or permitted transferees of such persons, including, without limitation, their spouses or former spouses or estates or the beneficiaries of such estates), pursuant to any equity subscription agreement, stock option agreement, severance agreement, shareholders' agreement or similar agreement or employee benefit plan or (b) the cancellation of indebtedness owing to Atlantic Power or any of its Subsidiaries from any current or former officer, director or employee of Atlantic Power or any of its Subsidiaries in connection with a repurchase of Equity Interests of Atlantic Power or any of its Subsidiaries; *provided* that the aggregate price paid for the actions in clause (a) may not exceed $5.0 million in any twelve-month period (with unused amounts in any period being carried over to succeeding periods); *provided further* that (i) such amount in any calendar year may be increased by the cash proceeds of "key man" life insurance policies received by Atlantic Power and its Subsidiaries after the date of the Indenture less any amount previously applied to the making of Restricted Payments pursuant to this clause (4) since the date of the Indenture and (ii) cancellation of the indebtedness owing to Atlantic Power from employees, officers, directors and consultants of Atlantic Power or any of its Subsidiaries in connection with a repurchase of

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Equity Interests of Atlantic Power from such Persons shall be permitted under this clause (4) as if it were a repurchase, redemption, acquisition or retirement for value subject hereto;

(5) (a) the repurchase of Equity Interests in connection with the exercise of stock options or warrants or the vesting of restricted stock, restricted stock units, deferred stock units or any similar securities, to the extent such Equity Interests represent a portion of the exercise price of such securities (or withholding of Equity Interests to pay related withholding taxes with regard to the exercise of such stock options or the vesting of any such restricted stock, restricted stock units, deferred stock units or any similar securities) and (b) payments of cash, dividends, distributions, advances or other Restricted Payments to allow the payment of cash in lieu of the issuance of fractional shares upon (i) the exercise of options or warrants, (ii) the vesting or settlement of restricted stock, restricted stock units, deferred stock units or any similar securities or (iii) the conversion or exchange of Equity Interests of any such Person;

(6) the declaration and payment of regularly scheduled or accrued dividends to holders of any class or series of (a) preferred stock outstanding on the date of the Indenture, (b) Disqualified Stock of Atlantic Power or any Subsidiary of Atlantic Power issued on or after the date of the Indenture in accordance with the terms of the Indenture or (c) preferred stock issued on or after the date of the Indenture in accordance with the terms of the Indenture;

(7) Restricted Payments to fund the payment of dividends on common stock of Atlantic Power of up to 6% per year out of the net proceeds received by Atlantic Power in connection with any Equity Offering;

(8) the purchase, redemption, acquisition, cancellation or other retirement for a nominal value per right of any rights granted to all the holders of Capital Stock of Atlantic Power pursuant to any shareholders' rights plan adopted for the purpose of protecting shareholders from unfair takeover tactics; *provided* that any such purchase, redemption, acquisition, cancellation or other retirement of such rights is not for the purpose of evading the limitations of this covenant (all as determined in good faith by Atlantic Power); and

(9) so long as no Default has occurred and is continuing or would be caused thereby, other Restricted Payments since the date of the Indenture in an aggregate amount not to exceed the greater of $50.0 million and 2.0% of Consolidated Net Assets.

The amount of all Restricted Payments (other than cash) will be the fair market value on the date of the Restricted Payment of the asset(s) or securities proposed to be transferred or issued by Atlantic Power or such Subsidiary, as the case may be, pursuant to the Restricted Payment.

Events of Default

With respect the notes, an Event of Default, as defined in the Indenture, will occur if:

(1) we default in paying principal or premium, if any, on the notes when due, upon acceleration, redemption or otherwise;

(2) we default in paying interest on the notes when such interest becomes due, and the default continues for a period of 30 days;

(3) we default in performing or breach any other covenant or agreement in the Indenture with respect to the notes and the default or breach continues for a period of 60 consecutive days (or 120 consecutive days in the case of a Reporting Failure) after written notice to Atlantic Power by the Trustee or to Atlantic Power and the Trustee by the holders of 25% or more in aggregate principal amount of the notes issued under the Indenture affected thereby;

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(4) a court having jurisdiction enters a decree or order for:

- relief in respect of Atlantic Power or any of our Material Subsidiaries (as defined below) in an involuntary case under any applicable bankruptcy, insolvency, or other similar law now or hereafter in effect,

- appointment of a receiver, interim receiver, receiver and manager, liquidator, assignee, custodian, trustee, sequestrator, or similar official of Atlantic Power or any of our Material Subsidiaries or for all or substantially all of the property and assets of Atlantic Power or any of our Material Subsidiaries, or

- the winding up, liquidation dissolution, readjustment of debt or reorganization of the affairs of Atlantic Power or any of our Material Subsidiaries,

and, in each case, such decree or order will remain unstayed and in effect for a period of 60 consecutive days;

(5) Atlantic Power or any of our Material Subsidiaries:

- commences a voluntary case under any applicable bankruptcy, insolvency, or other similar law now or hereafter in effect, or consents to the entry of an order for relief in an involuntary case under any such law,

- consents to the appointment of or taking possession by a receiver, interim receiver, receiver and manager, liquidator, assignee, custodian, trustee, sequestrator, or similar official of Atlantic Power or any of our Material Subsidiaries or for all or substantially all of the property and assets of Atlantic Power or any of our Material Subsidiaries, or

- effects any general assignment for the benefit of creditors, or

(6) an event of default, as defined in any indenture or instrument evidencing or under which Atlantic Power has at the date of the Indenture or will thereafter have outstanding any indebtedness, will happen and be continuing and either (a) such default results from the failure to pay the principal of such indebtedness in excess of $40.0 million at final maturity of such indebtedness or (b) as a result of such default the maturity of such indebtedness will have been accelerated so that the same will be or become due and payable prior to the date on which the same would otherwise have become due and payable, and such acceleration will not be rescinded or annulled within 60 days and the principal amount of such indebtedness, together with the principal amount of any other indebtedness of Atlantic Power in default, or the maturity of which has been accelerated, aggregates $40.0 million or more; *provided* that the Trustee will not be charged with knowledge of any such default unless written notice thereof will have been given to the Trustee by Atlantic Power, by the holder or an agent of the holder of any such indebtedness, by the trustee then acting under any indenture or other instrument under which such default will have occurred, or by the holders of not less than 25% in the aggregate principal amount of the notes then outstanding; and *provided further* that if such default will be remedied or cured by Atlantic Power or waived by the holder of such indebtedness, then the Event of Default under the Indenture by reason thereof will be deemed likewise to have been remedied, cured or waived without further action on the part of the Trustee, any holder of notes or any other person.

If an Event of Default (other than an Event of Default specified in clause (4) or (5) with respect to Atlantic Power) with respect to the notes occurs and continues, then the Trustee or the holders of at least 25% in principal amount of the then outstanding notes may, by written notice to us, and the Trustee at the request of at least 25% in principal amount of the then outstanding notes will, declare the principal, premium, if any, and accrued interest on the notes to be immediately due and payable.

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Upon declaration of acceleration, the principal, premium, if any, and accrued interest of the notes will be immediately due and payable.

If an Event of Default specified in clause (4) or (5) above occurs with respect to Atlantic Power, the principal, premium, if any, and accrued interest on the notes will be immediately due and payable, without any declaration or other act on the part of the Trustee or any holder. The holders of at least a majority in principal amount of the then outstanding notes that have been accelerated, by written notice to us and to the Trustee, may waive all past defaults with respect to the notes and rescind and annul a declaration of acceleration with respect to the notes if:

- all existing Events of Default, other than the nonpayment of the principal, premium, if any, and interest on the notes that have become due solely by that declaration of acceleration, have been cured or waived; and

- the rescission would not conflict with any judgment or decree of a court of competent jurisdiction.

For information as to the waiver of defaults, see " Modification and Waiver."

The holders of at least a majority in principal amount of the then outstanding notes may direct the time, method, and place of conducting any proceeding for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee. However, the Trustee may refuse to follow any direction that conflicts with law or the Indenture, that may involve the Trustee in personal liability, or that the Trustee determines in good faith may be unduly prejudicial to the rights of holders of the notes who did not join in giving that direction and the Trustee may take any other action it deems proper that is not inconsistent with the direction received from holders of outstanding notes. A holder of notes may not pursue any remedy with respect to the Indenture unless:

- the holder gives the Trustee written notice of a continuing Event of Default;

- the holders of at least 25% in principal amount of the then outstanding notes make a written request to the Trustee to pursue the remedy;

- the holder or holders offer and, if requested, provide the Trustee indemnity satisfactory to the Trustee against any costs, liability or expense;

- the Trustee does not comply with the request within 60 days after receipt of the request and the offer of indemnity; and

- within that 60-day period, the holders of at least a majority in principal amount of the then outstanding notes do not give the Trustee a written direction that is inconsistent with the request.

However, these limitations do not apply to the right of any holder of the notes to receive payment of the principal, premium, if any, or interest on, the notes or to bring suit for the enforcement of any payment, on or after the due date expressed in the notes, which right will not be impaired or affected without the consent of the holder.

The Indenture requires that certain of our officers certify, on or before a date not more than four months after the end of each fiscal year, that to the best of those officers' knowledge, we have fulfilled all our obligations under the Indenture. We are also obligated to notify the Trustee of any default or defaults in the performance of any covenants or agreements under the Indenture.

"**Material Subsidiary**" of any Person means, as of any date, any Subsidiary that would constitute a "**significant subsidiary**" within the meaning of Article 1 of Regulation S-X of the Securities Act of 1933, as amended.

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"**Reporting Failure**" means our failure to furnish with the Trustee (or file with the SEC in lieu thereof) all quarterly and annual financial and current reports that are required to be furnished in accordance with the provisions described in " Reports." A Reporting Failure will be deemed to be cured and any resulting Default or Event of Default rescinded upon the furnishing or filing of such report or information with the Trustee (or the SEC in lieu thereof).

Certain Definitions

"**Consolidated Cash Flow**" means, with respect to any specified Person for any period, the Consolidated Net Income of such Person for such period plus, without duplication:

(1) an amount equal to any extraordinary loss (including any loss on the extinguishment or conversion of indebtedness) plus any net loss realized by such Person or any of its Subsidiaries in connection with an asset sale or other disposition to the extent such losses were deducted in computing such Consolidated Net Income; plus

(2) provision for taxes based on income or profits of such Person and its Subsidiaries for such period, to the extent that such provision for taxes was deducted in computing such Consolidated Net Income; plus

(3) the Fixed Charges of such Person and its Subsidiaries for such period, to the extent that such Fixed Charges were deducted in computing such Consolidated Net Income; plus

(4) any expenses, accruals, payments or charges or any amortization thereof related to any equity offering, investment, acquisition, disposition, recapitalization or indebtedness permitted to be incurred by the indenture including a refinancing, amendment or modification thereof (whether or not successful), including such fees, expenses or charges related to the offering of the notes and related transactions described in this prospectus, and deducted in computing Consolidated Net Income; plus

(5) any professional and underwriting fees related to any equity or debt offering, investment, acquisition, recapitalization or indebtedness permitted to be incurred under the indenture and, in each case, deducted in such period in computing Consolidated Net Income; plus

(6) the amount of any minority interest expense deducted in calculating Consolidated Net Income (less the amount of any cash dividends paid to the holders of such minority interests); plus

(7) any non-ash gain or loss attributable to mark to market adjustments in connection with Hedging Obligations; plus

(8) any writeoffs, writedowns or other non-cash losses or charges reducing Consolidated Net Income for such period, excluding any such loss or charge that represents an accrual or reserve for a cash expenditure for a future period; plus

(9) all items classified as extraordinary, unusual or nonrecurring non-cash losses or charges (including, without limitation, severance, relocation and other restructuring costs), and related tax effects according to GAAP to the extent such non-cash charges or losses were deducted in computing such Consolidated Net Income; plus

(10) depreciation, depletion, amortization (including amortization of intangibles but excluding amortization of prepaid cash expenses that were paid in a prior period), impairment and other non-cash charges and expenses (excluding any such non-cash expense to the extent that it represents an accrual of or reserve for cash expenses in any future period or amortization of a prepaid cash expense that was paid in a prior period) of such Person and its Subsidiaries for such period to the extent that such depreciation, depletion, amortization, impairment and other non-cash charges or expenses were deducted in computing such Consolidated Net Income; plus

(11) all non-cash losses or expenses included or deducted in calculating net income (or loss) for such period, including, without limitation, any non-cash loss or expense due to the application of FAS No. 106 regarding post-retirement benefits, FAS No. 133 regarding hedging activity, FAS No. 142 regarding impairment of goodwill, FAS No. 150 regarding accounting for financial instruments with debt and equity characteristics and non-cash expenses deducted as a result of any grant of equity interests to employees, officers or directors, but excluding any non-cash loss or expense (A) that is an accrual of a reserve for a cash expenditure or payment to be made, or anticipated to be made, in a future period or (B) relating to a write-down, write-off or reserve with respect to accounts and inventory; plus

(12) any costs or expenses incurred pursuant to any management equity plan or stock option plan or any other management or employee benefit plan or agreement or any stock subscription or shareholder agreement, to the extent that such costs or expenses are funded with cash proceeds contributed to the capital of Atlantic Power or net cash proceeds of an issuance of equity interests of Atlantic Power (other than Disqualified Stock); plus

(13) severance, signing bonus, relocation costs or expenses, any fees or expenses incurred or paid by Atlantic Power and its Subsidiaries in connection with the transactions described in this prospectus (including expenses in connection with any Hedging Obligations or other derivative instruments), integration costs, duplicative running costs, transition costs, pre-opening, opening, consolidation and closing costs for facilities, costs incurred in connection with any non-recurring strategic initiatives, costs incurred in connection with acquisitions (whether or not successful) and non-recurring costs and charges (including costs and expenses relating to business optimization programs and new systems design and implementation costs, project start-up costs and restructuring charges), accruals or reserves (including restructuring costs related to acquisitions after the date of the Indenture and to closure/consolidation of facilities, retention charges, systems establishment costs and excess pension charges), minus

(14) non-cash gains increasing such Consolidated Net Income for such period, other than the accrual of revenue in the ordinary course of business,

in each case, on a consolidated basis and determined in accordance with GAAP (including, without limitation, any increase in amortization or depreciation or other non-cash charges resulting from the application of purchase accounting in relation to any acquisition that is consummated after the date of the Indenture).

"**Consolidated Net Income**" means, with respect to any specified Person for any period, the aggregate of the Net Income of such Person and its Subsidiaries for such period, on a consolidated basis, determined in accordance with GAAP; *provided* that:

(1) the Net Income of any Person that is not a Subsidiary or that is accounted for by the equity method of accounting will be included only to the extent of the amount of dividends or similar distributions or other payments (including pursuant to other intercompany payments) paid or payable in cash or cash equivalents to the specified Person or a Subsidiary of the Person;

(2) the cumulative effect of a change in accounting principles will be excluded;

(3) any net after-tax non-recurring or unusual gains, losses (less all fees and expenses relating thereto) or other charges or revenue or expenses (including, without limitation, relating to severance, relocation and one-time compensation charges) shall be excluded;

(4) any non-cash compensation expense recorded from grants of stock appreciation or similar rights, stock options, restricted stock or other rights to officers, directors or employees shall be excluded, whether under FASB 123R or otherwise;

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(5) any net after-tax income (loss) from disposed or discontinued operations and any net after-tax gains or losses on disposal of disposed or discontinued operations shall be excluded;

(6) any gains or losses (less all fees and expenses relating thereto) attributable to asset dispositions shall be excluded;

(7) any gains and losses related to currency re-measurements of indebtedness (including the net loss or gain (i) resulting from Hedging Obligations for currency exchange risk and (ii) resulting from intercompany indebtedness) shall be excluded;

(8) any adjustments resulting from the application of FAS No. 133 and International Accounting Standard No. 39 and their respective related pronouncements and interpretations shall be excluded;

(9) any income (loss) for such period attributable to the extinguishment of (i) indebtedness, (ii) obligations under any Hedging Obligation or (iii) other derivative instruments, shall be excluded; and

(10) any impairment charge or asset write-off pursuant to Financial Accounting Statement No. 142 and No. 144 or any successor pronouncement shall be excluded.

"**Disqualified Stock**" means any Capital Stock that, by its terms (or by the terms of any security into which it is convertible, or for which it is exchangeable, in each case at the option of the holder of the Capital Stock), or upon the happening of any event, matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or redeemable at the option of the holder of the Capital Stock, in whole or in part, on or prior to the date that is 91 days after the date on which the applicable series of notes mature. Notwithstanding the preceding sentence, any Capital Stock that would constitute Disqualified Stock solely because the holders of the Capital Stock have the right to require Atlantic Power to repurchase such Capital Stock upon the occurrence of a change of control or an asset sale will not constitute Disqualified Stock if the terms of such Capital Stock provide that Atlantic Power may not repurchase or redeem any such Capital Stock pursuant to such provisions unless such repurchase or redemption complies with the covenant described above under the caption " Certain Covenants Restricted Payments." The amount of Disqualified Stock deemed to be outstanding at any time for purposes of the indenture will be the maximum amount that Atlantic Power and its Subsidiaries may become obligated to pay upon the maturity of, or pursuant to any mandatory redemption provisions of, such Disqualified Stock, exclusive of accrued dividends.

"**Equity Interests**" means Capital Stock and all warrants, options or other rights to acquire Capital Stock (but excluding any debt security that is convertible into, or exchangeable for, Capital Stock).

"**Fixed Charge Coverage Ratio**" means with respect to any specified Person for any period, determined on a consolidated basis, the ratio of the Consolidated Cash Flow of such Person and its subsidiaries for such period to the Fixed Charges of such Person and its subsidiaries for such period. In the event that the specified Person or any of its Subsidiaries incurs, assumes, guarantees, repays, repurchases, redeems, defeases or otherwise discharges any indebtedness (other than ordinary working capital borrowings) or issues, repurchases or redeems preferred stock subsequent to the commencement of the period for which the Fixed Charge Coverage Ratio is being calculated and on or prior to the date on which the event for which the calculation of the Fixed Charge Coverage Ratio is made (for purposes of this definition, the "**Calculation Date**"), then the Fixed Charge Coverage Ratio will be calculated giving pro forma effect to such incurrence, assumption, guarantee, repayment, repurchase, redemption, defeasance or other discharge of indebtedness, or such issuance, repurchase or redemption of preferred stock, and the use of the proceeds therefrom, as if the same had occurred at the beginning of the applicable four-quarter reference period. For purposes of this definition, whenever *pro forma* effect is to be given to a transaction, the *pro forma* calculations shall be made in good faith by a responsible financial or accounting officer of Atlantic Power (and may include, for the avoidance of

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doubt, cost savings and operating expense reductions resulting from such investment, disposition, acquisition, merger or consolidation which is being given *pro forma* effect that have been or are expected to be realized).

In addition, for purposes of calculating the Fixed Charge Coverage Ratio:

(1) investments and acquisitions that have been made by the specified Person or any of its Subsidiaries, including through mergers or consolidations, or any Person or any of its Subsidiaries acquired by the specified Person or any of its Subsidiaries, and including any related financing transactions and including increases in ownership of Subsidiaries, during the four-quarter reference period or subsequent to such reference period and on or prior to the Calculation Date will be given pro forma effect as if they had occurred on the first day of the four-quarter reference period and Consolidated Cash Flow for such reference period will be calculated on the same pro forma basis;

(2) the Consolidated Cash Flow attributable to discontinued operations, as determined in accordance with GAAP, and operations or businesses (and ownership interests therein) disposed of prior to the Calculation Date, will be excluded;

(3) the Fixed Charges attributable to discontinued operations, as determined in accordance with GAAP, and operations or businesses (and ownership interests therein) disposed of prior to the Calculation Date, will be excluded, but only to the extent that the obligations giving rise to such Fixed Charges will not be obligations of the specified Person or any of its Subsidiaries following the Calculation Date;

(4) any Person that is a Subsidiary on the Calculation Date will be deemed to have been a Subsidiary at all times during such four-quarter period;

(5) any Person that is not a Subsidiary on the Calculation Date will be deemed not to have been a Subsidiary at any time during such four-quarter period;

(6) if any indebtedness that is being incurred on the Calculation Date bears a floating rate of interest, the interest expense on such indebtedness will be calculated as if the rate in effect on the Calculation Date had been the applicable rate for the entire period (taking into account any Hedging Obligation applicable to such indebtedness);

(7) interest on a capitalized lease obligation shall be deemed to accrue at an interest rate reasonably determined by a responsible financial or accounting officer of Atlantic Power to be the rate of interest implicit in such capitalized lease obligation in accordance with GAAP;

(8) interest on any indebtedness under a revolving credit facility computed on a pro forma basis shall be computed based upon the average daily balance of such indebtedness during the applicable period; and

(9) interest on indebtedness that may optionally be determined at an interest rate based upon a factor of a prime or similar rate, a eurocurrency interbank offered rate, or other rate, shall be deemed to have been based upon the rate actually chosen or, if none, then based upon such optional rate chosen as Atlantic Power may designate

If since the beginning of such period any Person (that subsequently became a Subsidiary or was merged with or into Atlantic Power or any Subsidiary since the beginning of such period) shall have made any investment, acquisition, disposition, merger, consolidation or disposed operation that would have required adjustment pursuant to this definition, then the Fixed Charge Coverage Ratio shall be calculated giving pro forma effect thereto for such period as if such investment, acquisition or disposition, or classification of such operation as discontinued had occurred at the beginning of the applicable four-quarter period.

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"**Fixed Charges**" means, with respect to any specified Person for any period, the sum, without duplication, of:

(1) the consolidated interest expense of such Person and its Subsidiaries for such period, whether paid or accrued, to the extent such expense was deducted in computing Consolidated Net Income, including, without limitation, amortization of debt issuance costs and original issue discount, non-cash interest payments (but excluding any non-cash interest expense attributable to the movement in the mark to market valuation of Hedge Agreements or other derivative instruments pursuant to GAAP), the interest component of any deferred payment obligations, the interest component of all payments associated with capital lease obligations (as determined in accordance with GAAP), imputed interest with respect to Attributable Debt, and net of the effect of all payments made or received pursuant to Hedging Obligations in respect of interest rates; plus

(2) the consolidated interest expense of such Person and its Subsidiaries that was capitalized during such period; plus

(3) any interest accruing on indebtedness of another Person that is guaranteed by such Person or one of its Subsidiaries or secured by a lien on assets of such Person or one of its Subsidiaries, whether or not such guarantee or lien is called upon; plus

(4) the product of (a) all dividends, whether paid or accrued and whether or not in cash, on any series of preferred stock of such Person or any of its Subsidiaries, other than dividends on Equity Interests payable in Equity Interests of Atlantic Power (other than Disqualified Stock) or to Atlantic Power or a Subsidiary of Atlantic Power, times (b) a fraction, the numerator of which is one and the denominator of which is one minus the then current combined federal, state and local statutory tax rate of such Person, expressed as a decimal, in each case, on a consolidated basis and in accordance with GAAP; minus

(5) interest income for such period.

"**GAAP**" means generally accepted accounting principles set forth in the opinions and pronouncements of the Accounting Principles Board of the American Institute of Certified Public Accountants and statements and pronouncements of the Financial Accounting Standards Board or in such other statements by such other entity as have been approved by a significant segment of the accounting profession, which are in effect as of the date of the Indenture; *provided, however,* that if any operating lease would be recharacterized as a capital lease due to changes in the accounting treatment of such operating leases under GAAP since the date of the Indenture, then solely with respect to the accounting treatment of any such lease, GAAP shall be interpreted as it was in effect on the date of the Indenture. At any time after the date of the Indenture, Atlantic Power may elect to apply IFRS accounting principles in lieu of GAAP and upon any such election, references herein to GAAP shall thereafter be construed to mean IFRS as in effect on the date of any such election (except as otherwise expressly provided); *provided* that any such election, once made, shall be irrevocable; *provided further* that any calculation or determination in the Indenture that requires the application of GAAP for periods that include fiscal quarters ended prior to Atlantic Power's election to apply IFRS shall remain as previously calculated or determined in accordance with GAAP. Atlantic Power shall give written notice of any such election made in accordance with this definition to the Trustee.

"**Hedging Obligations**" means, with respect to any specified Person, the obligations of such Person under:

(1) currency exchange, interest rate or commodity swap agreements, currency exchange, interest rate or commodity cap agreements and currency exchange, interest rate or commodity collar agreements, and

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(2) (i) agreements or arrangements designed to protect such Person against fluctuations in currency exchange, interest rates, commodity prices or commodity transportation or transmission pricing or availability; (ii) any netting arrangements, power purchase and sale agreements, fuel purchase and sale agreements, swaps, options and other agreements, in each case, that fluctuate in value with fluctuations in energy, power or gas prices; and (iii) agreements or arrangements for commercial or trading activities with respect to the purchase, transmission, distribution, sale, lease or hedge of any energy related commodity or service.

"**indebtedness**" means indebtedness for borrowed money represented by notes, bonds, loans, debentures or similar evidences of indebtedness to the extent such indebtedness would appear as a liability upon a balance sheet of the specified Person prepared in accordance with GAAP; provided that indebtedness will not be deemed to include undrawn letters of credit or reimbursement obligations repaid within 90 days.

"**Net Income**" means, with respect to any specified Person, the net income (loss) of such Person, determined in accordance with GAAP and before any reduction in respect of preferred stock dividends or accretion.

"**Permitted Indebtedness**" means, with respect to Atlantic Power or any of the Guarantors,

(1) indebtedness outstanding under one or more Credit Facilities for indebtedness in an aggregate principal amount not to exceed the greater of (i) $350,000,000 and (ii) 10% of Consolidated Net Assets at any time outstanding;

(2) indebtedness represented by purchase money mortgages and construction cost mortgages existing at or incurred within 365 days of the time of acquisition or completion of such construction or commencement of full operation of such property, whichever is later;

(3) indebtedness represented by any mortgage existing on any office equipment, data processing equipment (including computer and computer peripheral equipment) or transportation equipment (including motor vehicles, aircraft and marine vessels);

(4) indebtedness represented by the notes and the Guarantees issued on the date of the indenture (and any Guarantees of the Notes issued after the date of the Indenture) and any notes issued in exchange for the notes (including any Guarantees thereof) pursuant to the Registration Rights Agreement;

(5) indebtedness outstanding on the date of the indenture (and indebtedness acquired in connection with the acquisition of the Partnership to the extent described in the Offering Memorandum related to the offering and sale of the notes);

(6) indebtedness in respect of workmen's compensation or other insurance, good faith deposits in connection with tenders or leases of real estate, bids or contracts (other than contracts for the payment of money), deposits to secure public or statutory obligations, deposits to secure or in lieu of surety, stay or appeal bonds and deposits as security for the payment of taxes or assessments or other similar charges;

(7) undetermined mortgages and charges incidental to construction or maintenance;

(8) indebtedness under any Hedging Obligation;

(9) indebtedness of Atlantic Power to a Guarantor or a Subsidiary or indebtedness of a Guarantor to Atlantic Power or another Subsidiary that is not a Guarantor; *provided* that any such indebtedness owing to a Subsidiary that is not a Guarantor is expressly subordinated in right of payment to the notes;

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(10) indebtedness represented by cash management obligations and other obligations in respect of netting services, automatic clearinghouse arrangements, overdraft protections and similar arrangements in each case in connection with deposit accounts;

(11) indebtedness arising from agreements of Atlantic Power or any Guarantor providing for indemnification, adjustment of purchase price, earnout or similar obligations, in each case, incurred or assumed in connection with the acquisition or disposition of any business, assets or a Subsidiary;

(12) indebtedness and obligations in respect of (i) standby letters of credit, performance, bid, appeal and surety bonds, completion guarantees, bank guarantees, workers' compensation claims, self-insurance obligations, bankers' acceptances, statutory, appeal, completion, export or import, indemnities, customs, revenue bonds or similar instruments, including guarantees or obligations with respect thereto, and similar obligations provided by Atlantic Power or any of the Guarantors in the ordinary course of business and (ii) deferred compensation or other similar arrangements incurred by Atlantic Power or any of the Guarantors;

(13) indebtedness consisting of indebtedness issued by Atlantic Power or any Guarantor to current or former officers, directors, employees or consultants thereof, their respective estates, spouses or former spouses, in each case to finance the purchase or redemption of Equity Interests of Atlantic Power, any Guarantor or any of their direct or indirect parent companies to the extent described in clause (4) of the second paragraph under the caption " Limitations on Restricted Payments";

(14) the incurrence of indebtedness or the issuance of Disqualified Stock by Atlantic Power or any of the Guarantors the net proceeds of which are used to finance an acquisition of Persons (including the acquisition portion of the Transaction) by Atlantic Power or any of the Guarantors or a merger of such Persons into Atlantic Power or any of its Guarantors not in violation of the terms of this Indenture;

(15) the incurrence of Atlantic Power or any of the Guarantors of Permitted Refinancing Indebtedness in exchange for, or the net proceeds of which are used to renew, refund, refinance, replace, defease or discharge any indebtedness (other than intercompany indebtedness) that was permitted by the indenture to be incurred under the covenant described in " Limitations on the Incurrence of Indebtedness and Issuance of Preferred Stock" and clauses (4), (5), (14), (15) and (16); and

(16) additional indebtedness or Disqualified Stock in aggregate amount at any time outstanding not to exceed 15% of the Consolidated Net Assets.

For purposes of determining compliance with the " Limitations on the Incurrence of Indebtedness and Issuance of Disqualified Stock" covenant and this definition of "**Permitted Indebtedness**," in the event that an item of proposed indebtedness meets the criteria of more than one of the categories of Permitted Indebtedness described in clauses (1) through (16) above, or is entitled to be incurred pursuant to the covenant described in " Limitations on the Incurrence of Indebtedness and Issuance of Disqualified Stock", Atlantic Power will be permitted to classify such item of indebtedness or Disqualified Stock on the date of its incurrence or issuance, or later reclassify all or a portion of such item of indebtedness or Disqualified Stock, in any manner that complies with such covenant and definition. Indebtedness under Credit Facilities outstanding on the date on which notes are first issued and authenticated under the indenture will initially be deemed to have been incurred on such date in reliance on the exception provided by clause (1) of the definition of Permitted Indebtedness. The accrual of interest, the accretion or amortization of original issue discount, the payment of interest on any indebtedness in the form of additional indebtedness with the same terms, the reclassification of preferred stock as indebtedness due to a change in accounting principles, and the payment of dividends on Disqualified Stock in the form of additional shares of the same class of Disqualified Stock will not be deemed to be an incurrence of indebtedness or an issuance of Disqualified Stock for purposes of this covenant; *provided,* in each such case, that the amount of any such accrual, accretion or payment is included in Fixed Charges of Atlantic Power as accrued. Notwithstanding any other provision of this covenant, the maximum amount of indebtedness that Atlantic Power or any Subsidiary may incur or Disqualified Stock they may issue pursuant to such covenant and definition of Permitted Indebtedness shall not be deemed to be exceeded solely as a result of fluctuations in exchange rates or currency values.

The amount of any indebtedness outstanding as of any date will be:

(1) the accreted value of the indebtedness, in the case of any indebtedness issued with original issue discount;

(2) the principal amount of the indebtedness, in the case of any other indebtedness; and

(3) in respect of indebtedness of another Person secured by a Lien on the assets of the specified Person, the lesser of:

(a) the fair market value of such assets at the date of determination; and

(b) the amount of the indebtedness of the other Person.

"**Permitted Refinancing Indebtedness**" means any indebtedness of Atlantic Power or any of its Subsidiaries issued in exchange for, or the net proceeds of which are used to renew, refund, refinance, replace, defease or discharge other indebtedness of Atlantic Power or any of its Subsidiaries (other than intercompany indebtedness); *provided* that:

(1) the principal amount (or accreted value, if applicable) of such Permitted Refinancing Indebtedness does not exceed the principal amount (or accreted value, if applicable) of the indebtedness renewed, refunded, refinanced, replaced, defeased or discharged (plus all accrued interest on the indebtedness and the amount of all fees and expenses, including premiums, incurred in connection therewith);

(2) such Permitted Refinancing Indebtedness has a final maturity date later than the final maturity date of the indebtedness being renewed, refunded, refinanced, replaced, defeased or discharged;

(3) if the indebtedness being renewed, refunded, refinanced, replaced, defeased or discharged is subordinated in right of payment to the notes, such Permitted Refinancing Indebtedness has a final maturity date later than the final maturity date of, and is subordinated in right of payment to, the notes on terms at least as favorable to the holders of notes as those contained in the documentation governing the indebtedness being renewed, refunded, refinanced, replaced, defeased or discharged; and

(4) such indebtedness is incurred either by Atlantic Power or by the Subsidiary who is the obligor on the indebtedness being renewed, refunded, refinanced, replaced, defeased or discharged.

"**Person**" means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company or government or other entity.

Modification and Waiver

The Indenture may be amended or supplemented without the consent of any holder of the notes to:

- cure ambiguities, defects, or inconsistencies;

- comply with the terms in "Restriction on Mergers, Consolidations and Sales of Assets" described below;
- comply with any requirements of the SEC in connection with the qualification of the Indenture under the Trust Indenture Act of 1939, as amended;
- to evidence and provide for the acceptance of appointment hereunder by a successor trustee with respect to the notes;
- to establish the form or terms of the notes;
- to convey, transfer, assign, mortgage or pledge to the Trustee as security for the notes any property or assets;
- to supplement any provision of this Indenture to such extent as will be necessary to permit or facilitate the defeasance or discharge of the notes, *provided* that such change or modification does not adversely affect the interests of the Holders of the notes;
- provide for the issuance of Additional Notes ranking equally with the notes in all respects (other than (A) the payment of interest accruing prior to the issue date of such Additional Notes and (B) the first payment of interest following the issue date of such Additional Notes);
- conform any provision to the "Description of the Notes" contained in the prospectus to the notes;
- make any change in the Guarantee that would not materially and adversely affect the Holders;
- to add a Guarantor;
- evidence and provide for the acceptance of appointment with respect to the notes by a successor Trustee; and
- make any change that does not materially and adversely affect the rights of any holder.

Other modifications and amendments of the Indenture may be made with the consent of the holders of not less than a majority in principal amount of the notes then outstanding. However, no modification or amendment may, without the consent of each holder affected:

- change the stated maturity of the principal of, or any sinking fund obligation or any installment of interest on, the notes;
- reduce the principal amount, premium, if any, or interest on the notes;
- reduce the above-stated percentage of outstanding notes, the consent of whose holders is necessary to modify or amend the Indenture with respect to the notes;

reduce the percentage or principal amount of outstanding notes of any series, the consent of whose holders is necessary for waiver of compliance with certain provisions of the Indenture or for waiver of certain default; or

change the definition of "Change of Control" after a Change of Control occurs.

Additional Subsidiary Guarantees

If any of our Wholly Owned Domestic Subsidiaries, including any Wholly Owned Domestic Subsidiary that we or any of our Subsidiaries may organize, acquire or otherwise invest in after the date of the Indenture that is not a Guarantor guarantees or becomes obligated to guarantee the Senior Secured Revolving Credit Facility under the terms of the Senior Secured Revolving Credit Facility, then such Domestic Subsidiary will (i) execute and deliver to the Trustee a supplemental indenture pursuant to which such Domestic Subsidiary will unconditionally guarantee all of Atlantic Power's obligations

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under the notes and the Indenture on the terms set forth in the Indenture and (ii) deliver to the Trustee an opinion of counsel that such supplemental indenture has been duly authorized, executed and delivered by such Domestic Subsidiary. Thereafter, such Domestic Subsidiary will be a Guarantor for all purposes of the Indenture; *provided, however,* that to the extent that a Domestic Subsidiary is subject to any instrument governing indebtedness existing at the time such Person becomes a Subsidiary, as in effect at the time of acquisition thereof, that prohibits such Domestic Subsidiary from issuing a Guarantee, such Domestic Subsidiary will not be required to execute such a supplemental indenture until it is permitted to issue such a Guarantee pursuant to the terms of such indebtedness; *provided further, however,* that any such Guarantee will be released as provided under the last paragraph above under "   The Guarantees."

Restriction on Mergers, Amalgamations, Consolidations and Sales of Assets

Pursuant to the Indenture, we may not consolidate with, merge with or into, amalgamate with or transfer all or substantially all of our assets to any Person unless:

- Atlantic Power will be the resulting, surviving or continuing Person, or, if Atlantic Power is not the resulting, surviving or continuing Person, the Person formed by such consolidation or amalgamation or into which we merged or to which properties and assets of ours are transferred is a solvent corporation organized and existing under the laws of Canada, any province thereof or any territory thereof or the laws of the United States, any state thereof or the District of Columbia and expressly assumes in writing all our obligations under the notes; and

- immediately after giving effect to such transaction, no Event of Default has occurred and is continuing.

The Indenture will provide that each Guarantor (other than any Guarantor whose Guarantee is to be released in accordance with the terms of such Guarantee and the Indenture) will not, and we will not cause or permit any Guarantor to, consolidate, amalgamate with or merge with or into (whether or not such Guarantor is the surviving entity), or sell, assign, transfer, lease, convey, or otherwise dispose of all or substantially all of its properties or assets in one or more related transactions to, any person other than to us or a Guarantor unless:

- the Guarantor is the resulting, surviving or continuing person or the person formed by or resulting, surviving or continuing any such consolidation, amalgamation or merger (if other than the Guarantor) or to which such sale, assignment, transfer, lease, conveyance or other disposition will have been made is a corporation, limited partnership or limited liability company organized or existing under the laws of the United States, any state thereof or the District of Columbia, or the laws of Canada, any province thereof or any territory thereof;

- the person formed by or resulting, surviving or continuing any such consolidation, amalgamation or merger (if other than the Guarantor) or the person to which such sale, assignment, transfer, lease, conveyance or other disposition will have been made assumes all the obligations of the Guarantor, pursuant to a supplemental indenture, under the notes and the Indenture; and

- immediately after giving effect to such transaction, no Event of Default has occurred and is continuing.

Reports

Whether or not required by the rules and regulations of the SEC, so long as any notes are outstanding, we will furnish to the Trustee and the holders of notes, within the time periods that are

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applicable to us (or, if not applicable, would be if we were required to file such reports under Section 13(a) or 15(d) of the Exchange Act as a non-accelerated filer):

(1) all quarterly and annual financial information that would be required to be contained in a filing with the SEC on Forms 10-Q and 10-K, if we were required to file such Forms, including a "Management's Discussion and Analysis of Financial Condition and Results of Operations" that describes our consolidated financial condition and results of operation and, with respect to the annual information only, a report thereon by our independent registered public accountants; and

(2) all current reports that would be required to be filed with the SEC on Form 8-K if we were required to file such reports.

We may satisfy our obligation to furnish such information to the Trustee at any time by filing such information with the SEC. If, notwithstanding the foregoing, the SEC will not accept such filings for any reason, we will post the reports specified in the preceding sentence on our website within the time periods that would apply if we were required to file those reports with the SEC. In addition, we agree that, until the consummation of the Exchange Offer contemplated under " Exchange Offer; Registration Rights," we will furnish to any beneficial owner of notes or to any prospective purchaser of notes in connection with any sale thereof, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act to facilitate the resale of the notes pursuant to Rule 144A. So long as any notes are outstanding, we will also hold a conference call to discuss our results of operations and allow participants to ask questions at the end of each call within 10 Business Days from delivery of the quarterly and annual financial information discussed above.

Defeasance and Covenant Defeasance

The Indenture provides that we are deemed to have paid and will be discharged from all obligations in respect of the notes on the date the deposit referred to below has been made, and that the provisions of the Indenture will no longer be in effect with respect to the notes (except for, among other matters, certain obligations to register the transfer or exchange of notes, to replace stolen, lost or mutilated notes, to maintain paying agencies and to hold monies for payment in trust) if, among other things,

- we have deposited with the Trustee, in trust, money and/or United States Government Obligations that, through the payment of interest and principal in respect thereof, will provide money in an amount sufficient to pay the principal, premium, if any, and accrued interest on the notes, on the date due thereof or earlier redemption (irrevocably provided for under arrangements satisfactory to the Trustee), as the case may be, in accordance with the terms of the Indenture and the notes;

- we have delivered to the Trustee:

  (a) either:

    (i) an opinion of counsel to the effect that holders of the notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of the exercise of our option under this "Defeasance" provision and will be subject to U.S. federal income tax on the same amount and in the same manner and at the same times as would have been the case if the deposit, defeasance, and discharge had not occurred, which opinion of counsel, in the case of a legal defeasance, must be based upon a ruling of the Internal Revenue Service to the same effect unless there has been a change in applicable U.S. federal income tax law or related treasury regulations after the date of the Indenture that a ruling is no longer required, or

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(ii) a ruling directed to the Trustee received from the Internal Revenue Service to the same effect as the aforementioned opinion of counsel; and

(b) an opinion of counsel to the effect that the creation of the defeasance trust does not violate the Investment Company Act of 1940, as amended, and on the date of the deposit the trust fund will not be subject to the effect of Section 547 of the U.S. Bankruptcy Code or Section 15 of the New York Debtor and Creditor Law;

immediately after giving effect to that deposit on a pro forma basis, no Event of Default has occurred and is continuing on the date of the deposit, and the deposit will not result in a breach or violation of, or constitute a default under, any other agreement or instrument to which we are a party or by which we are bound; and

if at that time the notes are listed on a national securities exchange, we have delivered to the Trustee an opinion of counsel to the effect that the notes will not be delisted as a result of a deposit, defeasance and discharge.

In the case of legal defeasance or covenant defeasance, Atlantic Power must deliver to the Trustee an opinion of counsel qualified to practice in Canada (such counsel acceptable to the Trustee, acting reasonably) or a ruling from the Canada Revenue Agency to the effect that holders of the outstanding notes will not recognize income, gain or loss for Canadian federal, provincial or territorial income tax or other tax purposes as a result of such legal defeasance or covenant defeasance, as applicable, and will only be subject to Canadian federal, provincial income tax and other taxes on the same amounts, in the same manner and at the same times as would have been the case if such legal defeasance or covenant defeasance, as applicable, had not occurred.

Book-Entry, Delivery and Form

The exchange notes will initially be represented by a global note in registered form without interest coupons attached (the "**Global Notes**"). The Global Note representing the notes will be deposited upon issuance with the trustee as custodian for DTC and registered in the name of Cede & Co., as nominee of DTC. Except as set forth below, the Global Notes will be issued in registered, global form in minimum denominations of $2,000 and integral multiples of $1,000 in excess of $2,000.

Except as set forth below, the Global Notes may be transferred, in whole and not in part, only to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for notes in certificated form ("**Certificated Notes**") except in the limited circumstances described below. See " Exchange of Global Notes for Certificated Notes" below.

