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

Registration No. 333-181548

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 1
to
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)

**One Federal Street, Floor 30
Boston, Massachusetts 02110
(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
One Federal Street, Floor 30
Boston, Massachusetts 02110
(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(3)
Guarantees of 9% Senior Notes Due 2018				(4)
Guarantee of Atlantic Power Limited Partnership's Guarantee of 9% Senior Notes Due 2018 by Curtis Palmer LLC				(4)

(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) Previously paid.

(4) 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

One Federal Street, Floor 30
Boston, Massachusetts 02110
(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 JUNE 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.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements 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.

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 Inc. ("**Rollcast**"), a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly-owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs 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 associated with our power transmission project entitle 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.

Recent Developments

Acquisition of Rockland Wind

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 PPA with Idaho Power. Rockland is accounted for under the equity method of accounting.

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Acquisition of Canadian Hills Wind Power Development Project

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("**Atlantic OW**"), a Delaware limited liability company and a wholly owned subsidiary of Atlantic Power, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("**Apex**"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("**Canadian Hills**") for a nominal sum. Canadian Hills is the owner of a 298.45 MW wind energy project under construction in the State of Oklahoma. On March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project.

At the time, we also closed a $310 million non-recourse, project-level construction financing facility for the project. The facility includes a $290 million construction loan and a $20 million 5-year letter of credit facility. Proceeds from the construction loan were used, in part, to repay Atlantic Power $29.3 million in member loans that were made to the project to fund construction prior to closing the construction financing facility. The construction loan is structured to be repaid with a tax equity investment, which we are actively pursuing, by institutional investors at the time Canadian Hills commences commercial operations.

In connection with the closing of the construction financing facility on March 30, 2012, we committed to invest approximately $180 million in equity (net of financing costs) to cover the balance of the construction and development costs, expected to be drawn following the final disbursement of the construction loan. We have received an approximately $360 million bridge facility commitment (the "**Bridge Facility**") from Morgan Stanley to provide flexibility in the timing of the tax equity investment and our own equity commitment in the project.

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

PERH Interest Sale

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("**PERC**"), whereby PERC agreed to 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 closed on May 31, 2012 and we received proceeds of approximately $30.2 million.

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. The FERC approved the settlement agreement on May 23, 2012.

DuPont Litigation

In December 2008, the Chambers project, our investment in which is accounted for under the equity method of accounting, filed suit against E.I. du Pont de Nemours and Company ("**DuPont**") for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, the Chambers project received a favorable ruling from the court on its summary judgment motion as to liability. The court's decision included a description of the pricing methodology that is consistent with the project's position. On April 25, 2012, the court issued its written opinion which ordered DuPont to pay Chambers a total of approximately $15.7 million. This amount represents DuPont's electricity underpayments from January 2003 through June 2009, and interest through July 22, 2011. The court also ordered that from July 1, 2009 going forward, the pricing methodology should be calculated in accordance with the court's prior ruling on summary judgment. On May 18, 2012, the court issued a final judgment in the amount of $16.2 million. The Chambers project has submitted an additional $9.0 million in invoices to DuPont based on the calculation of electricity for underpayments and interest for the periods outside those covered by the final summary judgment.

DuPont has 45 days from the date of the final judgment to file an appeal. It is anticipated that DuPont will file a motion to stay payment of damages pending appeal.

Potential Offering of Common Shares and Convertible Debentures

We have filed registration statements related to the public offering of 6,000,000 of our common shares (plus up to an additional 900,000 common shares that we may issue and sell upon the exercise of the underwriters' option to purchase additional shares) and $130.0 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 One Federal Street, Floor 30, Boston, Massachusetts, USA 02110, 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,

	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.

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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

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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,

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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 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 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.

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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

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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.

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 June 14, 2012, the noon buying rate was $1.00 = C$1.0247.

	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

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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.

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 at any time prior to the expiration date, if (1) 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 which seeks to impair our ability to proceed with the exchange offer, or (3) there has been a change in our business or financial affairs which prevents us from consummating 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.

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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:	Corporate Capital Markets	*Confirm by Telephone:*
(302) 636-4139	Rodney Square North	(302) 636-6181
Attention: Sam Hamed	1100 North Market Street	
	Wilmington, Delaware 19890-1626	
	Attention: Sam Hamed	

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.

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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.

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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 million 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.

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. 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 acquisition of the Partnership. An unaudited pro forma condensed combined consolidated balance sheet is not presented herein as the acquisition of the Partnership 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 acquisition of the Partnership, (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 acquisition of the Partnership 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 ATLANTIC POWER LIMITED PARTNERSHIP

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 ATLANTIC POWER LIMITED PARTNERSHIP

**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 U.S. 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 ATLANTIC POWER LIMITED PARTNERSHIP

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 ATLANTIC POWER LIMITED PARTNERSHIP

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 period. 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 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.

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. 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
5	Canadian Hills	El Reno OK	Wind	298	99%	295

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	Project Name	Location	Fuel Type	Total MW	Ownership Interest	Net MW
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	Piedmont	Barnsville GA	Biomass	53	98%	53
31	Rockland	American Falls ID	Wind	80	30%	24
32	Rollcast	Charlottesville NC	NA	NA	60%	NA
33	Selkirk	Bethlehem NY	Natural Gas	345	18%	64
34	Tunis	Tunis ON	Natural Gas	43	100%	43
35	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

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system rights ("**TSRs**") associated with our power transmission project entitle 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 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 One Federal Street, Floor 30, Boston, Massachusetts, 02110 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 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.

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.

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 18 power generation assets of the Partnership through our direct and indirect acquisition of all of the issued and outstanding limited partnership units of the Partnership, the personnel that operated and maintained the assets of the Partnership 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.

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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.

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.

PPMS 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.

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

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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 agreed to purchase our 14.3% common ownership interests in PERH. The transaction closed on May 31, 2012 and we received proceeds of approximately 30.2 million.

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 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 previously held 14.3% of the common ownership interests in PERH. The remaining interest in PERH was 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.

On February 16, 2012, we entered into an agreement with PERC, whereby PERC agreed to 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 closed on May 31, 2012 and we received proceeds of approximately $30.2 million.

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.

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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.

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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, 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

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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.

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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 Inc. ("**Rollcast**"), a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly-owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs 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 associated with our power transmission project entitle 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 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

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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 standards, somewhat compensating for the increased interest rate spreads demanded by lenders.

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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 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

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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

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 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%			