ATLANTIC POWER CORP
Form 10-K
February 28, 2014

Use these links to rapidly review the document
Atlantic Power Corporation Index to Consolidated Financial Statements
TABLE OF CONTENTS

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2013

OR

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

For the transition period from to
Commission file number 001-34691

ATLANTIC POWER CORPORATION

(Exact Name of Registrant as Specified in its Charter)

British Columbia, Canada (State of Incorporation)	**55-0886410** (I.R.S. Employer Identification No.)
One Federal St, Floor 30 **Boston, MA** (Address of Principal Executive Offices)	**02110** (Zip Code)

(617) 977-2400
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Shares, no par value per share, and the associated Rights to Purchase Common Shares	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No ý

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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.

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

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

As of June 28, 2013, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $0.47 billion based upon the last reported sale price on the New York Stock Exchange. For purposes of the foregoing calculation only, all directors and executive officers of the registrant have been deemed affiliates.

As of February 27, 2014, 120,279,798 of the registrant's Common Shares were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2014 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the registrant's fiscal year, are incorporated by reference into Items 10 through 14 of Part III of this Annual Report on Form 10-K.

TABLE OF CONTENTS

Table of Contents

PART I

As used herein, 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. All references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$," "US$" and "U.S. dollars" are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements in this Annual Report on Form 10-K constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "outlook," "objective," "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "should," "plans," "continue," or similar expressions suggesting future outcomes or events. Examples of such statements in this Annual Report on Form 10-K include, but are not limited to, statements with respect to the following:

- our ability to generate sufficient cash flow to pay dividends, service our debt obligations or finance internal or external growth opportunities;
- our ability to evaluate and/or implement a broad range of potential options and the impact any such potential options may have on us or our stock price;
- our ability to meet the financial covenants under our New Senior Secured Credit Facilities and other indebtedness;
- expectations regarding the prepayment or redemption of certain debt;
- expectations regarding maintenance and capital expenditures; and
- the impact of legislative, regulatory, competitive and technological changes.

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Annual Report on Form 10-K. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf.

Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under "Item 1A. Risk Factors". Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- our ability to generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities;

the ability to evaluate and/or implement a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, the dividend level, as well as broader strategic options, and the impact any such potential options may have on us or our stock price;

the impact of our failure to meet the fixed charge coverage ratio test in the restricted payments covenants of the indenture governing our 9% senior unsecured notes;

our indebtedness and financing arrangements and the terms, covenants and restrictions included in our New Senior Secured Credit Facilities;

exchange rate fluctuations;

the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;

unstable capital and credit markets;

the outcome of certain shareholder class action lawsuits;

the expiration or termination of power purchase agreements;

the dependence of our projects on their electricity and thermal energy customers;

exposure of certain of our projects to fluctuations in the price of electricity or natural gas;

the dependence of our projects on third-party suppliers;

projects not operating according to plan;

the effects of weather, which affects demand for electricity and fuel as well as operating conditions;

the dependence of our windpower projects on suitable wind and associated conditions and of our hydropower projects on suitable precipitation and associated weather conditions;

U.S., Canadian and/or global economic conditions and uncertainty;

risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;

the adequacy of our insurance coverage;

the impact of significant energy, environmental and other regulations on our projects;

- the impact of impairment of goodwill or long-lived assets;
- increased competition, including for acquisitions;
- our limited control over the operation of certain minority owned projects;
- transfer restrictions on our equity interests in certain projects;
- risks inherent in the use of derivative instruments;
- labor disruptions;
- the impact of hostile cyber intrusions;
- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and
- our ability to retain, motivate and recruit executives and other key employees.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third party projections of regional fuel and electric capacity and energy prices that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this Annual Report on Form 10-K are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Annual Report on Form 10-K may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Annual Report on Form 10-K. These forward-looking statements are made as of the date of this Annual Report on Form 10-K and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

ITEM 1. BUSINESS

OVERVIEW

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of December 31, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,948 megawatts ("MW") in which our aggregate ownership interest is approximately 2,026 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012, which we expect to close in 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer in Seattle, Washington. Twenty-two of our projects are wholly owned subsidiaries.