Depository Procedures

The following description of the operations of DTC, Euroclear and Clearstream are provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. We take no responsibility for these operations and procedures and urge you to contact the system or their participants directly to discuss these matters.

DTC has advised us that it is a limited-purpose trust company created to hold securities for its participating organizations (collectively, the "**Participants**") and to facilitate the clearance and settlement of transactions in those securities between Participants through electronic book-entry changes in accounts of its Participants. The Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. Access to DTC's system is also available to other entities such as banks, brokers, dealers and trust companies that maintain a custodial relationship with a Participant, either directly or indirectly (collectively, the "**Indirect Participants**"). Persons who are not Participants may beneficially own securities held by or on behalf of DTC only through Participants or the Indirect Participants. The ownership of interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the Participants and the Indirect Participants.

DTC has also advised us that, pursuant to procedures established by it, ownership of interests in the Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the Participants) or by the Participants and the Indirect Participants (with respect to other owners of beneficial interest in the Global Notes).

All interests in a Global Note, including those held through Euroclear or Clearstream, may be subject to the procedures and requirements of DTC. Those interests held through Euroclear or Clearstream may also be subject to the procedures and requirements of such systems. The laws of some states require that certain Persons take physical delivery in definitive form of securities that they own. Consequently, the ability to transfer beneficial interests in a Global Note to such Persons will be limited to that extent. Because DTC can act only on behalf of the Participants, which in turn act on behalf of the Indirect Participants, the ability of a Person having beneficial interests in a Global Note to pledge such interests to Persons that do not participate in the DTC system, or otherwise take actions in respect of such interests, may be affected by the lack of a physical certificate evidencing such interests.

Except as described below, owners of interests in the Global Notes will not have notes registered in their names, will not receive physical delivery of notes in certificated form and will not be considered the registered owners or "holders" thereof under the indenture for any purpose.

Payments in respect of the principal of, and interest and premium, if any, and additional interest, if any, on, a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered holder under the indenture. Under the terms of the indenture, we and the trustee will treat the Persons in whose names the notes, including the Global Notes, are registered as the owners of the notes for the purpose of receiving payments and for all other purposes. Consequently, neither we, the trustee nor any agent of us or the trustee has or will have any responsibility or liability for:

(1) any aspect of DTC's records or any Participant's or Indirect Participant's records relating to or payments made on account of beneficial ownership interest in the Global Notes or for maintaining, supervising or reviewing any of DTC's records or any Participant's or Indirect Participant's records relating to the beneficial ownership interests in the Global Notes; or

(2) any other matter relating to the actions and practices of DTC or any of its Participants or Indirect Participants.

DTC has advised us that its current practice, upon receipt of any payment in respect of securities such as the notes (including principal and interest), is to credit the accounts of the relevant Participants with the payment on the payment date unless DTC has reason to believe that it will not receive payment on such payment date. Each relevant Participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant security as shown on the records of DTC. Payments by the Participants and the Indirect Participants to the beneficial owners of notes will be governed by standing instructions and customary practices and will be the responsibility of the Participants or the Indirect Participants and will not be the responsibility of DTC, the trustee or us. Neither we nor the trustee will be liable for any delay by DTC or any of the Participants or the Indirect Participants in identifying the beneficial owners of the notes, and we and the trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Transfers between the Participants will be effected in accordance with DTC's procedures, and will be settled in same-day funds, and transfers between participants in Euroclear and Clearstream will be effected in accordance with their respective rules and operating procedures.

Cross-market transfers between the Participants, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected through DTC in accordance with DTC's rules on behalf of Euroclear or Clearstream, as the case may be, by their respective depositaries; however, such cross-market transactions will require delivery of instructions to Euroclear or Clearstream, as the case may be, by the counterparty in such system in accordance with the rules and procedures and within the established deadlines (Brussels time) of such system. Euroclear or Clearstream, as the case may be, will, if the transaction meets its settlement requirements, deliver instructions to its respective depositary to take action to effect final settlement on its behalf by delivering or receiving interests in the relevant Global Note in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear participants and Clearstream participants may not deliver instructions directly to the depositories for Euroclear or Clearstream.

DTC has advised us that it will take any action permitted to be taken by a holder of notes only at the direction of one or more Participants to whose account DTC has credited the interests in the Global Notes and only in respect of such portion of the aggregate principal amount at maturity of the notes as to which such Participant or Participants has or have given such direction. However, if there is an Event of Default under the notes, DTC reserves the right to exchange the Global Notes for legended notes in certificated form, and to distribute such notes to its Participants.

Although DTC, Euroclear and Clearstream have agreed to the foregoing procedures to facilitate transfers of interests in the Global Notes among participants in DTC, Euroclear and Clearstream, they are under no obligation to perform or to continue to perform such procedures, and may discontinue such procedures at any time. None of us, the trustee and any of their respective agents will have any responsibility for the performance by DTC, Euroclear or Clearstream or their respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note is exchangeable for Certificated Notes of the same series if:

(1) DTC (a) notifies us that it is unwilling or unable to continue as depositary for the Global Notes, and we fail to appoint a successor depositary, or (b) has ceased to be a clearing agency registered under the Exchange Act;

(2) at our option, we notify the Trustee in writing that we elect to cause the issuance of the Certificated Notes; or

(3) there has occurred and is continuing a Default or Event of Default with respect to the notes.

In addition, beneficial interests in a Global Note may be exchanged for Certificated Notes of the same series upon prior written notice given to the Trustee by or on behalf of DTC in accordance with the Indenture. In all cases, Certificated Notes delivered in exchange for any Global Note or beneficial

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interests in Global Notes will be registered in the names, and issued in any approved denominations, requested by or on behalf of the depositary (in accordance with its customary procedures) and will bear the applicable restrictive legend referred to in "Notice to Investors," unless that legend is not required by applicable law.

Same Day Settlement and Payment

We will make payments in respect of the notes represented by the Global Notes (including principal, premium, if any, interest and liquidated damages, if any) by wire transfer of immediately available funds to the accounts specified by the Global Note holder. We will make all payments of principal, interest and premium and liquidated damages, if any, with respect to Certificated Notes by wire transfer of immediately available funds to the accounts specified by the holders thereof or, if no account is specified, by mailing a check to that holder's registered address. The notes represented by the Global Notes are expected to trade in DTC's Same Day Funds Settlement System, and any permitted secondary market trading activity in the notes will, therefore, be required by DTC to be settled in immediately available funds. We expect that secondary trading in any Certificated Notes will also be settled in immediately available funds.

Because of time zone differences, the securities account of a Euroclear or Clearstream participant purchasing an interest in a Global Note from a Participant in DTC will be credited and any crediting of this type will be reported to the relevant Euroclear or Clearstream participant, during the securities settlement processing day (which must be a business day for Euroclear and Clearstream) immediately following the settlement date of DTC. DTC has advised us that cash received in Euroclear or Clearstream as a result of sales of interests in a Global Note by or through a Euroclear or Clearstream participant to a Participant in DTC will be received with value on the settlement date of DTC but will be available in the relevant Euroclear or Clearstream cash account only as of the business day for Euroclear or Clearstream following DTC's settlement date.

Governing Law

The Indenture, the notes and the guarantees are governed by and construed in accordance with the laws of the State of New York.

Information Concerning the Trustee

The Trustee will be permitted to engage in other transactions; however, if it acquires any conflicting interest it must eliminate such conflict within 90 days, apply to the SEC for permission to continue as Trustee or resign. Atlantic Power and its subsidiaries may maintain deposit accounts and conduct other banking transactions with the Trustee in the ordinary course of business. The Trustee is the Exchange Agent for the exchange offer.

The indenture provides that in case an Event of Default occurs and is continuing, the Trustee will be required, in the exercise of its power, to use the degree of care of a prudent man in the conduct of his own affairs. The Trustee will be under no obligation to exercise any of its rights or powers under the indenture at the request of any holder of notes, unless such holder has offered to the Trustee security and indemnity satisfactory to it against any loss, liability or expense.

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CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

The following summary discusses certain U.S. federal income tax considerations relating to the exchange of Old Notes for Exchange Notes and the ownership and disposition of those Exchange Notes by a U.S. holder (as defined below). Non-U.S. persons considering an exchange of the Old Notes for Exchange Notes or other investment in the Exchange Notes should consult their own tax advisors about the tax consequences of exchanging, owning and disposing of notes.

The discussion below is based upon the provisions of the Internal Revenue Code of 1986, as amended (the "**Code**"), the Treasury regulations promulgated thereunder, and administrative and judicial interpretations of the foregoing, all as in effect as of the date hereof and all of which are subject to change, possibly on a retroactive basis which may materially and adversely affect the U.S. federal income tax consequences described herein. Except where otherwise stated, this summary deals only with notes held by U.S. holders as capital assets within the meaning of Section 1221 of the Code, and is applicable only to beneficial owners of the Exchange Notes who acquired them in the Exchange for Old Notes.

This summary does not deal with all aspects of U.S. federal income taxation that may be relevant to particular U.S. holders in light of their specific circumstances. For example, this summary does not address tax considerations to U.S. holders who may be subject to special tax treatment, such as dealers in securities or currencies; brokers; financial institutions or "financial service entities;" tax-exempt entities; traders in securities that elect to use a mark-to-market method of accounting for their securities holdings; regulated investment companies; real estate investment trusts; insurance companies; retirement plans; former citizens or long-term residents of the United States; partnerships, S corporations or other pass-through entities for U.S. federal income tax purposes or investors in such partnerships, S corporations or other pass-through entities; persons holding notes as part of a straddle, hedging, integrated, constructive sale or conversion transaction; and U.S. holders whose "functional currency" is not the U.S. dollar.

This summary does not consider the effect of any applicable foreign, state, local or other tax laws, alternative minimum tax considerations, or any U.S. federal tax considerations other than U.S. federal income tax considerations (such as estate or gift tax considerations or Medicare tax considerations) for any U.S. holders.

We have not sought any rulings from the Internal Revenue Service (the "**IRS**") with respect to the U.S. federal income tax considerations discussed below. The discussion below is not binding on the IRS or the courts. Accordingly, there can be no assurance that the IRS will not take a different position concerning the tax consequences of the exchange of Old Notes for Exchange Notes and the ownership and disposition of those Exchange Notes or that any such position would not be sustained.

As used herein, a "**U.S. holder**" is any beneficial owner of a note that is for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a corporation (or other entity taxable as a corporation) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if (1) it is subject to the primary supervision of a court within the United States and one or more U.S. persons have the authority to control all substantial decisions of the trust or (2) it was in existence on August 20, 1996 and has a valid election in effect under applicable Treasury regulations to be treated as a domestic trust for U.S. federal income tax purposes.

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If any entity treated as a partnership for U.S. federal income tax purposes is a beneficial owner of a note, the U.S. federal income tax treatment of a partner in the partnership generally will depend upon the status of the partner and the activities of the partnership. Prospective investors that are partnerships, and partners in such partnerships, should consult their own tax advisors about the U.S. federal income tax considerations of the exchange, ownership and disposition of the notes.

If you are considering exchanging your Old Notes for Exchange Notes, you should consult your own tax advisor concerning the U.S. federal income tax considerations to you of exchanging, owning and disposing of the notes, as well as any tax considerations that may arise under other U.S. federal tax laws or the laws of any other relevant foreign, state, local or other taxing jurisdiction.

Internal Revenue Service Circular 230 Notice

To ensure compliance with IRS Circular 230, you are hereby notified that: (a) any discussion of federal tax issues contained or referred to in this prospectus is not intended or written to be used, and cannot be used, by you for the purpose of avoiding penalties that may be imposed under the Code; (b) such discussion is written in connection with the promotion or marketing by us and the initial purchasers of the transactions or matters addressed herein; and (c) you should seek advice based on your particular circumstances from an independent tax advisor.

Exchange Offer

The exchange of Old Notes for Exchange Notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes and a U.S. holder will have the same tax basis and holding period in the Exchange Notes as it had in the Old Notes. Furthermore, any OID, market discount or bond premium associated with Old Notes will be treated as OID, market discount or bond premium with respect to the Exchange Notes for which a U.S. holder exchanges the applicable Old Notes.

Effect of Certain Contingencies

In certain circumstances (for example, see "Description of Exchange Notes Repurchase of Notes Upon a Change of Control," "Description of Exchange Notes Payment of Additional Amounts"), we may be obligated to pay amounts on the notes that are in excess of stated interest or principal on the notes. These potential contingencies may implicate the provisions of the Treasury regulations relating to "contingent payment debt instruments." Under these regulations, however, such contingencies should not cause the notes to be contingent payment debt instruments if, based on all facts and circumstances as of date on which such notes are issued, there is only a remote likelihood that any such contingencies will occur or such contingencies, in the aggregate, are considered incidental. We believe that the possibility of making such additional payments is remote and/or incidental and, accordingly, we do not intend to treat the notes as contingent payment debt instruments. Our position is binding on a U.S. holder unless such U.S. holder discloses its contrary position in the manner required by applicable Treasury regulations. Our determination, however, is not binding on the IRS and it may take a different position. If the IRS were to successfully challenge this position, a U.S. holder generally would be required to accrue ordinary income on its notes in excess of stated interest and any otherwise applicable original issue discount ("**OID**"), and to treat any income realized on the taxable disposition of a note as ordinary income rather than capital gain. The remainder of this discussion assumes that the Old Notes were not, and the Exchange Notes will not be, treated as contingent payment debt instruments. Investors should consult their own tax advisors regarding the possible application of the contingent payment debt instrument rules to the notes.

Stated Interest and Original Issue Discount on the Notes

A U.S. holder generally will be required to recognize as ordinary income any stated interest paid or accrued on the notes, in accordance with such holder's regular method of accounting for U.S. federal income tax purposes.

Because the stated principal amount of the Old Notes exceeded their issue price by more than a de minimis amount, the notes were treated as issued with OID. A U.S. holder that exchanges an Old Note for an Exchange Note will be required to continue to include the OID in gross income (as ordinary interest income) as it accrues (on a constant yield to maturity basis), in the same manner as if the Old Note had not been exchanged, before the receipt of cash payments attributable to the OID and regardless of such U.S. holder's regular method of accounting for U.S. federal income tax purposes. The amount of OID on an Old Note equals the excess of its stated principal amount over its issue price.

The amount of OID includible in income for a taxable year by a U.S. holder generally will equal the sum of the "daily portions" of the total OID on the note for each day during such taxable year on which such holder held the note. Generally, the daily portion of OID is determined by allocating to each day during an accrual period a ratable portion of OID on such note that is allocable to such accrual period. The amount of OID allocable to each accrual period generally will be an amount equal to the excess of (A) the product of the "adjusted issue price" of a note at the beginning of such accrual period and its "yield to maturity," over (B) the stated interest payable with respect to such note for such accrual period. The "adjusted issue price" of a note at the beginning of any accrual period will equal the issue price, increased by the total OID accrued for each prior accrual period. The "yield to maturity" of a note will be computed on the basis of a constant annual interest rate and compounded at the end of each accrual period.

A U.S. holder generally will not be required to include separately in income cash payments received on the notes to the extent such payments constitute payments of previously accrued OID (which for the avoidance of doubt do not include payments of stated interest) or payments of principal.

The rules regarding OID are complex and the rules described above may not apply in all cases. Accordingly, you should consult your own tax advisors regarding their application.

Sourcing of Interest

Interest and OID on the notes should constitute income from sources outside the United States and generally, with certain exceptions, should be "passive category income," which is treated separately from other types of income for purposes of computing any foreign tax credit allowable to a U.S. holder under the U.S. federal income tax law. Due to the complexity of the foreign tax rules, U.S. holders should consult their own tax advisors with respect to the amount of foreign taxes that may be claimed as a credit or deduction.

Market Discount, Acquisition Premium, and Amortizable Bond Premium

If a U.S. holder purchased an Old Note for which the Exchange Note was exchanged at a price that is less than its adjusted issue price as of the purchase date, the amount of the difference will be treated as "market discount." However, the market discount will be considered to be zero if it is less than $^1/_4$ of I% of the principal amount multiplied by the number of complete years to maturity from the date the U.S. holder purchased the Old Note.

Under the market discount rules of the Code, a U.S. holder generally will be required to treat any payment that does not constitute qualified stated interest or accrued but unpaid OID on, or any gain realized on the sale, exchange, repurchase, retirement or other disposition of, an Exchange Note as ordinary income (generally treated as interest income) to the extent of the market discount which accrued but was not previously included in income by the U.S. holder during the period the U.S. holder held the Exchange Note (and the Old Note for which the Exchange Note was exchanged). In addition, the U.S. holder may be required to defer, until the maturity of the Exchange Note or its earlier disposition in a taxable transaction, all or a portion of the interest expense on indebtedness incurred to purchase the Exchange Note (or an Old Note for which the Exchange Note was exchanged). In general, market discount will be considered to accrue ratably during the period from the date of the purchase of the Old Note for which the Exchange Note was exchanged to the maturity date of the Exchange Note, unless the U.S. Holder makes an irrevocable election (on an instrument-by-instrument basis) to accrue market discount under a constant yield method. A U.S. Holder may elect to include market discount in income currently as it accrues (under either a ratable or constant yield method), in which case the rules described above regarding the treatment as ordinary income of gain upon the disposition of the Exchange Note and upon the receipt of certain payments and the deferral of interest deductions will not apply. The election to include market discount in income currently, once made, applies to all market discount obligations acquired on or after the first day of the first taxable year to which the election applies, and may not be revoked without the consent of the IRS.

If a U.S. holder purchased an Old Note for which the Exchange Note was exchanged for an amount that is greater than its adjusted issue price but less than or equal to the sum of all amounts payable on the Old Note after the purchase date other than payments of qualified stated interest, the U.S. holder will be considered to have purchased that Old Note at an "acquisition premium," and that acquisition premium will carry over to the Exchange Note. Under the acquisition premium rules, the amount of OID that a U.S. holder must include in gross income with respect to the note for any taxable year will be reduced by a portion of the acquisition premium pursuant to a formula prescribed by the Code, unless the U.S. holder elects to treat all interest on the note, as adjusted for acquisition premium, as accruing on a constant yield basis, as described under " Stated Interest and Original Issue Discount on the Notes," above.

If a U.S. holder purchased an Old Note for which the Exchange Note was exchanged for an amount in excess of the sum of all amounts payable on the Exchange Note (or Old Note) after the purchase date other than qualified stated interest, the U.S. holder will be considered to have purchased the note at a "premium" and will not be required to include any OID in income. It may be possible for a U.S. holder of an Exchange Note to elect to amortize the premium using a constant yield method over the remaining term of the Exchange Note (or until an earlier call date, as applicable). The amortized amount of the premium for a taxable year generally will be treated first as a reduction of interest on the Exchange Note included in such taxable year to the extent thereof, then as a deduction allowed in that taxable year to the extent of the U.S. Holder's prior interest inclusions on the Exchange Note, and finally as a carryforward allowable against the U.S. Holder's future interest inclusions on the Exchange Note. The election, once made, is irrevocable without the consent of the IRS and applies to all taxable bonds held during the taxable year for which the election is made or subsequently acquired. A U.S. holder that does not make this election will be required to include in gross income the full amount of interest on the Exchange Note in accordance with its regular method of tax accounting, and will include the premium in its tax basis for the Exchange Note for purposes of computing the amount of its gain or loss recognized on the taxable disposition of the Exchange Note. U.S. holders should consult their own tax advisors concerning the computation and amortization of any bond premium on the Exchange Notes.

A U.S. holder may elect to include in gross income under a constant yield method all amounts that accrue on an Exchange Note that are treated as interest for tax purposes (i.e., stated interest, market discount and de minimis market discount, as adjusted by any amortizable bond premium). U.S. Holders should consult their tax advisors as to the desirability, mechanics and collateral consequences of making this election.

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Sale, Exchange, Redemption, Retirement or Other Taxable Disposition of the Notes

Unless a non-recognition provision applies and subject to the discussion below, a U.S. holder generally will recognize gain or loss upon a sale, exchange, repurchase, retirement (including a redemption) or other taxable disposition of an Exchange Note in an amount equal to the difference, if any, between the amount realized upon the sale, exchange, repurchase, retirement or other taxable disposition and such holder's adjusted tax basis in the note. The amount realized will include the amount of any cash and the fair market value of any other property received for the note, excluding any amount in respect of accrued and unpaid stated interest, which will be taxed as ordinary income to the extent not previously so taxed. A U.S. holder's adjusted tax basis in a note generally will be equal to the amount paid by such holder for the note, increased by the amount of OID and any market discount previously included in income by the U.S. holder up through the date of the sale, exchange, repurchase, retirement or other disposition and decreased by any amortized premium and any prior cash payments (other than payments constituting stated interest). Generally, except with respect to market discount, any gain or loss recognized on a taxable disposition of a note will be capital gain or loss, and generally will be long-term capital gain or loss if at the time of the sale, exchange, repurchase, redemption, retirement or other disposition the note has been held by such U.S. holder for more than one year. If the U.S. holder is an individual or other non-corporate taxpayer, any long-term capital gain generally will be eligible for reduced rates of taxation. The deductibility of net capital losses is subject to certain limitations.

Any gain or loss recognized by a U.S. Holder on the sale or other disposition of a note generally should be treated as income from sources within the United States or loss allocable to income from sources within the United States. Any loss attributable to accrued but unpaid interest will generally be sourced in the same manner as interest income (as described above).

Information Reporting and Backup Withholding

In general, information reporting requirements will apply to payments of stated interest, accruals of OID and any proceeds from sale or other disposition (including a retirement or redemption) of a note.

U.S. backup withholding tax will apply at the applicable rate (currently 28% and scheduled to increase to 31% in 2013) with respect to payments of stated interest, accruals of any OID on a note and the gross proceeds of sale or other disposition (including a retirement or redemption) of a note held by a U.S. holder if such U.S. holder, among other things, fails to furnish a social security number or other taxpayer identification number ("**TIN**") certified under penalties of perjury within a reasonable time after the request therefor; furnishes an incorrect TIN; is subject to backup withholding because of a prior failure to properly report interest or dividends; or under certain circumstances, fails to provide a certified statement, signed under penalties of perjury, that the TIN furnished is the correct number and that such U.S. holder is not subject to backup withholding. A U.S. holder that does not provide his, her or its correct TIN may be subject to penalties imposed by the IRS.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules will be allowed as a refund or a credit against such U.S. holder's U.S. federal income tax liability, provided the required information is timely furnished to the IRS. Certain persons are exempt from backup withholding, including corporations and tax-exempt entities, provided their exemption from backup withholding is properly established. U.S. holders should consult their tax advisors as to their qualifications for exemption from backup withholding and the procedure for obtaining such exemption.

New Legislation

Newly enacted legislation requires certain U.S. holders who are individuals, estates or trusts to pay an additional 3.8% tax on, among other things, interest on and capital gains from the sale or other disposition of the notes for taxable years beginning after December 31, 2012. U.S. holders should consult their tax advisors regarding the effect, if any, of this legislation on their ownership and disposition of the notes.

The preceding discussion of certain U.S. federal income tax considerations of the exchange of Old Notes for Exchange Notes and the ownership and disposition of those Exchange Notes by U.S. holders is for general information only and is not tax advice. Accordingly, each investor should consult his, her or its own tax advisor as to particular tax considerations to it of exchanging, holding and disposing of notes, including the applicability and effect of state, local or foreign tax laws, other federal tax laws, and of any proposed changes in applicable law.

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CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following summary discusses the principal Canadian federal income tax considerations generally applicable, at the date hereof, to a holder of notes that acquires Exchange Notes as a beneficial owner pursuant to the exchange offer and that, for the purposes of the *Income Tax Act* (Canada) (the "Tax Act") and at all relevant times: (i) is neither a resident of Canada nor deemed to be a resident of Canada; (ii) holds the notes as capital property; (iii) deals at arm's length, and is not affiliated, with Atlantic Power and/or its subsidiaries, any successor to Atlantic Power and/or its subsidiaries, or any transferee resident or deemed to be resident in Canada to which the holder disposes of, or is deemed to have disposed of, notes; (iv) is a holder for which the notes do not constitute "designated insurance property" for the purposes of the Tax Act; (v) is not a "specified shareholder", as defined in subsection 18(5) the Tax Act, of Atlantic Power and does not deal not at arm's length for purposes of the Tax Act with a "specified shareholder" of Atlantic Power and (vi) does not use or hold, and is not deemed to use or hold, notes in carrying on a business in Canada (a "**Holder**"). Generally, the notes will be considered capital property to a Holder provided that the Holder does not acquire or hold the notes in the course of carrying on a business of buying and selling securities and has not acquired them as an adventure or concern in the nature of trade. Generally, for the purposes of subsection 18(5) of the Tax Act, a "specified shareholder" is a shareholder that owns or is deemed to own, either alone or together with persons with which the shareholder does not deal at arm's length for purposes of the Tax Act, shares of Atlantic Power capital stock that either (i) give the shareholder 25% or more of the votes that could be cast at an annual meeting of the shareholders or (ii) have a fair market value of 25% or more of the fair market value of all of the issued and outstanding shares of Atlantic Power capital stock. Such Holders should consult their own tax advisors. This summary assumes that no payment of interest on the notes is in respect of a debt or other obligation to pay an amount to a person with which Atlantic Power does not deal at arm's length for the purposes of the Tax Act.

This summary is based upon the facts set out in this prospectus, the provisions of the Tax Act that are in force at the date of this prospectus, all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "**Tax Proposals**") and our counsel's understanding of the current published administrative practices and assessing policies of the Canada Revenue Agency (the "**CRA**"). This summary assumes all Tax Proposals will be amended as proposed, however there can be no assurance that the Tax Proposals will be implemented in their current form or at all. This summary is not exhaustive of all possible income tax considerations and, except for the Tax Proposals, does not otherwise take into account or anticipate any changes in law or practice, whether by way of judicial, governmental or legislative decision or action or changes in the administrative practices or assessing policies of the CRA, nor does it take into account tax legislation or considerations of any province or foreign jurisdiction.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular Holder, and no representations with respect to the income tax consequences to any particular Holder are made. Accordingly, prospective purchasers should consult their own tax advisors for advice with respect to the tax consequences to them of acquiring, holding and disposing of notes, including the application and effect of the income and other tax laws of any country, province, state or local tax authority.

An exchange of Old Notes for Exchange Notes pursuant to the exchange offer will not be a taxable event to a Holder for Canadian federal income tax purposes. Holders will not recognize any taxable gain or loss, or be subject to Canadian withholding tax, as a result of exchanging Old Notes for Exchange Notes pursuant to the exchange offer

Amounts paid or credited, or deemed to be paid or credited, as, on account or in lieu of payment of, or in satisfaction of, the principal of the notes or premium, discount or interest on the notes by

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Atlantic Power to a Holder, and proceeds received by a Holder on a disposition of a note, including a redemption, payment on maturity, repurchase or purchase for cancellation will be exempt from Canadian withholding tax. No other taxes on income (including taxable capital gains) will be payable under the Tax Act by a Holder in respect of the ownership or disposition of a note including a redemption, payment on maturity, repurchase or purchase for cancellation.

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PLAN OF DISTRIBUTION

If you are a broker-dealer that receives Exchange Notes for your own account pursuant to the exchange offer as a result of market-making activities or other trading activities, you must acknowledge that you will deliver a prospectus in connection with any resale of such Exchange Notes. This prospectus, as it may be amended or supplemented from time to time, may be used in connection with resales of Exchange Notes received in exchange for Old Notes where such Old Notes were acquired as a result of market-making activities or other trading activities. To the extent any broker-dealer participates in the exchange offer and so notifies us, we have agreed to promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests those documents in the letter of transmittal.

- We will not receive any proceeds from any sale of Exchange Notes by broker-dealers.

- Exchange Notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the Exchange Notes or a combination of such methods of resale, at prevailing market prices at the time of resale, at prices related to such prevailing market prices or at negotiated prices.

- Any resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers or any such Exchange Notes.

- Any broker-dealer that resells Exchange Notes that were received by it for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such Exchange Notes may be deemed to be an "underwriter" within the meaning of the Securities Act, and any profit on any such resale of Exchange Notes and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act.

- The letter of transmittal states that, by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act.

We have agreed to pay all expenses incident to the exchange offer (other than commissions and concessions of any broker-dealer), subject to certain prescribed limitations, and will provide indemnification against certain liabilities, including certain liabilities that may arise under the Securities Act, to broker-dealers that make a market in the Old Notes and exchange Old Notes in the exchange offer for Exchange Notes.

By its acceptance of the exchange offer, any broker-dealer that receives Exchange Notes pursuant to the exchange offer hereby agrees to notify us prior to using the prospectus in connection with the sale or transfer of Exchange Notes. It also agrees that, upon receipt of notice from us of the happening of any event which makes any statement in this prospectus untrue in any material respect or which requires the making of any changes in this prospectus in order to make the statements therein not misleading or which may impose upon us disclosure obligations that may have a material adverse effect on us (which notice we agree to deliver promptly to such broker-dealer), such broker-dealer will suspend use of this prospectus until we have notified such broker-dealer that delivery of this prospectus may resume and has furnished copies of any amendment or supplement to this prospectus to such broker-dealer.

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LEGAL MATTERS

The validity of the Exchange Notes will be passed upon by Goodwin Procter LLP, Boston, Massachusetts.

EXPERTS

The consolidated financial statements and financial statement schedule of Atlantic Power as of December 31, 2011 and 2010 and for each of the years in the three-year period ended December 31, 2011 have been included in this registration statement in reliance upon the reports of the United States and Canadian firms of KPMG LLP, independent registered public accounting firms, and upon the authority of said firms as experts in accounting and auditing.

The financial statements of Chambers Cogeneration Limited Partnership as of December 31, 2010 and for the year then ended included in this registration statement have been so included in reliance on the report (which contains an explanatory paragraph relating to the Chambers Cogeneration Limited Partnership restatement of its financial statements as described in the Restatement of Previously Issued Financial Statements section of Note 2 to the financial statements) of PricewaterhouseCoopers LLP, independent auditors, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of the Partnership as of December 31, 2010, 2009 and 2008 and for each of the years in the three-year period ended December 31, 2010 have been included in this registration statement in reliance on the report of the Canadian firm of KPMG LLP, an independent registered public accounting firm, and upon the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. Our SEC filings are also available to the public from the SEC's website at *http://www.sec.gov* and on our website at *http://www.atlanticpower.com.* We have included the SEC's web address and our web address as inactive textual references only. Our website is not incorporated into, and does not constitute a part of, this prospectus or any other report or documents we file with or furnish to the SEC.

We have filed with the SEC a registration statement on Form S-4 under the Securities Act with respect to the Exchange Notes being offered hereby. This prospectus, which forms a part of the registration statement, does not contain all of the information set forth in the registration statement. For further information with respect to us and the Exchange Notes, reference is made to the registration statement. Statements contained in this prospectus as to the contents of any contract or other document are not necessarily complete. If a contract or document has been filed as an exhibit to the registration statement, we refer you to the copy of the contract or document that has been filed. Each statement in this prospectus relating to a contract or document filed as an exhibit is qualified in all respects by the filed exhibit.

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You may obtain a copy of any of these documents at no cost, by writing or telephoning us at the following address:

Atlantic Power Corporation
200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400
Attn: Corporate Secretary

We have not authorized anyone to give you any information or to make any representations about us or the transactions we discuss in this prospectus other than those contained in this prospectus. If you are given any information or representations about these matters that is not discussed in this prospectus, you must not rely on that information. This prospectus is not an offer to sell or a solicitation of an offer to buy securities anywhere or to anyone where or to whom we are not permitted to offer or sell securities under applicable law.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited Atlantic Power Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlantic Power Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Atlantic Power Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Atlantic Power Corporation acquired Capital Power Income L.P. during 2011, and management excluded from its assessment of the effectiveness of Atlantic Power Corporation's internal control over financial reporting as of December 31, 2011, Capital Power Income L.P.'s internal control over financial reporting associated with total assets of $2.2 billion and total revenues of $74 million included in the consolidated financial statements of Atlantic Power Corporation and subsidiaries as of and for the year ended December 31, 2011. Our audit of internal control over financial reporting of Atlantic Power Corporation also excluded an evaluation of the internal control over financial reporting of Capital Power Income L.P.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atlantic Power Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011, and our report dated February 29, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New York, New York
February 29, 2012

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011. In connection with our audit of the consolidated financial statements, we also have audited financial statement schedule "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atlantic Power Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 29, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

New York, New York
February 29, 2012

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Report of Independent Registered Public Accounting Firm

The Board of Directors
Atlantic Power Corporation

We have audited the accompanying consolidated balance sheet of Atlantic Power Corporation as of December 31, 2009 and the related consolidated statements of operations, shareholders' equity and cash flows for the year then ended. In connection with our audits of the consolidated financial statements, we also have audited financial statement "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statements presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements on January 1, 2009, Atlantic Power Corporation adopted FASB's ASC 805 Business Combinations. In our opinion the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation as of December 31, 2009 and the results of its operations and its cash flows the year then ended., in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

April 12, 2010, except as to notes 4, 8 and 17, which are as of May 26, 2010, Notes 2(a) and 16 which are as of June 16, 2010 and as to Note 19 which is as of February 27, 2012.

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ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands of U.S. dollars)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 60,651	$ 45,497
Restricted cash	21,412	15,744
Accounts receivable	79,008	19,362
Note receivable related party (Note 20)		22,781
Current portion of derivative instruments asset (Notes 11 and 12)	10,411	8,865
Inventory (Note 5)	18,628	5,498
Prepayments and other	7,615	2,982
Refundable income taxes (Note 13)	3,042	1,593
Total current assets	200,767	122,322
Property, plant, and equipment, net (Note 6)	1,388,254	271,830
Transmission system rights (Note 7)	180,282	188,134
Equity investments in unconsolidated affiliates (Note 4)	474,351	294,805
Other intangible assets, net (Note 7)	584,274	88,462
Goodwill (Note 7)	343,586	12,453
Derivative instruments asset (Notes 11 and 12)	22,003	17,884
Other assets	54,910	17,122
Total assets	$ 3,248,427	$ 1,013,012
Liabilities		
Current Liabilities:		
Accounts payable	$ 18,122	$ 8,608
Accrued interest	19,916	3,975
Other accrued liabilities	43,968	11,025
Revolving credit facility (Note 9)	58,000	
Current portion of long-term debt (Note 9)	20,958	21,587
Current portion of derivative instruments liability (Notes 11 and 12)	20,592	10,009
Dividends payable	10,733	6,154
Other current liabilities	165	5
Total current liabilities	192,454	61,363
Long-term debt (Note 9)	1,404,900	244,299
Convertible debentures (Note 10)	189,563	220,616
Derivative instruments liability (Notes 11 and 12)	33,170	21,543
Deferred income taxes (Note 13)	182,925	29,439
Power purchase and fuel supply agreement liabilities, net (Note 7)	71,775	
Other non-current liabilities (Note 8)	57,859	2,376
Commitments and contingencies (Note 21)		
Total liabilities	2,132,646	579,636
Equity		
Common shares, no par value, unlimited authorized shares; 113,526,182 and 67,118,154 issued and outstanding at December 31, 2011 and 2010, respectively	1,217,265	626,108
Preferred shares issued by a subsidiary company (Note 17)	221,304	
Accumulated other comprehensive income (loss)	(5,193)	255
Retained deficit	(320,622)	(196,494)

Total Atlantic Power Corporation shareholders' equity	1,112,754	429,869
Noncontrolling interest	3,027	3,507
Total equity	1,115,781	433,376
Total liabilities and equity	$ 3,248,427	$ 1,013,012

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

	Years ended December 31,		
	2011	**2010**	**2009**
Project revenue:			
Energy sales	$ 106,062	$ 69,116	$ 58,953
Energy capacity revenue	131,362	93,567	88,449
Transmission services	30,087	31,000	31,000
Other	17,384	1,573	1,115
	284,895	195,256	179,517
Project expenses:			
Fuel	93,993	65,553	59,522
Operations and maintenance	56,832	31,237	28,153
Depreciation and amortization	63,638	40,387	41,374
	214,463	137,177	129,049
Project other income (expense):			
Change in fair value of derivative instruments (Notes 11 and 12)	(22,776)	(14,047)	(6,813)
Equity in earnings of unconsolidated affiliates (Note 4)	6,356	13,777	8,514
Gain on sales of equity investments, net (Note 4)		1,511	13,780
Interest expense	(20,053)	(17,660)	(18,800)
Other income, net	20	219	1,266
	(36,453)	(16,200)	(2,053)
Project income	33,979	41,879	48,415
Administrative and other expenses (income):			
Administration	38,108	16,149	26,028
Interest, net	25,998	11,701	55,698
Foreign exchange loss (gain) (Note 12)	13,838	(1,014)	20,506
Other (income) expense, net		(26)	362
	77,944	26,810	102,594
Income (loss) from operations before income taxes	(43,965)	15,069	(54,179)
Income tax expense (benefit) (Note 13)	(8,324)	18,924	(15,693)
Net loss	(35,641)	(3,855)	(38,486)
Net loss attributable to noncontrolling interest	(480)	(103)	
Net income attributable to Preferred share dividends of a subsidiary company	3,247		
Net loss attributable to Atlantic Power Corporation	$ (38,408)	$ (3,752)	$ (38,486)
Net loss per share attributable to Atlantic Power Corporation shareholders: (Note 18)			
Basic	$ (0.50)	$ (0.06)	$ (0.63)
Diluted	$ (0.50)	$ (0.06)	$ (0.63)
Weighted average number of common shares outstanding: (Note 18)			
Basic	77,466	61,706	60,632
Diluted	77,466	61,706	60,632

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in thousands of U.S. dollars)

	Common Shares (Shares)	Common Shares (Amount)	Retained Deficit	Accumulated Other Comprehensive Income	Noncontrolling Interest	Preferred Shares	Total Shareholders' Equity
December 31, 2008	60,941	$ 215,163	$ (60,401)	$ (3,136)	$	$	$ 151,626
Subordinated notes conversion	(114)	327,691					327,691
Common shares issued for LTIP	59	151					151
Common stock repurchases	(482)	(1,088)					(1,088)
Dividends declared			(28,054)				(28,054)
Comprehensive Income:							
Net loss			(38,486)				(38,486)
Unrealized loss on hedging activities, net of tax of ($1,518)				2,277			2,277
Net comprehensive loss							(36,209)
December 31, 2009	60,404	541,917	(126,941)	(859)			414,117
Convertible debenture conversion	579	7,147					7,147
Common shares issuance, net of costs	6,029	75,267					75,267
Common shares issued for LTIP	106	1,325					1,325
LTIP amendment		2,952					2,952
Piedmont equity costs		(2,500)					(2,500)
Noncontrolling interest					3,507		3,507
Dividends declared			(65,801)				(65,801)
Comprehensive Income:							
Net loss			(3,752)				(3,752)
Unrealized loss on hedging activities, net of tax of ($1,518)				1,114			1,114
Net comprehensive loss							(2,638)
December 31, 2010	67,118	626,108	(196,494)	255	3,507		433,376
Convertible debenture conversion	2,090	26,357					26,357
Common shares issuance, net of costs	12,650	155,424					155,424
Common shares issued for LTIP	168	1,951					1,951
Shares issued in connection with Partnership acquisition	31,500	407,425					407,425
Preferred shares of a subsidiary company assumed in connection with Partnership acquisition						221,304	221,304
Noncontrolling interest					(480)		(480)
Dividends declared on common shares			(85,720)				(85,720)
Dividends declared on preferred shares of a subsidiary company						(3,247)	(3,247)
Comprehensive Income:							
Net (loss) income			(38,408)			3,247	(35,161)
Unrealized loss on hedging activities, net of tax of $251				(1,638)			(1,638)
Foreign currency translation adjustments				(3,321)			(3,321)
Defined benefit plan, net of $264 tax				(489)			(489)
Net comprehensive loss							(40,609)

December 31, 2011	113,526	$ 1,217,265	$ (320,622)	$ (5,193)	$ 3,027	$ 221,304	$ 1,115,781

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)

	Years ended December 31,		
	2011	**2010**	**2009**
Cash flows from operating activities:			
Net loss	$ (35,641)	$ (3,855)	$ (38,486)
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation and amortization	63,638	40,387	41,374
Common share conversions recorded in interest expense			4,508
Subordinated note redemption premium recorded in interest expense			1,935
Long-term incentive plan expense	3,167	4,497	
Gain on sale of assets		(1,511)	(12,847)
Earnings from unconsolidated affiliates	(7,878)	(16,913)	(14,213)
Impairment of equity investments	1,522	3,136	5,500
Distributions from unconsolidated affiliates	21,889	16,843	27,884
Unrealized foreign exchange loss	8,636	5,611	24,370
Change in fair value of derivative instruments	22,776	14,047	6,813
Change in deferred income taxes	(9,908)	17,964	(6,436)
Other		(210)	106
Change in other operating balances			
Accounts receivable	(15,563)	1,729	10,520
Prepayments, refundable income taxes and other assets	1,653	9,311	(3,454)
Accounts payable and accrued liabilities	4,931	(6,551)	2,959
Other liabilities	(3,287)	2,468	(84)
Net cash provided by operating activities	55,935	86,953	50,449
Cash flows (used in) provided by investing activities:			
Acquisitions and investments, net of cash acquired	(591,583)	(78,180)	(3,068)
Proceeds from (loan to) Idaho Wind	22,781	(22,781)	
Change in restricted cash	(5,668)	945	575
Biomass development costs	(931)	(2,286)	
Proceeds from sale of assets	8,500	2,000	29,467
Purchase of property, plant and equipment	(115,107)	(46,695)	(2,016)
Net cash (used in) provided by investing activities	(682,008)	(146,997)	24,958
Cash flows (used in) provided by financing activities:			
Proceeds from issuance of long term debt	460,000		
Proceeds from issuance of equity, net of offering costs	155,424	72,767	
Proceeds from issuance of convertible debenture, net of offering costs		74,575	
Deferred financing costs	(26,373)	(7,941)	
Repayment of project-level debt	(21,589)	(18,882)	(12,744)
Proceeds from revolving credit facility borrowings	58,000	20,000	
Repayments of revolving credit facility borrowings		(20,000)	(55,000)
Dividends paid	(85,029)	(65,028)	(24,955)
Equity contribution from noncontrolling interest		200	
Proceeds from issuance of project level debt	100,794		78,330
Redemption of IPSs under normal course issuer bid			(3,369)
Redemption of subordinated notes			(40,638)
Costs associated with common share conversion			(4,508)
Net cash provided by (used in) financing activities	641,227	55,691	(62,884)
Net (decrease) increase in cash and cash equivalents	15,154	(4,353)	12,523
Cash and cash equivalents at beginning of year	45,497	49,850	37,327
Cash and cash equivalents at end of year	$ 60,651	$ 45,497	$ 49,850

Supplemental cash flow information						
Interest paid	$	40,238	$	26,687	$	69,186
Income taxes paid (refunded), net	$	1,109	$	(8,000)	$	(216)
Accruals for capital expenditures	$	4,095	$		$	

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of business

General

Atlantic Power Corporation ("Atlantic Power") is a power generation and infrastructure company with a portfolio of assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. The net generating capacity of our projects is approximately 2,140 MW, consisting of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada, one 53 MW biomass project under construction in Georgia, and an 84 mile, 500-kilovolt electric transmission line located in California. Atlantic Power also owns a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the TSX under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, 02116 USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Additionally, we make available on our website our Canadian securities filings.