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

We sell the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from August 2014 to December 2037, we receive payments for the actual electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

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

Table of Contents

We directly operate and maintain the majority of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Colorado Energy Management ("CEM") and Power Plant Management Services ("PPMS"). 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 initial public offering on the Toronto Stock Exchange ("TSX") 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 Energy, LLC ("Caithness"). Until December 31, 2009, we were externally managed under an agreement with Atlantic Power Management, LLC, an affiliate of ArcLight, when we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us. In connection with the termination of the management agreement, we hired all of the then-current employees of Atlantic Power Management 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"), 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 TSX under the symbol "ATP". On July 23, 2010, we also began trading on the New York Stock Exchange ("NYSE") under the symbol "AT".

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 on February 1, 2012 (the "Partnership"). 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 Primary Energy Recycling Holdings, LLC ("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. Capital Power Corporation employees that operated and maintained the Partnership assets and most of those who provided management support of operations, accounting, finance, tax and human resources became employees of Atlantic Power.

On December 31, 2012, we acquired Ridgeline, a wind and solar development company, which added interests in three operating wind projects totaling 150 net MW and strengthened our ability to execute development and construction stage projects. As part of the acquisition, we integrated Ridgeline's team of employees that have a broad set of competencies essential for the successful identification, resource assessment, development, construction and operation of large-scale renewable power projects. This team also assists our assessment and pursuit of other renewable acquisitions and in managing our renewable energy portfolio.

OUR BUSINESS STRATEGY

Our corporate strategy is to increase the value of the company through both organic growth and potential acquisitions in North America. We focus on generating stable operating margins via contracted cash flows from our existing assets. We use our depth of asset management experience to enhance the operating, contractual and financial performance of our current projects and use our

Table of Contents

knowledge of markets and industry relationships in North America to pursue accretive opportunities to finish development, build and/or acquire projects primarily in the electric power industry.

As previously disclosed, we have been focused on initiatives aimed at, among other things, improving our financial flexibility and addressing our near-term maturities. We believe that the execution of the New Term Loan Facility (as defined herein) and the use of the funds therefrom to address debt maturities in 2014, 2015 and 2017 and for possible further debt reduction, as discussed in more detail in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources", are important steps toward achieving these goals. The 50% cash sweep and amortization features of the New Term Loan Facility are expected to reduce leverage over time. The additional flexibility, liquidity and maturity extension associated with the New Revolving Credit Facility (as defined herein) is also a meaningful achievement with respect to these goals. We believe that these steps should improve our ability to strengthen our balance sheet and optimize our assets.

We recognize that our important next steps include considering the relative merits of further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash while continuing to focus on how to best position the Company overall to maximize shareholder value. Consistent with these objectives, we are also committed to evaluating a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options. No assurance can be given as to how the evaluation of any such potential options may evolve.

Organic growth

We intend to look for opportunities to enhance the operational and financial performance of our projects through:

- achievement of improved operating efficiencies, output, reliability and 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 hedging arrangements;

- to the extent we have sufficient cash flow or are able to obtain financing, the expansion or redevelopment of existing projects and the acquisition of other partners' interests in our existing portfolio.

Development and construction

We have invested and may invest in the future in energy-related projects primarily in the electric power industry, including investments in late stage development projects or companies where the prospects for creating long-term predictable cash flows are attractive. In 2012, we acquired a 100% ownership interest in Ridgeline. With the acquisition of Ridgeline, we added an experienced renewable energy project development, construction and operations team to enhance our ability to pursue renewable assets. We continue to assess late-stage renewable, development and construction projects and believe that there are opportunities in the market to acquire such assets.

When these development opportunities arise, we have the ability and experience to manage the construction process. During 2012, Canadian Hills became our first wholly-owned construction project to achieve commercial operations. Canadian Hills is a 300 MW wind farm in the state of Oklahoma that was purchased as a late stage development project from Apex Wind Energy Holdings, LLC

Table of Contents

("Apex"). Meadow Creek is a 120 MW wind project in Idaho that our Ridgeline team successfully brought to commercial operations in 2012. Not only did the Ridgeline team strengthen our construction management and engineering capabilities, but their experienced wind project asset management team now oversees all of our 521 MW of wind projects. Piedmont, our 53 MW biomass project in Georgia, achieved commercial operations in April 2013. Piedmont was developed by our former affiliate Rollcast. In November 2013, we completed the sale of our 60% interest in Rollcast to the other shareholders and as consideration for the sale, we were assigned asset management contracts for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont, bringing our total ownership of the project to 100%.

Acquisition and investment strategy

We believe that new electricity generation projects will continue to be required in selective markets 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 renewable project opportunities. We may also work with experienced development companies to acquire additional late stage development projects and there is also a very active secondary market for the purchase and sale of existing projects. To the extent we pursue acquisitions, we intend to expand our operations by making accretive acquisitions with a focus on power generation facilities in the United States and Canada.

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

Extending PPAs following their expiration

PPAs in our portfolio have expiration dates ranging from August 2014 to December 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" request for proposals by the projects to likely bilateral counterparties, including traditional PPAs, tolling agreements with creditworthy energy trading firms or the use of derivatives to lock in value. 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 and in some cases, significantly. Our projects may not be able to secure a new agreement and could be exposed to selling power at spot market prices. It is possible that subsequent PPAs or the spot markets may not be available at prices that permit the operation of the project on a profitable basis. See Item 1A. "Risk Factors Risk Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition." 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.

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 2,948 MW, and our net ownership interest in these projects is approximately 2,026 MW. These projects are diversified by fuel type, electricity and steam customers, technologies, project operators and geography. The majority are located in California, the U.S. Mid-Atlantic, New York and the provinces of Ontario and British Columbia.

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 allow us to see proprietary acquisition and partnership 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 aim to stabilize operating margins through a combination of a project's PPAs, fuel supply agreements and/or commodity hedges.

Strong in-house operations and asset management teams. We manage the operations of twenty-one of our power generation projects, which represent 70% of our portfolio's generating capacity. The remaining seven generation projects are operated by third-parties, which are recognized leaders in the independent power business.

ASSET MANAGEMENT

Our asset management strategy is to optimally manage our physical assets and commercial relationships to increase shareholder value. Our preference is to own the majority of, and operate all of our businesses. We proactively seek scale opportunities and to establish best practices that result in EBITDA and cash flow growth across all of our twenty-eight operating plants. In 2013 we established six cross functional task forces to drive these initiatives: Environmental, Health & Safety ("EH&S"), Optimization Initiatives, Asset Management Synergies, Sourcing, People Development and Stakeholder Management.

Our task forces help us achieve our strategy and mission, ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures, if justified, to provide for their safety, efficiency, availability, flexibility, longevity, and growth in EBITDA contribution. We also proactively look for opportunities to optimize power purchase, fuel supply, long term service and other agreements to deliver strong and predictable financial performance. The teams at each of the businesses have extensive experience in managing, operating and maintaining the assets. We also have people with extensive experience in renewable project development, construction and operations.

Consistent with our goals to internalize the operations of our business, in 2014 we entered into agreements, subject to lender approval, to assume the operations of Cadillac and Piedmont from Delta Power Services. For operations and maintenance services at the seven projects in our portfolio which we do not operate, we partner with recognized leaders in the independent power business.

Examples of our third-party operators include CEM and PPMS, which are experienced, well regarded energy infrastructure management services companies. 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 and calls.

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

Table of Contents

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.

OUR ORGANIZATION AND SEGMENTS

The following tables outline by segment our portfolio of power generating assets in operations as of February 27, 2014, 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.