2. Summary of significant accounting policies

(a) Principles of consolidation and basis of presentation:

The accompanying 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.

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 has both the power to direct the activities that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. We have determined that our investments are not VIEs by evaluating their design and capital structure. Accordingly, we use the equity method of accounting for all of our investments in which we do not have an economic controlling interest. We eliminate all intercompany accounts and transactions in consolidation.

(b) Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less when purchased.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(c) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the Projects to support payments for major maintenance costs and meet project level contractual debt obligations.

(d) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt which range from five to 28 years. The net carrying amount of deferred financing costs recorded in other assets on the consolidated balance sheets was $40.7 million and $16.7 million at December 31, 2011 and 2010, respectively. Amortization expense for the years ended December 31, 2011, 2010 and 2009 was $1.3 million, $1.2 million, and $14.6 million, respectively.

(e) Inventory:

Inventory represents small parts and other consumables and fuel, the majority of which is consumed by our projects in provision of their services, and are valued at the lower of cost or net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

(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 up to 45 years. 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) Other intangible assets:

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(i) 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 and liabilities 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 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 that 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.

(j) Distributions from equity method investments:

We make investments in entities that own power producing assets with the objective of generating accretive cash flow that is available to be distributed to our shareholders. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows.

We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

(k) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is allocated, as of the date of the business combination, to our reporting units that are expected to benefit from the synergies of the business combination.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired. In our test, we first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and other relevant entity-specific events. If the qualitative assessment determines that an impairment is more likely than not, then we perform a two-step quantitative impairment test. In the first step of the quantitative analysis, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired and the second step of the impairment test is unnecessary.

The second step is carried out when the carrying amount of a reporting unit exceeds its fair value, in which case, the implied fair value of the reporting unit's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of goodwill is determined in a business combination described in the preceding paragraphs, using the fair value of the reporting unit as if it were the purchase price. When the carrying amount of reporting unit goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess and is recorded in the consolidated statements of operations.

(l) 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. Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales in the ordinary course of conducting business. This exception applies when we have the ability to, and it is probable that we will deliver or take delivery of the underlying physical commodity.

We have designated two 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. Derivatives accounted for as hedges are recorded at fair value in the balance sheet. Unrealized gains or losses on derivatives designated as a hedge are deferred and recorded as a component of accumulated other comprehensive income 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.

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 for accounting purposes and the

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

Derivative financial instrument	Classification of changes in fair value	Classification of cash settlements
Foreign currency forward contracts	Foreign exchange (gain) loss	Foreign exchange loss (gain)
Natural gas swaps	Change in fair value of derivative instruments	Fuel expense
Interest rate swaps	Change in fair value of derivative instruments	Interest expense

(m) 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 13 for more information.

(n) Revenue recognition:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. Power purchase arrangements, steam purchase arrangements and energy services agreements (collectively referred to as PPAs) are long-term contracts to sell power and steam on a predetermined basis.

Energy Energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in our consolidated statements of operations.

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

(o) Other power purchase arrangements containing a lease:

We have entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Partnership's property, plant and equipment in return for future payments. Such arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as direct financing leases.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

Finance income related to leases or arrangements accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income over the lease term.

(p) Foreign currency translation and transaction gains and losses:

The local currency is the functional currency of our U.S. and Canadian projects. Our reporting currency is the United States dollar. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of our statements of operations for the period, but are accumulated and reported as a separate component of shareholders' equity until sale of the net investment in the project takes place. Foreign currency transaction gains or losses are reported within foreign exchange (gain) loss in our statements of operations.

(q) Long-term incentive plan:

The officers and certain other employees 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 was effective for grants beginning with the 2010 performance year. Under the amended LTIP, the number of notional units that vest is 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 occurs on a three-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendment.

Vested notional units are expected to 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. 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.

The final number of notional units for officers that will vest, if any, at the end of the three-year vesting period is based on our achievement of target levels of relative total shareholder return, which is the change in the value of an investment in our common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance period. The total number of notional units vesting will range from zero 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 relative total shareholder return during the measurement period.

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2. Summary of significant accounting policies (Continued)

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 the fair value of the award at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 LTIP 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 under the amended LTIP with market vesting conditions is based upon a Monte Carlo simulation model on the grant date. Compensation expense is recognized regardless of the relative total shareholder return performance, provided that the LTIP participant remains employed by Atlantic Power. The aggregate number of shares that may be issued from treasury under the amended LTIP is limited to 1.3 million.

(r) Asset retirement obligations:

The fair value for an asset retirement obligation is recorded in the period in which it is incurred. Retirement obligations associated with long-lived assets are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss.

(s) Pensions:

We offer pension benefits to certain employees through a defined benefit pension plan. We recognize the funded status of our defined benefit plan in the consolidated balance sheet in other long-term liabilities and record an offset to other comprehensive income. In addition, we also recognize on an after-tax basis, as a component of other comprehensive income, gains and losses as well as all prior service costs that have not been included as part of our net periodic benefit cost. The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of our pension obligation or expense recorded.

(t) Business combinations:

We account for our business combinations in accordance with the acquisition method of accounting, which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

(u) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. 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 19, *Segment and geographic information*, for a further discussion of customer concentrations.

(v) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the valuation of shares associated with our Long-Term Incentive Plan 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.

(w) Regulatory accounting:

Path 15 accounts for certain income and expense items in accordance with a standard where certain costs are deferred, which would otherwise be charged to expense, as regulatory assets based on Path 15's ability to recover these costs in future rates.

(x) Recently issued accounting standards:

Adopted

In September 2011, the FASB issued changes to the testing of goodwill for impairment. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, go directly to the two-step quantitative impairment test. These changes become effective for any goodwill impairment test performed on January 1, 2012 or later. We early adopted these changes for our annual review of goodwill in the fourth quarter of 2011. These changes did not have an impact on the consolidated financial statements.

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

In June 2011, the FASB issued changes to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements; the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity was eliminated. The items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We will adopt these changes on January 1, 2012. Other than the change in presentation, these changes will not have an impact on the consolidated financial statements.

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. These changes are reflected in Note 3, *Acquisitions and divestments*.

Issued

In May 2011, the FASB issued changes to conform existing guidance regarding fair value measurement and disclosure between US GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. These changes become effective on January 1, 2012. These changes will not have an impact on the consolidated financial statements.

3. Acquisitions and divestments

Acquisitions

(a) Capital Power Income L.P.

On November 5, 2011, we completed the acquisition of all of the outstanding limited partnership units of Capital Power Income, LP (renamed Atlantic Power Limited Partnership on February 1, 2012, the "Partnership") pursuant to the terms and conditions of an Arrangement Agreement, dated June 20, 2011, as amended by Amendment No. 1, dated July 15, 2011 (the"Arrangement Agreement"), by and among us, the Partnership, CPI Income Services, Ltd., the general partner of the Partnership and CPI Investments, Inc., a unitholder of the Partnership that was then owned by EPCOR Utilities Inc. and Capital Power Corporation. The transactions contemplated by the Arrangement Agreement were effected through a court-approved plan of arrangement under the *Canada Business Corporations Act* (the "Plan of Arrangement"). The Plan of Arrangement was approved by the unitholders of the Partnership, and the issuance of our common shares to the Partnership unitholders pursuant to the Plan of Arrangement was approved by our shareholders, at respective special meetings held on November 1, 2011. A Final Order approving the Plan of Arrangement was granted by the Court of Queen's Bench of Alberta on November 1, 2011. Pursuant to the Plan of Arrangement, the Partnership sold its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, for approximately Cdn$121.4 million which equates to approximately Cdn$2.15 per unit of the Partnership. In addition, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and the Partnership and certain of its subsidiaries were terminated in consideration of a payment of Cdn$10.0 million. Atlantic Power and its subsidiaries assumed the management of the Partnership upon closing and entered into a transitional services agreement with Capital Power Corporation for a term of six to twelve months to facilitate and support the integration of the Partnership into Atlantic Power.

The acquisition expands and diversifies our asset portfolio to include projects in Canada and regions of the United States where we did not have a presence. The enhanced geographic diversification is anticipated to lead to additional growth opportunities in those regions where we did not previously operate. Our average PPA term increases from 8.8 years to 9.1 years and enhances the credit quality of our portfolio of off takers. The acquisition increases our market capitalization and enterprise value which is expected to add liquidity and enhance access to capital to fuel the long-term growth of our asset base throughout North America.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

Pursuant to the Plan of Arrangement, we directly and indirectly acquired each outstanding limited partnership unit of the Partnership in exchange for Cdn$19.40 in cash ("Cash Consideration") or 1.3 Atlantic Power common shares ("Share Consideration") in accordance with elections and deemed elections in accordance with the Plan of Arrangement.

As a result of the elections made by the Partnership unitholders and pro-ration in accordance with the Plan of Arrangement, those unitholders who elected to receive Cash Consideration received in exchange for each limited partnership unit of the Partnership (i) cash equal to approximately 73% of the Cash Consideration and (ii) Share Consideration in respect of the remaining approximately 27% of the consideration payable for the unit. Any limited partnership units of the Partnership not exchanged for cash consideration in accordance with the Plan of Arrangement were exchanged for Share Consideration.

At closing, the consideration paid to acquire the Partnership totaled $1.0 billion, consisting of $601.8 million paid in cash and $407.4 million in shares of our common shares (31.5 million shares issued) less cash acquired of $22.7 million.

Our acquisition of the Partnership is accounted for under the acquisition method of accounting as of the transaction closing date. The purchase price allocation for the business combination is estimated as follows (in thousands):

Fair value of consideration transferred:		
Cash	$	601,766
Equity		407,424
Total purchase price	$	1,009,190
Preliminary purchase price allocation		
Working capital	$	37,951
Property, plant and equipment		1,024,015
Intangibles		528,531
Other long-term assets		224,295
Long-term debt		(621,551)
Other long-term liabilities		(129,341)
Deferred tax liability		(164,539)
Total identifiable net assets		899,361
Preferred shares		(221,304)
Goodwill		331,133
Total purchase price		1,009,190
Less cash acquired		(22,683)
Cash paid, net of cash acquired	$	986,507

The purchase price was computed using the Partnership's outstanding units as of June 30, 2011, adjusted for the exchange ratio at November 4, 2011. The purchase price reflects the market value of our common shares issued in connection with the transaction based on the closing price of the Partnership's units on the Toronto Stock Exchange on November 4, 2011. The goodwill is attributable to the expansion of our asset portfolio to include projects in Canada and regions of the United States

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

where we did not have a presence and this enhanced geographic diversification should lead to additional growth opportunities in those regions we did not previously operate. It is not expected to be deductible for tax purposes. Of the $331.1 million of goodwill, $135.3 million was assigned to the Northeast segment, $138.2 million was assigned to the Northwest segment and $57.6 million was assigned to the Southwest segment.

The fair values of the assets acquired and liabilities assumed were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of acquired facilities, remaining useful lives and discount rates based of the weighted average cost of capital ("WACC") on a merchant basis. The WACCs were based on a set of comparable companies as well as existing yields for debt and equity as of the acquisition date.

The partnership contributed revenues of $73.8 million and a loss of less than $0.1 million to our consolidated statements of operations for the period from November 5, 2011 to December 31, 2011. The following unaudited pro-forma consolidated results of operations for years ended December 31, 2011 and 2010, assume the Partnership acquisition occurred as of January 1 of each year. The pro forma results of operations are presented for informational purposes only and are not indicative of the results of operations that would have been achieved if the acquisition had taken place on January 1, 2011 and January 1, 2010 or of results that may occur in the future (amounts in thousands):

	Unaudited	
	Years ended December 31,	
	2011	**2010**
Total project revenue	$ 694,162	$ 669,985
Net income (loss) attributable to Atlantic Power Corporation	(95,772)	(2,462)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders:		
Basic	$ (0.85)	$ (0.02)
Diluted	$ (0.85)	$ (0.02)

(b) Rockland

On December 28, 2011, we purchased a 30% interest for $12.5 million in the Rockland Wind Project ("Rockland"), an 80 MW wind farm near American Falls, Idaho, that began operations in early December 2011. The Rockland Wind Project sells power under a 25-year power purchase agreement with Idaho Power. Rockland is accounted for under the equity method of accounting.

(c) Cadillac

On December 21, 2010, we acquired 100% of Cadillac Renewable Energy, LLC, which owns and operates a 39.6 MW wood-fired facility in Cadillac, Michigan. The purchase price was funded by $37.0 million using a portion of the cash raised in the public equity and convertible debenture offerings in October 2010 and the assumption of $43.1 million of project-level debt. The cash payment for the

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

acquisition of Cadillac was allocated to the net assets acquired based on our estimate of fair value. The total cash paid for the acquisition, less cash acquired in December 2010 was $35.1 million.

The allocation of the purchase price to the net assets acquired is as follows:

Recognized amounts of identifiable assets acquired and liabilities assumed:	
Working capital	$ 5,643
Property, plant and equipment	42,101
Power purchase agreements	36,420
Interest rate swap derivative	(4,038)
Project-level debt	(43,131)
Total purchase price	36,995
Less cash acquired	(1,870)
Cash paid, net of cash acquired	$ 35,125

(d) Piedmont

On October 21, 2010, we completed the closing of non-recourse, project-level bank financing for our Piedmont Green Power project ("Piedmont"). The terms of the financing include an $82.0 million construction and term loan and a $51.0 million bridge loan for approximately 95% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations. In addition, we made an equity contribution of approximately $75.0 million for substantially all of the equity interest in the project. Piedmont is a 53.5 MW biomass plant located in Barnesville, Georgia, approximately 70 miles south of Atlanta. The Project was developed and will be managed by Rollcast Energy, Inc., a biomass developer in which we own a 60% interest.

(e) Idaho Wind

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("Idaho Wind") for $38.9 million and approximately $3.1 million in transaction costs. Idaho Wind began commercial operation in the fourth quarter of 2010. Our investment in Idaho Wind was funded with cash on hand and a $20.0 million borrowing under our revolving credit facility, which was repaid in October 2010 with a portion of the proceeds from a public offering. Idaho Wind is accounted for under the equity method of accounting.

(f) 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 that 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%.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

Rollcast is a developer of biomass power plants in the southeastern U.S. with several 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.

The following table summarizes the consideration transferred to acquire Rollcast and the preliminary estimated amounts of identifiable assets acquired and liabilities assumed at the March 1, 2010 acquisition date, as well as the fair value of the noncontrolling 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 Un-allocated Corporate segment.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

Divestments

(a) Onondaga Renewables

In the fourth quarter of 2011, the partners of Onondaga Renewables initiated a plan to sell their interests in the project. We determined that the carrying value of the Onondaga Renewables project was impaired and recorded a pre-tax long-lived asset impairment of $1.5 million. Our estimate of the fair market value of our 50% investment in the Onondaga Renewables project was determined based on quoted market prices for the remaining land and equipment. The Onondaga Renewables project is accounted for under the equity method of accounting and the impairment charge is included in equity earnings from unconsolidated affiliates in the consolidated statements of operations.

(b) Topsham

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

(c) Rumford

During the three months ended September 30, 2009, we reviewed the recoverability of our 23.5% equity investment in the Rumford project. The review was undertaken as a result of not receiving distributions from the Project through the first nine months of 2009 and our view about the long-term economic viability of the plant upon expiration of the project's PPA on December 31, 2009.

Based on this review, we determined that the carrying value of the Rumford project was impaired and recorded a pre-tax long-lived asset impairment of $5.5 million during 2009. The Rumford project is accounted for under the equity method of accounting and the impairment charge is included in equity in earnings of unconsolidated affiliates in the consolidated statements of operations.

In the fourth quarter of 2009, Atlantic Power and the other limited partners in the Rumford project settled a dispute with the general partner related to the general partner's failure to pay distributions to the limited partners in 2009. Under the terms of the settlement, we received $2.9 million in distributions from Rumford in the fourth quarter of 2009. In addition, the general partner agreed to purchase the interests of all the limited partners in June 2010. In November 2010 we received our share of the sale proceeds of $2.0 million and recognized a gain on sale of investment of $1.5 million.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Equity method investments

The following tables summarize our equity method investments:

Entity name	Percentage of Ownership as of December 31, 2011	Carrying value as of December 31, 2011	2010
Frederickson	50.0%	166,837	
Orlando Cogen, LP	50.0%	25,955	31,543
Badger Creek Limited	50.0%	6,477	7,839
Onondaga Renewables, LLC	50.0%	291	1,761
Topsham Hydro Assets	50.0%		8,500
Koma Kulshan Associates	49.8%	5,856	6,491
Chambers Cogen, LP	40.0%	143,797	139,855
Delta-Person, LP	40.0%		
Rockland Wind Farm	30.0%	12,500	
Idaho Wind Partners 1, LLC	27.6%	36,143	41,376
Selkirk Cogen Partners, LP	18.5%	47,357	53,575
Gregory Power Partners, LP	17.1%	3,520	3,662
PERH	14.3%	25,609	
Other		9	203
Total		$ 474,351	$ 294,805

Equity in earnings (loss) of unconsolidated affiliates was as follows:

Entity name	Year Ended December 31, 2011	2010	2009
Chambers Cogen, LP	$ 7,739	$ 13,144	$ 6,599
Orlando Cogen, LP	863	2,031	3,152
Gregory Power Partners, LP	524	2,162	1,791
Koma Kulshan Associates	483	452	458
Frederickson	444		
Onondaga Renewables, LLC	(1,761)	(320)	(600)
Idaho Wind Partners 1, LLC	(1,563)	(126)	
Selkirk Cogen Partners, LP	(406)	(3,454)	(280)
Badger Creek Limited	(4)	749	1,948
Delta-Person, LP			(644)
Topsham Hydro Assets		(436)	1,506
Rumford Cogeneration, LP		(359)	(1,904)
Mid-Georgia Cogen, LP			(2,686)
Rollcast Energy, Inc. (Note 3(f))		(66)	(267)
Other	37		(559)
Total	6,356	13,777	8,514
Distributions from equity method investments	(21,889)	(16,843)	(27,884)
Equity in earnings (loss) of unconsolidated affiliates, net of distributions	$ (15,533)	$ (3,066)	$ (19,370)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Equity method investments (Continued)

The following summarizes the balance sheets at December 31, 2011, 2010 and 2009, and operating results for each of the years ended December 31, 2011, 2010 and 2009, respectively, for our proportional ownership interest in equity method investments:

	2011	2010	2009
Assets			
Current assets			
Chambers	$ 9,937	$ 11,391	$ 10,356
Orlando	6,892	6,965	6,725
Gregory	3,933	3,063	11,358
Selkirk	15,852	11,782	9,431
Badger Creek	766	2,714	2,567
Other	10,671	7,563	2,043
Non-Current assets			
Chambers	245,842	253,388	259,989
Orlando	23,805	29,419	34,975
Gregory	16,092	19,490	12,351
Selkirk	47,737	65,036	78,748
Badger Creek	6,011	6,645	9,177
Other	313,142	128,763	34,631
	$ 700,680	$ 546,219	$ 472,351
Liabilities			
Current liabilities			
Chambers	$ 16,016	$ 15,914	$ 16,898
Orlando	4,742	4,841	5,313
Gregory	3,132	3,421	4,118
Selkirk	14,743	17,371	13,495
Badger Creek	300	1,520	1,795
Other	10,980	76,910	1,704
Non-Current liabilities			
Chambers	95,966	109,010	123,946
Orlando			
Gregory	13,373	15,470	16,660
Selkirk	1,489	5,872	17,654
Badger Creek			
Other	65,588	1,085	11,538
	$ 226,329	$ 251,414	$ 213,121

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Equity method investments (Continued)

	2011	2010	2009
Operating results			
Revenue			
Chambers	$ 49,336	$ 55,469	$ 50,745
Orlando	40,345	42,062	41,911
Gregory	28,474	31,291	28,477
Selkirk	54,613	51,915	47,577
Badger Creek	6,546	13,485	12,861
Mid-Georgia			6,521
Other	16,499	3,501	23,327
	195,813	197,723	211,419
Project expenses			
Chambers	39,358	38,377	40,540
Orlando	39,414	39,898	38,694
Gregory	27,440	27,324	24,893
Selkirk	49,595	48,496	44,045
Badger Creek	6,526	11,723	10,897
Mid-Georgia			6,519
Other	12,126	2,049	22,560
	174,459	167,867	188,148
Project other income (expense)			
Chambers	(2,239)	(3,948)	(3,606)
Orlando	(68)	(133)	(65)
Gregory	(510)	(1,805)	(1,793)
Selkirk	(5,424)	(6,873)	(3,812)
Badger Creek	(24)	(1,013)	(16)
Mid-Georgia			(2,688)
Other	(6,733)	(2,307)	(2,777)
	(14,998)	(16,079)	(14,757)
Project income (loss)			
Chambers	$ 7,739	$ 13,144	$ 6,599
Orlando	863	2,031	3,152
Gregory	524	2,162	1,791
Selkirk	(406)	(3,454)	(280)
Badger Creek	(4)	749	1,948
Mid-Georgia			(2,686)
Other	(2,360)	(855)	(2,010)
	6,356	13,777	8,514

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Inventory

Inventory consists of the following:

	December 31, 2011	December 31, 2010
Parts and other consumables	$ 11,884	$ 3,592
Fuel	6,744	1,906
Total inventory	$ 18,628	$ 5,498

6. Property, plant and equipment

	2011	2010	Depreciable Lives
Land	$ 8,868	$ 3,321	
Office equipment, machinery and other	7,633	8,040	3 10 years
Leasehold improvements	3,413	2,810	7 15 years
Plant in service	1,487,375	349,411	1 45 years
	1,507,289	363,582	
Foreign currency translation adjustment	(2,748)		
Less accumulated depreciation	(116,287)	(91,752)	
	$ 1,388,254	$ 271,830	

Depreciation expense of $24.3 million, $11.1 million and $11.1 million was recorded for the years ended December 31, 2011, 2010 and 2009, respectively.

7. Goodwill, transmission system rights and other intangible assets and liabilities

The following table details the changes in the carrying amount of goodwill by operating segment:

	Northeast	Northwest	Southwest	Un-allocated Corporate	Total
Balance at December 31, 2009	$	$	$ 8,918	$	$ 8,918
Acquisition of businesses				3,535	3,535
Balance at December 31, 2010			8,918	3,535	12,453
Acquisition of businesses	135,268	138,263	57,602		331,133
Balance at December 31, 2011	$ 135,268	$ 138,263	$ 66,520	$ 3,535	$ 343,586

Other intangible assets include power purchase agreements, fuel supply agreements and development costs. Transmission system rights represent the long-term right to approximately 72% of the regulated revenues of the Path 15 transmission line.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Goodwill, transmission system rights and other intangible assets and liabilities (Continued)

The following tables summarize the components of our intangible assets and other liabilities subject to amortization for the years ended December 31, 2011 and 2010:

		Other Intangible Assets, Net			
	Transmission System Rights	Power Purchase Agreements	Fuel Supply Agreements	Development Costs	Total
Gross balances, December 31, 2011	$ 231,669	$ 639,699	$ 33,845	$ 1,786	$ 675,330
Foreign currency translation adjustment		(877)			(877)
Less: accumulated amortization	(51,387)	(63,908)	(26,271)		(90,179)
Net carrying amount, December 31, 2011	$ 180,282	$ 574,914	$ 7,574	$ 1,786	$ 584,274

		Power Purchase and Fuel Supply Agreement Liabilities, Net			
	Transmission System Rights	Power Purchase Agreements	Fuel Supply Agreements	Development Costs	Total
Gross balances, December 31, 2011	$	$ (35,288)	$ (38,106)	$	$ (73,394)
Foreign currency translation adjustment		127	121		248
Less: accumulated amortization		398	973		1,371
Net carrying amount, December 31, 2011	$	$ (34,763)	$ (37,012)	$	$ (71,775)

		Other Intangible Assets, Net			
	Transmission System Rights	Power Purchase Agreements	Fuel Supply Agreements	Development Costs	Total
Gross balances, December 31, 2010	$ 231,669	$ 110,470	$ 33,845	$ 1,147	$ 145,462
Less: accumulated amortization	(43,535)	(39,190)	(17,810)		(57,000)
Net carrying amount, December 31, 2010	$ 188,134	$ 71,280	$ 16,035	$ 1,147	$ 88,462

The following table presents amortization of intangible assets for the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
Transmission system rights	$ 7,852	$ 7,849	$ 7,849
Power purchase agreements	24,021	12,411	12,406
Fuel supply agreements	7,091	8,461	9,468

Total amortization	$ 38,964	$ 28,721	$ 29,723

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Goodwill, transmission system rights and other intangible assets and liabilities (Continued)

The following table presents estimated future amortization for the next five years related to our transmission system rights, purchase power agreements and fuel supply agreements:

Year Ended December 31,	Transmission System Rights	Power Purchase Agreements	Fuel Supply Agreements
2012	$ 7,849	$ 69,039	$ 1,722
2013	7,849	66,218	(5,852)
2014	7,849	55,282	(5,852)
2015	7,849	55,282	(5,852)
2016	7,849	55,282	(5,852)

8. Other long-term liabilities

Other long-term liabilities consist of the following:

	2011	2010
Asset retirement obligations	$ 52,336	$
Net pension liability	2,243	
Deferred revenue	1,623	
Other	1,657	2,376
	$ 57,859	$ 2,376

We assumed asset retirement obligations in our acquisition of the Partnership. We recorded these retirement obligations as it is legally required to remove these facilities at the end of their useful lives and restore the sites to their original condition. The following table represents the fair value of ARO obligations at the date of acquisition along with the additions, reductions and accretion related to our ARO obligations for the year ended December 31, 2011:

	2011
Asset retirement obligations beginning of year	$
Asset retirement obligations assumed in acquisition	52,230
Accretion of asset retirement obligations	223
Foreign currency translation adjustments	(117)
Asset retirement obligations, end of year	$ 52,336

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Long-term debt

Long-term debt consists of the following:

	December 31, 2011	December 31, 2010	Interest Rate
Recourse Debt:			
Senior notes, due 2018	$ 460,000	$	9.00%
Senior unsecured notes, due June 2036 (Cdn$210,000)	206,490		5.95%
Senior unsecured notes, due July 2014	190,000		5.90%
Senior unsecured notes, due August 2017	150,000		5.87%
Senior unsecured notes, due August 2019	75,000		5.97%
Non-Recourse Debt:			
Epsilon Power Partners term faciliy, due 2019	34,982	36,482	7.40%
Path 15 senior secured bonds	145,879	153,868	7.90% 9.00%
Auburndale term loan, due 2013	11,900	21,700	5.10%
Cadillac term loan, due 2025	40,231	42,531	6.02% 8.00%
Piedmont construction loan, due 2013	100,796		Libor plus 3.50%
Purchase accounting fair value adjustments	10,580	11,305	
Less current maturities	(20,958)	(21,587)	
Total long-term debt	$ 1,404,900	$ 244,299	

Notes of Atlantic Power Corporation

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

Notes of the Partnership

The Partnership, a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($206.5 million at December 31, 2011) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (the "Partnership Notes"). Interest on the Partnership Notes is payable semi-annually at 5.95%. Pursuant to the terms of the Partnership Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Partnership Notes are guaranteed by Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

Notes of Curtis Palmer LLC

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Long-term debt (Continued)

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

Notes of Atlantic Power (US) GP

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

Non-Recourse Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met. At December 31, 2011, all but one of our projects were in compliance with the covenants contained in project-level debt. The project that was not in compliance with its debt covenants received a waiver from the creditor subsequent to December 31, 2011. However, our Epsilon Power Partners, Selkirk, Delta-Person and Gregory projects had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to make distributions and were therefore restricted from making distributions to us.

The required coverage ratio at Epsilon Power Partners is calculated based on the most recent four quarters cash flow results from Chambers. 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 in the first nine months of 2010. The Chambers project began to meet the cash flow coverage ratio for its non-recourse debt again as of September 30, 2010, and the project began distributions to our project holding company, Epsilon Power Partners, in October 2010. However, the required cash flow coverage ratio on the debt at Epsilon Power Partners has not been achieved and, as a result, Epsilon has not made any distributions to us during 2009, 2010 and 2011. Based on our current projections, Epsilon will continue receiving distributions from the project in 2012 based on meeting the required debt service coverage ratios, and we expect Epsilon to resume making distributions to us in late 2013.

The required coverage ratio at Selkirk is calculated based on both historical project cash flows for the previous six months, as well as projected project cash flows for the next six months. Increased natural gas transportation costs attributable to a contractual price increase at Selkirk are the primary contributors to the project not currently meeting its minimum coverage ratio. The Selkirk debt will be paid in full during 2012, after which we expect to resume receiving distributions from the project.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Long-term debt (Continued)

The required coverage ratio at Delta-Person is based on the most recent four-quarter period. The higher operations and maintenance costs caused Delta-Person to fail its debt service coverage ratio and restrict cash distributions for 2010 and 2011.

The required coverage ratio at Gregory is calculated based on both historical project cash flows for the previous six months, as well as projected cash flows for the next six months. Increased fuel costs in 2011 attributable to fuel hedges that expired at the end of 2010 are the primary contributors to the project not currently meeting its debt service coverage ratio requirements.

Senior Credit Facility

On November 4, 2011, we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $200.0 million of which may be utilized for letters of credit. Borrowings under the facility are available in U.S. dollars and Canadian dollars and bear interest at a variable rate equal to the U.S. Prime Rate, the London Interbank Offered Rate or the Canadian Prime Rate, as applicable, plus an applicable margin of between 0.75% and 3.00% that varies based on our corporate credit rating. The credit facility matures on November 4, 2015.

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

As of December 31, 2011, the applicable margin was 2.75%. As of December 31, 2011, $58.0 million was drawn on the senior credit facility and $107.3 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects.

Principal payments on the maturities of our debt due in the next five years and thereafter are as follows:

2012	$ 20,958
2013	75,059
2014	209,854
2015	21,771
2016	21,677
Thereafter	1,065,959
	$ 1,415,278

10. Convertible debentures

In 2006 we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures (the "2006 Debentures") for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The 2006 Debentures had an initial 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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Convertible debentures (Continued)

holder, representing a conversion price of Cdn$12.40 per common share. In 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.

On December 17, 2009, we issued, in a public offering, Cdn$86.3 million aggregate principal amount of 6.25% convertible unsecured debentures (the "2009 Debentures") for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning on September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share.

On October 20, 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures (the "2010 Debentures") for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of 2010 Debentures, at any time, at the option of the holder, representing an initial conversion price of approximately Cdn$18.10 per common share.

The following table provides details related to outstanding convertible debentures:

	6.5% Debentures due 2014	6.25% Debentures due 2017	5.6% Debentures due 2017	Total
Balance at December 31, 2009 (Cdn$)	60,000	86,250		146,250
Principal amount converted to equity (Cdn$)	(4,199)	(3,126)		(7,325)
Issuance of 5.6% Debentures			80,500	80,500
Balance at December 31, 2010 (Cdn$)	55,801	83,124	80,500	219,425
Principal amount converted to equity (Cdn$)	(10,948)	(15,691)		(26,639)
Balance at December 31, 2011 (Cdn$)	44,853	67,433	80,500	192,786
Balance at December 31, 2011 (US$)	$ 44,103	$ 66,306	$ 79,154	$ 189,563
Common shares issued on conversion during the year ended December 31, 2011	882,893	1,206,992		2,089,885

Aggregate interest expense related to the 2006, 2009 and 2010 Debentures was $12.1 million, $9.9 million and $3.5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Fair value of financial instruments

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 60,651	$ 60,651	$ 45,497	$ 45,497
Restricted cash	21,412	21,412	15,744	15,744
Derivative assets current	10,411	10,411	8,865	8,865
Derivative assets non-current	22,003	22,003	17,884	17,884
Derivative liabilities current	20,592	20,592	10,009	10,009
Derivative liabilities non-current	33,170	33,170	21,543	21,543
Revolving credit facility and long-term debt, including current portion	1,483,858	1,462,474	265,886	281,491
Convertible debentures	189,563	207,888	220,616	242,316

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

The three levels of the fair value hierarchy are defined below:

Level 1 Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2 Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3 Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Fair value of financial instruments (Continued)

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

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of December 31, 2011, the credit valuation adjustments resulted in a $5.8 million net increase in fair value, which consists of a $0.9 million pre-tax gain in other comprehensive income and a $5.1 million gain in change in fair value of derivative instruments, offset by a $0.2 million loss in foreign exchange. As of December 31, 2010, the credit reserve resulted in a $0.6 million net increase in fair value, which is attributable to a $0.2 million pre-tax gain in other comprehensive income and a $0.5 million gain in change in fair value of derivative instruments, partially offset by a $0.1 million loss in foreign exchange.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. The fair value of long-term debt, subordinated notes and convertible debentures was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. For certain contracts designated as cash flow hedges, we defer the effective portion of the change in fair value of the derivatives to accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

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

Natural gas swaps

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In the third quarter of 2010 we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. Also in the third quarter of 2011, we entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

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

Our strategy to mitigate the future exposure to changes in natural gas prices at Orlando, Lake and Auburndale consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value and the changes in their fair market value are recorded in the consolidated statement of operations.

Interest rate swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.02% from February 16, 2011 to February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and changes in the fair market value is recorded in accumulated other comprehensive income.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Auburndale project hedged a portion of its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 3.12%. The notional amount of the swap matches the outstanding principal balance over the remaining life of Auburndale's debt. This swap agreement is effective through November 30, 2013. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt agreement and changes in the fair market value is recorded in accumulated other comprehensive income.

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% from March 31, 2011 to February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's cash grant bridge loan and the construction loan facility that will convert to a term loan. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

In July 2007, we executed an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt at our wholly-owned subsidiary Epsilon Power Partners. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 5.29%. In June 2010, the swap agreement was amended to reduce the fixed interest rate 4.24% and extend the maturity date from July 2012 to July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. This interest rate swap agreement is not designated as a hedge and changes in its fair market value are recorded in the consolidated statements of operations.

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars and Canadian dollars but pay dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 99% of our expected dividend and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At December 31, 2011, the forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$215.5 million at an average exchange rate of Cdn$1.134 per U.S. dollar. It is our intention to periodically consider extending the length or terminating these forward contracts.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of December 31, 2011 and 2010:

	Units	December 31, 2011	December 31, 2010
Natural gas swaps	Natural gas (Mmbtu)	14,140	15,540
Interest rate swaps	Interest (US$)	$ 52,711	$ 44,228
Currency forwards	Cdn$	$ 312,533	$ 219,800

Fair value of derivative instruments

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Accumulated other comprehensive income

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

For the year ended December 31, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at January 1, 2011	$ (427)	$ 682	$ 255
Change in fair value of cash flow hedges	(2,647)		(2,647)
Realized from OCI during the period	1,370	(361)	1,009
Accumulated OCI balance at December 31, 2011	$ (1,704)	$ 321	$ (1,383)
Gains (losses) expected to be realized from OCI in the next 12 months, net of $471 tax	$ 936	$ (230)	$ 706

For the year ended December 31, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at January 1, 2010	$ (538)	$ (321)	$ (859)
Change in fair value of cash flow hedges	(360)		(360)
Realized from OCI during the period	471	1,003	1,474
Accumulated OCI balance at December 31, 2010	$ (427)	$ 682	$ 255

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the year ended December 31, 2009	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at January 1, 2009	$ (501)	$ (2,635)	$ (3,136)
Change in fair value of cash flow hedges	(565)	(1,985)	(2,550)
Realized from OCI during the period	528	4,299	4,827
Accumulated OCI balance at December 31, 2009	$ (538)	$ (321)	$ (859)

A $5.1 million loss was deferred in other comprehensive loss for natural gas swap contracts accounted for as cash flow hedges prior to July 1, 2009 when hedge accounting for these natural gas swaps was discontinued prospectively. Amortization of the remaining loss (income) in other comprehensive income of $(0.6) million, $1.7 million, and $7.2 million was recorded in change in fair value of derivative instruments for the years ended December 31, 2011, 2010 and 2009, respectively.

Impact of derivative instruments on the consolidated income statements

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

	Classification of (gain) loss recognized in income	Year ended December 31, 2011	2010	2009
Natural gas swaps	Fuel	$ 9,269	$ 9,141	$ 10,089
Interest rate swaps	Interest, net	4,166	1,664	1,446
Foreign currency forwards	Foreign exchange (gain) loss	5,201	(6,625)	(3,864)

The following table summarizes the unrealized gains and (losses) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Year ended December 31, 2011	2010	2009
Natural gas swaps	Change in fair value of derivatives	$ 10,540	$ 17,470	$ (7,182)
Interest rate swaps	Change in fair value of derivatives	12,236	(3,423)	369
		$ 22,776	$ 14,047	$ (6,813)
Forward currency forwards	Foreign exchange (gain) loss	$ 14,211	$ (3,542)	$ (31,138)

13. Income taxes

	2011	2010	2009
Current income tax expense (benefit)	$ 1,584	$ 960	$ (9,257)
Deferred tax expense (benefit)	(9,908)	17,964	(6,436)
Total income tax expense (benefit)	$ (8,324)	$ 18,924	$ (15,693)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Income taxes (Continued)

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 26.5%, 28.5%, and 30.0% at December 31, 2011, 2010 and 2009, respectively, to the provision for income taxes in the consolidated statements of operations:

	2011	2010	2009
Computed income taxes at Canadian statutory rate	$ (11,651)	$ 4,295	$ (16,254)
Increases (decreases) resulting from:			
Operating countries with different income tax rates	(5,636)	1,537	(5,418)
	$ (17,287)	$ 5,832	$ (21,672)
Valuation allowance	9,373	12,289	22,005
	(7,914)	18,121	333
Dividend withholding tax	371	765	
Foreign exchange	(113)		
Permanent differences	(1,479)		(1,131)
Canadian loss carryforwards			(13,204)
Non-deductible acquisition costs	4,287		
Non-deductible interest expense	2,134		
Federal grant	(6,573)		
Prior year true-up	2,246		(1,970)
Other	(1,283)	38	279
	(410)	803	(16,026)
	$ (8,324)	$ 18,924	$ (15,693)

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Income taxes (Continued)

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below:

	2011	2010
Deferred tax assets:		
Intangible assets	$	$ 37,488
Loss carryforwards	122,472	58,702
Other accrued liabilities	28,059	18,869
Issuance costs	6,532	2,312
Disallowed interest carryforward	9,189	
Unrealized foreign exchange gain	441	
Other		130
Total deferred tax assets	166,693	117,501
Valuations allowance	(89,020)	(79,420)
	77,673	38,081
Deferred tax liabilities:		
Intangible assets	(121,055)	
Property, plant and equipment	(133,689)	(66,535)
Natural gas and interest rate hedges		(170)
Derivative contracts	(4,752)	
Unrealized foreign exchange gain		(815)
Other long-term investments	(921)	
Other	(181)	
Total deferred tax liabilities	(260,598)	(67,520)
Net deferred tax liability	$ (182,925)	$ (29,439)

The following table summarizes the net deferred tax position as of December 31, 2011 and 2010:

	2011	2010
Long-term deferred tax liabilities, net	(182,925)	(29,439)
Net deferred tax liabilities	$ (182,925)	$ (29,439)

As of December 31, 2011, we have recorded a valuation allowance of $89.0 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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Income taxes (Continued)

As of December 31, 2011, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

2022	$ 4,245
2023	9,320
2024	8,504
2025	243
2026	5,865
2027	70,447
2028	103,477
2029	79,911
2030	25,941
2031	44,922
	$ 352,875

14. Long-term incentive plan

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2011, 2010 and 2009:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2008	263,592	$ 9.76
Granted	267,408	5.76
Additional shares from dividends	49,540	7.80
Vested and redeemed	(109,260)	9.71
Outstanding at December 31, 2009	471,280	7.30
Granted	305,112	13.29
Additional shares from dividends	46,854	9.54
Vested and redeemed	(222,265)	7.94
Outstanding at December 31, 2010	600,981	10.28
Granted	216,110	14.02
Additional shares from dividends	36,204	11.04
Forfeitures	(103,991)	11.55
Vested and redeemed	(263,523)	9.40
Outstanding at December 31, 2011	485,781	$ 11.49

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Long-term incentive plan (Continued)

The fair value of all outstanding notional units under the LTIP was $6.4 million and $7.8 million for the years ended December 31, 2011 and 2010. Compensation expense related to LTIP was $3.2 million, $4.5 million and $2.2 million for the years ended December 31, 2011, 2010 and 2009, respectively. Cash payments made for vested notional units were $1.5 million, $2.8 million and $0.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The fair value of awards granted under the amended LTIP with market vesting conditions is based upon a Monte Carlo simulation model on their grant date.

The Monte Carlo simulation model utilizes multiple input variables over the performance period in order to determine the likely relative total shareholder return. The Monte Carlo simulation model simulated our total shareholder return and for our 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 Atlantic Power Corporation and 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. Both the total shareholder return performance and the fair value of the notional units under the Monte Carlo simulation are determined with the assistance of a third party.

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

	Year ended December 31, 2011	Year ended December 31, 2010
Weighted average risk free rate of return	0.15 0.28%	0.71%
Dividend yield	7.90%	9.39%
Expected volatility Company	22.2%	40.0%
Expected volatility peer companies	17.3 112.9%	25.0 55.0%
Weighted average remaining measurement period	0.87 years	1.43 years

15. Defined benefit plan

As a result of our acquisition of the Partnership, we will continue to sponsor and operate a defined benefit pension plan that is available to certain legacy employees of the acquired company. The Atlantic Power Services Canada LP Pension Plan (the "Plan") is maintained solely for certain eligible legacy Partnership participants. The Plan is a defined benefit pension plan that allows for employee contributions.

We expect to contribute $1.3 million to the pension plans in 2012.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Defined benefit plan (Continued)

The net annual periodic pension cost related to the pension plan for the period beginning November 5, 2011 and ended on December 31, 2011 includes the following components:

	2011
Service cost benefits earned	$ 103
Interest cost on benefit obligation	91
Expected return on plan assets	(89)
Net period benefit cost	$ 105

A comparison of the pension benefit obligation and related plan assets for the pension plan is as follows:

	2011
Benefit obligation at November 5, 2011	$ (11,909)
Service cost	(103)
Interest cost	(90)
Actuarial loss	(599)
Employee contributions	(11)
Foreign currency translation adjustment	(13)
Benefit obligation at December 31, 2011	(12,725)
Fair value of plan assets at November 5, 2011	10,525
Actual return on plan assets	(65)
Employee contributions	11
Foreign currency translation adjustment	11
Fair value of plan assets at December 31, 2011	10,482
Funded status at December 31, 2011 excess of obligation over assets	$ (2,243)

Amounts recognized in the balance sheet were as follows:

	2011
Non-current liabilities	$ 2,243

Amounts recognized in accumulated OCI that have not yet been recognized as components of net periodic benefit cost were as follows, net of tax:

	2011
Unrecognized loss	$ 489

We estimate that there will be no amortization of net loss for the pension plan from accumulated OCI to net periodic cost over the next fiscal year.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Defined benefit plan (Continued)

The following table presents the balances of significant components of the pension plan:

	2011
Projected benefit obligation	$ 12,725
Accumulated benefit obligation	9,900
Fair value of plan assets	10,482

The market-related value of the pension plan's assets is the fair value of the assets. The fair values of the pension plan's assets by asset category and their level within the fair value hierarchy are as follows:

	Level 1	Level 2	Level 3	Total
Common/Collective Trust Canadian equity investments	$	$ 3,166	$	$ 3,166
Common/Collective Trust U.S. equity investments		1,429		1,429
Common/Collective Trust International equity investments		1,383		1,383
Common/Collective Trust Corporate bond investment fixed income		4,200		4,200
Common/Collective Trust Other fixed income		304		304
Total	$	$ 10,482	$	$ 10,482

We determine the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trusts is valued at a fair value which is equal to the sum of the market value of all of the fund's underlying investments, and is categorized as Level 2. There are no investments categorized as Level 1 or 3.

The following table presents the significant assumptions used to calculate our benefit obligations:

	2011
Weighted-Average Assumptions	
Discount rate	4.75%
Rate of compensation increase	3.00% 4.00%

The following table presents the significant assumptions used to calculate our benefit expense:

	2011
Weighted-Average Assumptions	
Discount rate	4.75%
Rate of return on plan assets	5.50%
Rate of compensation increase	3.0% 4.0%

We use December 31 as the measurement date for the Plan, and we set the discount rate assumptions on an annual basis on the measurement date. This rate is determined by management

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Defined benefit plan (Continued)

based on information provided by our actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of December 31, 2011 was based on the CIA / Natcan curve, which was designed by the Canadian Institute of Actuaries and Natcan Investment Management to provide a means for sponsors of Canadian plans to value the liabilities of their postretirement benefit plans. The CIA / Natcan curve is a hypothetical yield curve represented by extrapolating the corporate AA-rated yield curve beyond 10 years using yields on provincial AA bonds with a spread added to the provincial AA yields to approximate the difference between corporate AA and provincial AA credit risk. The CIA / Natcan curve utilizes this approach because there are very few corporate bonds rated AA or above with maturities of 10 years or more in Canada.

We employ a balanced total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, and the plan's funded status. Plan assets are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across Canadian, U.S. and other international equities, as well as among growth, value and small and large capitalization stocks.

The pension plan assets weighted average allocations were as follows:

	2011
Canadian equity	30%
U.S. equity	14%
International equity	13%
Canadian fixed income	40%
International fixed income	3%
	100%

Our expected future benefit payments for each of the next five years and in the aggregate for the five years thereafter, are as follows:

	2011
2012	$ 225
2013	252
2014	293
2015	319
2016	362
2017 2021	412

16. Common shares

On November 5, 2011, we issued 31,500,215 common shares as part of the consideration paid in the acquisition of the Partnership. See Note 3 for further details.

On October 19, 2011, we closed a public offering of 12,650,000 of our common shares, which included 1,650,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a purchase price of $13.00 per common share sold in U.S. dollars and Cdn$13.26 per common share sold in Canadian dollars, for net proceeds of $155.4 million. We used the

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Common shares (Continued)

net proceeds from the offering to fund a portion of the cash portion of our acquisition of the Partnership.

On October 20, 2010, we completed a public offering of 6,029,000 common shares, including 784,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a price of $13.35 per common share. We received net proceeds from the common share offering, after deducting the underwriters' discounts and expenses, of approximately $75.3 million.

17. Preferred shares issued by a subsidiary company

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

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares are redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%.

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

The subsidiary company paid aggregate dividends of Cdn$3.3 million (U.S. $3.2 million) on the Series 1 Shares and the Series 2 Shares in 2011.

18. 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

into shares at January 1, 2011. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the years ended December 31, 2011, 2010 and 2009, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
Numerator:			
Net loss attributable to Atlantic Power Corporation	$ (38,408)	$ (3,752)	$ (38,486)
Denominator:			
Weighted average basic shares outstanding	77,466	61,706	60,632
Dilutive potential shares:			
Convertible debentures	13,962	12,339	5,095
LTIP notional units	438	542	476
Potentially dilutive shares	91,866	74,587	66,203
Diluted EPS	$ (0.50)	$ (0.06)	$ (0.63)

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the years ended December 31, 2011, 2010 and 2009 because their impact would be anti-dilutive.

19. Segment and geographic information

We revised our reportable business segments during the fourth quarter of 2011subsequent to our acquisition of the Partnership. The new operating segments are Northeast, Northwest, Southeast and Southwest. Financial results for the years ended December 31, 2010 and 2009 have been presented to reflect the change in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Segment and geographic information (Continued)

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

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Year ended December 31, 2011:						
Operating revenues	$ 58,201	$ 160,911	$ 8,982	$ 55,501	$ 1,300	$ 284,895
Segment assets	1,153,627	428,996	798,475	743,574	123,755	3,248,427
Goodwill	135,268		138,263	66,520	3,535	343,586
Capital expenditures	965	113,826	65	169	82	115,107
Project Adjusted EBITDA	$ 59,299	$ 79,445	$ 11,363	$ 37,717	$ (2,546)	$ 185,278
Change in fair value of derivative instruments	3,624	22,031			(321)	25,334
Depreciation and amortization	30,818	37,627	9,554	17,495	70	95,564
Interest, net	11,512	1,022	2,877	12,538	41	27,990
Other project (income) expense	2,406	67	(206)	26	118	2,411
Project income	10,939	18,698	(862)	7,658	(2,454)	33,979
Administration					38,108	38,108
Interest, net					25,998	25,998
Foreign exchange loss					13,838	13,838
Loss from operations before income taxes	10,939	18,698	(862)	7,658	(80,398)	(43,965)
Income tax expense (benefit)					(8,324)	(8,324)
Net income (loss)	$ 10,939	$ 18,698	$ (862)	$ 7,658	$ (72,074)	$ (35,641)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Year ended December 31, 2010:						
Operating revenues	$ 596	$ 163,205	$	$ 30,318	$ 1,137	$ 195,256
Segment assets	285,711	342,608	47,687	222,437	114,569	1,013,012
Goodwill				8,918	3,535	12,453
Capital expenditures	123	46,397			175	46,695
Project Adjusted EBITDA	$ 36,030	$ 78,245	$ 736	$ 37,867	$ (294)	$ 152,584
Change in fair value of derivative instruments	3,470	14,173				17,643
Depreciation and amortization	15,653	37,630	364	12,100	44	65,791
Interest, net	8,321	1,611	(1)	13,700	(3)	23,628
Other project (income) expense	1,592	135	47	2,080	(211)	3,643
Project income	6,994	24,696	326	9,987	(124)	41,879
Administration					16,149	16,149
Interest, net					11,701	11,701
Foreign exchange gain					(1,014)	(1,014)
Other income, net					(26)	(26)
Income from operations before income taxes	6,994	24,696	326	9,987	(26,934)	15,069
Income tax expense (benefit)					18,924	18,924
Net income (loss)	$ 6,994	$ 24,696	$ 326	$ 9,987	$ (45,858)	$ (3,855)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Year ended December 31, 2009:						
Operating revenues	$	$ 148,517	$	$ 31,000	$	$ 179,517
Segment assets	199,959	327,844	7,003	232,179	102,591	869,576
Goodwill				8,918		8,918
Capital expenditures		1,954			62	2,016
Project Adjusted EBITDA	$ 32,435	$ 75,265	$ 822	$ 35,891	$ (234)	$ 144,179
Change in fair value of derivative instruments	(1,569)	6,616				5,047
Depreciation and amortization	14,286	41,014	365	11,964	14	67,643
Interest, net	10,450	6,084	(1)	14,960	18	31,511
Other project (income) expense	6,672	(15,788)		679		(8,437)
Project income	2,596	37,339	458	8,288	(266)	48,415
Administration					26,028	26,028
Interest, net					55,698	55,698
Foreign exchange loss					20,506	20,506
Other expense, net					362	362
Loss from operations before income taxes	2,596	37,339	458	8,288	(102,860)	(54,179)
Income tax expense (benefit)					(15,693)	(15,693)
Net income (loss)	$ 2,596	$ 37,339	$ 458	$ 8,288	$ (87,167)	$ (38,486)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. Segment and geographic information (Continued)

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2011, 2010 and 2009 and as of December 31, 2011 and 2010, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Revenue			Property, Plant & Equipment, net	
	2011	2010	2009	2011	2010
United States	$ 249,109	$ 195,256	$ 179,517	$ 816,744	$ 271,830
Canada	35,786			571,510	
Total	$ 284,895	$ 195,256	$ 179,517	$ 1,388,254	$ 271,830

Progress Energy Florida ("PEF") and the California Independent System Operator ("CAISO") provide for 52.0% and 10.6%, respectively, of total consolidated revenues for the year ended December 31, 2011, 78.0% and 15.9%, respectively, of total consolidated revenues for the year ended December 31, 2010 and 71.1% and 17.3%, respectively, of total consolidated revenues for the year ended December 31, 2009. PEF purchases electricity from the Auburndale and Lake projects in the Southeast segment, and the CAISO makes payments to Path 15 in the Southwest segment.

20. Related party transactions

During 2010, we made a short-term $22.8 million loan to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing was completed. As of December 31, 2011, the project repaid the loan in full with a combination of excess proceeds from the federal stimulus cash grant after repaying the cash grant facility, funds from a third closing for additional debt, and project cash flow. We received $1.6 million of interest income related to this loan in the year ended December 31, 2011.

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 agreed to pay ArcLight an aggregate of $15.0 million, to be satisfied by a payment of $6.0 million that was made at the termination date, and additional payments of $5.0 million, $3.0 million and $1.0 million on the respective first, second and third anniversaries of the termination date. We recorded the remaining liability associated with the termination fee at its estimated fair value of $0.9 million at December 31, 2011. The contract termination liability is being accreted to the final amounts due over the term of these payments.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. Commitments and contingencies

Commitments

Operating Lease Commitments

We lease our office properties and equipment under operating leases expiring on various dates through 2021. Certain operating lease agreements over their lease term include provisions for scheduled rent increases. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. Lease expense under operating leases was $1.0 million, $0.9 million and $0.9 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Future minimum lease commitments under operating leases for the years ending after December 31, 2011, are as follows (in thousands):

2012	$ 1,149
2013	942
2014	619
2015	404
2016	335
Thereafter	1,609
	$ 5,058

Transmission, Interconnection and Long-Term Service Commitments

Our projects have entered into long-term contractual arrangements to provide energy transmission services, operate and maintain an electrical interconnection facility and obtain maintenance services for combustion turbines expiring on various dates through 2024.

As of December 31, 2011, our commitments under such outstanding agreements are estimated as follows (in thousands):

2012	$ 9,102
2013	6,671
2014	2,752
2015	2,822
2016	2,894
Thereafter	22,663
	$ 46,904

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. Commitments and contingencies (Continued)

Fuel Supply and Transportation Commitments

We have entered into long-term contractual arrangements to procure fuel and transportation services for our projects. As of December 31, 2011, our commitments under such outstanding agreements are estimated as follows (in thousands):

2012	$ 67,712
2013	61,303
2014	64,214
2015	64,449
2016	66,006
Thereafter	66,732
	$ 390,416

Construction Contract

We entered into an agreement with an unrelated third party to design, engineer, procure, install, construct, test, commission and start-up the generating facility, on a turnkey basis, for a contracted price for our Piedmont project. The Piedmont project will pay an estimated $21.5 million in construction costs under the contract during 2012.

Contingencies

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

In February 2011, we filed a rate application with the FERC to establish Path 15's revenue requirement of $30.3 million for the 2011-2013 period. We engaged in a formal settlement with three parties that challenged certain aspects of how Path 15 determined the rates in its filing. After exchanges of information and direct discussions, we concluded that a fair and equitable settlement between the parties was not achievable through the settlement process and therefore, we ended settlement discussions and informed the judge that we would pursue resolution of the issues through the formal hearing process at FERC. We may engage the parties in informal settlement discussions during the hearing process. If a settlement can be reached with the parties, the hearing process will be terminated.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. Commitments and contingencies (Continued)

In September 2011, FERC appointed a presiding judge in Atlantic Path 15's rate case hearing proceeding. Under the Judge's order establishing the procedural schedule for the case, the discovery period commenced in October 2011 and will conclude in April 2012. The formal rate case hearing is scheduled to commence on May 1, 2012. The initial decision from the presiding judge will be due on or before August 16, 2012. The timing of FERC's issuance of its final decision in the rate case has no set schedule or time constraint, and final resolution of the rate case proceeding could take from 15 to 21 months. During the pendency of the rate case, we continue to collect the rates we filed as permitted under the initial FERC order it received in April 2011. Those rates are subject to refund, including interest, based on a final disposition of the proceeding. We believe that the resolution of this matter will not have a material impact on our financial position or results of operations.

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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

22. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data are as follows:

	Quarter Ended 2011			
(In millions, except per share data)	**December 31,**	**September 30,**	**June 30,**	**March 31,**
Project revenue	$ 125,639	$ 52,333	$ 53,258	$ 53,665
Project income	1,728	4,351	13,031	14,869
Net income (loss) attributable to Atlantic Power Corporation	(29,830)	(27,900)	13,186	6,136
Weighted average number of common shares outstanding basic	113,088	68,910	68,573	67,654
Net income (loss) per weighted average common share basic	$ (0.26)	$ (0.40)	$ 0.19	$ 0.09
Weighted average number of common shares outstanding diluted	113,088	68,910	82,939	82,980
Net income (loss) per weighted average common share diluted*	$ (0.26)	$ (0.40)	$ 0.18	$ 0.09

* The calculation excludes potentially dilutive shares from convertible debentures because their impact would be anti-dilutive.

	Quarter Ended 2010			
(In millions, except per share data)	**December 31,**	**September 30,**	**June 30,**	**March 31,**
Project revenue	$ 46,092	$ 54,039	$ 47,904	$ 47,221
Project income	14,840	7,634	15,541	3,864
Net income (loss) attributable to Atlantic Power Corporation	1,304	(438)	1,445	(6,063)
Weighted average number of common shares outstanding basic	65,388	60,511	60,481	60,404
Net income (loss) per weighted average common share basic	$ 0.02	$ (0.01)	$ 0.02	$ (0.10)
Weighted average number of common shares outstanding diluted	80,966	60,511	72,363	60,404
Net income (loss) per weighted average common share diluted*	$ 0.02	$ (0.01)	$ 0.02	$ (0.10)

* The calculation excludes potentially dilutive shares from convertible debentures because their impact would be anti-dilutive.

23. Subsequent events

On January 31, 2012, we invested approximately $23 million of late-stage development capital to own 51% of Canadian Hills Wind, LLC ("Canadian Hills"). Canadian Hills is the 100% owner of the Canadian Hills Project which is a 298.45 MW wind power project in the late stages of development, located approximately 20 miles west of Oklahoma City, Oklahoma. Apex Wind Energy Holdings, LLC, is the project developer. Canadian Hills has executed long-term power purchase agreements with investment grade offtakers for 250.45 MW and is currently negotiating a similar PPA for the remaining 48 MW. Construction is expected to begin by April 2012 with commercial operations expected in November 2012. We will be responsible for the operations and management of Canadian Hills. Total project costs are expected to be approximately $460 million. Subject to final due diligence, Board approval and other conditions, we will have the right to invest 100% of the project equity or approximately $170 million.

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

24. Consolidating financial information

As of December 31, 2011, we had $460.0 million of 9.00% Senior Notes due November 2018. These notes are guaranteed by certain of our wholly-owned subsidiaries, or guarantor subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 31, 2011:

Atlantic Power Income Limited Partnership, Atlantic Power GP Inc., Atlantic Power (US) GP, Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Atlantic Power Holdings, Inc., Atlantic Power Services Canada GP Inc., Atlantic Power Services Canada LP, Atlantic Power Services, LLC, Teton Power Funding, LLC, Harbor Capital Holdings, LLC, Epsilon Power Funding, LLC, Atlantic Auburndale, LLC, Auburndale LP, LLC, Auburndale GP, LLC, Badger Power Generation I, LLC, Badger Power Generation, II, LLC, Badger Power Associates, LP, Atlantic Cadillac Holdings, LLC, Atlantic Idaho Wind Holdings, LLC, Atlantic Idaho Wind C, LLC, Baker Lake Hydro, LLC, Olympia Hydro, LLC, Teton East Coast Generation, LLC, NCP Gem, LLC, NCP Lake Power, LLC, Lake Investment, LP, Teton New Lake, LLC, Lake Cogen Ltd., Atlantic Renewables Holdings, LLC, Orlando Power Generation I, LLC, Orlando Power Generation II, LLC, NCP Dade Power, LLC, NCP Pasco LLC, Dade Investment, LP, Pasco Cogen, Ltd., Atlantic Piedmont Holdings LLC, Teton Selkirk, LLC, and Teton Operating Services, LLC.

In addition, as of December 31, 2011, Curtis Palmer, LLC, fully and unconditionally guaranteed Atlantic Power Limited Partnership's guarantee of the Senior Notes.

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

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

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ATLANTIC POWER CORPORATION

CONSOLIDATING BALANCE SHEET

December 31, 2011

(in thousands of U.S. dollars

	Guarantor Subsidiaries	Curtis Palmer	APC	Eliminations	Consolidated Balance
Assets					
Current assets:					
Cash and cash equivalents	$ 58,370	$ (15)	$ 2,296	$	$ 60,651
Restricted cash	21,412				21,412
Accounts receivable	93,855	13,637	12,088	(40,572)	79,008
Current portion of derivative instruments asset	3,519		6,892		10,411
Prepayments, supplies, and other	24,436	1,225	582		26,243
Deferred income taxes					
Refundable income taxes	3,012		30		3,042
Total current assets	204,604	14,847	21,888	(40,572)	200,767
Property, plant, and equipment, net	1,213,080	176,017		(843)	1,388,254
Transmission system rights	180,282				180,282
Equity investments in unconsolidated affiliates	5,109,196		870,279	(5,505,124)	474,351
Other intangible assets, net	415,454	168,820			584,274
Goodwill	285,358	58,228			343,586
Derivative instruments asset	15,490		6,513		22,003
Other assets	463,110		433,035	(841,235)	54,910
Total assets	$ 7,886,574	$ 417,912	$ 1,331,715	$ (6,387,774)	$ 3,248,427
Liabilities					
Current Liabilities:					
Accounts payable and accrued liabilities	$ 97,129	$ 7,241	$ 16,500	$ (40,572)	$ 80,298
Revolving credit facility	8,000		$ 50,000		58,000
Current portion of long-term debt	20,958				20,958
Current portion of derivative instruments liability	20,592				20,592
Interest payable on convertible debentures			1,708		1,708
Dividends payable	36		10,697		10,733
Other current liabilities	165				165
Total current liabilities	146,880	7,241	78,905	(40,572)	192,454
Long-term debt	754,900	190,000	460,000		1,404,900
Convertible debentures			189,563		189,563
Derivative instruments liability	33,170				33,170
Deferred income taxes	182,925				182,925
Other non-current liabilities	961,899	8,072	898	(841,235)	129,634
Equity					
Preferred shares issued by a subsidiary company	221,304				221,304
Common shares	5,156,644	208,991	1,217,265	(5,365,635)	1,217,265
Accumulated other comprehensive income (loss)	(5,193)				(5,193)
Retained deficit	431,018	3,608	(614,916)	(140,332)	(320,622)
Total Atlantic Power Corporation shareholders' equity	5,803,773	212,599	602,349	(5,505,967)	1,112,754

Noncontrolling interest	3,027				3,027
Total equity	5,806,800	212,599	602,349	(5,505,967)	1,115,781
Total liabilities and equity	$ 7,886,574	$ 417,912	$ 1,331,715	$ (6,387,774)	$ 3,248,427

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ATLANTIC POWER CORPORATION

CONSOLIDATING STATEMENT OF OPERATIONS

December 31, 2011

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

	Guarantor Subsidiaries	Curtis Palmer	APC	Eliminations	Consolidated Balance
Project revenue:					
Energy sales	$ 97,053	$ 9,009	$	$	$ 106,062
Energy capacity revenue	131,362				131,362
Transmission services	30,087				30,087
Other	17,819			(435)	17,384
	276,321	9,009		(435)	284,895
Project expenses:					
Fuel	93,993				93,993
Project operations and maintenance	55,334	851	922	(275)	56,832
Depreciation and amortization	60,999	2,639			63,638
	210,326	3,490	922	(275)	214,463
Project other income (expense):					
Change in fair value of derivative instruments	(22,776)				(22,776)
Equity in earnings of unconsolidated affiliates	5,989			367	6,356
Interest expense, net	(16,694)	(1,911)	128	(1,576)	(20,053)
Other income, net	20				20
	(33,461)	(1,911)	128	(1,209)	(36,453)
Project income	32,534	3,608	(794)	(1,369)	33,979
Administrative and other expenses (income):					
Administration expense	12,636		25,472		38,108
Interest, net	67,666		(41,668)		25,998
Foreign exchange loss	4,057		9,781		13,838
	84,359		(6,415)		77,944
Income (loss) from operations before income taxes	(51,825)	3,608	5,621	(1,369)	(43,965)
Income tax expense (benefit)	(8,566)		242		(8,324)
Net income (loss)	(43,259)	3,608	5,379	(1,369)	(35,641)
Net loss attributable to noncontrolling interest	(480)				(480)
Net income attributable to Preferred share dividends of a subsidiary company	3,247				3,247
Net income (loss) attributable to Atlantic Power Corporation	$ (46,026)	$ 3,608	$ 5,379	$ (1,369)	$ (38,408)

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ATLANTIC POWER CORPORATION

CONSOLIDATING STATEMENT OF CASH FLOWS

December 31, 2011

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	APC	Eliminations	Consolidated Balance
Cash flows from operating activities:					
Net loss	$ (44,628)	$ 3,608	$ 5,379	$	$ (35,641)
Adjustments to reconcile to net cash provided by operating activities:					
Depreciation and amortization	60,999	2,639			63,638
Long-term incentive plan expense	3,167				3,167
Earnings from unconsolidated affiliates	(6,356)				(6,356)
Distributions from unconsolidated affiliates	13,552		8,337		21,889
Unrealized foreign exchange loss	4,105		4,531		8,636
Change in fair value of derivative instruments	22,776				22,776
Change in deferred income taxes	(9,908)				(9,908)
Change in other operating balances					
Accounts receivable	23,952	(8,880)	298	(30,933)	(15,563)
Prepayments, refundable income taxes and other assets	1,783	583	(713)		1,653
Accounts payable and accrued liabilities	(46,561)	2,095	18,464	30,933	4,931
Other liabilities	(1,918)		(1,369)		(3,287)
Net cash provided by operating activities	20,963	45	34,927		55,935
Cash flows (used in) provided by investing activities:					
Acquisitions and investments, net of cash acquired	12,143		(603,726)		(591,583)
Short-term loan to Idaho Wind	21,465		1,316		22,781
Change in restricted cash	(5,668)				(5,668)
Biomass development costs	(931)				(931)
Proceeds from sale of assets	8,500				8,500
Purchase of property, plant and equipment	(115,047)	(60)			(115,107)
Net cash (used in) provided by investing activities	(79,538)	(60)	(602,410)		(682,008)
Cash flows (used in) provided by financing activities:					
Proceeds from issuance of long term debt			460,000		460,000
Proceeds from project-level debt	100,794				100,794
Proceeds from issuance of equity, net of offering costs			155,424		155,424
Deferred financing costs			(26,373)		(26,373)
Repayment of project-level debt	(21,589)				(21,589)
Proceeds from revolving credit facility borrowings	8,000		50,000		58,000
Dividends paid	(3,247)		(81,782)		(85,029)
Net cash provided by (used in) financing activities	83,958		557,269		641,227
Net (decrease) increase in cash and cash equivalents	25,383	(15)	(10,214)		15,154
Cash and cash equivalents at beginning of period	32,987		12,510		45,497
Cash and cash equivalents at end of period	$ 58,370	$ (15)	$ 2,296	$	$ 60,651

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ATLANTIC POWER CORPORATION
VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009
(in thousands)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Income tax valuation allowance, deducted from deferred tax assets:					
Year ended December 31, 2011	$ 79,420	$ 9,600	$	$	$ 89,020
Year ended December 31, 2010	67,131	12,289			79,420
Year ended December 31, 2009	45,126	22,005			67,131

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ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands of U.S. dollars)

	March 31, 2012 (unaudited)	December 31, 2011
Assets		
Current Assets:		
Cash and cash equivalents	$ 106,609	$ 60,651
Restricted cash	27,761	21,412
Accounts receivable	59,501	79,008
Current portion of derivative instruments asset (Notes 6 and 7)	10,610	10,411
Inventory	18,214	18,628
Prepayments and other	23,647	7,615
Refundable income taxes	2,301	3,042
Total current assets	248,643	200,767
Property, plant, and equipment, net	1,549,626	1,388,254
Transmission system rights	178,319	180,282
Equity investments in unconsolidated affiliates (Note 3)	477,098	474,351
Other intangible assets, net	597,633	584,274
Goodwill	343,586	343,586
Derivative instruments asset (Notes 6 and 7)	16,589	22,003
Other assets	64,216	54,910
Total assets	$ 3,475,710	$ 3,248,427
Liabilities		
Current Liabilities:		
Accounts payable	$ 20,561	$ 18,122
Accrued interest	33,534	19,916
Other Accrued liabilities	41,456	43,968
Revolving credit facility (Note 5)	72,800	58,000
Current portion of long-term debt (Note 5)	246,520	20,958
Current portion of derivative instruments liability (Notes 6 and 7)	50,030	20,592
Dividends payable	10,921	10,733
Other current liabilities	1,278	165
Total current liabilities	477,100	192,454
Long-term debt (Note 5)	1,364,685	1,404,900
Convertible debentures	193,269	189,563
Derivative instruments liability (Notes 6 and 7)	109,873	33,170
Deferred income taxes	165,413	182,925
Power purchase and fuel supply agreement liabilities, net	46,811	71,775
Other non-current liabilities	60,022	57,859
Commitments and contingencies (Note 12)		
Total liabilities	2,417,173	2,132,646
Equity		
Common shares, no par value, unlimited authorized shares; 113,680,643 and 113,526,182 issued and outstanding at March 31, 2012 and December 31, 2011, respectively	1,217,893	1,217,265
Preferred shares issued by a subsidiary company	221,304	221,304
Accumulated other comprehensive income (loss)	12,216	(5,193)
Retained deficit	(395,743)	(320,622)
Total Atlantic Power Corporation shareholders' equity	1,055,670	1,112,754

Noncontrolling interest		2,867		3,027
Total equity		1,058,537		1,115,781
Total liabilities and equity	$	3,475,710	$	3,248,427

See accompanying notes to consolidated financial statements.

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

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands of U.S. dollars)

(Unaudited)

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

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands of U.S. dollars)

(Unaudited)

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

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of presentation and summary of significant accounting policies

Overview

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

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, 02116, USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Additionally, we make available on our website our Canadian securities filings.

The interim consolidated financial statements have been prepared in accordance with the SEC regulations for interim financial information and with the instructions to Form 10-Q. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to our financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011. Interim results are not necessarily indicative of results for the full year.

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

Use of estimates

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

assets, tax provisions, the valuation of shares associated with our Long-Term Incentive Plan ("LTIP") and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Recently issued accounting standards

Adopted

On January 1, 2012, we adopted changes issued by the Financial Accounting Standards Board ("FASB") to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. The adoption of these changes had no impact on our consolidated financial statements.

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

2. Acquisitions and divestitures

2012 Acquisition

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and our wholly owned subsidiary, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestitures (Continued)

Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 298.45 MW wind energy project under construction in the state of Oklahoma. On March 30, 2012, we completed the purchase of an additional 48% interest in the Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. We also closed on a $310 million non-recourse, project-level construction financing facility for the project, which includes a $290 million construction loan and a $20 million 5-year letter of credit facility. The construction loan is structured to be repaid by a tax equity investment, in which we are actively pursuing, when Canadian Hills commences commercial operations. We are committed to investing approximately $180 million of equity (net of financing costs) following the funding of the construction financing. The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at March 31, 2012.

Purchase Accounting Adjustment

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

2012 Divestiture

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("Primary Energy" or "PERC"), whereby PERC agreed to purchase our 7,462,830.33 common membership interests in Primary Energy Recycling Holdings, LLC ("PERH") (14.3% of PERH total interests) for approximately $24 million, plus a management agreement termination fee of approximately $6.1 million, for a total sale price of $30.1 million. The agreed upon price for our private interest in PERH was established as of December 19, 2011 and represented a 16% discount to the 60-day volume weighted average trading price of PERH's common shares at that time. The transaction remains subject to pricing adjustment or termination under certain circumstances. Completion of the transaction is subject to PERC obtaining financing and is expected to close during the second quarter of 2012.

2011 Divestiture

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Equity method investments

The following summarizes the operating results for the three months ended March 31, 2012 and 2011, respectively, for our equity earnings interest in our equity method investments:

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Accumulated depreciation and amortization

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

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

5. Long-term debt

Long-term debt consists of the following:

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

Notes of Atlantic Power (US) GP

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Long-term debt (Continued)

Non-Recourse Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met. At March 31, 2012, all of our projects were in compliance with the covenants contained in project-level debt. However, our Epsilon Power Partners, Selkirk, Delta-Person and Gregory projects had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to make distributions and were therefore restricted from making distributions to us.

Senior Credit Facility

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

6. Fair value of financial instruments

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Fair value of financial instruments (Continued)

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

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of March 31, 2012, the credit valuation adjustments resulted in a $27.1 million net increase in fair value, which consists of a $0.6 million pre-tax gain in other comprehensive income and a $26.6 million gain in change in fair value of derivative instruments, offset by a $.01 million loss in foreign exchange. As of December 31, 2011, the credit valuation adjustments resulted in a $5.8 million net increase in fair value, which consists of a $0.9 million pre-tax gain in other comprehensive income and a $5.1 million gain in change in fair value of derivative instruments, offset by a $0.2 million loss in foreign exchange.

7. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. For certain contracts designated as cash flow hedges, we defer the effective portion of the change in fair value of the derivatives to accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Gas purchase agreements

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

Natural gas swaps

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In the third quarter of 2010 we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. Also in the third quarter of 2011, we entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

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

Interest rate swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.02% from February 16, 2011 to February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and changes in the fair market value is recorded in accumulated other comprehensive income.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% from March 31, 2011 to February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's cash grant bridge loan and the construction loan facility that will convert to a term loan. The interest rate swaps were executed in the fourth quarter 2010 and expire on February 29, 2016 and November 30, 2030. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

In July 2007, we executed an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt at our wholly owned subsidiary Epsilon Power Partners. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 5.29%. In June 2010, the swap agreement was amended to reduce the fixed interest rate 4.24% and extend the maturity date from July 2012 to July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. This interest rate swap agreement is not designated as a hedge and changes in its fair market value are recorded in the consolidated statements of operations.

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars and Canadian dollars but pay dividends to shareholders and interest on convertible debentures and long-term debt predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 85% of our expected dividend and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At March 31, 2012, the forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$123.0 million at an average exchange rate of Cdn$1.127 per U.S. dollar. It is our intention to periodically consider extending the length or terminating these forward contracts.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of March 31, 2012 and December 31, 2011:

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

Fair value of derivative instruments

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

Accumulated other comprehensive income

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

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

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Impact of derivative instruments on the consolidated statements of operations

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

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

The following table summarizes the unrealized gains and (losses) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

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

8. Income taxes

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

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

As of March 31, 2012, we have recorded a valuation allowance of $97.4 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Long-term incentive plan

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

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

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies. Compensation expense for notional units granted in 2012 is recorded net of estimated forfeitures. See further details as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period for awards with market conditions included the following assumptions as of March 31, 2012 and December 31, 2011:

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

10. Basic and diluted earnings (loss) per share

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the three months ended March 31, 2012 and 2011:

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

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

11. Segment and geographic information

We revised our reportable business segments during the fourth quarter of 2011 subsequent to our acquisition of the Partnership. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Financial results for the three months ended March 31, 2012 and 2011 have been presented to reflect the change in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

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

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

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

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

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

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

12. Commitments and contingencies

IRS Examination

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

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

Path 15

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Commitments and contingencies (Continued)

Lake

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

Morris

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

Other

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

13. Condensed consolidating financial information

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

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

Atlantic Power Limited Partnership, Atlantic Power GP Inc., Atlantic Power (US) GP, Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Atlantic Power Holdings, Inc., Atlantic Power Services Canada GP Inc., Atlantic Power Services Canada LP, Atlantic

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

Power Services, LLC, Teton Power Funding, LLC, Harbor Capital Holdings, LLC, Epsilon Power Funding, LLC, Atlantic Auburndale, LLC, Auburndale LP, LLC, Auburndale GP, LLC, Badger Power Generation I, LLC, Badger Power Generation, II, LLC, Badger Power Associates, LP, Atlantic Cadillac Holdings, LLC, Atlantic Idaho Wind Holdings, LLC, Atlantic Idaho Wind C, LLC, Baker Lake Hydro, LLC, Olympia Hydro, LLC, Teton East Coast Generation, LLC, NCP Gem, LLC, NCP Lake Power, LLC, Lake Investment, LP, Teton New Lake, LLC, Lake Cogen Ltd., Atlantic Renewables Holdings, LLC, Orlando Power Generation I, LLC, Orlando Power Generation II, LLC, NCP Dade Power, LLC, NCP Pasco LLC, Dade Investment, LP, Pasco Cogen, Ltd., Atlantic Piedmont Holdings LLC, Teton Selkirk, LLC, Atlantic Oklahoma Wind, LLC, and Teton Operating Services, LLC.

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

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING BALANCE SHEET

March 31, 2012

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

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Three months ended March 31, 2012

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Three months ended March 31, 2012

(in thousands of U.S. dollars)

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

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The consolidated financial statements of Chambers Cogeneration Limited Partnership and Subsidiary for the years ended December 31, 2011 and 2009, are presented herein without the related report of independent accountants.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Consolidated Financial Statements

December 31, 2011 and 2010

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Consolidated Balance Sheets

December 31, 2011 and 2010

(Dollars in thousands)

	2011	As Restated 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 50	53
Restricted cash	6,108	8,292
Accounts receivable	9,601	15,195
Inventory	8,725	8,201
Emission allowances		
Other assets	360	469
Total current assets	24,844	32,210
Construction in progress	683	9
Property and equipment, net of accumulated depreciation of $306,824 and $288,412, respectively	238,395	255,428
Deferred financing costs net of accumulated amortization of $5,386 and $5,182, respectively	1,444	1,648
Other asset	13	
Total assets	$ 265,379	289,295
Liabilities and Partners' Capital		
Current liabilities:		
Current portion of long-term debt	$ 30,666	28,235
Accounts payable	4,230	4,670
Due to affiliates	2,004	1,887
Accrued liabilities	2,631	1,822
Interest rate swap	2,169	4,470
Total current liabilities	41,700	41,084
Long-term debt	129,818	159,376
Interest rate swap	1,560	3,243
Asset retirement obligation	10,943	10,357
Total liabilities	184,021	214,060
Commitments and contingencies		
Partners' capital:		
General partners	81,183	75,964
Limited partner	820	767
Accumulated other comprehensive loss	(645)	(1,496)
Total partners' capital	81,358	75,235
Total liabilities and partners' capital	$ 265,379	289,295

See accompanying notes to consolidated financial statements.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Consolidated Statements of Operations

Years ended December 31, 2011 and 2010

(Dollars in thousands)

	2011	As Restated 2010
Operating revenues:		
Energy	$ 46,741	62,440
Capacity	59,760	59,996
Steam	15,420	16,443
Total operating revenues	121,921	138,879
Operating expenses:		
Fuel	48,903	59,129
Operations and maintenance	27,170	25,910
General end administrative	6,087	6,270
Depreciation	18,412	18,385
Total operating expenses	100,572	109,694
Operating income	21,349	29,185
Other income (expense):		
Interest income	1	1
Miscellaneous income	4	133
Unrealized gain on interest rate swaps	3,984	2,980
Interest expense	(10,566)	(11,747)
Net income	$ 14,772	20,552

See accompanying notes to consolidated financial statements.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Consolidated Statements of Changes in Partners' Capital and Comprehensive Income

Years ended December 31, 2011 and 2010

(Dollars in thousands)

	General partners	Limited partner	Comprehensive income	Accumulated other comprehensive loss	Total
Partners' capital at December 31, 2009, as restated	$ 37,909	25,270		$ (2,784)	60,395
Conversion of partnership interest	26,809	(26,809)			
Net income, as restated	18,176	2,376	$ 20,552		20,552
Amortization of previously deferred loss on interest rate swap agreement			1,288	1,288	1,288
Total comprehensive income, as restated			$ 21,840		
Capital distributions	(6,930)	(70)			(7,000)
Partners' capital at December 31, 2010, Conversion of partnership interest as restated	75,964	767		(1,496)	75,235
Net income	14,624	148	$ 14,772		14,772
Amortization of previously deferred loss on interest rate swap agreement			851	851	851
Total comprehensive income			$ 15,623		
Capital distributions	(9,405)	(95)			(9,500)
Partners' capital at December 31, 2011	$ 81,183	820		$ (645)	81,358

See accompanying notes to consolidated financial statements.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Consolidated Statements of Cash Flows

Years ended December 31, 2011 and 2010

(Dollars in thousands)

	2011	As Restated 2010
Cash flows from operating activities:		
Net income	$ 14,772	20,552
Noncash items included in net income:		
Amortization of deferred interest rate swap losses	851	1,288
Unrealized gain on interest rate swaps	(3,984)	(2,980)
Depreciation	18,412	18,385
Amortization of deferred financing costs	204	225
Accretion of asset retirement obligation	586	555
Loss on disposal of assets		
Changes in operating assets and liabilities:		
Accounts receivable	5,594	(3,230)
Inventory	(524)	(966)
Emission allowances		2,540
Other assets	96	773
Accounts payable	(440)	(736)
Due to affiliates	117	103
Accrued liabilities	752	160
Net cash provided by operating activities	36,436	36,669
Cash flows from investing activities:		
(Decrease) increase in restricted cash	2,184	(1,987)
Proceeds from the sale of assets		
Capital expenditures	(1,996)	(100)
Net cash (used in) provided by investing activities	188	(2,087)
Cash flows from financing activities:		
Repayments of long-term debt	(27,127)	(27,628)
Capital distributions	(9,500)	(7,000)
Cash used in financing activities	(36,627)	(34,628)
Net decrease in cash and cash equivalents	(3)	(46)
Cash and cash equivalents:		
Beginning of period	53	99
End of period	$ 50	53
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 7,396	10,312
Noncash investing and financing activities:		
Capital lease	$ 151	

See accompanying notes to consolidated financial statements.

CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements

December 31, 2011 and 2010

(1) Organization and Business

Chambers Cogeneration Limited Partnership (the Partnership) is a Delaware limited partnership formed on August 17, 1988. The general partners are Peregrine Power, LLC (Peregrine), a California limited liability company, and EIF/Carneys Point, LLC (EIF/Carneys), a Delaware limited liability company, who own 60% of the partnership collectively. As of December 31, 2011, EIF/Carneys and Peregrine were each wholly owned indirect subsidiaries of Calypso Energy Holdings, LLC (Calypso). The following entities, managed by EIF Management, LLC, collectively hold 100% of the partnership interests of Calypso:

EIF Calypso, LLC	80%
EIF Calypso II, LLC	20%

Prior to May 2011, the 20% interest in Calypso was owned by Cogentrix Energy, LLC (CELLC). Epsilon Power (Epsilon), a wholly owned indirect subsidiary of Atlantic Power Corporation holds a 40% interest in the Partnership. In May 2010, Epsilon converted 39% of their 40% limited partnership interest to a general partnership interest.

The Partnership was formed to construct, own and operate a 262-megawatt (MW) coal-fired cogeneration station (the Facility) at DuPont's Chambers Works chemical complex in Carneys Point, New Jersey. The Facility produces energy for sale to Atlantic City Electric Company (AE), and energy and process steam to E.I. DuPont de Nemours & Company (DuPont) for use in its industrial operations. The Facility achieved final completion and commercial operations in 1994.

The net income and losses of the Partnership are allocated to Peregrine, EIF/Carneys and Epsilon (collectively, the Partners) based on the following ownership percentages:

Peregrine	50%
EIF/Carneys	10%
Epsilon (39% general Partnership, 1% limited partnership)	40%

All distributions other than liquidating distributions are made based on the Partners' percentage interests, as shown above, in accordance with the Partnership documents and at such times and in such amounts as the Board of Control of the Partnership determines.

Carneys Point Generating Company, L.P.

The Partnership has a lease agreement with Carneys Point Generating Company, L.P. (CPGC), which is equally owned by Topaz Power, LLC (Topaz) and by Garnet Power, LLC (Garnet), both of which are wholly owned direct subsidiaries of Calypso. CPGC leases the facility and subleases the site from the Partnership. In addition, certain contracts and agreements related to the Partnership have been assigned to CPGC by the Partnership. The lease commenced on September 20, 1994 and has a 24-year term. CPGC's operations have been established to effectively break-even under the lease agreement.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

On January 1, 2010, the Partnership adopted an accounting standards update that changes when and how to determine, or re-determine, whether an entity is a variable interest entity (VIE), which could require consolidation. In addition, the accounting standards update replaces the quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach and requires ongoing assessments of whether an entity is the primary beneficiary of a VIE.

The Partnership is required to consolidate any entities that they control. In most cases, control can be determined based on majority ownership or voting interests. However, for certain entities, control is difficult to discern based on ownership or voting interests alone. These entities are referred to as VIE's. A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest if it has the obligation to absorb expected losses or receive expected gains that could potentially be significant to a VIE and the power to direct activities that are most significant to a VIE's economic performance. An enterprise that has a controlling financial interest is known as the VIE's primary beneficiary and is required to consolidate the VIE. The Partnership reassesses its determination of whether the Partnership is the primary beneficiary of a VIE at each reporting date or if there are changes in facts and circumstances that could potentially alter the Partnership's assessment.