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as a result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the years ended December 31, 2013, 2012 and 2011 have been presented to reflect these changes in operating segments. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative 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.

The sections below provide descriptions of our projects as they are aligned in our segment reporting structure for financial reporting purposes.

See Note 21 to the consolidated financial statements for information on revenue from external customers, Project Adjusted EBITDA (a non-GAAP measure), total assets by segment and revenue and total assets by geography.

East Segment

Our East segment accounted for 54.2%, 60.7% and 70.3% of consolidated revenue in 2013, 2012 and 2011, respectively and total net generation capacity of 791 MW at December 31, 2013. Ontario Electricity Financial Corp ("OEFC") accounted for 27.7% of total revenues and 51.1% of total revenues from the East segment for the year ended December 31, 2013.

The table below provides the revenue and project income (loss) for the East segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss).

On April 12, 2013 we completed our sale of our Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects") and have therefore excluded their revenue and project income (loss) from the table as they are recorded in income (loss) from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011. Revenue for the Florida Projects was $62.1 million, $188.0 million and $160.9 million for the years ended December 31, 2013, 2012 and

Table of Contents

2011, respectively. Project income (loss) for the Florida Projects was ($1.1) million, $31.8 million and $7.6 million for the years ended December 31, 2013, 2012 and 2011, respectively.

	East Segment			
	Revenue ($ in millions)		Project income (loss) ($ in millions)	
2013	$	299.1	$	25.8
2012		267.5		(18.1)
2011[1]		66.0		(2.1)

(1) The Partnership was acquired on November 5, 2011.

Set forth below is a list of our East projects in operation:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	December 2028	BBB
Chambers[1]	New Jersey	Coal	262	40.00%	89	Atlantic City Electric[2]	December 2024	BBB+
					16	DuPont	December 2024	A
Kenilworth	New Jersey	Natural Gas	30	100.00%	30	Merck, & Co., Inc.	September 2018	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	December 2027	A-
Selkirk[1][3]	New York	Natural Gas	345	17.70%	15	Merchant	N/A	NR
					49	Consolidated Edison	August 2014	A-
Calstock	Ontario	Biomass	35	100.00%	35	Ontario Electricity Financial Corp	June 2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2017	AA-

Nipigon	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2022	AA-
North Bay	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2017	AA-
Tunis[3]	Ontario	Natural Gas	43	100.00%	43	Ontario Electricity Financial Corp	December 2014	AA-
Piedmont	Georgia	Biomass	53	100.00%	53	Georgia Power	December 2032	A
Orlando[1]	Florida	Natural Gas	129	50.00%	65	Progress Energy Florida	December 2023	BBB+
Morris	Illinois	Natural Gas	177	100.00%	77	Merchant	N/A	NR
					100	Equistar Chemicals, LP	November 2023	BBB+

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

(2) The base PPA with Atlantic City Electric ("ACE") makes up the majority of the 89 Net MW. For sales of energy and capacity not purchased by ACE under the base PPA and sold to the spot market, profits are shared with ACE under a separate power sales agreement.

(3) We are currently in negotiations with counter parties regarding the renewal or entry into new power purchase agreements.

Table of Contents

West Segment

Our West segment accounted for 33.0%, 38.5% and 28.4% of consolidated revenue in 2013, 2012 and 2011, respectively and total net generation capacity of 714 MW at December 31, 2013. San Diego Gas & Electric and British Columbia Hydro and Power Authority ("BC Hydro") provided for 14.4% and 10.1% of total consolidated revenues, respectively, and 43.6% and 30.5%, respectively, of total revenues from the West segment for the year ended December 31, 2013.

The table below provides the revenue and project income for the West segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss).

	West Segment	
	Revenue ($ in millions)	Project income ($ in millions)
2013	$ 182.3	$ 36.4
2012	169.6	7.3
2011(1)	26.7	0.7

(1) The Partnership was acquired on November 5, 2011.