The Partnership has determined that CPGC is a VIE of the Partnership primarily due to its lease arrangements with CPGC. The Partnership has determined that it is the primary beneficiary of the VIE and therefore the Partnership consolidates CPGC in its financial statements. All material intercompany transactions have been eliminated.

(b) Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(c) Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

(d) Restricted Cash

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for debt service, major maintenance and other specifically designated accounts under a disbursement agreement. Restricted cash associated with transactions expected to occur beyond one-year are classified as long-term. All restricted accounts are classified as current assets.

CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(2) Summary of Significant Accounting Policies (Continued)

(e) Inventory

Fuel is valued using the average cost method and includes the fuel contract purchase price as well as the transportation and related costs incurred to deliver the fuel to the Facility (note 3).

Spare parts are recorded at the lower of average cost or market and consist of Facility equipment components and supplies required to facilitate maintenance activities. Spare parts are classified as current in the accompanying consolidated balance sheets (note 3).

The Partnership performs periodic assessments to determine the existence of obsolete, slow-moving and unusable inventory and records necessary provisions to reduce such inventories to market.

(f) Emission Allowances

Emission allowances are valued under the weighted average costing method subject to the lower of cost or market principle. In applying the lower of cost or market principle, a reduction in the carrying value is not recognized so long as the Partnership will recover/pass-through the cost in its operating margin.

The historical cost of emission allowances is calculated as follows:

- Granted from regulatory body-emission allowances obtained via grants are not assigned any value by the Partnership as their cost is zero.
- Acquired as part of an acquisition-emission allowances are recorded at fair value as of the acquisition date, subject to pro rata reduction if overall purchase price is less than the entity's fair value.
- Purchased from third parties-emission allowances that are transferable and can be purchased or sold in the normal course of business are recorded at cost.

As of December 31, 2011 the partnership has accrued approximately $91,000 in emission allowances which are classified as current and included in accrued liabilities in the accompanying consolidated balance sheets.

(g) Derivative Contracts

In accordance with guidance on accounting for derivative instruments and hedging activities all derivatives should be recognized at fair value. Derivatives or any portion thereof, that are not designated as, and effective as, hedges must be adjusted to fair value through earnings. Derivative contracts are classified as either assets or liabilities on the consolidated balance sheets. Certain contracts that require physical delivery may qualify for and be designated as normal purchases/normal sales. Such contracts are accounted for on an accrual basis. The Partnership's interest rate swap agreement (note 8), power purchase agreement (PPA) (note 10) and power sales agreement (PSA) (note 10) meet the definition of a derivative. The Partnership's PPA qualifies for, and the Partnership has elected, the normal purchases and normal sales exception and accordingly accounts for the PPA on an accrual basis. The Partnership's PSA is marked to market through earnings.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(2) Summary of Significant Accounting Policies (Continued)

The Partnership engages in activities to manage risks associated with changes in interest rates. The Partnership has entered into swap agreements to reduce exposure to interest rate fluctuations on certain debt commitments (note 5). These agreements were designated and qualified as cash flow hedging instruments through December 31, 2004. The Partnership discontinued applying cash flow hedge accounting on January 1, 2005. The balance of accumulated other comprehensive loss, as of December 31, 2004, is amortized as interest expense in the accompanying consolidated statements of operations in accordance with the originally forecasted interest payments schedule through the expiration of the interest rate swaps on March 31, 2014.

(h)

Fair Value Measurements

The Partnership uses a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy are described below:

Level 1: Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2: Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3: Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (note 8). As of December 31, 2011 and 2010, the Partnership does not have any nonfinancial assets or liabilities remeasured at fair value on a recurring basis.

(i)

Property and Equipment

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. Depreciation is provided over the lease term of the land using the straight-line method (note 4).

The Partnership's depreciation is based on the Facility being considered a single property unit. Certain components within the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where a replacement of a Facility component is significant and the Partnership can reasonably estimate the original cost of the component being replaced, the Partnership will write-off the replaced component and capitalize the cost of the replacement. The component will be

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(2) Summary of Significant Accounting Policies (Continued)

depreciated over the lesser of the EUL of the component or the remaining useful life of the Facility and also the lease term, when the component is a capitalized modification to leased property.

The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property is used, and the effects of obsolescence, demand, competition, and other economic factors.

(j)

Deferred Financing Costs

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the related financing (note 5).

(k)

Asset Retirement Obligations

Asset retirement obligations, including those conditioned on future events, are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset in the same period. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the EUL of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership recognized an asset retirement obligation at December 31, 2011 and 2010 of approximately $10,943,000 and $10,357,000, respectively. This obligation represents the weighted average probability of costs the Partnership would incur to perform environmental clean-up and remove or sell the facility.

(l)

Income Taxes

As partnerships, the income tax effects attributable to Chambers Cogeneration Partnership Limited accrue directly to the partners. Each partner is individually responsible for its share of the respective Partnerships' and CPCG taxable income or loss.

In addition, during 2010 and 2011, there were no unrecognized tax benefits, current income taxes or penalties and interest related to income taxes recognized in the consolidated statements of operations or the consolidated statements of financial position. If interest or penalties were incurred, they would be recognized in income tax expense in the accompanying consolidated statements of operations.

The tax years that remain subject to examination are December 31, 2008 through December 31, 2011.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(2) Summary of Significant Accounting Policies (Continued)

(m)

Revenue Recognition

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in operating expenses.

(n)

Reclassifications

Certain reclassifications have been made to the prior year's consolidated financial statements to conform to the current year presentation. These reclassifications had no effect on the previously reported results of operations or partners' capital.

(o)

Subsequent Events

The Partnership evaluated subsequent events through March 30, 2012.

(3) Inventory

Inventory consisted of the following as of December 31:

	2011	2010
	(In thousands of dollars)	
Coal	$ 3,958	3,727
Fuel oil	444	335
Lime	103	120
Spare parts	4,220	4,019
	$ 8,725	8,201

(4) Property and Equipment

Property and equipment consisted of the following components as of December 31:

	2011	2010 Restated
	(In thousands of dollars)	
Facility	$ 538,652	537,273
Other equipment	6,567	6,567
Construction in progress	683	9
	545,902	543,849
Less accumulated depreciation	(306,824)	(288,412)

	$	239,078	255,437

The EUL for significant property and equipment categories are as follows:

Facility	30 years
Other equipment	5 to 30 years

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(5) Long-Term Debt

Long-term debt consisted of the following as of December 31(In thousands of dollars):

	As of December 31, 2011			Year ended December 31, 2011	
Description	**Commitment amount**	**Due date**	**Balance outstanding**	**Interest expense**	**Letter of credit fees**
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	1,573	N/A
Credit agreement:					
Term loans(3)(6)	59,376	3/31/14	59,376	1,216	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	1,527
Debt service reserve letter of credit(5)(6)(7)(8)(9)	22,750	12/15/12		N/A	394
Loan Payable(2)	1,108	06/30/16	1,108	42	N/A
			160,484		
Less current portion			30,666		
			$ 129,818		

	As of December 31, 2010			Year ended December 31, 2010	
Description	**Commitment amount**	**Due date**	**Balance outstanding**	**Interest expense**	**Letter of credit fees**
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	352	N/A
Credit agreement:					
Term loans(3)(6)	87,611	3/31/14	87,611	1,695	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	1,480
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	386
			187,611		
Less current portion			28,235		
			$ 159,376		

(1) The bonds are collateralized by an irrevocable letter of credit and provide for interest at variable rates. The weighted average interest rates on the bonds were 1.58% and 0.36% for the years ended December 31, 2011 and 2010, respectively. Remarketing fees paid to the remarketing agent were approximately $100,000 in both 2011 and 2010. These fees are included in interest expense in the accompanying consolidated statements of operations.

(2) Loan payable is collateralized by equipment. The term is 60-months commencing July 2011 with interest fixed at 5.69%.

(3)

The term loans accrue interest at the applicable London Interbank Offered Rate (L1BOR), plus an applicable margin (1.25% at December 31, 2011 and December 31, 2010). The weighted average interest rates on the term loan were 1.58% and 1.62% for 2011 and 2010, respectively.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(5) Long-Term Debt (Continued)

(4) The letter of credit fee for 2011 and 2010 was 1.25%. In addition, the facility provides for a fronting fee of 0.30% effective August 12, 2011 (previously 0.175%) on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(5) The letter of credit fee for 2011 through December 19 and 2010 was 1.50%. In addition, the facility provided for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(6) All bonds, loans and credit facilities are collateralized by the assets of the Facility and the real estate covered by the ground lease (note 1) and are nonrecourse to the Partners.

(7) As of December 31, 2011 and 2010, there were no amounts drawn under the letter of credit commitments.

(8) On December 15, 2011, EIF Calypso, LLC, EIF United States Power Fund IV, LP, and Atlantic Power Corporation posted acceptable replacement security letters of credit totaling $22,750,000 replacing the previous debt service reserve letter of credit. The replacement letters of credit each expire on December 15, 2012 with an automatic one (1) year extension unless the issuing bank(s) give 90 days written notification.

(9) As of December 31, 2011, there were no amounts drawn on the DSR letter of credit.

Accrued interest payable of $17,000 and $3,000 is included in accrued liabilities in the consolidated balance sheets as of December 31, 2011 and 2010, respectively.

Future minimum principal payments as of December 31, 2011 are as follows (dollars in thousands):

2012	$ 30,666
2013	27,197
2014	2,235
2015	269
2016	117
Thereafter	100,000
	$ 160,484

In connection with the various agreements discussed above, certain financial covenants must be met and reported on an annual basis. The Partnership was in compliance with all debt covenants at December 31, 2011 with the exception of two, for which the Partnership has obtained a waiver for one violation and is expected to cure the second violation within the designated cure period.

Interest Rate Swap Agreements

The Partnership is a party to one amortizing interest rate swap agreement with an outstanding notional amount of $59,376,000 at December 31, 2011 and expiring on various dates through March 31, 2014. Swap payments related to the agreements covering the variable rate bank debt are made based on the spread between 6.18% (weighted average of the outstanding agreement as of December 31, 2011) and LIBOR multiplied by the notional amounts outstanding. Net amounts paid to the

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(5) Long-Term Debt (Continued)

counterparties were approximately $4,569,000 and $6,170,000 in 2011 and 2010, respectively. These amounts were recorded as interest expense in the accompanying consolidated statements of operations.

(6) Operating Leases

The Partnership leases certain equipment, land and buildings under noncancelable operating leases expiring at various dates through 2024. For the years ended December 31, 2011 and 2010, the Partnership incurred lease expense of approximately $205,000 and $208,000, respectively, which is included in operations and maintenance expense and general and administrative expense in the accompanying consolidated statements of operations.

Future minimum lease payments, as of December 31, 2011, are as follows (dollars in thousands):

2012	$	204
2013		204
2014		204
2015		200
2016		192
Thereafter		974
	$	1,978

(7) Payment in Lieu of Taxes

In January 1991, the Partnership entered into a Payment in Lieu of Taxes (PILOT) agreement with the Township of Carneys Point, a municipal corporation of the state of New Jersey, which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1994, and will terminate on December 31, 2033. PILOT payments are paid annually and are expensed on a straight-line basis as incurred over the term of the agreement. Property taxes are due and paid quarterly and are deducted from the annual PILOT payments made. The Partnership expensed approximately $2,800,000 and $2,700,000 related to the PILOT which is included in general and administrative in the accompanying consolidated statements of operations for the years ended December 31, 2011 and 2010, respectively.

As of December 31, 2011, future payments remaining under the PILOT are as follows (dollars in thousands):

2012	$	3,000
2013		3,400
2014		3,700
2015		3,900
2016		4,100
Thereafter		110,600
	$	128,700

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(8) Fair Value of Financial Instruments

The Partnership's swap agreements and PSA are accounted for as derivative contracts (note 2). The Partnership uses a valuation model to derive the fair value of its derivative contracts based upon the present value of known or estimated cash flows taking into consideration multiple inputs including contractual terms of the swap agreements and PSA, observable market based inputs when available, interest rate curves, and counterparty credit risk. The models used reflect the contractual terms of, and specific risks inherent in, the contracts as well as the availability of pricing information in the market. Where possible, the Partnership verifies the values produced by its pricing model to market transactions. Due to the fact that the Partnership's PSA contract trades in less liquid markets, model selection requires significant judgment because such contracts tend to be more complex and pricing information is less available in these markets. Price transparency is inherently more limited for more complex structures because of the nature, location and tenor of the arrangement, which requires additional inputs such as correlations and volatilities. In addition to model selection, management makes significant judgments based upon the Partnership's proprietary views of market factors and conditions regarding price and correlation inputs in unobservable periods and adjustments to reflect various factors such as liquidity, bid/offer spreads and credit considerations. If available, these adjustments are based on market evidence.

The Partnership adjusts the inputs to its valuation models only to the extent that changes in these inputs can be verified by similar market transactions, third-party pricing services and/or broker quotes, or can be derived from other substantive evidence such as empirical market data. In circumstances where the Partnership cannot verify the models to market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value.

The following table sets forth the Partnership's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level at December 31, 2011:

	Quoted prices in active markets for identical assets or liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant other unobservable inputs (Level 3)	Total
Assets:				
Interest Rate Swaps	$			
PSA				
Liabilities:				
Interest Rate Swaps			(3,729)	(3,729)
PSA			(1,420)	(1,420)
	$		(5,149)	(5,149)

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(8) Fair Value of Financial Instruments (Continued)

The following table sets forth a reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs for the year ended December 31, 2011 (dollars in thousands).

Fair value of derivatives based on significant unobservable inputs at January 1, 2011	$	(7,713)
Unrealized gains, net(1)		2,564
Fair value of derivatives based on significant unobservable inputs at December 31, 2011	$	(5,149)

The following table sets forth the Partnership's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level at December 31, 2010:

	Quoted prices in active markets for identical assets or liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant other unobservable inputs (Level 3)	Total
Assets:				
Interest Rate Swap	$			
Liabilities:				
Interest Rate Swap			(7,713)	(7,713)
	$		(7,713)	(7,713)

The following table sets forth a reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs for the year ended December 31, 2010 (dollars in thousands).

Fair value of derivatives based on significant unobservable inputs at January 1, 2010	$	(10,693)
Unrealized losses(1)		2,980
Fair value of derivatives based on significant unobservable inputs at December 31, 2010	$	(7,713)

---

(1) Unrealized gain on the interest swap is recognized in operating expenses in the consolidated statements of operations for the years ended December 31, 2010 and 2011. Unrealized loss on the PSA is recognized in revenue in the consolidated statement of operations for the year ended December 31, 2011. Each of the contracts contributing to the unrealized gain, net was still held by the Partnership at December 31, 2011.

The Partnership's additional financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, other assets, accounts payable, due to affiliates, and accrued liabilities. These instruments approximate their fair values as of December 31, 2011 and 2010 due to their short-term nature.

The fair value of the Partnership's bonds and long term loans payable approximates their carrying value due to the variable nature of the interest obligations thereon.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(9) Concentrations of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations. The Partnership primarily conducts business with counterparties in the energy industry. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated investment grade by a major credit rating agency or have a history of reliable performance within the energy industry.

The Partnership's credit risk is primarily concentrated with AE and DuPont. AE and DuPont provided 76% and 24%, respectively, of the Partnership's revenues for the year ended December 31, 2011 and accounted for approximately 72% and 28%, respectively, of the Partnership's trade accounts receivable balance at December 31, 2011. The Partnership has a coal supply contract with Consolidated Coal Company, Consolidated Pennsylvania Coal Company, Consolidated Coal Sales Company and Nineveh Coal Company (together Consol) who are responsible for providing 100% of the Partnership's coal requirements through 2014. The Partnership's credit risk is also impacted by the credit risk associated with its issuing bank of the bond letter of credit, BNP Paribas (previously Dexia Credit Locale).

The Partnership is exposed to credit-related losses in the event of nonperformance by counterparties to the Partnership's interest rate swap agreements (notes 2 and 5). The Partnership does not obtain collateral or other security to support such agreements, but continually monitors its positions with, and the credit quality of, the counterparties to such agreements.

(10) Commitments and Contingencies

(a) Power Purchase Agreement

The Partnership has a power purchase agreement (PPA) with AE for sales of the Facility's power output during a 30-year period commencing in 1994. The PPA provides AE with dispatch rights over the Facility, with a contractual minimum of the equivalent of 3,500 hours of full load operation. The pricing structure provides for both capacity and energy payments. Capacity payments are fixed over the life of the contract. Energy payments are based on a contractual formula which is adjusted annually, as defined in the PPA, based on a utility coal index.

(b) Power Sales Agreement

The Partnership has entered into a supplemental power sales agreement (PSA) with AE which provides the Partnership self-dispatch rights for both undispatched PPA and excess energy as well as the right to market excess capacity. The pricing structure provides for both capacity and energy payments. The Partnership shares margins on the self-dispatched energy with AE based on hourly wholesale prices. Excess capacity is sold in PJM's periodic auctions and the resulting revenue is shared between the Partnership and AE. The PSA expired on December 31, 2011. The Partnership has entered into a new PSA with AE in December 2011 that commences January 1, 2012 and expires on December 31, 2012.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(10) Commitments and Contingencies (Continued)

(c) Steam and Electricity Sales Agreement

The Partnership has a steam and electricity sales agreement with DuPont (the DuPont Agreement) for a 30-year period commencing in 1994. Thereafter, the agreement will remain in effect unless terminated by either party upon at least 36-months' notice. DuPont is required to purchase a minimum of 525,600,000 pounds of process steam per year and no minimum amount of electricity. The steam price is adjusted quarterly based on coal price index formulas defined in the agreement. The electricity price is also adjusted quarterly based on coal price index formulas and the AE average retail rate, as defined in the agreement. The Partnership has ongoing litigation with DuPont over the electric energy payment calculation. Amounts under dispute have not been reflected in revenues in the accompanying consolidated statements of operations.

(d) Fly Ash Disposal Agreement

As of November 1, 2011, the Partnership entered into an Ash Management Services Agreement (Ash Agreement) with HEI of PA, Inc. (HEI) for disposal of a minimum of 50,000 tons per calendar year (prorated for any partial year) of bottom ash and fly ash, including pugged ash and dry ash generated or produced at the facility. The contract has an initial term of ten (10) years commencing November 1, 2011 with three (3) additional five (5) year period automatic extensions unless either party gives written notice of nonextension to the other party twelve (12) months prior to the expiration of the then current term. Disposal pricing is adjusted annually, as defined in the Ash Agreement, beginning on the third anniversary date.

(e) Reverse Osmosis Boiler Feed Water System

In 2011, the Partnership entered into a capital lease agreement with Wells Fargo Equipment Finance, Inc (Wells Fargo) to lease a Reverse Osmosis Boiler Feed Water System (RO) that was designed, fabricated, and installed by Western Reserve Water Systems. The capital lease is for a term of 60 months commencing in July 2011. At the end of the lease term, the Partnership will have the option to purchase the RO for $1.

(f) Other

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

(11) Related Parties

(a) Operations and Maintenance Agreement

The Partnership is party to an Operations and Maintenance Agreement (O&M Agreement) with US Operating Services Company, LLC (USOSC), a wholly owned subsidiary of Calypso, for the operation and maintenance (O&M) of the Carneys Point Project. During the third quarter 2010, ownership of USOSC was acquired by Calypso from CELLC. The O&M Agreement expires on April 1, 2014. Thereafter, the O&M agreement will be automatically renewed for periods of five-years, until terminated by either party with 12-months prior notice. Compensation to OSC under the agreement

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(11) Related Parties (Continued)

includes (i) an annual base fee, of which a portion is subordinate to debt service and certain other costs, (ii) certain earned fees and bonuses based on the Facility's performance and (iii) reimbursement for certain costs, including payroll, supplies, spare parts, equipment, certain taxes, licensing fees, insurance and indirect costs expressed as a percentage of payroll and personnel costs. The fees are adjusted annually by a measure of inflation as defined in the agreement. If targeted Facility performance is not reached on a monthly basis, OSC may be required to pay liquidated damages to the Partnership. The Partnership incurred related expense of approximately $10,479,000 and $9,771,000 which is recorded in operations and maintenance in the consolidated statements of operations during the years ended December 31, 2011 and 2010, respectively. As of December 31, 2011 and 2010, the Partnership owed OSC $1,712,000 and $1,844,000, respectively, under the O&M Agreement, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, approximately $560,000 and $350,000 of the amounts owed at December 31, 2011 and 2010, respectively, is subordinate to the debt service for the Partnership's bonds payable and term loans.

USOSC is party to a Technical Services Agreement (TSA) with Power Services Company, LLC (PSC), a wholly owned subsidiary of Calypso, for services to assist in the day-to-day O&M of the Carneys Point Project. During the third quarter 2010, ownership of PSC was acquired by Calypso from CELLC.

PSC and NAES Corporation (NAES), an independent third-party O&M provider, are parties to a subcontract (NAES Agreement) for NAES to perform all tasks commercially and reasonably necessary to operate, maintain and manage the Company, including administering, managing, monitoring, and performing all of USOSC's obligations and responsibilities of the O&M agreement between USOSC and the Partnership. The NAES agreement expires on August 23, 2015.

(b) Management Services Agreement

The Partnership has a Management Services Agreement (MSA) with PSC to provide day-to-day management and administration services to the Carneys Point Project through September 20, 2018. PSC and Power Plant Management Services, LLC (PPMS), an independent third party management services provider, are parties to a subcontract formalized under a Project Management and Administrative Services Agreement (PMAS) for the Carneys Point Project. The initial term of the PMAS agreement expires on August 23, 2015. The initial term automatically extends for successive two year periods or, if the Facility MSA is scheduled to terminate or expire pursuant to its own terms prior to the expiration of any two year period, a shorter period equal to the time remaining under the Facility MSA unless either party notifies the other party at least three months prior to expiration of the then existing term. Under the PMAS, PPMS provides overall project management, administrative, and related support services as may be necessary to the Partnership and oversees the execution of the NAES agreement on behalf of the Partnership. Compensation to PSC under the agreement includes a monthly fee of $50,000, and PMAS pass-through costs. Payments to PSC of $1,292,000 and $1,731,000 are included in operations and maintenance in the consolidated statements of operations in 2011 and 2010, respectively. As of December 31, 2011 and 2010, the Partnership owed PSC approximately $50,000 for each of 2011 and 2010, which is included in due to affiliates in the accompanying consolidated balance sheets and is subordinate to debt service for the Partnership's bonds payable and term loans.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(12) Restatement of Previously Issued Financial Statements

Following a review of its accounting policies, the Partnership determined that it had incorrectly calculated depreciation expense of the Facility. The Partnership has a ground lease for the Facility with a term of 30 years from the start of the lease with no renewal options. The lease term began with the commencement of commercial operations of the Facility in 1994. The Partnership had been depreciating the Facility over an EUL of 60 years. The Partnership should have been depreciating the Facility over the lesser of its EUL or the term of the ground lease. Therefore, the Partnership understated previously reported depreciation expense and overstated the carrying value of its property and equipment. Additionally, the Partnership determined that it had incorrectly calculated its estimate of the fair value of asset retirement obligations and related accretion and depreciation expense. As a result, the Partnership restated its financial statements for the years ended December 31, 2010 and 2009. These non-cash adjustments had no material impact on the Partnership's previously reported cash flows, cash position or revenues in any period, or on the Partnership's compliance with any of its debt covenants.

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(12) Restatement of Previously Issued Financial Statements (Continued)

The impact of the corrections to 2010 previously issued financial statements is as follows:

(in thousands of dollars)	Amount previously reported	Adjustments	As Restated
Assets			
Current assets			
Cash and cash equivalents	$ 53		53
Restricted cash	8,292		8,292
Accounts receivable	15,195		15,195
Inventory	8,201		8,201
Other assets	469		469
Total current assets	32,210		32,210
Construction in Progress	9		9
Property and equipment, net of accumulated depreciation of $288,412 (previously reported as $189,541)	350,800	(95,372)	255,428
Deferred financing costs, net of accumulated amortization of $5,182	1,648		1,648
Total assets	384,667	(95,372)	289,295
Liabilities and Partners' Capital			
Current liabilities			
Current portion on long-term debt	$ 28,235		28,235
Accounts payable	4,670		4,670
Due to affiliates	1,887		1,887
Accrued liabilities	1,822		1,822
Interest rate swap	4,470		4,470
Total current liabilities	41,084		41,084
Long-term debt	159,376		159,376
Interest rate swap	3,243		3,243
Asset retirement obligation	2,107	8,250	10,357
Total liabilities	205,810	8,250	214,060
Partners' capital			
General partners	178,549	(102,585)	75,964
Limited partner	1,804	(1,037)	767
Accumulated other comprehensive loss	(1,496)		(1,496)
Total partners' capital	178,857	(103,622)	75,235
Total liabilities and partners' capital	384,667	(95,372)	289,295

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(12) Restatement of Previously Issued Financial Statements (Continued)

(in thousands of dollars)	Amount previously reported	Adjustments	As Restated
Operating revenues			
Energy	$ 62,440		62,440
Capacity	59,996		59,996
Steam	16,443		16,443
Total operating revenues	138,879		138,879
Operating expenses			
Fuel	59,129		59,129
Operations and maintenance	25,910		25,910
General and administrative	5,824	446	6,270
Depreciation	8,173	10,212	18,385
Total operating expenses	99,036	10,658	109,694
Operating income	39,843	(10,658)	29,185
Other income (expense)			
Interest income	1		1
Miscellaneous income	133		133
Unrealized gain on interest rate swaps	2,980		2,980
Interest expense	(11,747)		(11,747)
Net income	$ 31,210	(10,658)	20,552

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(12) Restatement of Previously Issued Financial Statements (Continued)

(in thousands of dollars)	Restated General Partners	Restated Limited Partner	Restated Comprehensive Income	Restated Accumulated Other Comprehensive Loss	Restated Total
Partners' capital at December 31, 2009 (as restated)	$ 37,909	25,270		(2,784)	60,395
Conversion of partnership interest (as previously reported)	64,652	(64,652)			
Restatement adjustment	(37,843)	37,843			
Net income (as previously reported)	27,140	4,070	31,210		31,210
Restatement adjustment	(8,964)	(1,694)	(10,658)		(10,658)
Amortization of previously deferred loss on interest rate swap agreement			1,288	1,288	1,288
Total comprehensive income			$ 21,840		
Capital distributions	(6,930)	(70)			(7,000)
Partners' capital at December 31, 2010 (as restated)	$ 75,964	767		$ (1,496)	75,235

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CHAMBERS COGENERATION LIMITED PARTNERSHIP

Notes to Consolidated Financial Statements (Continued)

December 31, 2011 and 2010

(12) Restatement of Previously Issued Financial Statements (Continued)

(in thousands of dollars)	Amount previously reported	Adjustments	As Restated
Cash flows from operating activities			
Net income	$ 31,210	(10,658)	20,552
Noncash items included in net income:			
Amortization of deferred interest rate swap losses	1,288		1,288
Unrealized gain on interest rate swaps	(2,980)		(2,980)
Depreciation	8,173	10,212	18,385
Amortization of deferred financing costs	225		225
Accretion of asset retirement obligation	109	446	555
Loss on disposal of assets			
Changes in operating assets and liabilities:			
Accounts receivable	(3,230)		(3,230)
Inventory	(966)		(966)
Emission allowances	2,540		2,540
Other assets	773		773
Accounts payable	(736)		(736)
Due to affiliates	103		103
Accrued liabilities	160		160
Net cash provided by operating activities	36,669		36,669
Cash flows from investing activities			
(Decrease) increase in restricted cash	(1,987)		(1,987)
Proceeds from the sale of assets			
Capital expenditures	(100)		(100)
Net cash (used in) providing by investing activities	(2,087)		(2,087)
Cash flows from financing activities			
Repayments of long-term debt	(27,628)		(27,628)
Capital distributions	(7,000)		(7,000)
Cash used in financing activities	(34,628)		(34,628)
Net decrease in cash and cash equivalents	(46)		(46)
Cash and cash equivalents			
Beginning of period	99		99
End of period	$ 53		53
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 10,312		10,312

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Chambers Cogeneration Limited Partnership

Consolidated Financial Statements

December 31, 2010 and 2009

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Chambers Cogeneration Limited Partnership

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December 31, 2010 and 2009

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Report of Independent Auditors

To the Board of Control of
Chambers Cogeneration Limited Partnership:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, of changes in partners' capital and comprehensive income, and of cash flows present fairly, in all material respects, the financial position of Chambers Cogeneration Limited Partnership and its subsidiaries at December 31, 2010, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 2, the Company has restated its financial statements for the years ended December 31, 2010 and 2009 to correct errors.

/s/ PricewaterhouseCoopers LLP

March 16, 2011, except for the Restatement of Previously Issued Financial Statements section of Note 2, which is as of March 30, 2012

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Chambers Cogeneration Limited Partnership

Consolidated Balance Sheets

December 31, 2010 and 2009

(in thousands of dollars)	**Restated 2010**	**Restated 2009**
Assets		
Current assets		
Cash and cash equivalents	$ 53	$ 99
Restricted cash	8,292	6,305
Accounts receivable	15,195	11,965
Inventory	8,201	7,235
Emission allowances		2,540
Other assets	469	1,162
Total current assets	32,210	29,306
Construction in Progress	9	
Property and equipment, net of accumulated depreciation of $288,412 and $270,027, respectively	255,428	273,715
Deferred financing costs, net of accumulated amortization of $5,182 and $4,957 respectively	1,648	1,873
Other assets		80
Total assets	$ 289,295	$ 304,974
Liabilities and Partners' Capital		
Current liabilities		
Current portion of long-term debt	$ 28,235	$ 27,628
Accounts payable	4,670	5,406
Due to affiliates	1,887	1,784
Accrued liabilities	1,822	1,655
Interest rate swap	4,470	5,851
Total current liabilities	41,084	42,324
Long-term debt	159,376	187,611
Interest rate swap	3,243	4,842
Asset retirement obligation	10,357	9,802
Total liabilities	214,060	244,579
Commitments and contingencies		
Partners' capital		
General partners	75,964	37,909
Limited partner	767	25,270
Accumulated other comprehensive loss	(1,496)	(2,784)
Total partners' capital	75,235	60,395
Total liabilities and partners' capital	$ 289,295	$ 304,974

The accompanying notes are an integral part of these consolidated financial statements.

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Chambers Cogeneration Limited Partnership

Consolidated Statements of Operations

Years Ended December 31, 2010 and 2009

(in thousands of dollars)	Restated 2010	Restated 2009
Operating revenues		
Energy	$ 62,440	$ 52,727
Capacity	59,996	59,665
Steam	16,443	14,266
Total operating revenues	138,879	126,658
Operating expenses		
Fuel	59,129	53,625
Operations and maintenance	25,910	34,322
General and administrative	6,270	5,397
Depreciation	18,385	18,245
Loss on disposal of assets		1,030
Total operating expenses	109,694	112,619
Operating income	29,185	14,039
Other income (expense)		
Interest income	1	3
Miscellaneous income	133	
Unrealized gain on interest rate swaps	2,980	5,599
Interest expense	(11,747)	(15,614)
Net income	$ 20,552	$ 4,027

The accompanying notes are an integral part of these consolidated financial statements.

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Chambers Cogeneration Limited Partnership

Consolidated Statements of Changes in Partners' Capital and Comprehensive Income

Years Ended December 31, 2010 and 2009

(in thousands of dollars)	Restated General Partners	Restated Limited Partner	Restated Comprehensive Income	Restated Accumulated Other Comprehensive Loss	Restated Total
Partners' capital at December 31, 2008	$ 37,202	$ 24,800		$ (4,570)	$ 57,432
Net income	2,417	1,610	$ 4,027		4,027
Amortization of previously deferred loss on interest rate swap agreement			1,786	1,786	1,786
Total comprehensive income			$ 5,813		
Capital distributions	(1,710)	(1,140)			(2,850)
Partners' capital at December 31, 2009	$ 37,909	$ 25,270		$ (2,784)	$ 60,395
Conversion of partnership interest	$ 26,809	$ (26,809)			
Net income	18,176	2,376	$ 20,552		20,552
Amortization of previously deferred loss on interest rate swap agreement			1,288	1,288	1,288
Total comprehensive income			$ 21,840		
Capital distributions	(6,930)	(70)			(7,000)
Partners' capital at December 31, 2010	$ 75,964	$ 767		$ (1,496)	$ 75,235

The accompanying notes are an integral part of these consolidated financial statements.

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Chambers Cogeneration Limited Partnership

Consolidated Statements of Cash Flows

Years Ended December 31, 2010 and 2009

(in thousands of dollars)	Restated 2010	Restated 2009
Cash flows from operating activities		
Net income	$ 20,552	$ 4,027
Noncash items included in net income:		
Amortization of deferred interest rate swap losses	1,288	1,786
Unrealized gain on interest rate swaps	(2,980)	(5,599)
Depreciation	18,385	18,245
Amortization of deferred financing costs	225	244
Accretion of asset retirement obligation	555	525
Loss on disposal of assets		1,030
Changes in operating assets and liabilities:		
Accounts receivable	(3,230)	2,709
Inventory	(966)	1,116
Emission allowances	2,540	(2,540)
Other assets	773	1,864
Accounts payable	(736)	(1,265)
Due to affiliates	103	(444)
Accrued liabilities	160	(740)
Net cash provided by operating activities	36,669	20,958
Cash flows from investing activities		
(Decrease) increase in restricted cash	(1,987)	7,347
Proceeds from the sale of assets		32
Capital expenditures	(100)	(1,602)
Net cash (used in) provided by investing activities	(2,087)	5,777
Cash flows from financing activities		
Repayments of long-term debt	(27,628)	(23,920)
Capital distributions	(7,000)	(2,850)
Cash used in financing activities	(34,628)	(26,770)
Net decrease in cash and cash equivalents	(46)	(35)
Cash and cash equivalents		
Beginning of period	99	134
End of period	$ 53	$ 99
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 10,312	$ 13,586

The accompanying notes are an integral part of these consolidated financial statements.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

1. Organization and Business

Chambers Cogeneration Limited Partnership (the "Partnership") is a Delaware limited partnership formed on August 17, 1988. The general partners are Peregrine Power, LLC ("Peregrine"), a California limited liability company, and Cogentrix/Carneys Point, LLC ("Cogentrix/Carneys"), a Delaware limited liability company. Cogentrix/Carneys and Peregrine were each wholly-owned indirect subsidiaries of Cogentrix Energy, LLC ("CELLC"). In November 2007, CELLC transferred 100% of its indirect equity interest in Peregrine and Cogentrix/Carneys to Calypso Energy Holdings, LLC ("Calypso"), then a wholly-owned subsidiary of CELLC. Following such transfer, on November 14, 2007, CELLC sold an 80% equity interest in Calypso to EIF Calypso, LLC ("EIF"), a limited liability company owned by one or more private equity funds managed by EIF Management, LLC (collectively, the "Calypso Transaction"). CELLC holds a 20% equity interest in Calypso and a 12% indirect interest in the Partnership. Epsilon Power ("Epsilon"), a wholly-owned indirect subsidiary of Atlantic Power Corporation holds a 40% interest in the Partnership. In May 2010, Epsilon converted 39% of their 40% limited partnership interest to a general partnership interest.

The Partnership was formed to construct, own and operate a 262-megawatt ("MW") coal-fired cogeneration station (the "Facility") at DuPont's Chambers Works chemical complex in Carneys Point, New Jersey. The Facility produces energy for sale to Atlantic City Electric Company ("AE"), and energy and process steam to E.I. DuPont de Nemours & Company ("DuPont") for use in its industrial operations. The Facility achieved final completion and commercial operations in 1994.

In December 2008, the Partnership submitted an application to PJM Interconnection ("PJM") to increase the Facility's capacity rating from 225 MW to 240 MW. On April 28, 2009, the Partnership received notice from PJM that the capacity interconnection rights assigned to the Facility have been increased to 240 MW. The Facility currently sells excess energy under a separate power sales agreement (Note 10).

The net income and losses of the Partnership are allocated to Peregrine, Cogentrix/Carneys and Epsilon (collectively, the "Partners") based on the following ownership percentages:

Peregrine	50%
Cogentrix/Carneys	10%
Epsilon (39% general partnership, 1% limited partnership)	40%

All distributions other than liquidating distributions are made based on the Partners' percentage interests, as shown above, in accordance with the Partnership documents and at such times and in such amounts as the Board of Control of the Partnership determines.

Carneys Point Generating Company, L.P.

The Partnership has a lease agreement with Carneys Point Generating Company, L.P. ("CPGC"), which is equally owned by Topaz Power, LLC ("Topaz") and by Garnet Power, LLC (Garnet"), both of which were wholly-owned direct subsidiaries of Power Services Company, LLC ("PSC"), an indirect wholly-owned subsidiary of CELLC. In November 2007, CELLC transferred 100% of its ownership interest in Topaz and Garnet to Calypso in connection with the Calypso Transaction. CPGC leases the facility and subleases the site from the Partnership. In addition, certain contracts and agreements related to the Partnership have been assigned to CPGC by the Partnership. The lease commenced on September 20, 1994 and has a 24-year term. CPGC's operations have been established to effectively break-even under the lease agreement.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies

Basis of Presentation

On January 1, 2010, the Partnership adopted an accounting standards update that changes when and how to determine, or re-determine, whether an entity is a variable interest entity ("VIE"), which could require consolidation. In addition, the accounting standards update replaces the quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach and requires ongoing assessments of whether an entity is the primary beneficiary of a VIE.

The Partnership is required to consolidate any entities that they control. In most cases, control can be determined based on majority ownership or voting interests. However, for certain entities, control is difficult to discern based on ownership or voting interests alone. These entities are referred to as VIE's. A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest if it has the obligation to absorb expected losses or receive expected gains that could potentially be significant to a VIE and the power to direct activities that are most significant to a VIE's economic performance. An enterprise that has a controlling financial interest is known as the VIE's primary beneficiary and is required to consolidate the VIE. The Partnership reassesses its determination of whether the Partnership is the primary beneficiary of a VIE at each reporting date or if there are changes in facts and circumstances that could potentially alter the Partnership's assessment.

The Partnership has determined that CPGC is a VIE of the Partnership primarily due to its lease arrangements with CPGC. The Partnership has determined that it has the power to direct the activities that most significantly impact CPGC's economic performance, and therefore the Partnership consolidates CPGC into its financial statements. All material intercompany transactions have been eliminated.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for operations, debt service, major maintenance and other specifically designated accounts under a disbursement agreement. All restricted accounts are classified as current assets.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Inventory

Fuel is valued using the average cost method and includes the fuel contract purchase price as well as the transportation and related costs incurred to deliver the fuel to the Facility (Note 3). Spare parts are recorded at the lower of average cost or market and consist of Facility equipment components and supplies required to facilitate maintenance activities. Spare parts are classified as current in the accompanying consolidated balance sheets (Note 3).

The Partnership performs periodic assessments to determine the existence of obsolete, slow-moving and unusable inventory and records necessary provisions to reduce such inventories to net realizable value.

Emission Allowances

Emission allowances are valued under the weighted average costing method subject to the lower of cost or market principle. In applying the lower of cost or market principle, a reduction in the carrying value is not recognized so long as the Partnership will recover/pass-through the cost in its operating margin.

The historical cost of emission allowances is calculated as follows:

Granted from regulatory body emission allowances obtained via grants are not assigned any value by the Partnership as their cost is zero.

Acquired as part of an acquisition emission allowances are recorded at fair value as of the acquisition date, subject to pro rata reduction if overall purchase price is less than the entity's fair value.

Purchased from third parties emission allowances that are transferable and can be purchased or sold in the normal course of business are recorded at cost.

Derivative Contracts

In accordance with guidance on accounting for derivative instruments and hedging activities all derivatives should be recognized at fair value. Derivatives or any portion thereof, that are not designated as, and effective as, hedges must be adjusted to fair value through earnings. Derivative contracts are classified as either assets or liabilities on the consolidated balance sheets. Certain contracts that require physical delivery may qualify for and be designated as normal purchases/normal sales. Such contracts are accounted for on an accrual basis. The Partnership's interest rate swap agreement (Notes 5 and 8) and power purchase agreement ("PPA") (Note 10) meet the definition of a derivative. The Partnership's PPA qualifies for, and the Partnership has elected, the normal purchases and normal sales exception and accordingly accounts for the PPA on an accrual basis.

The Partnership engages in activities to manage risks associated with changes in interest rates. The Partnership has entered into swap agreements to reduce exposure to interest rate fluctuations on certain debt commitments (Note 5). These agreements were designated and qualified as cash flow hedging instruments through December 31, 2004. The Partnership discontinued applying cash flow hedge accounting on January 1, 2005. The balance of accumulated other comprehensive loss, as of

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

December 31, 2004, is amortized as interest expense in the accompanying consolidated statements of operations in accordance with the originally forecasted interest payments schedule through the expiration of the interest rate swaps on March 31, 2014.

Fair Value Measurements

The Partnership uses a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy are described below:

Level 1:	Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.
Level 2:	Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
Level 3:	Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (Note 8). As of December 31, 2010 and 2009, the Partnership does not have any non-financial assets or liabilities remeasured at fair value on a recurring basis

Property and Equipment

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. Depreciation is provided over the estimated useful life ("EUL") of the related assets using the straight-line method (Note 4).

The Partnership's depreciation is based on the Facility being considered a single property unit. Certain components within the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where a replacement of a Facility component is significant and the Partnership can reasonably estimate the original cost of the component being replaced, the Partnership will write-off the replaced component and capitalize the cost of the replacement. The component will be depreciated over the lesser of the EUL of the component or the remaining useful life of the Facility.

The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property is used, and the effects of obsolescence, demand, competition, and other economic factors.

Deferred Financing Costs

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the related financing (Note 5).

Asset Retirement Obligations

Asset retirement obligations, including those conditioned on future events, are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset in the same period. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the EUL of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership records at fair value all reclamation costs the Partnership would incur to perform environmental clean-up of land under lease to the Partnership.

Income Taxes

As a partnership, the income tax effects accrue directly to the partners, and each partner is individually responsible for its share of the combined income or loss. Accordingly, no provision has been made for income taxes.

Revenue Recognition

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in operating expenses.

Reclassifications

Certain reclassifications have been made to the prior year's consolidated financial statements to conform to the current year presentation. These reclassifications had no effect on the previously reported results of operations or partners' capital.

Subsequent Events

The Partnership evaluated subsequent events through March 16, 2011.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Recent Accounting Pronouncements

Effective July 1, 2009 the Partnership adopted the Accounting Standards Codification ("ASC") issued by the FASB. The ASC does not change GAAP, but instead takes the numerous individual accounting pronouncements that previously constituted GAAP and reorganizes them into approximately 90 accounting topics, which are then broken down into subtopics, sections and paragraphs. The intent is to simplify user access to authoritative GAAP by providing all of the guidance related to a particular topic in one place. ASC supersedes all previously existing non-Security and Exchange Commission or non-grandfathered accounting and reporting standards. The adoption of ASC did not have any impact on the Partnership's consolidated financial statements.

Restatement of Previously Issued Financial Statements

Following a review of its accounting policies, the Partnership determined that it had incorrectly calculated depreciation expense of the Facility. The Partnership has a ground lease for the Facility with a term of 30 years from the start of the lease with no renewal options. The lease term began with the commencement of commercial operations of the Facility in 1994. The Partnership had been depreciating the Facility over an EUL of 60 years. The Partnership should have been depreciating the Facility over the lesser of its EUL or the term of the ground lease. Therefore, the Partnership understated previously reported depreciation expense and overstated the carrying value of its property and equipment. Additionally, the Partnership determined that it had incorrectly calculated its estimate of the fair value of asset retirement obligations and related accretion and depreciation expense. As a result, the Partnership restated its financial statements for the years ended December 31, 2010 and 2009. These non-cash adjustments had no material impact on the Partnership's previously reported cash flows, cash position or revenues in any period, or on the Partnership's compliance with any of its debt covenants.

The following tables represent the adjustment as a result of the restatement to the previously reported balance sheets as of December 31, 2010 and 2009 and the related statements of operations, of changes in partners capital and comprehensive income, and of cash flows for the fiscal years ended December 31, 2010 and 2009.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Balance Sheets
December 31, 2010

(in thousands of dollars)	As Previously Reported	Adjustments	As Restated
Assets			
Current assets			
Cash and cash equivalents	$ 53		$ 53
Restricted cash	8,292		8,292
Accounts receivable	15,195		15,195
Inventory	8,201		8,201
Other assets	469		469
Total current assets	32,210		32,210
Construction in Progress	9		9
Property and equipment, net of accumulated depreciation of $288,412 (previously reported as $189,541)	350,800	$ (95,372)	255,428
Deferred financing costs, net of accumulated amortization of $5,182	1,648		1,648
Total assets	$ 384,667	$ (95,372)	$ 289,295
Liabilities and Partners' Capital			
Current liabilities			
Current portion of long-term debt	$ 28,235		$ 28,235
Accounts payable	4,670		4,670
Due to affiliates	1,887		1,887
Accrued liabilities	1,822		1,822
Interest rate swap	4,470		4,470
Total current liabilities	41,084		41,084
Long-term debt	159,376		159,376
Interest rate swap	3,243		3,243
Asset retirement obligation	2,107	$ 8,250	10,357
Total liabilities	205,810	8,250	214,060
Partners' capital			
General partners	178,549	(102,585)	75,964
Limited partner	1,804	(1,037)	767
Accumulated other comprehensive loss	(1,496)		(1,496)
Total partners' capital	178,857	(103,622)	75,235
Total liabilities and partners' capital	$ 384,667	$ (95,372)	$ 289,295

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Balance Sheets
December 31, 2009

(in thousands of dollars)	As Previously Reported	Adjustments	As Restated
Assets			
Current assets			
Cash and cash equivalents	$ 99		$ 99
Restricted cash	6,305		6,305
Accounts receivable	11,965		11,965
Inventory	7,235		7,235
Emission allowances	2,540		2,540
Other assets	1,162		1,162
Total current assets	29,306		29,306
Property and equipment, net of accumulated depreciation of $270,027, (previously reported as $181,368)	358,875	$ (85,160)	273,715
Deferred financing costs, net of accumulated amortization of $4,957	1,873		1,873
Other assets	80		80
Total assets	$ 390,134	$ (85,160)	$ 304,974
Liabilities and Partners' Capital			
Current liabilities			
Current portion of long-term debt	$ 27,628		$ 27,628
Accounts payable	5,406		5,406
Due to affiliates	1,784		1,784
Accrued liabilities	1,655		1,655
Interest rate swap	5,851		5,851
Total current liabilities	42,324		42,324
Long-term debt	187,611		187,611
Interest rate swap	4,842		4,842
Asset retirement obligation	1,998	$ 7,804	9,802
Total liabilities	236,775	7,804	244,579
Partners' capital			
General partners	93,687	(55,778)	37,909
Limited partner	62,456	(37,186)	25,270
Accumulated other comprehensive loss	(2,784)		(2,784)
Total partners' capital	153,359	(92,964)	60,395
Total liabilities and partners' capital	$ 390,134	$ (85,160)	$ 304,974

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Statements of Operations
December 31, 2010

(in thousands of dollars)	As Previously Reported	Adjustments	As Restated
Operating revenues			
Energy	$ 62,440		$ 62,440
Capacity	59,996		59,996
Steam	16,443		16,443
Total operating revenues	138,879		138,879
Operating expenses			
Fuel	59,129		59,129
Operations and maintenance	25,910		25,910
General and administrative	5,824	$ 446	6,270
Depreciation	8,173	10,212	18,385
Total operating expenses	99,036	10,658	109,694
Operating income	39,843	(10,658)	29,185
Other income (expense)			
Interest income	1		1
Miscellaneous income	133		133
Unrealized gain on interest rate swaps	2,980		2,980
Interest expense	(11,747)		(11,747)
Net income	$ 31,210	$ (10,658)	$ 20,552

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Statements of Operations
December 31, 2009

(in thousands of dollars)	As Previously Reported	Adjustments	As Restated
Operating revenues			
Energy	$ 52,727		$ 52,727
Capacity	59,665		59,665
Steam	14,266		14,266
Total operating revenues	126,658		126,658
Operating expenses			
Fuel	53,625		53,625
Operations and maintenance	34,322		34,322
General and administrative	4,975	$ 422	5,397
Depreciation	8,278	9,967	18,245
Loss on disposal of assets	1,030		1,030
Total operating expenses	102,230	10,389	112,619
Operating income	24,428	(10,389)	14,039
Other income (expense)			
Interest income	3		3
Unrealized gain on interest rate swaps	5,599		5,599
Interest expense	(15,614)		(15,614)
Net income	$ 14,416	$ (10,389)	$ 4,027

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Statements of Changes in Capital and Comprehensive Income
December 31, 2010

(in thousands of dollars)	Restated General Partners	Restated Limited Partner	Restated Comprehensive Income	Restated Accumulated Other Comprehensive Loss	Restated Total
Partners' capital at December 31, 2009 (as restated)	$ 37,909	$ 25,270		$ (2,784)	$ 60,395
Conversion of partnership interest (as previously reported)	$ 64,652	$ (64,652)			
Restatement adjustment	(37,843)	37,843			
Net income (as previously reported)	27,140	4,070	$ 31,210		$ 31,210
Restatement adjustment	(8,964)	(1,694)	(10,658)		(10,658)
Amortization of previously deferred loss on interest rate swap agreement			1,288	1,288	1,288
Total comprehensive income			$ 21,840		
Capital distributions	(6,930)	(70)			(7,000)
Partners' capital at December 31, 2010 (as restated)	$ 75,964	$ 767		$ (1,496)	$ 75,235

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Statements of Changes in Capital and Comprehensive Income
December 31, 2009

(in thousands of dollars)	Restated General Partners	Restated Limited Partner	Restated Comprehensive Income	Restated Accumulated Other Comprehensive Loss	Restated Total
Partners' capital at December 31, 2008 (as previously reported)	$ 86,747	$ 57,830		$ (4,570)	$ 140,007
Restatement adjustment	$ (49,545)	$ (33,030)			$ (82,575)
Net income (as previously reported)	8,650	5,766	$ 14,416		14,416
Restatement adjustment	(6,233)	(4,156)	(10,389)		(10,389)
Amortization of previously deferred loss on interest rate swap agreement			1,786	1,786	1,786
Total comprehensive income			$ 5,813		
Capital distributions	(1,710)	(1,140)			(2,850)
Partners' capital at December 31, 2009 (as restated)	$ 37,909	$ 25,270		$ (2,784)	$ 60,395

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Statements of Cash Flows
December 31, 2010

(in thousands of dollars)	As Previously Reported	Adjustments	As Restated
Cash flows from operating activities			
Net income	$ 31,210	$ (10,658)	$ 20,552
Noncash items included in net income:			
Amortization of deferred interest rate swap losses	1,288		1,288
Unrealized gain on interest rate swaps	(2,980)		(2,980)
Depreciation	8,173	10,212	18,385
Amortization of deferred financing costs	225		225
Accretion of asset retirement obligation	109	446	555
Loss on disposal of assets			
Changes in operating assets and liabilities:			
Accounts receivable	(3,230)		(3,230)
Inventory	(966)		(966)
Emission allowances	2,540		2,540
Other assets	773		773
Accounts payable	(736)		(736)
Due to affiliates	103		103
Accrued liabilities	160		160
Net cash provided by operating activities	36,669		36,669
Cash flows from investing activities			
(Decrease) increase in restricted cash	(1,987)		(1,987)
Proceeds from the sale of assets			
Capital expenditures	(100)		(100)
Net cash (used in) provided by investing activities	(2,087)		(2,087)
Cash flows from financing activities			
Repayments of long-term debt	(27,628)		(27,628)
Capital distributions	(7,000)		(7,000)
Cash used in financing activities	(34,628)		(34,628)
Net decrease in cash and cash equivalents	(46)		(46)
Cash and cash equivalents			
Beginning of period	99		99
End of period	$ 53	$	$ 53
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 10,312		$ 10,312

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

2. Summary of Significant Accounting Policies (Continued)

Chambers Cogeneration Limited Partnership
Consolidated Statements of Cash Flows
December 31, 2009

(in thousands of dollars)	As Previously Reported	Adjustments	As Restated
Cash flows from operating activities			
Net income	$ 14,416	$ (10,389)	$ 4,027
Noncash items included in net income:			
Amortization of deferred interest rate swap losses	1,786		1,786
Unrealized gain on interest rate swaps	(5,599)		(5,599)
Depreciation	8,278	9,967	18,245
Amortization of deferred financing costs	244		244
Accretion of asset retirement obligation	103	422	525
Loss on disposal of assets	1,030		1,030
Changes in operating assets and liabilities:			
Accounts receivable	2,709		2,709
Inventory	1,116		1,116
Emission allowances	(2,540)		(2,540)
Other assets	1,864		1,864
Accounts payable	(1,265)		(1,265)
Due to affiliates	(444)		(444)
Accrued liabilities	(740)		(740)
Net cash provided by operating activities	20,958		20,958
Cash flows from investing activities			
(Decrease) increase in restricted cash	7,347		7,347
Proceeds from the sale of assets	32		32
Capital expenditures	(1,602)		(1,602)
Net cash (used in) provided by investing activities	5,777		5,777
Cash flows from financing activities			
Repayments of long-term debt	(23,920)		(23,920)
Capital distributions	(2,850)		(2,850)
Cash used in financing activities	(26,770)		(26,770)
Net decrease in cash and cash equivalents	(35)		(35)
Cash and cash equivalents			
Beginning of period	134		134
End of period	$ 99	$	$ 99
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 13,586		$ 13,586

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

3. Inventory

Inventory consisted of the following as of December 31:

(in thousands of dollars)	2010	2009
Coal	$ 3,727	$ 3,142
Fuel oil	335	376
Lime	120	95
Spare parts	4,019	3,622
	8,201	7,235

4. Property and Equipment

Property and equipment consisted of the following components as of December 31:

(in thousands of dollars)	Restated 2010	Restated 2009
Facility	$ 537,273	$ 537,175
Other equipment	6,567	6,567
Construction in progress	9	
	543,849	543,742
Less: Accumulated depreciation	(288,412)	(270,027)
	$ 255,437	$ 273,715

The EUL for significant property and equipment categories are as follows:

Facility	30 years
Other equipment	5 to 30 years

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

5. Long-Term Debt

Long-term debt consisted of the following as of December 31:

(in thousands of dollars)

	As of December 31, 2010			For the Year Ended December 31, 2010	
Description	**Commitment Amount**	**Due Date**	**Balance Outstanding**	**Interest Expense**	**Letter of Credit Fees**
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	$ 352	N/A
Credit agreement					
Term loans(3)(6)	87,611	3/31/14	87,611	1,695	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	1,480
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	386
			187,611		
Less: Current portion			28,235		
			$ 159,376		

(in thousands of dollars)

	As of December 31, 2009			For the Year Ended December 31, 2009	
Description	**Commitment Amount**	**Due Date**	**Balance Outstanding**	**Interest Expense**	**Letter of Credit Fees**
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	$ 1,795	N/A
Loan payable(2)		6/10/09		3	N/A
Credit agreement					
Term loans(3)(6)	115,239	3/31/14	115,239	2,856	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	1,495
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	389
			215,239		
Less: Current portion			27,628		
			$ 187,611		

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(1) The bonds are collateralized by an irrevocable letter of credit and provide for interest at variable rates. The weighted-average interest rates on the bonds were 0.36% and 1.79% for the years ended December 31, 2010 and 2009, respectively. Remarketing fees paid to the remarketing agent were approximately $100,000 in both 2010 and 2009. These fees are included in interest expense in the accompanying consolidated statements of operations.

(2)

Loan payable is collateralized by equipment. The term is 60-months commencing July 2004 with interest fixed at 6.25%.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

5. Long-Term Debt (Continued)

(3) The term loans accrue interest at the applicable London Interbank Offered Rate ("LIBOR"), plus an applicable margin (1.25% at December 31, 2010 and December 31, 2009). The weighted average interest rates on the term loan were 1.62% and 2.16% for 2010 and 2009, respectively.

(4) The letter of credit fee for 2010 and 2009 was 1.25%. In addition, the facility provides for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(5) The letter of credit fee for 2010 and 2009 was 1.5%. In addition, the facility provided for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(6) All bonds, loans and credit facilities are collateralized by the assets of the Facility and the real estate covered by the ground lease (Note 1) and are nonrecourse to the Partners.

(7) As of December 31, 2010 and 2009, there were no amounts available under the letter of credit commitments.

Accrued interest payable of $3,000 and $81,000 is included in accrued liabilities in the consolidated balance sheets as of December 31, 2010 and 2009, respectively.

Future minimum principal payments as of December 31, 2010 are as follows:

(in thousands of dollars)	
2011	28,235
2012	30,439
2013	26,957
2014	1,980
2015	
Thereafter	100,000
	$ 187,611

In connection with the various agreements discussed above, certain financial covenants must be met and reported on an annual basis. The Partnership was in compliance with all debt covenants at December 31, 2010.

Interest Rate Swap Agreements

The Partnership is a party to two amortizing interest rate swap agreements with notional amounts outstanding aggregating $87,611,000 at December 31, 2010 and expiring on various dates through March 31, 2014. Swap payments related to the agreements covering the variable rate bank debt are made based on the spread between 5.81% (weighted average of all agreements as of December 31, 2010) and LIBOR multiplied by the notional amounts outstanding. Net amounts paid to the counterparties were approximately $6,170,000 and $6,871,000 in 2010 and 2009, respectively. These amounts were recorded as interest expense in the accompanying consolidated statements of operations.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

6. Operating Leases

The Partnership leases certain equipment under non-cancelable operating leases expiring at various dates through 2024. For the years ended December 31, 2010 and 2009, the Partnership incurred lease expense of approximately $208,000 and $219,000, respectively, which is included in operations and maintenance expense and general and administrative expense in the accompanying consolidated statements of operations.

Future minimum lease payments, as of December 31, 2010, are as follows:

(in thousands of dollars)	
2011	201
2012	199
2013	197
2014	197
2015	196
Thereafter	1,166
	$ 2,156

7. Payment in Lieu of Taxes

In January 1991, the Partnership entered into a Payment in Lieu of Taxes ("PILOT") agreement with the Township of Carneys Point, a municipal corporation of the state of New Jersey, which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1994, and will terminate on December 31, 2033. PILOT payments are paid annually and are expensed as incurred over the term of the agreement. Property taxes are due and paid quarterly and are deducted from the annual PILOT payments made. The Partnership expensed approximately $2,700,000 and $2,600,000 related to the PILOT which is included in general and administrative in the accompanying consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively.

As of December 31, 2010, future payments remaining under the PILOT are as follows:

(in thousands of dollars)	
2011	2,800
2012	3,000
2013	3,400
2014	3,700
2015	3,900
Thereafter	114,700
	$ 131,500

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

8. Fair Value of Financial Instruments

The fair value of the Partnership's swap agreements, based upon Level 2 significant other observable inputs, is estimated to be a liability of approximately $7,713,000 and $10,693,000 as of December 31, 2010 and 2009, respectively (Notes 2 and 5). The valuation of the Partnership's swap agreements is based on widely accepted valuation techniques including discounted cash flow analyses which take into consideration among other things the contractual terms of the swap agreements, observable market based inputs when available, interest rate curves and counterparty credit risk. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the fair value estimates as of December 31, 2010 and 2009, are not necessarily indicative of amounts the Partnership could have realized in current markets.

The Partnership's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, other assets, accounts payable, due to affiliates, and accrued liabilities. These instruments approximate their fair values as of December 31, 2010 and 2009 due to their short-term nature.

The fair value of the Partnership's bonds and term loans payable approximates their carrying value due to the variable nature of the interest obligations thereon.

9. Concentrations of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations. The Partnership primarily conducts business with counterparties in the energy industry. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated investment grade by a major credit rating agency or have a history of reliable performance within the energy industry.

The Partnership's credit risk is primarily concentrated with AE, DuPont and the Partnership's coal supplier. AE and DuPont provided 80.5% and 19.5%, respectively, of the Partnership's revenues for the year ended December 31, 2010 and accounted for approximately 78.7% and 21.3%, respectively, of the Partnership's trade accounts receivable balance at December 31, 2010. The Partnership has a coal supply contract with Consolidated Coal Company, Consolidated Pennsylvania Coal Company, Consolidated Coal Sales Company and Nineveh Coal Company (together "Consol") who are responsible for providing 100% of the Partnership's coal requirements through 2014. The Partnership's credit risk is also impacted by the credit risk associated with its issuing bank of the bond letter of credit, Dexia Credit Locale.

The Partnership is exposed to credit-related losses in the event of nonperformance by counterparties to the Partnership's interest rate swap agreements (Notes 2 and 5). The Partnership does not obtain collateral or other security to support such agreements, but continually monitors its positions with, and the credit quality of, the counterparties to such agreements.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

10. Commitments and Contingencies

Power Purchase Agreement

The Partnership has a power purchase agreement ("PPA") with AE for sales of the Facility's power output during a 30-year period commencing in 1994. The PPA provides AE with dispatch rights over the Facility, with a contractual minimum of the equivalent of 3,500 hours of full load operation. The pricing structure provides for both capacity and energy payments. Capacity payments are fixed over the life of the contract. Energy payments are based on a contractual formula which is adjusted annually, as defined in the PPA, based on a utility coal index.

Power Sales Agreement

The Partnership has entered into a supplemental power sales agreement ("PSA") with AE which provides the Partnership self-dispatch rights for both undispatched PPA and excess energy as well as the right to market excess capacity. The pricing structure provides for both capacity and energy payments. The Partnership shares margins on the self-dispatched energy with AE based on hourly wholesale prices. Excess capacity is sold in PJM's periodic auctions and the resulting revenue is shared between the Partnership and AE. The PSA expired on December 31, 2010. The Partnership has entered into a new PSA with AE that commences January 1, 2011 and expires on December 31, 2011.

Steam and Electricity Sales Agreement

The Partnership has a steam and electricity sales agreement with DuPont (the "DuPont Agreement") for a 30-year period commencing in 1994. Thereafter, the agreement will remain in effect unless terminated by either party upon at least 36-months' notice. DuPont is required to purchase a minimum of 525,600,000 pounds of process steam per year and no minimum amount of electricity. The steam price is adjusted quarterly based on coal price index formulas defined in the agreement. The electricity price is also adjusted quarterly based on coal price index formulas and the AE average retail rate, as defined in the agreement. The Partnership has ongoing litigation with DuPont over electric energy payment calculation. Amounts under dispute have not been reflected in revenues in the accompanying consolidated statements of operations.

Fly Ash Disposal Agreement

The Partnership has an agreement with Consolidation Coal Company, Consol Pennsylvania Coal Company, Consolidation Coal Sales Company and Nineveh Coal Company, jointly ("CONSOL"), for a 20-year period commencing in 1994 for the disposal of fly ash with a minimum requirement of 130,000 tons per contract year. The Partnership does not anticipate meeting this requirement by the end of the contract year ending on March 14, 2011. Accordingly, the Partnership has accrued approximately $204,000 related to this shortage at December 31, 2010 which is included in fuel expense on the accompanying consolidated statement of operations. CONSOL transports the facilities coal ash to Pennsylvania where it is used for mine reclamation. The Pennsylvania Department of Environmental Protection ("PADEP") has recently issued revisions to the standards required for beneficial use of coal ash in the State of Pennsylvania. The facilities ash will have a difficult time meeting the new standards. The Partnership is evaluating process changes to meet the new PADEP standards as well as evaluating alternate disposal sites outside the State of Pennsylvania. The Partnership expects no material impact related to the potential changes in ash disposal.

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Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

10. Commitments and Contingencies (Continued)

Reverse Osmosis Boiler Feed Water System

The Partnership has entered into a capital lease agreement with Wells Fargo Equipment Finance, Inc ("Wells Fargo") to lease a new Reverse Osmosis Boiler Feed Water System ("RO") to be designed, fabricated, and installed by Western Reserve Water Systems in 2011. The capital lease is for a term of 60 months to commence upon final acceptance of the Partnership of the installed RO. At the end of the lease term, the Partnership will have the option to purchase the RO for $1.

Other

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

11. Related Parties

Operations and Maintenance Agreement

The Partnership is party to an Operations and Maintenance Agreement ("O&M Agreement") with US Operating Services Company, LLC ("USOSC"), a wholly-owned subsidiary of Calypso, for the operation and maintenance ("O&M") of the Carneys Point Project. During the third quarter 2010, ownership of USOSC was acquired by Calypso from CELLC. The O&M Agreement expires on April 1, 2014. Thereafter, the O&M agreement will be automatically renewed for periods of five-years until terminated by either party with 12-months prior notice. Compensation to OSC under the agreement includes (i) an annual base fee, of which a portion is subordinate to debt service and certain other costs, (ii) certain earned fees and bonuses based on the Facility's performance and (iii) reimbursement for certain costs, including payroll, supplies, spare parts, equipment, certain taxes, licensing fees, insurance and indirect costs expressed as a percentage of payroll and personnel costs. The fees are adjusted annually by a measure of inflation as defined in the agreement. If targeted Facility performance is not reached on a monthly basis, OSC may be required to pay liquidated damages to the Partnership. The Partnership incurred related expense of approximately $9,771,000 and $9,857,000 which is recorded in operations and maintenance in the consolidated statements of operations during the years ended December 31, 2010 and 2009, respectively. As of December 31, 2010 and 2009, the Partnership owed OSC $1,844,000 and $1,649,000, respectively, under the O&M Agreement, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, approximately $350,000 and $287,000 of the amounts owed at December 31, 2010 and 2009, respectively, is subordinate to the debt service for the Partnership's bonds payable and term loans. In addition, approximately $549,000 in other costs had been advanced to OSC at December 31, 2009 and are included in other current assets in the accompanying consolidated balance sheets.

USOSC is party to a Technical Services Agreement ("TSA") with Power Services Company, LLC ("PSC"), a wholly-owned subsidiary of Calypso, for services to assist in the day-to-day O&M of the Carneys Point Project. During the third quarter 2010, ownership of PSC was acquired by Calypso from CELLC.

PSC and NAES Corporation ("NAES"), an independent third-party O&M provider, are parties to a subcontract ("NAES Agreement") for NAES to perform all tasks commercially and reasonably

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2010 and 2009

11. Related Parties (Continued)

necessary to operate, maintain and manage the Company, including administering, managing, monitoring and performing all of USOSC's obligations and responsibilities of the O&M agreement between USOSC and the Partnership. The NAES agreement expires on August 23, 2015.

Management Services Agreement

The Partnership has a Management Services Agreement ("MSA") with PSC to provide day-to-day management and administration services to the Carneys Point Project through September 20, 2018. PSC and Power Plant Management Services, LLC ("PPMS"), an independent third party management services provider, are parties to a subcontract formalized under a Project Management and Administrative Services Agreement ("PMAS") for the Carneys Point Project. The initial term of the PMAS agreement expires on August 23, 2015. The initial term automatically extends for successive two year periods or, if the Facility MSA is scheduled to terminate or expire pursuant to its own terms prior to the expiration of any two year period, a shorter period equal to the time remaining under the Facility MSA unless either party notifies the other party at least three months prior to expiration of the then existing term. Under the PMAS, PPMS provides overall project management, administrative, and related support services as may be necessary to the Partnership and oversees the execution of the NAES agreement on behalf of the Partnership. Compensation to PSC under the agreement includes a monthly fee of $50,000, and PMAS pass-through costs. Payments to PSC of $1,731,000 and $1,860,000 are included in operations and maintenance in the consolidated statements of operations in 2010 and 2009, respectively. As of December 31, 2010 and 2009, the Partnership owed PSC approximately $50,000 and $135,000, respectively, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, $50,000 of the amounts owed for each of 2010 and 2009 is subordinate to debt service for the Partnership's bonds payable and term loans.

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INDEPENDENT AUDITORS' REPORT

To the Partners of Capital Power Income L.P.

We have audited the accompanying consolidated balance sheets of Capital Power Income L.P. and subsidiaries ("the Partnership") as of December 31, 2010, 2009, and 2008 and the related consolidated statements of income and loss, partners' equity, comprehensive loss and cash flows for each year in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2010, 2009, and 2008 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010 in conformity with Canadian generally accepted accounting principles.

Accounting principles generally accepted in Canada vary in certain significant respects from U.S. generally accepted accounting principles. Information relating to the nature and effect of such differences is presented in note 27 to the consolidated financial statements.

"signed KPMG"

KPMG LLP
Edmonton, Canada

March 2, 2011, except as to notes 27 and 28, which are as of July 25, 2011

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CAPITAL POWER INCOME L.P.

CONSOLIDATED STATEMENTS OF INCOME AND LOSS

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars except units and per unit amounts)		
Revenues	**$ 532.4**	$ 586.5	$ 499.3
Cost of fuel	**230.7**	271.4	288.8
Operating and maintenance expense	**114.2**	103.4	99.1
	187.5	211.7	111.4
Other costs			
Depreciation, amortization and accretion (Note 5)	**98.3**	93.3	88.3
Financial charges and other, net (Note 9)	**40.1**	46.4	70.7
Management and administration	**13.9**	15.2	20.2
Asset impairment charge (Note 8)			24.1
	152.3	154.9	203.3
Net income (loss) from continuing operations before income tax and preferred share dividends	**35.2**	56.8	(91.9)
Income tax recovery (Note 14)	**9.4**	8.9	31.4
Net income (loss) from continuing operations before preferred share dividends	**44.6**	65.7	(60.5)
Preferred share dividends of a subsidiary company (Note 11)	**14.1**	7.9	6.6
Net income (loss) from continuing operations	**30.5**	57.8	(67.1)
Loss from discontinued operations (Note 25)		(0.2)	(0.7)
Net income (loss)	**$ 30.5**	$ 57.6	$ (67.8)
Net income (loss) per unit from continuing operations	**$ 0.55**	$ 1.07	$ (1.24)
Net loss per unit from discontinued operations			(0.01)
Net income (loss) per unit	**$ 0.55**	$ 1.07	$ (1.26)
Weighted average units outstanding (millions)	**55.0**	53.9	53.9

See accompanying notes to the consolidated financial statements.

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CAPITAL POWER INCOME L.P.

CONSOLIDATED STATEMENTS OF CASH FLOW

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
Operating activities			
Net income (loss) from continuing operations	**$ 30.5**	$ 57.8	$ (67.1)
Items not affecting cash:			
Depreciation, amortization and accretion	**98.3**	93.3	88.3
Asset impairment charge			24.1
Future income tax recovery	**(13.9)**	(12.4)	(34.4)
Fair value changes on derivative instruments	**3.6**	(6.2)	98.4
Unrealized foreign exchange losses		0.3	26.2
Other	**6.6**	10.0	8.7
	125.1	142.8	144.2
Change in non-cash working capital (Note 16)	**(7.3)**	(8.3)	13.3
Cash provided by operating activities of continuing operations	**117.8**	134.5	157.5
Cash (used in) provided by operating activities of discontinued operations		(2.8)	2.7
Cash provided by operating activities	**117.8**	131.7	160.2
Investing activities			
Additions to property, plant and equipment and other assets	**(28.3)**	(100.7)	(40.0)
Change in non-cash working capital	**(7.2)**	4.2	2.7
Dividends from equity investment		1.3	3.2
Acquisition of Morris Cogeneration LLC (Note 24)			(90.7)
Acquisition of equity investment		(8.8)	
Cash used in investing activities of continuing operations	**(35.5)**	(104.0)	(124.8)
Cash provided by (used in) investing activities of discontinued operations		11.6	(3.5)
Cash used in investing activities	**(35.5)**	(92.4)	(128.3)
Financing activities			
Distributions paid	**(69.5)**	(127.7)	(135.8)
Net borrowings under credit facilities	**8.1**	1.8	85.7
Proceeds from preferred share offering (Note 11)		100.0	
Long-term debt repaid	**(1.4)**	(1.3)	(1.1)
Issue costs	**(0.5)**	(4.1)	
Cash used in financing activities	**(63.3)**	(31.3)	(51.2)
Foreign exchange gains (losses) on cash held in a foreign currency	**(1.0)**	(1.5)	2.2
Increase (decrease) in cash and cash equivalents	**18.0**	6.5	(17.1)
Cash and cash equivalents, beginning of year	**9.5**	3.0	20.1
Cash and cash equivalents, end of year	**$ 27.5**	$ 9.5	$ 3.0
Supplementary cash flow information			
Income taxes paid	**$ 5.6**	$ 2.4	$ 6.7

Interest paid	**$ 38.0**	$ 43.6	$ 37.1

See accompanying notes to the consolidated financial statements.

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CAPITAL POWER INCOME L.P.

CONSOLIDATED BALANCE SHEETS

	As at December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
ASSETS			
Current assets			
Cash and cash equivalents	**$ 27.5**	$ 9.5	$ 3.0
Accounts receivable	**52.5**	51.8	60.6
Inventories (Note 4)	**19.5**	24.6	23.2
Prepaids and other	**4.0**	4.5	5.0
Derivative assets (Note 15)	**10.4**	7.8	22.8
Future income taxes (Note 14)	**7.1**	1.9	2.3
Current assets of discontinued operations			2.3
	121.0	100.1	119.2
Property, plant and equipment (Note 5)	**994.1**	1,064.7	1,106.0
Power purchase arrangements (Note 6)	**290.0**	330.4	408.6
Goodwill (Note 7)	**45.0**	47.6	55.1
Derivative assets (Note 15)	**29.7**	31.8	27.1
Future income taxes (Note 14)	**41.2**	35.0	16.8
Other assets (Note 8)	**62.8**	58.5	64.4
Long-term assets of discontinued operations (Note 25)			12.0
	$ 1,583.8	$ 1,668.1	$ 1,809.2
LIABILITIES AND PARTNERS' EQUITY			
Current liabilities			
Accounts payable	**$ 52.9**	$ 59.6	$ 70.3
Distributions payable	**8.2**	7.9	33.9
Long-term debt due within one year (Note 9)		1.4	1.3
Derivative liabilities (Note 15)	**21.1**	2.9	13.0
Current liabilities of discontinued operations			1.2
Future income taxes (Note 14)		3.8	
	82.2	75.6	119.7
Long-term debt (Note 9)	**704.5**	719.4	798.5
Derivative liabilities (Note 15)	**81.9**	36.4	38.5
Other liabilities (Note 10)	**37.1**	34.8	33.3
Long-term liabilities of discontinued operations (Note 25)			4.2
Future income taxes (Note 14)	**50.7**	62.7	60.7
Preferred shares issued by a subsidiary company (Note 11)	**219.7**	219.7	122.0
Partners' equity	**407.7**	519.5	632.3
Commitments (Note 23)			
Subsequent event (Note 28)			
	$ 1,583.8	$ 1,668.1	$ 1,809.2

Approved by CPI Income Services Ltd., as General Partner of Capital Power Income L.P.

"signed Brian Vaasjo" *"signed Brian Felesky"*

Brian T. Vaasjo	**Brian A. Felesky**
Director and Chairman of the Board	Director and Chairman of the Audit Committee

See accompanying notes to the consolidated financial statements.

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CAPITAL POWER INCOME L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
Partnership capital (Note 12)			
Balance, beginning of year	**$ 1,200.6**	$ 1,197.1	$ 1,197.1
Partnership units issued pursuant to distribution reinvestment plan	**27.0**	3.5	
Balance, end of year	**$ 1,227.6**	$ 1,200.6	$ 1,197.1
Deficit			
Balance, beginning of year:	**(543.7)**	(496.1)	(296.5)
Net income (loss)	**30.5**	57.6	(67.8)
Distributions	**(96.9)**	(105.2)	(135.8)
Balance, end of year	**$ (610.1)**	$ (543.7)	$ (500.1)
Accumulated other comprehensive loss (Note 13)			
Balance, beginning of year	**$ (137.4)**	$ (64.7)	$ 5.1
Other comprehensive loss	**(72.4)**	(72.7)	(69.8)
Balance, end of year	**$ (209.8)**	$ (137.4)	$ (64.7)
Total of deficit and accumulated other comprehensive loss	**$ (819.9)**	$ (681.1)	$ (564.8)
Partners' equity	**$ 407.7**	$ 519.5	$ 632.3

See accompanying notes to the consolidated financial statements.

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CAPITAL POWER INCOME L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
Net income (loss)	**$ 30.5**	$ 57.6	$ (67.8)
Other comprehensive income (loss), net of income taxes			
Losses on translating net assets of self-sustaining foreign operations(1)	**(27.4)**	(65.9)	(66.0)
Amortization of deferred gains on derivative instruments de-designated as cash flow hedges to income(2)	**(0.5)**	(0.4)	(3.8)
Unrealized losses on derivative instruments designated as cash flow hedges(3)	**(46.7)**	(6.7)	
Ineffective portion of cash flow hedges reclassified to net income(2)	**2.2**	0.3	
	(72.4)	(72.7)	(69.8)
Comprehensive loss	**$ (41.9)**	$ (15.1)	$ (137.6)

(1) Includes income tax expense of $0.6 million (2009 and 2008 $nil).

(2) Net of income tax of $nil.

(3) Net of income tax of $14.6 million (2009 $2.5 million; 2008 $nil).

See accompanying notes to the consolidated financial statements.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Description of the Partnership

Capital Power Income L.P. (the Partnership) is a limited partnership created under the laws of the Province of Ontario pursuant to a Partnership Agreement dated March 27, 1997, as amended and restated November 4, 2009. The Partnership commenced operations on June 18, 1997 and currently has independent power generating facilities in British Columbia, Ontario, California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington State.

CPI Income Services Ltd., the general partner of the Partnership (the General Partner), has the responsibility for overseeing the management of the Partnership and distributions to unitholders. The General Partner is a wholly owned subsidiary of CPI Investments Inc. (Investments). Capital Power Corporation (collectively with its subsidiaries, CPC, unless otherwise indicated) indirectly owns all of the 49 voting, participating shares of Investments and EPCOR Utilities Inc. (EPCOR) indirectly owns all of the 51 voting, non-participating shares of Investments. The General Partner has engaged certain other subsidiaries of CPC (collectively herein, the Manager) to perform management and administrative services on behalf of the Partnership and to operate and maintain the power plants pursuant to management and operations agreements.

Note 2. Significant Accounting Policies

Basis of Presentation

The consolidated financial statements of the Partnership have been prepared by the management of the General Partner in accordance with Canadian generally accepted accounting principles (GAAP) and include the accounts of the Partnership and of its subsidiaries. All significant intercompany transactions and balances have been eliminated.

Measurement Uncertainty

The preparation of the Partnership's financial statements in accordance with GAAP requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. The Partnership uses the most current information available and exercises careful judgment in making these estimates and assumptions.

For determining asset impairments, recording financial assets and liabilities and for certain disclosures, the Partnership is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values, depreciated replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

Revenue Recognition

Power purchase arrangements, steam purchase arrangements and energy services agreements (collectively referred to as power purchase arrangements or PPAs) are long-term contracts to sell power and steam from the Partnership on a predetermined basis. As explained in "Power purchase arrangements containing a lease," PPAs may be classified as a lease (either operating or capital) and the income is recognized in revenue according to lease revenue recognition standards. For those PPAs

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Significant Accounting Policies (Continued)

that are not considered to contain a lease, income earned on the PPA is recognized in revenue as follows: Revenue from the sales of electricity, steam and natural gas are recognized on delivery or availability for delivery under take or pay contracts. Revenue from certain long-term contracts with fixed payments is recognized at the lower of (1) the megawatt hours (MWhs) made available during the period multiplied by the billable contract price per MWh and (2) an amount determined by the MWhs made available during the period multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the current period contract price over the average price is recorded as deferred revenue.

Gains and losses on non-financial derivative instruments settlements are recorded in revenues or cost of fuel, as appropriate.

Financial Instruments

Financial assets are identified and classified as either available for sale, held for trading, held to maturity or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in net income. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available for sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of or becomes impaired. Investments in equity instruments classified as available for sale that do not have quoted market prices in an active market are measured at cost.

Upon initial recognition, the Partnership may designate financial instruments as held for trading when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognising gains and losses on them on a different basis. The Partnership has designated its cash and cash equivalents as held for trading. All other non-derivative financial assets not meeting the Partnership's criteria for designation as held for trading are classified as available for sale, loans and receivables or held to maturity.

Financial assets purchased or sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a settlement date basis.

Transaction costs on financial assets and liabilities classified as other than held for trading are capitalized and amortized over the expected life of the instrument, based on contractual cash flows, using the effective interest method (EIM). The EIM calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

Derivative Instruments and Hedging Activities

To reduce its exposure to movements in energy commodity prices, interest rate changes and foreign currency exchange rates, the Partnership uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Significant Accounting Policies (Continued)

swaps and option contracts. Such instruments are used to establish a fixed price for an energy commodity, a cash flow denominated in a foreign currency or an interest-bearing obligation. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a commodity that was entered into and continues to be held for the purpose of the receipt or delivery of that commodity in accordance with the Partnership's expected purchase, sale or usage requirements is not treated as a derivative. All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income.

The Partnership uses non-financial forward delivery contracts and financial contracts-for-differences to manage the Partnership's exposure to fluctuations in natural gas prices related to obligations arising from its natural gas fired generation facilities. Under the non-financial forward delivery contracts, the Partnership agrees to purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe. Under the financial contracts-for-differences derivatives, the Partnership agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

Foreign exchange forward contracts are used by the Partnership to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies.

The Partnership may use forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt.

The Partnership may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Partnership documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis. The Partnership uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in natural gas prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. The hedging relationship for the natural gas contracts, which are derivative instruments, was established after the inception of the contracts. The fair value of these contracts at the date of hedge designation is recognized in net income as the natural gas is delivered under the contracts based on the anticipated fair value of the deliveries at the inception of the hedging relationship.

A hedging relationship is discontinued if the hedging relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Partnership terminates its designation of the hedging relationship or if either the hedged or hedging instrument ceases to exist as a result of its maturity,

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Significant Accounting Policies (Continued)

expiry, sale, termination or cancellation and is not replaced as part of the Partnership's hedging strategy.

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized as described above. The fair value of derivative financial instruments reflects changes in the commodity market prices and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Income Taxes

Future income tax assets and liabilities are determined based on temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The Partnership was not subject to Canadian income taxes and accordingly those taxes which are the responsibility of individual partners have not been reflected in these consolidated financial statements. Certain subsidiaries are taxable and applicable income, withholding and other taxes have been reflected in these consolidated financial statements. However, the Partnership is subject to Canadian income taxes after 2010. As a result, the Partnership recognized future income taxes based on the estimated net taxable timing differences which are expected to reverse after 2010.

Cash and Cash Equivalents

Cash and cash equivalents include cash or highly liquid, investment-grade, short-term investments and are recorded at fair value.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Significant Accounting Policies (Continued)

Inventories

Inventories represent small parts and other consumables and fuel, the majority of which is consumed by the Partnership in provision of its goods and services, and are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Previous write downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Power generation plant and equipment, less estimated residual value, is depreciated on a straight-line basis over estimated service lives of one to fifty years. Other equipment, which includes the costs of office furniture, tools and vehicles, is capitalized and depreciated over estimated service lives of three to fifteen years.

Property, plant and equipment, including asset retirement costs, is periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to income.

Power Purchase Arrangements

On acquisition of power plants with existing PPAs in place, the acquired PPAs are capitalized as an intangible asset and included within the balance sheet as PPAs. The Partnership records acquired PPAs at their fair value and amortizes them over the remaining terms of the contracts.

Power Purchase Arrangements Containing a Lease

The Partnership has entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Partnership's property, plant and equipment in return for future payments. Such arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as direct financing leases.

Finance income related to leases or arrangements accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income over the lease term.

Payments received under PPAs classified as direct financing leases are segmented into those for the lease and those for other elements on the basis of their relative fair value.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Significant Accounting Policies (Continued)

Long-term Investments

Investments that are not controlled by the Partnership, but over which it has significant influence are accounted for using the equity method and recorded at original cost and adjusted periodically to recognize the Partnership's proportionate share of the investee's net income or losses after the date of investment, additional contributions made and dividends received. Other investments are stated at cost. When there has been a decline in value that is other than temporary, the carrying amount of an investment is reduced to its fair value.

Investment in Joint Venture

The investment in a joint venture is accounted for using the proportionate consolidation method. Under this method, the Partnership records its proportionate share of assets, liabilities, revenue and expenses of the joint venture.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the net assets acquired based on their fair values. Goodwill is not amortized, but rather is tested for impairment at least annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared to the carrying amount, including goodwill, of the reporting unit. If the carrying amount of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any. The Partnership determines the fair value of a reporting unit using discounted cash flow techniques and estimated future cash flows.

Other Intangible Assets

Other intangible assets consist primarily of emissions allowances and are amortized over their remaining lives.

Asset Retirement Obligations

The Partnership recognizes asset retirement obligations for its power plants. The fair value of the liability is added to the carrying amount of the associated plant asset and depreciated accordingly. The liability is accreted at the end of each period through charges to depreciation, amortization and accretion. The Partnership has recorded these asset retirement obligations, as it is legally required to remove the facilities at the end of their useful lives and restore the plant sites to their original condition.