On April 30, 2013 we completed our sale of our interest in the Path 15 Transmission Line ("Path 15") and have therefore excluded its revenue and project income from the table as they are recorded in income (loss) from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011. Revenue for Path 15 was $9.5 million, $28.7 million and $30.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Project income for Path 15 was $2.1 million, $5.1 million and $7.6 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Set forth below is a list of our West projects in operation:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
Mamquam	British Columbia	Hydro	50	100.00%	50	British Columbia Hydro and Power Authority	September 2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00%	6	British Columbia Hydro and Power Authority	August 2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00%	66	British Columbia Hydro and Power Authority	March 2018	AAA
Frederickson(1)	Washington	Natural Gas	250	50.15%	50	Benton Co. PUD	August 2022	A+
					45	Grays Harbor PUD	August 2022	A

					30	Franklin Co. PUD	August 2022	A
Koma Kulshan[1]	Washington	Hydro	13	49.80%	6	Puget Sound Energy	December 2037	BBB
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	December 2019	A
Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	December 2019	A
North Island	California	Natural Gas	40	100.00%	40	San Diego Gas & Electric	December 2019	A
Oxnard	California	Natural Gas	49	100.00%	49	Southern California Edison	May 2020	BBB+
Manchief	Colorado	Natural Gas	300	100.00%	300	Public Service Company of Colorado	October 2022	A-

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

Table of Contents

Wind Segment

Our Wind segment accounted for 12.8% of consolidated revenue in 2013 and total net generation capacity of 521 MW from continuing operations at December 31, 2013. Southwestern Electric Power Company, PacifiCorp and Idaho Power Co. accounted for 33.1%, 25.8% and 20.8% of total revenues from the Wind segment for the year ended December 31, 2013, respectively. No customer from the Wind segment was responsible for greater than 10% of total consolidated revenues in the year ended December 31, 2013.

The table below provides the revenue and project income (loss) for the Wind segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss).

	Wind Segment	
	Revenue ($ in millions)	Project income (loss) ($ in millions)
2013	$ 70.8	$ 18.6
2012	1.9	(7.4)
2011		(1.6)

Set forth below is a list of our Wind projects in operation:

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
Idaho Wind[1]	Idaho	Wind	183	27.56%	50	Idaho Power Co.	December 2030	BBB
Rockland Wind Farm	Idaho	Wind	80	50.00%	40	Idaho Power Co.	December 2036	BBB
Goshen North[1]	Idaho	Wind	125	12.50%	16	Southern California Edison	November 2030	BBB+
Meadow Creek	Idaho	Wind	120	100.00%	120	PacifiCorp	December 2032	A-
Canadian Hills	Oklahoma	Wind	300	99.0%	199	Southwestern Electric Power Company	December 2037	BBB
					48	Oklahoma Municipal Power Authority	December 2037	A
					48	Grand River Dam Authority	December 2032	A

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

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.

According to the North American Electric Reliability Council's ("NERC") Long-Term Reliability Assessment, published in December 2013, summer peak demand within the United States in the ten-year period from 2014 through 2023 is projected to increase at a compound annual growth rate of approximately 1.2%, while winter peak demand in Canada is projected to increase 1.1%. In addition, many states and regions have aggressive demand side management programs designed to reduce current load and future local growth. NERC's Reliability Assessment also projects increased dependence on natural gas and renewables for electricity capacity. The adoption of highly efficient combined-cycle technology and the economic viability of shale gas have made gas-fired generation the

Table of Contents

primary choice for new capacity with almost 100 gigawatts ("GW"), or approximately 50% of planned generation capacity expected over the next 10 years. The share of capacity from renewable resources will also continue to grow. According to NERC's Reliability Assessment, renewable generation made up 15.2% of all on-peak capacity resources in 2013 and is expected to reach almost 25.2% percent in 2023.