Foreign Currency Translation

The Partnership's functional and presentation currency is the Canadian dollar. The Partnership indirectly owns U.S. subsidiaries which are self-sustaining foreign operations translated to Canadian dollars using the current rate method. Assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Significant Accounting Policies (Continued)

other comprehensive income until there is a reduction in the Partnership's net investment in the foreign operations. Prior to October 1, 2008, the U.S. subsidiaries were considered integrated foreign operations.

Net Income Per Unit

Net income per unit is calculated by dividing net income by the weighted average number of units outstanding, including those held by CPC.

Note 3. Changes in Accounting Policies

Future Accounting Changes

International financial reporting standards

The CICA has announced that Canadian reporting issuers will need to begin reporting under IFRS, including comparative figures, by the first quarter of 2011. In the fourth quarter of 2010, the Audit Committee reviewed accounting policy decisions for all standards that were in effect at the end of the year ended December 31, 2010.

Note 4. Inventories

	2010	2009	2008
Parts and other consumables	**$ 9.0**	$ 14.2	$ 7.7
Fuel	**10.5**	10.4	15.5
	$ 19.5	$ 24.6	$ 23.2

Inventories expensed in cost of fuel and other plant operating expenses were $47.1 million for the year ended December 31, 2010 (December 31, 2009 $21.2 million; December 31, 2008 $40.5 million).

No write-down of inventory or reversal of a previous write-down was recognized in the years ended December 31, 2010, 2009 or 2008. As at December 31, 2010, 2009 and 2008, no inventories were pledged as security for liabilities.

Note 5. Property, Plant and Equipment

	2010			2009		
	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Land	**$ 4.9**	**$**	**$ 4.9**	$ 5.0	$	$ 5.0
Plant and equipment	**1,439.2**	**455.3**	**983.9**	1,421.6	399.0	1,022.6
Other equipment	**10.1**	**9.3**	**0.8**	11.0	8.7	2.3
Construction in progress	**4.5**		**4.5**	34.8		34.8
	$ 1,458.7	**$ 464.6**	**$ 994.1**	$ 1,472.4	$ 407.7	$ 1,064.7

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5. Property, Plant and Equipment (Continued)

	2008 Cost	2008 Accumulated Depreciation	2008 Net Book Value
Land	$ 3.3	$	$ 3.3
Plant and equipment	1,423.9	346.3	1,077.6
Other equipment	8.7	7.7	1.0
Construction in progress	24.1		24.1
	$ 1,460.0	$ 354.0	$ 1,106.0

Depreciation, amortization and accretion expense consists of:

	2010	2009	2008
Depreciation of property, plant and equipment	**$ 69.6**	$ 65.0	$ 55.9
Accretion of asset retirement obligations	**2.9**	1.9	1.6
Amortization of PPAs	**25.4**	27.8	31.4
Other amortization	**0.4**	(1.4)	(0.6)
	$ 98.3	$ 93.3	$ 88.3

Note 6. Power Purchase Arrangements

	2010			2009			2008		
	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
PPAs	**$ 440.9**	**$ 150.9**	**$ 290.0**	$ 462.8	$ 132.4	$ 330.4	$ 530.0	$ 121.4	$ 408.6

The PPAs are being amortized over the remaining terms of the contracts, which range from four months to seventeen years.

Note 7. Goodwill

The changes in the carrying value of goodwill are as follows:

	2010	2009	2008
Goodwill, beginning of year	**$ 47.6**	$ 55.1	$ 50.9
Foreign currency translation adjustment	**(2.6)**	(7.5)	4.2
Goodwill, end of year	**$ 45.0**	$ 47.6	$ 55.1

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8. Other Assets

	2010	2009	2008
Net investment in lease	**$ 23.7**	$ 26.9	$ 33.2
Other long-term receivable	**17.6**		
Long-term investments	**20.3**	21.4	19.2
Receivable from Equistar		9.1	9.6
Other intangible assets:			
Cost	**1.4**	1.2	2.5
Accumulated amortization	**(0.2)**	(0.1)	(0.1)
	$ 62.8	$ 58.5	$ 64.4

Net Investment in Lease

The PPA under which the power generation facility located in Oxnard, California operates is considered to be a direct financing lease for accounting. The PPA expires in 2020. The current portion of the net investment in lease of $1.5 million is included in accounts receivable (2009 $1.6 million; 2008 $1.8 million). Financing income for the year ended December 31, 2010 of $2.5 million is included in revenues (2009 $2.9 million; 2008 $2.8 million).

Other Long-term Receivable

Other long-term receivable relates to amounts recoverable over the remaining term of the Oxnard PPA for unbilled services.

Long-term Investment and Asset Impairment Charge

The Partnership's common ownership interest in Primary Energy Recycling Holdings LLC (PERH) was accounted for on the equity basis up to August 24, 2009 and on a cost basis thereafter as a result of a recapitalization of PERH and changes to the management agreement between the Partnership, PERH, Primary Energy Recycling Corporation (PERC) and Primary Energy Operations LLC. The Partnership has converted all of its common and preferred interests in PERH to a 14.3% common equity interest in PERH in connection with a recapitalization of PERH pursuant to which all previously outstanding common and preferred interests in PERH, including those held by the Partnership and PERC, were converted to new common equity interests. No gain or loss was recorded on the conversion.

In November 2009, the Partnership exercised its pre-emptive right to maintain its pro-rata interest (14.3%) in PERH whereby the Partnership subscribed for new common equity interests at an aggregate subscription price of $8.8 million (US$8.3 million).

The Partnership recorded a pre-tax impairment charge of $24.1 million during the year ended December 21, 2008 to write down the investment based on its fair value.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9. Long-term Debt

	Effective interest rate	2010	2009	2008
Senior unsecured notes, due June 2036 at 5.95%	**6.12%**	**210.0**	$ 210.0	$ 210.0
Senior unsecured notes (US$190.0 million), due July 2014 at 5.90%	**6.16%**	**189.0**	199.7	231.4
Senior unsecured notes (US$150.0 million), due August 2017 at 5.87%	**6.01%**	**149.2**	157.6	182.7
Senior unsecured notes (US$75.0 million), due August 2019 at 5.97%	**6.11%**	**74.6**	78.8	91.4
Secured term loan at 11.25%	**11.57%**		1.4	2.6
Revolving credit facilities at floating rates	**2.85%**	**86.1**	78.3	86.7
		708.9	725.8	804.8
Less: Current portion of long-term debt			1.4	1.3
Deferred debt issue costs		**4.4**	5.0	5.0
		$ 704.5	$ 719.4	$ 798.5

Senior Unsecured Notes

The notes are unsecured obligations of the Partnership and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Partnership. Interest on the senior unsecured notes is payable semi-annually.

Revolving Credit Facilities

The Partnership has available to it unsecured two-year credit facilities of $100.0 million, $100.0 million and $125.0 million, for a total of $325.0 million, committed to 2012 and uncommitted amounts of $20.0 million and $20.0 million (US$20.0 million). At December 31, 2010, $86.1 million was drawn against these facilities (December 31, 2009 $78.3 million; December 31, 2008 $86.7 million).

Under the terms of the extendible facilities, the Partnership may obtain advances by way of prime loans, US base rate loans, US LIBOR loans and bankers' acceptances. Depending on the facility, amounts drawn by way of prime loans bear interest at the prevailing Canadian prime rate or the average one-month bankers' acceptance rate plus a spread based on the Partnership's credit rating. Amounts drawn by way of US LIBOR loans bear interest at the prevailing LIBOR rate plus a spread based on the Partnership's credit rating. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread based on the Partnership's credit rating. The Partnership's revolving credit facilities may be used for general partnership purposes including working capital support.

Deferred Debt Issue Costs

At December 31, 2010 deferred debt issue costs were $7.3 million, net of accumulated amortization of $2.9 million (December 31, 2009 deferred debt issue costs were $6.8 million, net of accumulated amortization of $1.8 million; December 31, 2008 deferred debt issue costs were $6.4 million, net of accumulated amortization of $1.4 million).

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 9. Long-term Debt (Continued)

Financial Charges and Other, Net

	2010	2009	2008
Interest on long-term debt	**$ 39.0**	$ 42.6	$ 40.3
Foreign exchange losses	**0.3**	1.0	26.2
Interest on Equistar receivable	**(1.8)**		
Losses from equity investment		3.1	6.3
Dividend income		(1.1)	(1.9)
Other	**2.6**	0.8	(0.2)
	$ 40.1	$ 46.4	$ 70.7

Note 10. Other Liabilities

	2010	2009	2008
Asset retirement obligations	**$ 29.3**	$ 28.8	$ 28.6
Deferred revenue	**6.5**	4.5	
Other long-term liabilities	**1.3**	1.5	4.7
	$ 37.1	$ 34.8	$ 33.3

Asset Retirement Obligations

	2010	2009	2008
Asset retirement obligations, beginning of year	**$ 28.8**	$ 28.6	$ 21.1
Adjustment to asset retirement obligations	**(1.5)**		
Assumption of Morris asset retirement obligations			5.9
Accretion of asset retirement obligations	**2.9**	1.9	1.6
Foreign currency translation adjustment	**(0.9)**	(1.7)	
Asset retirement obligations, end of year	**$ 29.3**	$ 28.8	$ 28.6

At December 31, 2010, the estimated cost to settle the Partnership's asset retirement obligations was $129.4 million (2009 $146.0 million; 2008 $156.9 million) calculated using inflation rates ranging from 2.0% to 3.0% per annum (2009 2.1% to 3.0%; 2008 3.0%). The estimated cash flows were discounted at rates ranging from 6.4% to 7.5% (2009 6.4% to 7.5%; 2008 6.4%-7.5%). At December 31, 2010, the expected timing of payment for settlement of the obligations ranges from 9 to 80 years.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11. Preferred Shares Issued by a Subsidiary Company

In November 2009, a subsidiary of the Partnership issued 4 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) priced at $25.00 per share. The Series 2 Shares pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by the Partnership on December 31, 2014 and on December 31 every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of the Partnership, subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the Partnership, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%.

A subsidiary of the Partnership has issued 5 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. On or after June 30, 2012, the shares are redeemable by the subsidiary company at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders. Under the terms of the preferred share issue, the Partnership will not make any distributions on partnership units if the declaration or payment of dividends on the preferred shares is in arrears.

Dividends will not be paid on the preferred shares if the senior unsecured notes of the Partnership are in default.

The Partnership paid dividends of $13.1 million in 2010 (2009 $7.2 million; 2008 $6.1 million) and incurred associated net current and future income taxes of $1.0 million (2009 $0.7 million; 2008 $0.5 million) for an after-tax preferred share dividend of $14.1 million (2009 $7.9 million; 2008 $6.6 million).

Note 12. Partners' Capital

	2010		2009	
	Number of Units	Millions of Dollars	Number of Units	Millions of Dollars
Partnership capital, beginning of year	**54,153,871**	**$ 1,200.6**	53,897,279	$ 1,197.1
Partnership units issued pursuant to distribution reinvestment plan	**1,670,657**	**27.0**	256,592	3.5
Partnership capital, end of year	**55,824,528**	**$ 1,227.6**	54,153,871	$ 1,200.6

	2008	
	Number of Units	Millions of Dollars
Partnership capital, beginning and end of year	53,897,279	$ 1,197.1

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 12. Partners' Capital (Continued)

The Partnership is authorized to issue an unlimited number of limited partnership units. Each unit represents an equal, undivided limited partnership interest in the Partnership and entitles the holder to participate equally in distributable cash and net income. Units are not subject to future calls or assessments and entitle the holder to limited liability. Each unit is transferable, subject to the requirements referred to in the Partnership Agreement.

In October 2009, the Partnership implemented a Premium Distribution (Premium Distribution is a trademark of Canaccord Capital Corporation) and Distribution Reinvestment Plan (the Plan) that provides eligible unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional units in the Partnership by reinvesting cash distributions in additional units issued at a 5% discount to the Average Market Price of such units (as defined in the Plan) on the applicable distribution payment date. Alternatively, under the Premium Distribution™ component of the Plan, eligible unitholders may elect to exchange these additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

In 2010, the weighted average number of units outstanding was 54,968,742 (2009 53,914,046; 2008 53,897,279).

Note 13. Accumulated Other Comprehensive Income

The components of accumulated other comprehensive income are as follows:

	2010	2009	2008
Cumulative unrealized losses on translating net assets of self-sustaining foreign operations	**$ (159.3)**	$ (131.9)	$ (66.0)
Deferred gains on derivatives de-designated as cash flow hedges	**0.4**	0.9	1.3
Unrealized losses on derivative instruments designated as cash flow hedges	**(50.9)**	(6.4)	
Total accumulated other comprehensive income	**$ (209.8)**	$ (137.4)	$ (64.7)

Note 14. Income Taxes

Components of income tax recovery	2010	2009	2008
Current income taxes	**$ 0.4**	$ 1.3	$ 1.7
Future income taxes	**(9.8)**	(10.2)	(33.1)
	$ (9.4)	$ (8.9)	$ (31.4)

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 14. Income Taxes (Continued)

Reconciliation of Income Tax Recovery

	2010	2009	2008
Net income (loss) from continuing operations before income taxes and preferred share dividends	**$ 35.2**	$ 56.8	$ (91.9)
Combined federal and provincial tax rate	**29.0%**	31.0%	31.5%
Expected income tax expense (recovery)	**10.2**	17.6	(28.9)
Amounts related to (non-taxable) non-deductible foreign exchange and other permanent differences	**(9.9)**	(6.7)	2.7
Changes in valuation allowance	**(0.1)**	(4.5)	12.7
Change due to enactment of rate changes	**0.5**	0.7	
Income allocated to Partnership unitholders	**(7.5)**	0.1	(15.8)
Taxes related to prior periods	**1.3**	(9.9)	
Statutory and other rate differences	**1.4**	(9.6)	6.4
Other	**(5.3)**	3.4	(8.5)
Actual income tax recovery	**$ (9.4)**	$ (8.9)	$ (31.4)

Future Income Tax Assets and Liabilities

	2010	2009	2008
Loss carryforwards	**$ 87.1**	$ 75.4	$ 53.9
Difference in accounting and tax basis of intangible assets	**2.7**	4.5	6.7
Asset retirement obligations	**5.7**	4.1	3.9
Deferred financing charges	**3.5**	2.4	1.8
Non-deductible accrued amounts	**1.7**	1.8	2.1
Unrealized losses on derivative instruments	**16.0**	0.8	5.1
Deferred revenue	**2.9**	1.7	
Long-term receivable		0.8	1.0
Other			0.9
Future income tax assets	**$ 119.6**	$ 91.5	$ 75.4
Difference in accounting and tax basis of plant, equipment and PPAs	**$ (109.2)**	$ (114.5)	$ (115.4)
Unrealized foreign exchange gains	**(4.9)**	(4.3)	(1.6)
Long-term receivable	**(7.0)**		
Other	**(0.9)**	(2.3)	
Future income tax liabilities	**$ (122.0)**	$ (121.1)	$ (117.0)
Net future income tax liabilities	**$ (2.4)**	$ (29.6)	$ (41.6)

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 14. Income Taxes (Continued)

Presented on the Balance Sheet as Follows:

	2010	2009	2008
Current assets	**$ 7.1**	$ 1.9	$ 2.3
Non-current assets	**41.2**	35.0	16.8
Current liabilities		(3.8)	
Non-current liabilities	**(50.7)**	(62.7)	(60.7)
	$ (2.4)	$ (29.6)	$ (41.6)

Income Taxes

The Partnership follows the liability method of accounting for income taxes, whereby income taxes are recognized on differences between the financial statement carrying values and the respective income tax basis of assets and liabilities. Future income tax assets and liabilities are measured using the substantively enacted tax rates and laws that will be effect when the temporary differences are expected to be recovered or settled. To the extent that the realization of a future tax asset is not considered 'more likely than not,' a valuation allowance is provided.

Taxation of Flow-through Entities

Pursuant to the Income Tax Act (Canada), beginning on January 1, 2011, the Partnership will be subject to a specified investment flow-through (SIFT) distribution tax of 16.5% (15% beginning in 2012) along with a provincial tax component of 10%. The tax rates are equivalent to the substantially enacted corporate income tax rates, but apply to distributions of certain types of income. As the partnership generates cash flows from both Canada and the United States, only the cash flows generated in Canada would be subject to the SIFT tax. Cash flows generated in the United States are exempt from the SIFT tax as they are subject to United States taxation. The Partnership expects that its distributions will be treated as eligible dividends starting on January 1, 2011.

The net future income tax liability relating to the SIFT legislation decreased $17.0 million to $45.7 million in 2010 (2009 $62.7 million; 2008 $60.7 million) due a reduction in the net taxable temporary differences which are expected to reverse subsequent to 2010. This estimate of the net future tax liability is based on the current best estimate of the accounting and tax values that exist on December 31, 2010. The Partnership and its Canadian subsidiary limited partnerships have net taxable temporary differences of $185.8 million (2009 $245.7 million, 2008 $309.1 million) of which the tax effects of $184.0 million (2009 $250.5 million, 2008 $230.5 million) are reflected in these consolidated financial statements due to the enactment of the SIFT legislation in 2007.

Taxation of Corporate Subsidiaries

Current and future taxes have been reflected in respect of taxable income and temporary differences relating to the corporate subsidiaries of the Partnership. The Canadian corporate subsidiaries of the Partnership are subject to tax on their taxable income at a rate of approximately 29% (2009 31.0%; 2008 31.5%) whereas the U.S. corporate subsidiaries are subject to tax on their taxable income at rates varying from 34% to 41% (2009 34.0% to 41.0%; 2008 34.0%-41.0%). Future income taxes relating to the corporate subsidiaries have been reflected in these consolidated

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 14. Income Taxes (Continued)

financial statements except in respect of deductible temporary differences of $4.4 million (2009 $4.4 million; 2008 $54.9 million) for which no tax benefit has been recognized.

Income Tax Loss Carry Forwards

As at December 31, 2010, the Partnership has income tax loss carry forwards of approximately US $151.4 million (2009 US$128.9 million, 2008 US$84.8 million) in the US, which may be used to reduce future US taxable income. Of these losses, US$22.3 million (2009 US$22.3 million; 2008 US$22.3 million) expire between 2022 and 2025 with the remainder expiring thereafter and $18.1 million (2009 US$18.1 million; 2008 US$22.3 million) of the losses are restricted under Section 382 of the Internal Revenue Code. Under Section 382 of the Internal Revenue Code of 1986, as amended, the utilization of the restricted losses is limited to an annual amount of US$4.7 million.

As at December 31, 2010, the Partnership has both non-capital losses and capital losses that are available for carry forward in Canada. For Canadian income tax purposes, there are non-capital loss carry forwards of approximately $120.7 million (2009 $96.7 million; 2008 $56.3 million), which may be used to reduce future income taxes otherwise payable and which expire in the years 2011 to 2030. There are also capital loss carry forwards of $3.5 million (2009 $3.5 million; 2008 $14.9 million) which can be carried forward indefinitely. The tax benefit on $0.3 million (2009 $0.2 million; 2008 $0.1 million) of the non-capital losses carry forwards and on $3.5 million (2009 $3.5 million; 2008 $14.9 million) of the capital loss carry forwards have been fully offset by the recognition of a valuation allowance.

Out of Period Adjustment

During the year ended December 31, 2009, the Partnership recorded an out-of-period adjustment of $9.7 million relating to 2007 and 2008 in order to recognize net future income tax assets associated with the Partnership's interest in PERH. Management determined that the impact of the adjustment was not material, either individually or in aggregate, to any of the prior periods' financial statements and accordingly, that a restatement of previously issued financial statements was not necessary.

Note 15. Financial Instruments

Fair Values and Classification of Financial Assets and Liabilities

The Partnership classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables and accounts payable and distributions payable are classified as other financial liabilities and are measured at amortized cost. The fair values of accounts receivable, accounts payable and distributions payable are not materially different from their carrying amounts due to their short-term nature. The investment in PERH is classified as available for sale and the net investment in lease is classified as loans and receivables. The net investment in lease and other long-term receivable relates to the Oxnard PPA, which is considered a direct financing lease for accounting purposes.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15. Financial Instruments (Continued)

The classification, carrying amounts and fair values of the Partnership's other financial instruments are summarized as follows:

	2010			
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets net investment in lease and other long-term receivable	**$ 41.3**	**$**	**$ 41.3**	**$ 42.4**
Long-term debt (including current portion)		**(704.5)**	**(704.5)**	**(697.7)**

	2009			
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets net investment in lease and other long-term receivable	$ 26.9	$	$ 26.9	$ 27.1
Other assets receivable from Equistar	9.1		9.1	$ 9.1
Long-term debt (including current portion)		(720.8)	(720.8)	(667.7)

	2008			
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets net investment in lease and other long-term receivable	$ 33.2	$	$ 33.2	$ 33.1
Other assets receivable from Equistar	9.6		9.6	$ 9.6
Long-term debt (including current portion)		(799.8)	(799.8)	(685.9)

The fair value of the Partnership's long-term debt is based on determining an appropriate yield for the Partnership's debt as at December 31, 2010, 2009 and 2008. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Partnership's debt. The estimated credit spread is based on the Partnership's indicative spread as published by independent financial institutions.

The Partnership has used the carrying amount of its investment in PERH as its fair value as the shares are not quoted in an active market and their fair value therefore cannot be measured reliably.

The fair value of the Partnership's net investment in the financing lease and related long-term receivables is based on the estimated interest rate implicit in a comparable lease arrangement as at December 31, 2010, 2009 and 2008.

Derivative Instruments

Derivative instruments are held to manage financial risk related to energy procurement and treasury management. All derivative instruments, including embedded derivatives, are classified as held

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15. Financial Instruments (Continued)

for trading and are recorded at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase, sale or usage. All changes in their fair value are recorded in net income.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	December 31, 2010			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	**$**	**$**	**$ 10.4**	**$ 10.4**
Non-current			**29.7**	**29.7**
Derivative instruments liabilities:				
Current	**(16.2)**	**(3.0)**	**(1.9)**	**(21.1)**
Non-current	**(76.9)**		**(5.0)**	**(81.9)**
	$ (93.1)	**$ (3.0)**	**$ 33.2**	**$ (62.9)**
Net notional amounts:				
Gigajoules (GJs) (millions)	**37.8**	**6.5**		
U.S. foreign exchange (U.S. dollars in millions)			**309**	
Contract terms (years)	**6.0**	**0.8 to 2.0**	**0.2 to 5.5**	

	December 31, 2009			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 1.0	$ 2.5	$ 4.3	$ 7.8
Non-current		6.0	25.8	31.8
Derivative instruments liabilities:				
Current	(2.1)		(0.8)	(2.9)
Non-current	(32.8)		(3.6)	(36.4)
	$ (33.9)	$ 8.5	$ 25.7	$ 0.3
Net notional amounts:				
Gigajoules (GJs) (millions)	45.0	11.0		
U.S. foreign exchange (U.S. dollars in millions)			395	
Contract terms (years)	1.0 to 7.0	0.0 to 3.0	0.2 to 6.0	

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15. Financial Instruments (Continued)

	December 31, 2008			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$	$ 15.5	$ 7.3	$ 22.8
Non-current		23.5	3.6	27.1
Derivative instruments liabilities:				
Current		(1.5)	(11.5)	(13.0)
Non-current		(0.6)	(37.9)	(38.5)
	$	$ 36.9	$ (38.5)	$ (1.6)
Net notional amounts:				
Gigajoules (GJs) (millions)		69.0		
U.S. foreign exchange (U.S. dollars in millions)			456.9	
Contract terms (years)		0.1 to 8.0	0.2 to 6.0	

The fair value of derivative instruments are determined, where possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask, or closing market prices, as appropriate in active markets. Where there are limited observable prices due to illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling commonly used by market participants to estimate fair value. Fair value determined using valuation models requires the use of assumptions concerning the amount and timing of future cash flows. In general, fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility for all of the Partnership's financial instruments. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Unrealized and realized pre-tax gains and (losses) on derivative instruments recognized in net income and other comprehensive income were:

	Income statement category	2010	2009	2008
Foreign exchange non-hedges	Revenue	**$ 12.4**	$ 59.8	$ (57.6)
Natural gas non-hedges	Cost of fuel	**(9.3)**	(52.1)	(30.4)
Natural gas hedges ineffective portion	Cost of fuel	**(2.2)**	(0.3)	
Natural gas hedges effective portion	Other comprehensive loss	**(59.1)**	(8.9)	

If hedge accounting requirements are not met, unrealized and realized gains and losses on natural gas derivatives are recorded in cost of fuel. If hedge accounting requirements are met, realized gains and losses on natural gas derivatives are recorded in cost of fuel while unrealized gains and losses are recorded in other comprehensive income.

The Partnership has elected to apply hedge accounting effective July 31, 2009, on certain derivative instruments it uses to manage commodity price risk relating to natural gas prices. For the year ended December 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was $2.2 million. Of the $50.9 million of after tax losses related to derivative instruments designated as cash-flow hedges included in accumulated other

CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15. Financial Instruments (Continued)

comprehensive income at December 31, 2010, losses of $8.8 million, net of income taxes of $3.2 million are expected to settle and be reclassified to net income during the year ended December 31, 2011. The Partnership's cash flow hedges extend up to 2016.

Fair Value Hierarchy

Fair value represents the Partnership's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated balance sheets are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs, and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Financial instruments classified in Level 1 include cash and cash equivalents, including highly liquid short term investments.

Level 2: Fair value is based on other than unadjusted quoted prices included in Level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those financial instruments that are valued using commonly used valuation techniques, such as the discounted cash flow model or black-scholes option pricing models. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument. Financial instruments classified in Level 2 includes commodity, foreign exchange, and interest rate derivatives whose values are determined based on broker quotes, observable trading activity for similar, but not identical instruments, and prices published on information platforms and exchanges.

Level 3: Fair value is based unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes financial instruments that are also valued using commonly used valuation techniques described in Level 2, however some inputs used in the models may not be based on observable market data and therefore based on the Partnership's best estimate from the perspective of a market participant. There are no financial instruments classified in Level 3 at the reporting date.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Partnership's assessment of the significance of a particular input to the fair value measurement requires judgment thereby affecting the placement within the fair value hierarchy levels. The following table presents the Partnership's financial instruments measured at fair value on a

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 15. Financial Instruments (Continued)

recurring basis in the consolidated balance sheets, classified using the fair value hierarchy described above:

	Level 1	Level 2	Level 3	Total
Financial assets:				
Cash	**$ 27.5**	**$**	**$**	**$ 27.5**
Derivative instrument assets:				
Foreign exchange non-hedges		**40.1**		**40.1**
Derivative instrument liabilities:				
Natural gas hedges		**(93.1)**		**(93.1)**
Natural gas non-hedges		**(3.0)**		**(3.0)**
Foreign exchange non-hedges		**(6.9)**		**(6.9)**

There were no significant transfers between Level 1 and 2 for the period ended December 31, 2010.

Note 16. Changes in Non-cash Working Capital

	2010	2009	2008
Accounts receivable	**$ 8.4**	$ 8.5	$ 10.5
Inventories	**(14.7)**	(1.2)	(4.7)
Accounts payable	**(1.1)**	(16.7)	8.9
Other	**0.1**	1.1	(1.4)
	$ (7.3)	$ (8.3)	$ 13.3

Note 17. Risk Management

Risk Management Overview

The Partnership is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments which include market, interest, credit and liquidity risks. The Partnership's overall risk management process is designed to identify, manage and mitigate business risk which includes financial risk, among others. Financial risk is managed according to objectives, targets and policies set forth by the Board of Directors. Risk management strategies, policies and limits are designed to ensure the risk exposures are managed within the Partnership's business objectives and risk tolerance. The Partnership's risk management objective is to protect and minimize volatility in cash provided by operating activities and distributions therefrom.

Market Risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and composition of the Partnership's financial assets and liabilities held, non-trading physical assets and contract portfolios. Commodity price risk management and the associated credit risk management are carried out in accordance with Partnership's financial risk management policies, as approved by the Board of Directors.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17. Risk Management (Continued)

To manage the exposure related to changes in market risk, the Partnership uses various risk management techniques including the use of derivative instruments. Derivative instruments may include financial and physical forward contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Market risk exposures are monitored regularly against approved risk limits and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Partnership's actual exposure to market risks is constantly changing as the Partnership's portfolio of debt, foreign currency and commodity contracts change. Changes in fair value based on market variable fluctuations cannot be extrapolated as the relationship between the change in the market variable and the change in fair value may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Partnership.

Commodity price risk

The Partnership is exposed to commodity price risk as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and coal. The Partnership actively manages commodity price risk by optimizing its asset and contract portfolios in the following manner:

- The Partnership commits substantially all of its power supply to long-term fixed price PPAs which limits the exposure to electricity prices;

- The Partnership purchases natural gas under long-term fixed price supply contracts to reduce the exposure to natural gas prices on certain of its natural gas fired generation plants; and

- The Partnership has entered into certain PPAs whereby the counterparty bears the variable costs linked to the price of natural gas or coal.

The following represents the sensitivity of net income to derivative instruments that are accounted for on a fair value basis. As at December 31, 2010, with all other variables unchanged, a $1.00/GJ increase (decrease) of the natural gas price is estimated to increase (decrease) net income by approximately $4 million after tax and other comprehensive income by approximately $24 million after tax. This assumption is based on the volumes or position held at December 31, 2010.

Foreign exchange risk

The Partnership is exposed to foreign exchange risk on its net investment in self-sustaining foreign operations. The risk is that the Canadian dollar value of the U.S. dollar net investment in self-sustaining foreign operations will vary as a result of the movements in exchange rates.

The Partnership's foreign exchange management policy is to manage economic and material transactional exposures arising from movements in the Canadian dollar against the U.S. dollar. The Partnership's foreign currency exposure arises from anticipated U.S. dollar denominated cash flows from its U.S. operations and from debt service obligations on U.S. dollar borrowings. The Partnership

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17. Risk Management (Continued)

coordinates and manages foreign currency risk through the General Partner's central Treasury function. Foreign exchange risk is managed by considering naturally occurring opposite movements wherever possible and then managing any material residual foreign currency exchange risks according to the policies approved by the Board of Directors.

The Partnership primarily uses foreign currency forward contracts to fix the Canadian currency equivalent of its U.S. currency expected cash flows thereby reducing its anticipated U.S. denominated transactional exposure. The Partnership's foreign currency risk management practice is to ensure a majority of the net currency exposure on anticipated transactions within 7 years are economically hedged. At December 31, 2010, US$308.9 million of future anticipated net cash flows from its U.S. plants were economically hedged for 2011 to 2016 at a weighted average rate of $1.13 per US $1.00.

At December 31, 2010, holding all other variables constant, a $0.10 strengthening (weakening) of the Canadian dollar against the U.S. dollar would increase (decrease) net income by approximately $19 million after tax as a result of changes in the fair value of foreign exchange contracts.

This sensitivity analysis excludes translation risk associated with the application of the current rate and temporal translation methods, financial instruments that are non-monetary items, and financial instruments denominated in the functional currency in which they are transacted and measured.

Interest rate risk

The Partnership is exposed to changes in interest rates on its cash and cash equivalents and floating rate short-term and long-term obligations. The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At December 31, 2010 the Partnership held $86.1 million in floating rate debt (December 31, 2009 $78.3 million; December 31, 2008 $86.7 million). The Partnership may also use derivative instruments to manage interest rate risk. At December 31, 2010, 2009 and 2008 the Partnership did not hold any interest rate derivative instruments.

Holding all other variables constant and assuming that the amount and mix of floating rate debt remains unchanged from that held at December 31, 2010, a 100 basis point change to interest rates would have a $0.9 million impact on net income and would have no impact on other comprehensive income.

Credit Risk

The electricity and steam generated at the Partnership's facilities are sold under long-term contracts to 23 customers. Customers accounting for 10% or more of the Partnership's revenue in 2010 were as follows:

	2010	2009	2008
Ontario Electricity Financial Corporation	**26%**	23%	26%
San Diego Gas & Electric Company	**11%**	10%	18%
British Columbia Hydro and Power Authority	**11%**	10%	11%

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17. Risk Management (Continued)

The Partnership has exposure to credit risk associated with counterparty default under the Partnership's PPAs, fuel supply agreements and foreign currency hedges. In the event of a default by a counterparty, existing PPAs may not be replaceable on similar terms as pricing in many of these agreements is favourable relative to their current markets. Credit risk is associated with the ability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. Credit risk is managed by making appropriate credit assessments of counterparties on an ongoing basis, dealing primarily with creditworthy counterparties, diversifying the risk by using several counterparties and where appropriate and contractually allowed, requiring the counterparty to provide appropriate security.

Maximum credit risk exposure

The Partnership has the following financial assets that are exposed to credit risk:

	2010		
	Canada	U.S.	Total
Trade receivables	$ 21.1	$ 31.4	$ 52.5
Other assets net investment in lease and other long-term receivable		41.3	41.3
Derivative instruments current assets	10.4		10.4
Derivative instruments non-current assets	29.7		29.7
	$ 61.2	$ 72.7	$ 133.9

The maximum credit exposure of these assets is their carrying amount. No amounts were held as collateral at December 31, 2010.

Accounts receivable

Accounts receivable consist primarily of amounts due from customers including industrial and commercial customers, government-owned or sponsored entities, regulated public utility distributors and other counterparties. The Partnership historically has not experienced credit losses and accordingly has not provided for an allowance for doubtful accounts. The Partnership evaluates the need for an allowance for potential credit losses by reviewing any overdue accounts and monitoring changes in the credit profiles of counterparties. The Partnership manages its credit risk exposures by dealing with creditworthy counterparties and, where appropriate and contractually allowed, taking back appropriate security from the counterparty. The Partnership determines the creditworthiness of counterparties using its own assessments and credit ratings by Standard and Poor's (S&P) and DBRS Limited (DBRS) if available.

No material accounts receivable were past due and there was no provision for credit losses associated with these receivables and financial derivative instruments as all balances are considered to be fully recoverable. Accounts receivable are mostly from counterparties with an investment grade rating assigned by S&P.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 17. Risk Management (Continued)

Liquidity Risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they come due. The Partnership's liquidity is managed centrally through the General Partner's Treasury function. The Partnership manages liquidity through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities and access to capital markets.

As at December 31, 2010, the Partnership had available bank credit facilities of $238.8 million committed to 2012 as discussed in Note 11 Long-term debt. In addition, the Partnership has a Canadian shelf prospectus under which it may raise up to $600.0 million in partnership units or debt securities. The Canadian shelf prospectus expires in August 2012.

The Partnership has a long-term debt rating of BBB/stable and BBB(high)/under review (negative), assigned by S&P and DBRS respectively.

The following are the undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments as at December 31, 2010:

	Within 1 year	Between 1 & 2 years	Between 2 & 3 years	Between 3 & 4 years	Between 4 & 5 years	Beyond 5 years	Total
Non-derivative financial liabilities:							
Long-term debt(1)	$	$ 86.1	$	$ 189.0	$	$ 433.8	$ 708.9
Interest payments on long-term debt	39.5	39.1	36.9	32.2	25.7	291.5	464.9
Accounts payable and accrued liabilities(2)	36.5						36.5
Distributions payable	8.2						8.2
Derivative financial liabilities:							
Net forward exchange contracts	$ 1.9	$ 2.2	$ 1.4	$ 0.9	$ 0.9	$	$ 7.3
Total	$ 86.1	$ 127.4	$ 38.3	$ 222.1	$ 26.6	$ 725.3	$ 1,225.8

(1) Excluding deferred debt issue costs of $4.4 million.

(2) Excluding interest on long-term debt of $10.5 million and non-cash accruals of $5.9 million.

Note 18. Capital Management

The Partnership's primary objectives when managing capital are to safeguard the Partnership's ability to continue as a going concern, provide stable distributions to unitholders, to maintain an investment grade credit rating and to facilitate the acquisition or development of power projects in Canada and the U.S. consistent with the growth strategy of the Partnership. The Partnership's objective of maintaining an investment grade credit rating is subject to change in order to manage the Partnership's growth strategy with changing economic circumstances. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. This

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 18. Capital Management (Continued)

overall objective and policy for managing capital remained unchanged in 2010 from the prior comparative period.

The Partnership considers its capital structure to consist of long-term debt, preferred shares and partners' equity. The following table represents the total capital of the Partnership:

	2010	2009	2008
Long-term debt (including current portion)	**$ 704.5**	$ 720.8	$ 799.8
Preferred shares	**219.7**	219.7	122.0
Partners' equity	**407.7**	519.5	632.3
Total capital	**$ 1,331.9**	$ 1,460.0	$ 1,554.1

The Partnership's credit and stability ratings are presented in the following table:

	2010	2009	2008
Credit rating			
S&P	BBB (stable)	BBB+/negative outlook	BBB+
DBRS	BBB(high)/under review (negative)	BBB(high)/negative trend	BBB(high)
Stability rating			
S&P	Not Rated	SR-2	SR-2
DBRS	STA-2 (low)	STA-2	STA-2

The Partnership has the following externally imposed requirements on its capital:

- The Partnership must maintain a debt to total capitalization ratio, as defined in the debt agreements, of not more than 65%; and

- In the event the Partnership is assigned both a rating of less than BBB+ by S&P and a rating of less than BBB(high) by DBRS, the Partnership also would be required to maintain a ratio of earnings before interest, income taxes, depreciation and amortization to interest expense of not less than 2.5 to 1.

At December 31, 2010, the Partnership's debt to capitalization ratio was 53% (December 31, 2009 49%; December 31, 2008 51%) and ratings of BBB/stable and BBB(high)/under review (negative) were assigned by S&P and DBRS respectively (December 31, 2009 BBB+/negative outlook and BBB(high)/negative trend; December 31, 2008 BBB+ and BBB(high)).

In order to manage its capital structure, the Partnership may adjust the amount of distributions paid to unitholders, issue or redeem preferred shares, issue or repay debt or issue or buy back partnership units.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19. Related Party Transactions

In operating the Partnership's 20 power plants, the Partnership and CPC (and prior to July 1, 2009, EPCOR) engage in a number of related party transactions which are in the normal course of business. These transactions are based on contracts and many of the fees are escalated by inflation. The table below summarizes the amounts included in the calculation of net income for the years ended December 31, 2010, 2009 & 2008.

	2010	2009	2008
Transactions with CPC(1)			
Revenue Frederickson duct firing capacity fees	**$ 0.1**	$ 0.1	$ 0.1
Cost of fuel Greeley natural gas swap contract	**1.5**	2.6	0.3
Operating and maintenance expense	**47.5**	50.5	45.1
Management and administration			
Base fee	**0.9**	1.1	1.4
Incentive fee			2.3
Enhancement fee	**0.1**	0.2	2.4
General and administrative costs	**8.4**	8.0	5.9
	9.4	9.3	12.0
Transactions of discontinued operations			
Cost of fuel gas demand charge		1.1	2.2
Operating and maintenance expense		1.4	2.9
Acquisition and divestiture fees		0.2	1.9
Distributions	**29.1**	32.2	41.6

(1) Prior to July 1, 2009, EPCOR.

Greeley Natural Gas Swap Contract

The Partnership has entered into a three year natural gas swap contract with CPC to cover most of the anticipated natural gas supply for Greeley.

Operating and Maintenance

CPC is entitled to receive a fee for services related to the operation and maintenance of the power plants under the Management and Operations Agreements. The annual fees are payable on an equal monthly basis. The annual fees for the Canadian plants and two U.S. plants are annually adjusted for inflation. The annual fees for the other U.S. plants are determined using a cost recovery basis.

Base and Incentive Fee

CPC is entitled to a base fee and an incentive fee under the Management and Operations Agreements in each fiscal year of the Partnership. The base fee is equal to 1% of the Partnership's annual cash distributions. The incentive fee is equal to 10% of annual distributable cash flow greater than $2.40 per unit. Annual distributable cash flow is defined as cash flow from operating activities before changes in non-cash operating working capital plus dividends from PERH less scheduled debt repayments and maintenance capital.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 19. Related Party Transactions (Continued)

Enhancement Fee

CPC can curtail operations of the Ontario power plants and re-sell contracted natural gas at market prices, rather than produce off-peak power at lower rates. CPC is entitled to receive an enhancement fee equivalent to 35% of the incremental profit.

General and Administrative Costs

CPC is entitled to a fee related to the salaries and wages for management and administration employees for the U.S. plants. The fee is payable monthly on a cost recovery basis. CPC is also entitled to receive a fee for Canadian support staff costs for public entity services required per the Management and Operations Agreements. The annual fee is payable on an equal monthly basis and is adjusted annually for changes in salary costs.

Acquisition and Divestiture Fees

CPC is entitled to acquisition and divestiture fees under the Transaction Fees and Costs Agreements. The fee is based on the transaction value of the acquisition or disposition.

Distributions

During the year ended December 31, 2010, the Partnership made cash distributions to CPC in the amount proportionate to its ownership interest. At December 31, 2010, CPC owned 29.6% of the Partnership's units (30.5% at December 31, 2009; at December 31, 2008 EPCOR owned 30.6% of the Partnership's units).

Note 20. Joint Venture

A financial summary of the Partnership's investments in the Fredericksen joint venture is as follows:

	2010	2009	2008
Current assets	**$ 1.8**	$ 4.9	$ 2.3
Long-term assets	**109.5**	120.3	145.3
Current liabilities	**0.7**	0.4	1.0
Long term liabilities	**0.5**	0.5	0.5
Revenues	**21.3**	23.3	23.0
Expenses	**12.9**	15.5	21.9
Net income	**8.4**	7.8	1.1
Cash provided by operating activities	**13.2**	13.3	8.1
Cash used in investing activities			
Cash used in financing activities	**(16.4)**	(10.2)	(8.4)

Note 21. Operating Leases

From the point of view of a lessor, the terms of the Manchief, Mamquam, Moresby Lake, Greeley and Kenilworth PPAs (2009 and 2008 Manchief, Mamquam, Moresby Lake, Greeley, Kenilworth, Southport and Roxboro PPAs) are operating leases. At December 31, 2010, the carrying amounts of the

CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 21. Operating Leases (Continued)

property, plant and equipment of these facilities was $247.7 million less accumulated depreciation of $46.7 million (2009 $359.7 million and $47.6 million respectively; 2008 $317.6 million and $39.6 million respectively). The Partnership's revenues for the year ended December 31, 2010 include $74.9 million with respect to the PPAs for these plants (2009 $116.2 million; 2008 $141.8 million).

Note 22. Segment Disclosures

The Partnership operates in one reportable business segment involved in the operation of independent power generation plants within British Columbia, Ontario and in the U.S. in California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington State.