The increase of gas and renewable capacity will be offset by large-scale retirements of coal-fired generation plants. NERC projects a net 35.1 GW reduction of coal-fired generation by 2023, with over 90% retiring by 2017 primarily due to existing and potential federal environmental regulations and low natural gas prices.

The non-utility power generation industry

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. Our 28 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 $363 billion in 2012, based on information published by the Energy Information Administration in November 2013. 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, independent power producers represented approximately 38% of total net generation in 2013. 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.

COMPETITION

The power generation industry is characterized by intense competition, and we compete with utilities, industrial companies and other independent power producers. Supply has surpassed demand plus appropriate reserve margins in numerous U.S. and Canadian markets contributing to reduced capacity and energy prices and increasing competition among generators to obtain power sales agreements.

We compete for acquisition opportunities with numerous private equity, infrastructure and pension funds, Canadian and U.S. independent power firms, utility non-regulated subsidiaries and other strategic and financial players. Our competitive advantages include our experienced management team, our experience as project operators and constructors and our diversified projects generally with medium to long-term power purchase agreements.

INDUSTRY REGULATION

Overview

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 aspects of our facilities and properties, including environmental matters.

In the United States, the power generation and sale aspects of our projects are primarily regulated by the Federal Energy Regulation Commission ("FERC"), although most of our projects benefit from the special provisions accorded to Qualifying Facilities ("QFs") or Exempt Wholesale Generators ("EWGs").

Table of Contents

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

Regulation generating projects

(i) United States

Eighteen of our power generating projects are QFs under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and FERC regulations. 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.

The generating projects with QF status and which are currently party to a PPA 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. However, state regulators review the prudency of utilities entering into PPAs entered into by QFs and the siting of the generation facilities. The majority of our generation is sold by QFs under PPAs that required approval by state authorities.

PURPA, as initially implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided costs. The Energy Policy Act of 2005 (the "EP Act of 2005"), however, established new limits on PURPA's requirement that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. The Delta-Person project is a EWG under the Public Utility Holding Company Act of 2005, as amended ("PUHCA"). The projects with EWG status are also exempt from state regulation respecting the rates of electric utilities, and the projects with EWG and QF status are exempt from regulations under PUHCA.

Notwithstanding their status as QFs and EWGs, our projects remain subject to various aspects of FERC regulation, including those relating to power marketer status and to oversight of mergers, acquisitions and investments relating to utilities under the Federal Power Act, as amended by the EP Act of 2005. All of our projects are also subject to reliability standards developed and enforced by 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.

Pursuant to its authority, NERC has issued, and the FERC has approved, a series of mandatory reliability standards. 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 (the "BCUC"), which is governed by the Utilities Commission Act (British Columbia) and is responsible for the regulation of British Columbia's public energy utilities including publicly owned and investor owned utilities (i.e., independent power producers).

Table of Contents

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

All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the 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.

The BCUC has adopted the NERC standards as being applicable to, among others, all generators of electricity in British Columbia, including independent power producers. In addition, 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.

The *Clean Energy Act,* which became law in British Columbia in 2010, sets out British Columbia's energy objectives. This Act states, among other things, that British Columbia aims to accelerate and expand the development of clean and renewable energy sources in British Columbia to, among other things, achieve energy self-sufficiency by 2016, promote economic development and job creation and continue to work toward 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. BC Hydro is required to meet these objectives and submit reports to the BCUC updating on its progress.

Other provincial regulators in British Columbia 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 overall responsibility for the regulation and supervision of the natural gas and electricity industries in Ontario and with the 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's general functions include:

- Determination of the rates charged for regulated services in the electricity sector;
- Licensing of market participants;
- Inspections, particularly with respect to compelling production of records and information;
- Formulation of rules to govern the conduct of participants in the electricity market;
- Market monitoring and reporting, including on anti-competitive practice;
- Consumer advocacy; and
- Enforcement and compliance.

The OEB has the authority effectively to modify licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the 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.