Geographic Information

	2010			2009			2008		
	Canada	U.S.	Total	Canada	U.S.	Total	Canada	U.S.	Total
Revenue	**$ 217.6**	**$ 314.8**	**$ 532.4**	$ 263.8	$ 322.7	$ 586.5	$ 159.2	$ 340.1	$ 499.3

	As at December 31, 2010			As at December 31, 2009			As at December 31, 2008		
	Canada	U.S.	Total	Canada	U.S.	Total	Canada	U.S.	Total
Assets									
PP&E	**$ 502.2**	**$ 491.9**	**$ 994.1**	$ 534.5	$ 530.2	$ 1,064.7	$ 559.3	$ 546.7	$ 1,106.0
PPAs	**33.6**	**256.4**	**290.0**	36.6	293.8	330.4	39.7	368.9	408.6
Goodwill		**45.0**	**45.0**		47.6	47.6		55.1	55.1
Other assets		**62.8**	**62.8**		58.5	58.5		64.4	64.4
	$ 535.8	**$ 856.1**	**$ 1,391.9**	$ 571.1	$ 930.1	$ 1,501.2	$ 599.0	$ 1,035.1	$ 1,634.1

Note 23. Commitments

As of December 31, 2010 the Partnership's future purchase obligations were estimated as follows, based on existing contract terms and estimated inflation.

	2011	2012	2013	2014	2015	Later years	Total payments
Natural gas purchase contracts	$ 51.9	$ 53.7	$ 43.9	$ 47.2	$ 50.7	$ 53.6	$ 301.0
Natural gas transportation contracts	12.9	10.4	10.6	10.2	7.6	15.6	67.3
Operating and maintenance contracts	27.5	28.1	28.6	29.2	29.8	46.0	189.2

The North Bay, Kapuskasing and Nipigon plants operate under fixed long-term natural gas supply contracts and natural gas transportation contracts with built-in annual escalators. Expiry dates for the contracts vary with an average remaining contract life of six years as at December 31, 2010. The remaining fuel requirements, which account for approximately 2% of the power plants' fuel costs, are purchased at current market prices. Morris operates under a long-term natural gas transportation contract expiring in 2013.

The operating and maintenance contracts with the Manager are based on fixed fees escalated annually by inflation and have expiry terms of June 30, 2017.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 24. Morris Acquistion

On October 31, 2008, the Partnership acquired 100% of the equity interest in Morris Cogeneration LLC (Morris), a combined heat and power facility in Illinois. The total purchase price was $90.7 million including $88.4 million (US$73.4 million) in cash plus acquisition costs of approximately $2.3 million.

The financial results of Morris are included in the Partnership's consolidated statements of income and loss from the date of acquisition. The purchase price for the acquisition of Morris was allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

Current assets excluding cash and derivative instruments assets	$ 9.9
Derivative instruments assets current	0.7
Derivative instruments assets long term	2.9
Property, plant and equipment	87.2
Power purchase arrangements	2.1
Other assets	1.5
Current liabilities	(6.6)
Asset retirement obligations	(5.9)
Contract liabilities	(1.1)
Fair value of net assets acquired	$ 90.7
Consideration	
Cash	$ 88.4
Acquisition costs	2.3
	$ 90.7

Note 25. Discontinued Operations

The Partnership completed the sale of its Castleton facility (Castleton) on May 26, 2009. The disposition of Castleton resulted in proceeds of $11.9 million (US$10.7 million) less transaction costs of

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 25. Discontinued Operations (Continued)

$0.2 million (US$0.2 million) and a pre-tax accounting gain of $2.4 million. Revenues and expenses of Castleton were as follows:

	2009	2008
	(millions of dollars)	
Revenues	**$ 2.1**	$ 12.9
Expenses		
Cost of fuel	**2.1**	6.5
Operating and maintenance expense	**2.1**	4.4
Depreciation and amortization		3.7
Foreign exchange gains		(0.2)
Loss from operations	**(2.1)**	(1.5)
Gain on sale of Castleton	**2.4**	
Income (loss) before income tax	**0.3**	(1.5)
Income tax expense (recovery)	**0.5**	(0.8)
Loss from discontinued operations	**$ (0.2)**	$ (0.7)

The carrying amounts of the assets and liabilities of the discontinued operations at December 31, 2009 and December 31, 2008 were as follows:

	2009	2008
Assets of the discontinued operations		
Accounts receivable	$	$ 0.7
Inventories		1.0
Prepaids and other		0.6
Current assets of the discontinued operations		2.3
Property, plant and equipment		11.2
Future income taxes		0.8
Long-term assets of the discontinued operations		12.0
Total assets of the discontinued operations	$	$ 14.3
Liabilities of the discontinued operations		
Accounts payable	$	$ 1.2
Asset retirement obligations		2.1
Future income taxes		2.1
Long-term liabilities of the discontinued operations		4.2
Total liabilities of the discontinued operations	$	$ 5.4

Note 26. Comparative Figures

Certain comparative figures have been reclassified to conform to the current year's presentation. The Partnership made an immaterial adjustment to the 2009 financial statements to reflect the

CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 26. Comparative Figures (Continued)

reclassification of $5.2 million of costs from property, plant and equipment to inventory and to correspondingly decrease cash flow from operating activities and decrease cash flow used in investing activities. There was no impact to net earnings resulting from this adjustment.

Note 27. Canadian and U.S. Accounting Policy Differences

The consolidated financial statements of the Partnership have been prepared in accordance with Canadian GAAP which differs in some respects from U.S. GAAP. Differences in accounting principles as they pertain to the consolidated financial statements are immaterial except as described below.

The application of U.S. GAAP would have the following effect on income and comprehensive loss as reported for the years ended December 31, 2010 and 2009:

	2010	2009
Net income in accordance with Canadian GAAP	**$ 30.5**	$ 57.6
Preferred share dividends	**14.1**	7.9
Change in effective portion of hedging derivatives(a)	**3.9**	(2.1)
Net income in accordance with U.S. GAAP	**48.5**	63.4
Attributable to:		
Equity holders of the Partnership	**34.4**	55.5
Preferred share dividends of a subsidiary company	**14.1**	7.9
	$ 48.5	$ 63.4
Other comprehensive loss in accordance with Canadian GAAP	**$ (72.4)**	$ (72.7)
Change in effective portion of hedging derivatives(a)	**(3.9)**	2.1
Other comprehensive loss in accordance with U.S. GAAP	**$ (76.3)**	$ (70.6)
Attributable to:		
Equity holders of the Partnership	**(90.4)**	(78.5)
Preferred share dividends of a subsidiary company	**14.1**	7.9
	$ (76.3)	$ (70.6)
Net income per unit in accordance with U.S. GAAP basic and diluted	**$ 0.63**	$ 1.03

(a) Accounting standards under U.S. GAAP requires the measurement of hedge effectiveness incorporate the credit risk of the Partnership or its counterparty. Canadian GAAP does not have a similar requirement which results in changes in the effective portion of the hedging derivatives.

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CAPITAL POWER INCOME L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 27. Canadian and U.S. Accounting Policy Differences (Continued)

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported at December 31, 2010 and 2009:

	2010		2009	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets	**$ 121.0**	**$ 121.0**	$ 100.1	$ 100.1
Long-term assets(b)	**1,462.8**	**1,467.2**	1,568.0	1,573.0
Current liabilities	**82.2**	**82.2**	75.6	75.6
Long term liabilities(b)	**874.2**	**878.6**	853.3	858.3
Partners' equity and preferred shares(c)	**627.4**	**627.4**	739.2	739.2

(b) Under Canadian GAAP, deferred financing fees are presented in the consolidated balance sheet as a reduction of the debt balance, while under U.S. GAAP, deferred financing fees are presented as other assets.

(c) Under Canadian GAAP, the preferred shares issued by a subsidiary company are classified between liabilities and equity, while under U.S. GAAP, they are classified in equity attributed to non-controlling interests.

U.S. GAAP requires the Partnership's investment in a joint venture to be accounted for using the equity method. However, under an accommodation of the Securities and Exchange Commission, accounting for joint ventures needs not be reconciled from Canadian to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or partners' equity.

Under U.S. GAAP, no sub-total would be provided in the operating section of the consolidated statement of cash flows. As well, under U.S. GAAP, reconciliation in the consolidated statement of cash flows would commence with net income instead of income of continuing operation. However, there are no differences in the total operating, investing and financing cash flows.

Note 28. Subsequent Event

On June 20, 2011, the Partnership and Atlantic Power Corporation (Atlantic Power) jointly announced that they have entered into an arrangement agreement to which Atlantic Power would acquire, directly and indirectly, all of the outstanding limited partnership units of the Partnership for $19.40 per limited partnership unit, payable in cash or shares of Atlantic Power (the "Transaction"). The Transaction is expected to be completed in the fourth quarter of 2011, subject to customary approvals including unitholder and shareholder approvals

In connection with Atlantic Power's acquisition of the Partnership, the Partnership will sell Roxboro and Southport to an affiliate of CPC. The Transaction values the Southport and Roxboro at approximately $121 million. This Transaction will have the effect of reducing the number of Partnership units outstanding by approximately 6.2 million units.

Additionally, in connection with the Transaction, the management agreement between CPC and the Partnership will be terminated (or assigned to Atlantic Power). Atlantic Power will assume the management of the Partnership.

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Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF INCOME (LOSS)

	Three months ended September 30		Nine months ended September 30	
(unaudited)	**2011**	**2010**	**2011**	**2010**
(In millions of Canadian dollars except units and per unit amounts)				
Revenues	**$ 116.2**	$ 140.7	**$ 377.7**	$ 382.2
Cost of fuel	**58.0**	57.8	**167.5**	174.7
Operating and maintenance expense	**26.3**	24.9	**78.7**	71.7
	31.9	58.0	**131.5**	135.8
Other costs (income)				
Depreciation	**20.9**	26.2	**66.4**	74.1
Impairments		46.8		46.8
Administrative and other expenses	**6.8**	5.3	**20.6**	10.9
Finance costs (Note 4)	**10.8**	11.2	**32.3**	32.6
Finance income				(1.8)
Income (loss) before income tax	**(6.6)**	(31.5)	**12.2**	(26.8)
Income tax recovery	**(3.1)**	(8.1)	**(1.9)**	(19.0)
Net income (loss)	**$ (3.5)**	$ (23.4)	**$ 14.1**	$ (7.8)
Attributable to:				
Equity holders of the Partnership	**(7.0)**	(26.8)	**3.5**	(18.4)
Preferred share dividends of a subsidiary company	**3.5**	3.4	**10.6**	10.6
	$ (3.5)	$ (23.4)	**$ 14.1**	$ (7.8)
Income (loss) per unit attributable to the equity holders of the Partnership (basic and diluted)	**$ (0.12)**	$ (0.49)	**$ 0.06**	$ (0.34)
Weighted average units outstanding (millions)	**56.6**	55.2	**56.3**	54.8

See accompanying notes to the condensed interim consolidated financial statements.

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Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited)	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
(In millions of Canadian dollars)				
Income (loss) for the period	**$ (3.5)**	$ (23.4)	**$ 14.1**	$ (7.8)
Other comprehensive income (loss), net of income tax				
Cash flow hedges:				
Amortization of deferred gains on derivative instruments de-designated as cash flow hedges to income(1)	**(0.1)**	(0.1)	**(0.3)**	(0.3)
Unrealized gains (losses) on derivative instruments designated as cash flow hedges(2)	**1.8**	(24.3)	**1.6**	(49.1)
Ineffective portion of cash flow hedges reclassified to income for the period(3)	**0.2**		**1.5**	0.8
Net investment in foreign operations:				
Gain (loss) on translating investment in foreign operations(4)	**41.0**	(18.6)	**26.8**	(11.6)
Available for sale financial asset:				
Net change in fair value of investment(5)	**(3.7)**	2.3	**(2.8)**	4.4
	39.2	(40.7)	**26.8**	(55.8)
Total comprehensive income (loss) for the period:	**$ 35.7**	$ (64.1)	**$ 40.9**	$ (63.6)
Attributable to:				
Equity holders of the Partnership	**$ 32.2**	$ (67.5)	**$ 30.3**	$ (74.2)
Preferred share dividends of a subsidiary company	**3.5**	3.4	**10.6**	10.6

(1) Net of income tax expense of $nil and $nil (2010 $nil and $nil) for the three and nine months ended September 30, 2011.

(2) Net of income tax expense of $0.6 million and $0.4 million (2010 income tax recovery of $8.7 million and $14.9 million) for the three and nine months ended September 30, 2011.

(3) Net of income tax expense of $0.1 million and $0.5 million (2010 $nil and $nil) for the three and nine months ended September 30, 2011.

(4) Includes income tax recovery of $2.4 million and $1.5 million (2010 income tax expense of $1.0 million and $0.6 million) for the three and nine months ended September 30, 2011.

(5) Net of income tax recovery of $1.9 million and $1.4 million (2010 $1.2 million and $1.8 million) for the three and nine months ended September 30, 2011.

See accompanying notes to the condensed interim consolidated financial statements.

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Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited)	September 30, 2011	December 31, 2010
(In millions of Canadian dollars)		
ASSETS		
Current assets		
Cash and cash equivalents	**$ 19.0**	$ 27.5
Trade and other receivables	**53.3**	52.5
Inventories	**12.6**	19.5
Prepaids and other	**6.9**	4.0
Derivative assets (Note 3)	**3.0**	10.4
Assets classified as held for sale (Note 2)	**143.4**	
Total current assets	**238.2**	113.9
Non-current assets		
Derivative assets (Note 3)	**12.3**	29.7
Other financial assets	**67.9**	72.5
Deferred tax asset	**25.2**	38.4
Intangible assets	**284.8**	290.1
Property, plant and equipment	**872.9**	958.5
Goodwill	**24.8**	43.8
Total non-current assets	**1,287.9**	1,433.0
Total assets	**$ 1,526.1**	$ 1,546.9
LIABILITIES AND PARTNERS' EQUITY		
Liabilities		
Trade and other payables	**$ 53.1**	$ 61.5
Derivative liabilities (Note 3)	**22.0**	21.1
Liabilities classified as held for sale (Note 2)	**22.1**	
Total current liabilities	**97.2**	82.6
Non-current liabilities		
Derivative liabilities (Note 3)	**70.3**	81.9
Loans and borrowings	**721.1**	704.5
Deferred tax liabilities	**10.1**	30.1
Decommissioning provision	**56.1**	50.1
Other liabilities	**11.7**	7.8
Total non-current liabilities	**869.3**	874.4
Total liabilities	**966.5**	957.0
Equity attributable to equity holders of the Partnership		
Partners' capital	**1,241.6**	1,227.6
Deficit	**(853.8)**	(782.9)
Accumulated other comprehensive loss	**(48.3)**	(75.1)
	339.5	369.6

Preferred shares issued by a subsidiary company		**220.1**		220.3
Total equity		**559.6**		589.9
Contingencies (Note 6)				
Total liabilities and equity	**$**	**1,526.1**	$	1,546.9

See accompanying notes to the condensed interim consolidated financial statements.

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Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY

(unaudited) (in millions of Canadian dollars)	Partnership capital	Cumulative translation account*	Available for sale financial assets*	Cash flow hedges*	Deficit	Equity attributable to the Partnership	Non-controlling interests**	Total
Equity as at January 1, 2011	$ 1,227.6	$ (29.6)	$ 6.8	$ (52.3)	$ (782.9)	$ 369.6	$ 220.3	$ 589.9
Net income (loss) for the period					3.5	3.5	10.6	14.1
Other comprehensive income (loss):								
Amortization of deferred gains on de-designated cash flow hedges				(0.3)		(0.3)		(0.3)
Unrealized gains on derivative instruments designated as cash flow hedges				1.6		1.6		1.6
Ineffective portion of cash flow hedges reclassified to income for the period				1.5		1.5		1.5
Loss on translating investment in foreign operations		26.8				26.8		26.8
Net change in fair value of investment			(2.8)			(2.8)		(2.8)
Total comprehensive income (loss)		26.8	(2.8)	2.8	3.5	30.3	10.6	40.9
Distributions					(74.4)	(74.4)		(74.4)
Preferred share dividends paid							(9.8)	(9.8)
Tax on preferred share dividends							(1.0)	(1.0)
Issue of Partnership units	14.0					14.0		14.0
Equity as at September 30, 2011	$ 1,241.6	$ (2.8)	$ 4.0	$ (49.5)	$ (853.8)	$ 339.5	$ 220.1	$ 559.6

(unaudited) (in millions of Canadian dollars)	Partnership capital	Cumulative translation account*	Available for sale financial assets*	Cash flow hedges*	Retained earnings	Equity attributable to the Partnership	Non-controlling interests**	Total
Equity as at January 1, 2010	$ 1,200.6	$	$ (2.2)	$ (3.4)	$ (687.5)	$ 507.5	$ 220.7	$ 728.2
Net income (loss) for the period					(18.4)	(18.4)	10.6	(7.8)
Other comprehensive income (loss)								
Amortization of deferred gains on de-designated cash flow hedges				(0.3)		(0.3)		(0.3)
Unrealized losses on derivative instruments designated as cash flow hedges				(49.1)		(49.1)		(49.1)
Ineffective portion of cash flow hedges reclassified to income for the period				0.8		0.8		0.8
Loss on translating investment in foreign operations		(11.6)				(11.6)		(11.6)
Net change in fair value of investment			4.4			4.4		4.4
Total comprehensive income (loss)		(11.6)	4.4	(48.6)	(18.4)	(74.2)	10.6	(63.6)
Distributions					(72.4)	(72.4)		(72.4)
Preferred share dividends paid							(9.8)	(9.8)
Tax on preferred share dividends							(1.1)	(1.1)
Issue of Partnership units	20.2					20.2		20.2
Equity as at September 30, 2010	$ 1,220.8	$ (11.6)	$ 2.2	$ (52.0)	$ (778.3)	$ 381.1	$ 220.4	$ 601.5

* Accumulated other comprehensive loss

** Preferred share dividends of a subsidiary company

See accompanying notes to the condensed interim consolidated financial statements.

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Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Nine months ended September 30 2011	2010
(In millions of Canadian dollars)		
Operating activities		
Income (loss) before income tax for the period	**$ 12.2**	$ (26.8)
Adjustments:		
Depreciation	**66.4**	74.1
Fair value changes on derivative instruments	**17.9**	13.3
Preferred share dividends paid	**(9.8)**	(9.8)
Principal repayments on finance lease receivable	**1.6**	1.4
Impairments		46.8
Deferred revenue	**2.1**	2.2
Income taxes paid	**(4.4)**	(4.3)
Interest expense	**29.3**	29.1
Interest income		(1.8)
Interest paid	**(31.9)**	(32.5)
Interest received		1.8
Other	**3.5**	2.1
	86.9	95.6
Increase in operating working capital	**(5.7)**	(15.4)
Cash provided by operating activities	**81.2**	80.2
Investing activities		
Additions to property, plant and equipment	**(16.5)**	(21.5)
Change in non-operating working capital	**(1.7)**	(4.5)
Cash used in investing activities	**(18.2)**	(26.0)
Financing activities		
Distributions paid	**(60.3)**	(52.0)
Net repayments under credit facilities	**(6.0)**	(1.6)
Repayment of loans and borrowings		(1.4)
Cash used in financing activities	**(66.3)**	(55.0)
Foreign exchange gains (losses) on cash held in a foreign currency	**0.8**	(0.3)
Decrease in cash and cash equivalents	**(2.5)**	(1.1)
Cash and cash equivalents, beginning of period	**27.5**	9.5
Cash and cash equivalents, end of period	**$ 25.0**	$ 8.4

See accompanying notes to the condensed interim consolidated financial statements.

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

1. Basis of presentation and conversion to IFRS

These condensed interim consolidated financial statements have been prepared by management of the General Partner in accordance with International Financial Reporting Standards (IFRS) International Accounting Standard (IAS) 34 Interim Financial Reporting as issued by the International Accounting Standards Board and adopted by the Canadian Institute of Chartered Accountants applicable companies for years beginning on or after January 1, 2011. For prior reporting periods up to and including the year ended December 31, 2010, the Partnership prepared its condensed interim consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP). The condensed consolidated interim financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the financial position, financial performance and cash flows of the Partnership is provided in note 7. This note includes reconciliations of equity and total comprehensive income for comparative periods reported under previous Canadian GAAP to those reported under IFRSs. A reconciliation of equity at the date of transition reported under previous Canadian GAAP to equity reported under IFRSs is included in the condensed interim consolidated financial statements for the first quarter of 2011.

The Partnership's condensed interim consolidated financial statements are prepared under the historical cost convention, except for the revaluation of the Partnership's derivative instruments, cash and available for sale financial assets, which are recognized at fair value and certain property, plant and equipment which is recognized at deemed cost as fair value, at January 1, 2010.

Quarterly revenues, income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in United States (US) dollar exchange rates, fulfillment of firm energy requirements, natural gas prices, waste heat availability and planned and unplanned plant outages, as well as items outside of the normal course of operations. Quarterly income is also affected by unrealized foreign exchange gains and losses and fair value changes in derivative instruments. The California plants normally generate the majority of their operating margin during the summer months when the plants can earn performance bonuses. Additionally, the plants located on Naval bases earn approximately 75% of their capacity revenue during these months. Revenues, income and cash provided by operating activities from the Partnership's Ontario plants are generally higher in the winter months (October to March) and lower in the summer months (April to September) due to seasonal pricing under the power purchase arrangements. Revenues and income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows.

Use of judgements and estimates

The preparation of the Partnership's condensed interim consolidated financial statements in accordance with IFRS requires management to make judgements, estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the condensed interim consolidated financial statements.

The Partnership reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgement in making these estimates and

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

1. Basis of presentation and conversion to IFRS (Continued)

assumptions. Adjustments to previous estimates, which may be material, will be recorded in the period they become known. Actual results may differ from these estimates.

In the opinion of management of the Partnership's General Partner, these condensed interim consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Partnership's accounting policies.

Future accounting standards

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended September 30, 2011 and have not been applied in preparing the unaudited condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committees with effective dates relating to the annual periods starting on or after the effective dates as follows:

International Accounting Standards (IAS/IFRS)	Effective Date
IAS 1 Presentation of Financial Statements	July 1, 2012
IFRS 10 Consolidated Financial Statements	January 1, 2013
IFRS 11 Joint Arrangements	January 1, 2013
IFRS 12 Disclosures of Interests in Other Entities	January 1, 2013
IFRS 13 Fair Value Measurement	January 1, 2013
IAS 19 Employee Benefits	January 1, 2013
IFRS 9 Financial Instruments	January 1, 2015

IAS 1 In June 2011, the International Accounting Standards Board (IASB) issued amendments to IAS 1 which will require entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to profit or loss in a future period. The amendments are to be applied retrospectively. Early adoption is permitted.

IFRS 10 In May 2011, the IASB issued IFRS 10 which replaces IAS 27 *Consolidated and Separate Financial Statements* and SIC 12 *Consolidation Special Purpose Entities*. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. The new standard provides a revised definition of control and a single consolidation model as the basis for consolidation for all types of entities. The standard also provides additional guidance to assist in the determination of control where this is difficult to assess. IFRS 10 is to be applied retrospectively. Early adoption is permitted but must be applied simultaneously with IFRS 11 *Joint Arrangements* and IFRS 12 *Disclosure of Interests in Other Entities*.

IFRS 11 IFRS 11 was issued in May 2011 and supersedes IAS 31 *Interests in Joint Ventures* and SIC 13 *Jointly Controlled Entities Non-Monetary Contributions by Venturers*. The standard provides a revised method to the classification of joint arrangements in the financial statements and may result in a different method of accounting for the Partnership's existing arrangements. The Partnership currently accounts for its joint arrangement using the proportionate consolidation method. IFRS 11 is to be

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

1. Basis of presentation and conversion to IFRS (Continued)

applied retrospectively. Early adoption is permitted but must be applied simultaneously with and IFRS 12 *Disclosure of Interests in Other Entities*.

IFRS 12 In May 2011, the IASB issued IFRS 12, a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is to be applied retrospectively. Early adoption is permitted but must be applied simultaneously with IFRS 10 *Consolidated Financial Statements* and IFRS 11 *Joint Arrangements*.

IFRS 13 In May 2011, the IASB issued IFRS 13 which defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs. It does not introduce any new requirements to measure an asset or a liability at fair value, change what is measured at fair value in IFRSs or address how to present changes in fair value. Earlier adoption of the amendment is permitted.

IAS 19 In June 2011, the IASB issued an amendment to IAS 19. The amendment introduced improvements related to: (a) eliminating the option to defer the recognition of actuarial gains and losses, known as the 'corridor method', (b) requiring a new presentation approach the improves the visibility of different types of gains and losses, and (c) enhancing the disclosure requirements about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. Earlier application of the amendment is permitted.

IFRS 9 In November 2009, the IASB issued IFRS 9 *Financial Instruments* which addresses the classification and measurement requirements of financial assets. The standard was amended in October 2010 to include the requirements for classification and measurement of financial liabilities. This amendment to IFRS 9 is to be applied retrospectively. Early adoption of the amendment is permitted.

The extent of the impact of adoption of these standards and interpretations on the consolidated financial statements of the Partnership has not been determined.

2. Assets and liabilities held for sale

On June 20, 2011 the Partnership agreed to sell its Southport and Roxboro facilities (the disposal group) to an affiliate of Capital Power Corporation for approximately $121 million contingent on the sale of the Partnership to Atlantic Power Corporation. The sale is expected to close in the fourth quarter of 2011. The Partnership will not have any continuing involvement in the disposal group after

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

2. Assets and liabilities held for sale (Continued)

the disposal transaction. Accordingly, the assets and liabilities of the disposal group at September 30, 2011 have been segregated and presented as assets and liabilities held for sale as follows:

	September 30, 2011
Assets held for sale	
Cash and cash equivalents	$ **6.0**
Accounts receivable	**5.8**
Inventories	**7.9**
Prepaids and other	**0.1**
Property, plant and equipment	**102.2**
Goodwill	**21.4**
	$ **143.4**
Liabilities held for sale	
Accounts payable	$ **5.1**
Decommissioning provision	**16.6**
Other liabilities	**0.4**
	$ **22.1**

No impairment loss was recognized in the condensed statement of comprehensive income for the three and nine months ended September 30, 2011 as the carrying amount of the disposal group approximates its fair value less cost to sell.

At September 30, 2011, accumulated other comprehensive loss included accumulated foreign exchange losses of $0.3 million related to the Partnership's investment in the disposal group that will be reclassified to net income (loss) on disposal.

3. Derivative instruments

Derivative instruments are held to manage financial risk related to energy procurement and treasury management. All derivative instruments, including embedded derivatives, are classified as held at fair value through profit or loss and are recorded at fair value on the statement of financial position as derivative instruments assets and derivative instruments liabilities unless exempted from derivative treatment as a normal purchase, sale or usage. All changes in their fair value are recorded in the condensed interim consolidated statement of income.

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Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

3. Derivative instruments (Continued)

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	September 30, 2011			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$	$	$ 3.0	$ 3.0
Non-current			12.3	12.3
Derivative instruments liabilities:				
Current	(19.6)	(1.8)	(0.6)	(22.0)
Non-current	(69.9)	(0.1)	(0.3)	(70.3)
	$ (89.5)	$ (1.9)	$ 14.4	$ (77.0)
Net notional amounts:				
Gigajoules (GJs)(millions)	33.1	3.3		
US foreign exchange (US dollars in millions)			297.3	
Contract terms (years)	5.3	0.1 to 1.3	0.2 to 4.7	

	December 31, 2010			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$	$	$ 10.4	$ 10.4
Non-current			29.7	29.7
Derivative instruments liabilities:				
Current	(16.2)	(3.0)	(1.9)	(21.1)
Non-current	(76.9)		(5.0)	(81.9)
	$ (93.1)	$ (3.0)	$ 33.2	$ (62.9)
Net notional amounts:				
Gigajoules (GJs)(millions)	37.8	6.5		
US foreign exchange (US dollars in millions)			309.0	
Contract terms (years)	6.0	0.8 to 2.0	0.2 to 5.5	

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

3. Derivative instruments (Continued)

Unrealized and realized pre-tax gains and losses on derivative instruments recognized in the condensed interim consolidated statement of income and other comprehensive income were:

	Financial statement category	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
Foreign exchange non-hedges	Revenue	**$ (20.6)**	$ 11.4	**$ (10.3)**	$ 1.4
Natural gas non-hedges	Cost of fuel	**0.6**	(3.6)	**2.6**	(9.5)
Natural gas hedges ineffective portion	Cost of fuel	**(0.3)**		**(2.0)**	(0.8)
Natural gas hedges effective portion	Other comprehensive income (loss)	**2.9**	(33.0)	**4.0**	(63.2)

The Partnership has elected to apply hedge accounting on certain derivative instruments it uses to manage commodity price risk relating to natural gas prices. For the three and nine months ended September, 2011, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the condensed interim consolidated statement of income was $0.3 million and $2.0 million respectively.

Net after tax gains and losses on derivative instruments designated as cash flow hedges are included in accumulated other comprehensive income at September 30, 2011. Losses of $49.5 million are expected to settle and be reclassified to the condensed interim consolidated statement of income in the following periods:

	September 30, 2011
Within one year	**$ 12.4**
Between 1 to 5 years	**35.2**
After more than 5 years	**1.9**
	$ 49.5

The Partnership's cash flow hedges extend up to 2016.

4. Finance costs

	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
Interest on long-term debt	**$ 9.7**	$ 9.8	**$ 28.8**	$ 29.1
Accretion and amortization	**1.3**	0.7	**2.5**	2.0
Other	**(0.2)**	0.7	**1.0**	1.5
	$ 10.8	$ 11.2	**$ 32.3**	$ 32.6

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

5. Segment information

The Partnership operates in one reportable business segment involved in the operation of electrical generation plants within British Columbia, Ontario and in the US in California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington State.

Geographic information

	Three months ended September 30, 2011			Three months ended September 30, 2010		
	Canada	US	Total	Canada	US	Total
Revenue	**$ 27.3**	**$ 88.9**	**$ 116.2**	$ 57.4	$ 83.3	$ 140.7

	Nine months ended September 30, 2011			Nine months ended September 30, 2010		
	Canada	US	Total	Canada	US	Total
Revenue	**$ 143.2**	**$ 234.5**	**$ 377.7**	$ 154.6	$ 227.6	$ 382.2

	As at September 30, 2011			As at December 31, 2010		
	Canada	US	Total	Canada	US	Total
Assets						
PP&E	**$ 435.0**	**$ 437.9**	**$ 872.9**	$ 448.5	$ 510.0	$ 958.5
Goodwill		**24.8**	**24.8**		43.8	43.8
Intangible assets	**31.3**	**253.5**	**284.8**	33.6	256.5	290.1
	$ 466.3	**$ 716.2**	**$ 1,182.5**	$ 482.1	$ 810.3	$ 1,292.4

	Nine months ended September 30, 2011			Nine months ended September 30, 2010		
	Canada	US	Total	Canada	US	Total
Capital additions	**$ 6.1**	**$ 10.4**	**$ 16.5**	$ 10.6	$ 10.9	$ 21.5

6. Contingencies

The Partnership and Atlantic Power Corporation (Atlantic Power) have entered into an agreement pursuant to which Atlantic Power would acquire, directly and indirectly, all of the outstanding limited partnership units of the Partnership (the "Transaction"). If the Transaction fails to receive unitholder approval, the Partnership will reimburse Atlantic Power for its costs associated with the Transaction up to $8 million. Further, any solicitation or recommendation of a competing proposal or offer prior to completion of this agreement will result in the payment of a $35 million termination fee. There is no possibility of any reimbursement of these amounts once paid.

Contingent on the completion of the Transaction, the Partnership will pay $8.5 million to affiliates of Capital Power Corporation for the termination of certain management and operations agreements and will pay success fees of approximately $12 million to its financial advisors.

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS

For all periods up to and including the year ended December 31, 2010, the Partnership prepared its financial statements in accordance with previous Canadian GAAP.

The Partnership has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010 as described in note 2. In preparing these financial statements, the Partnership's opening statement of financial position was prepared as at January 1, 2010, the Partnership's date of transition to IFRS. This note explains the principal adjustments made by the Partnership in restating its previously published Canadian GAAP financial statements for the three and nine months ended September 30, 2010. Explanations of the principal adjustments made by the Partnership in restating its Canadian GAAP Statement of Financial Position as at January 1, 2010 and its financial statements for the twelve months ended December 31, 2010 are included in the condensed interim consolidated financial statements for the first quarter of 2011. The Partnership has applied the following optional exemptions in its transition from Canadian GAAP to IFRS:

Business combinations

IFRS 1 provides the option to apply IFRS 3, Business Combinations, retrospectively or prospectively from the date of transition. The Partnership has taken the IFRS 1 election to not restate previous business combinations at the date of transition. Goodwill arising on such business combinations before the date of transition has not been adjusted from its carrying value previously reported.

Translation of foreign operations

The Partnership has elected the option available under IFRS 1, to deem the cumulative translation account for all foreign operations to be $nil at the date of transition, and to reclassify all amounts determined in accordance with previous GAAP at that date to retained earnings.

Decommissioning liabilities

IFRS 1 provides an optional election to adopt a simplified approach, whereby the Partnership can elect to not calculate retrospectively the effect of each change in estimate that occurred prior to the date of transition. The Partnership has elected to use the simplified approach.

Fair value as deemed cost

IFRS 1 also provides an optional election on transition to IFRS which allows the use of fair value as deemed cost on items of property, plant and equipment. The Partnership has elected under IFRS 1 to fair value certain items of property, plant and equipment.

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Reconciliation of equity

Reconciliation of equity September 30, 2010

	Canadian GAAP	IAS 16 and 37 (a)	IAS 36 (b)	IFRS 1 (c)	Other impacts (d)	Presentation adjustment	IFRS
ASSETS							
Current assets							
Cash and cash equivalents	$ 8.4	$	$	$	$	$	$ 8.4
Trade and other receivables	57.2						57.2
Inventories	40.3						40.3
Prepaids and other	7.2						7.2
Future income tax asset	1.7					(1.7)	
Derivative assets	7.5						7.5
Total current assets	122.3					(1.7)	120.6
Non-current assets							
Derivative assets	21.6						21.6
Other financial assets	47.2				3.4	(1.3)	49.3
Deferred tax asset	39.2				(3.7)	1.7	37.2
Intangible assets	305.2		(0.8)			1.3	305.7
Property, plant and equipment	1,020.0	(11.5)	(67.2)	53.7			995.0
Goodwill	46.6		(1.2)				45.4
Total non-current assets	1,479.8	(11.5)	(69.2)	53.7	(0.3)	1.7	1,454.2
Total assets	$ 1,602.1	$ (11.5)	$ (69.2)	$ 53.7	$ (0.3)	$	$ 1,574.8
LIABILITIES AND PARTNERS' EQUITY							
Liabilities							
Trade and other payables	$ 60.0	$	$	$	$	$	$ 60.0
Derivative liabilities	21.8						21.8
Total current liabilities	81.8						81.8
Non-current liabilities							
Derivative liabilities	84.0						84.0
Loans and borrowings	709.1						709.1
Deferred tax liabilities	46.9				(16.0)		30.9
Decommissioning provision		30.5				29.4	59.9
Other liabilities	37.0					(29.4)	7.6
Total non-current liabilities	877.0	30.5			(16.0)		891.5

Total liabilities	958.8	30.5			(16.0)		973.3
Equity attributable to equity holders of the Partnership							
Partners' capital	1,220.8						1,220.8
Retained earnings	(600.2)	(42.5)	(69.7)	(76.4)	10.5		(778.3)
Accumulated other comprehensive loss	(197.0)	0.5	0.5	130.1	4.5		(61.4)
	423.6	(42.0)	(69.2)	53.7	15.0		381.1
Preferred shares issued by a subsidiary company	219.7				0.7		220.4
Total equity	643.3	(42.0)	(69.2)	53.7	15.7		601.5
Total liabilities and equity	$ 1,602.1	$ (11.5)	$ (69.2)	$ 53.7	$ (0.3)	$	$ 1,574.8

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Notes to the equity reconciliations

a) **IAS 16 Property, plant and equipment (PP&E) & IAS 37 provisions**

IFRS are more specific with respect to the level at which component accounting is required and mandates that overhauls embedded within the initial carrying amount of a component must be treated as a separate component.

In accordance with IAS 16, PP&E has decreased by $36.3 million at September 30, 2010 as a result of identifying the significant components and calculating the adjustment to accumulated depreciation for the components' useful lives as well as derecognizing the overhauls that were inherent in the original turbines and a subsequent overhaul has been performed.

In accordance with IAS 37, provisions are required to be measured at the best estimate of the expected expenditure using discount rates appropriate for each liability. Under Canadian GAAP the provision was measured at fair value. The provision is to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Partnership re-measured its asset retirement obligations with revised discount rates for all decommissioning liabilities. The re-measurement of the decommissioning liabilities resulted in an increase of $30.5 million at September 30, 2010 to the non-current provision. The re-measurement of the decommissioning liability also resulted in an increase to the associated PP&E of $24.8 million at September 30, 2010.

These adjustments resulted in an increase to the deficit of $42.5 million at September 30, 2010.

Accumulated other comprehensive loss (AOCL) decreased by $0.5 million at September 30, 2010 as a result of translating the IFRS adjustments for the Partnership's operations with a US dollar functional currency.

b) **IAS 36 Impairments**

In accordance with IAS 36, the Partnership reviewed the recoverable amount for its CGUs with allocated goodwill at both the date of transition and in the third quarter of 2010. IAS 36 also requires that impairment testing be done on a CGU level and requires that goodwill be allocated to the CGU level and included in the impairment test for each plant. The Partnership has determined its CGUs to be at the plant level. For these CGU's, management assessed whether there were any triggering events at December 31, 2010. The recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Partnership's long term planning model. Previously under GAAP, the carrying values were compared to the undiscounted cash flows first and if the undiscounted cash flows exceeded carrying value then no further steps were taken.

As a result of the changes to the determination of recoverable amounts and the allocation of the goodwill to the CGUs, the Partnership recorded total impairments of $23.7 million at December 31, 2009, which includes $12.9 million for Roxboro and $8.0 million for Greeley. The impairments at Roxboro and Greeley were the result of weakening economic conditions in their respective markets. Impairment charges of $25.1 million and $21.7 million related to the Calstock and Tunis CGUs respectively were recorded in the third quarter of 2010 primarily due to lower expectations for waste heat as a result of lower expected pipeline throughput. The impacts at September 30, 2010 to intangible assets, PP&E and goodwill were decreases of $0.8 million, $67.2 million and $1.2 million respectively.

These adjustments resulted in an increase to the deficit of $69.7 million at September 30, 2010.

AOCL decreased by $0.5 million at September 30, 2010 as a result of translating the IFRS adjustments for the Partnership's operations with a US dollar functional currency.

c)

IFRS 1 First time adoption of IFRS

As a result of the Partnership taking the IFRS 1 election to use fair value as deemed cost for the PP&E at Manchief and Curtis Palmer, the PP&E balance increased by $53.7 million at September 30, 2010. The change in the value of the increase to fair value subsequent to January 1, 2010 is a result of depreciation of the increase to fair value and foreign exchange impacts. The aggregate fair value deemed as cost for the PP&E of these plants at January 1, 2010 was $210.2 million.

As a result of the Partnership taking the IFRS 1 election to deem the balance for the cumulative translation amount to be $nil on January 1, 2010, the accumulated other comprehensive loss decreased by $131.9 million.

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

These adjustments resulted in an increase to the deficit of $76.4 million at September 30, 2010.

AOCL increased by $1.9 million at September 30, 2010 as a result of translating the fair value as deemed cost election taken by the Partnership's operations with a US dollar functional currency.

d) Other impacts

In accordance with IAS 39, Financial Instruments: Recognition and Measurement, financial assets available for sale must be measured at fair value. Under Canadian GAAP, the investment in PERH was carried at the lower of historic cost and fair value. IAS 39 requires financial assets to be measured at fair value even if it is not traded in an active market. Fair value was established using the market price of Primary Energy Recycling Corporation (PERC), a publicly traded company whose sole asset is an investment in PERH. As a result of measuring the investment in PERH at its fair value, other financial assets were increased by $3.4 million at September 30, 2010. As this adjustment is unrealized, the offset is included in AOCL.

In accordance with IAS 39, hedge effectiveness testing must incorporate the Partnerships' credit risk which resulted in the Partnership's deficit increasing by $0.4 million at September 30, 2010. As this adjustment is unrealized, the offset is included in AOCL, which is recorded net of tax.

The tax impacts recorded against the above adjustments were $1.1 million at September 30, 2010.

Other impacts also include the impact to the deferred tax assets and deferred tax liabilities resulting from all of the IFRS transition adjustments discussed above. The deferred tax asset decreased by $3.7 million at September 30, 2010. The deferred tax liability decreased by $16.0 million at September 30, 2010.

AOCL decreased by $2.0 million at September 30, 2010 as a result of translating the other adjustments for the Partnership's operations with a US dollar functional currency.

Reconciliation of total comprehensive income (loss)

Reconciliation of total comprehensive income three months ended September 30, 2010

	Canadian GAAP	IAS 16 and 37	IAS 36 (a)	IFRS 1	Other impacts (b)	Presentation adjustment	IFRS
Revenues	$ 140.7	$	$	$	$	$	$ 140.7
Cost of fuel	59.1				(1.3)		57.8
Operating and maintenance expense	24.9						24.9
	56.7				1.3		58.0
Other costs (income)							
Depreciation	25.1	1.0	(0.3)	1.0		(0.6)	26.2
Impairments			46.8				46.8
Administrative and other expenses	5.3						5.3

Finance costs	10.6					0.6	11.2
Income (loss) before income tax	15.7	(1.0)	(46.5)	(1.0)	1.3		(31.5)
Income tax expense (recovery)	1.7				(9.8)		(8.1)
Income (loss) for the period	14.0	(1.0)	(46.5)	(1.0)	11.1		(23.4)
Other comprehensive income (loss)	(43.5)	0.8	0.8	(3.0)	4.2		(40.7)
Total comprehensive income (loss)	$ (29.5)	$ (0.2)	$ (45.7)	$ (4.0)	$ 15.3	$	$ (64.1)
Attributable to:							
Equity holders of the Partnership	$ (32.9)	$ (0.2)	$ (45.7)	$ (4.0)	$ 15.3	$	$ (67.5)
Preferred share dividends of a subsidiary company	3.4						3.4

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Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Reconciliation of total comprehensive income nine months ended September 30, 2010

	Canadian GAAP	IAS 16 and 37	IAS 36 (a)	IFRS 1	Other impacts (b)	Presentation adjustment	IFRS
Revenues	$ 382.2	$	$	$	$		