Table of Contents

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 both the Northeast Power Coordinating Council (the "NPCC") and NERC. 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.

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, including power contracts, were kept in OEFC. Once all of OEFC's debts (approximately $26.9 billion as of March 2012) 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 for 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. The process for awarding power purchase contracts in respect of large-scale energy projects under the feed-in-tariff program is undergoing review. No such contracts have been awarded in the past 12 months.

Carbon emissions

In the United States, during the past several years government action addressing carbon emissions has been focused on the regional and state level. Beginning in 2009, the Regional Greenhouse Gas Initiative ("RGGI") was established by certain Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for CO_2 emissions. The nine states currently participating in RGGI have varied implementation plans and schedules. In February 2013, RGGI released an updated model rule that reduces the regional CO_2 budget beginning in 2014. The one RGGI state where we have project interests, New York, also provides cost mitigation for independent power projects with certain types of power contracts. California's cap-and-trade program governing greenhouse gas emissions became effective for the electricity sector on January 1, 2013. 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.

At the federal level, President Obama has identified climate change as one of the major priorities for his second term. The U.S. Environmental Protection Agency has taken several recent actions

Table of Contents

respecting CO_2 emissions, including issuance of a finding that such emissions endanger public health and welfare, its final regulations to require annual reporting of greenhouse gas emissions by certain source categories considered to be large emitters, its final regulations to establish emissions standards for new fossil fuel power plants, and its anticipated proposed regulations to establish emissions standards for existing fossil fuel power plants.

The Government of British Columbia has enacted a number of significant pieces of climate-action legislation that frame British Columbia's approach to reducing greenhouse gas emissions with the goal of supporting the Province's participation in the emerging low-carbon economy.

One key piece of legislation is the Greenhouse Gas Reduction Targets Act (British Columbia) ("GGRTA"), which came into force in 2008 and sets legislated targets for the reduction of greenhouse gas emissions in the Province. Using 2007 as a base year, GGRTA (along with related Ministerial Orders) requires that emissions must be reduced by a minimum of 18% by 2016, 33% by 2020 and 80% by 2050. Also required in connection with GGRTA are annual (from 2010 onward) British Columbia Greenhouse Gas Inventory Reports, Community Energy and Emissions Inventory Reports and Carbon Neutral Action Reports, all of which are designed to provide scientific, comparable and consistent reporting of greenhouse gas sources.

Other related, key pieces of legislation include the Carbon Tax Act (British Columbia) ("CTA") and the Greenhouse Gas Reduction (Cap and Trade) Act ("GGRCTA"). CTA operates to put a price on greenhouse gas emissions, providing an incentive for sustainable choices and practices by producers of greenhouse gases. GGRCTA authorizes the imposition of hard caps on greenhouse gas emissions by providing a statutory basis for establishing a market-based cap and trade framework to reduce greenhouse gas emissions from large emitters operating in the Province. GGRCTA is currently in the process of being brought into full force. British Columbia is the first Canadian province to introduce such legislation.

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 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.

Regulatory and legislative tax incentives

The U.S. regulatory environment has undergone significant changes in the last several years due to the creation of incentives for the addition of large amounts of new renewable energy generation and, in some cases, transmission. Certain U.S. and Canadian government policies support renewable power generation and other clean infrastructure technologies and enhance the economic feasibility of developing and operating energy projects in the regions in which we operate. The viability of potential future renewable energy projects, including our windpower projects, is largely contingent on public policy mechanisms and favorable regulatory incentives, including production and investment tax credits, loan guarantees, accelerated depreciation tax benefits, state renewable portfolio standards, and regional carbon trading plans. For example, the American Taxpayer Relief Act was passed by Congress on January 1, 2013 and signed into law by the President on January 2, 2013. This legislation extended production tax credits and investment tax credits for certain projects that start construction prior to January 1, 2014 and extended bonus depreciation for projects that are placed in service prior to January 1, 2014. To date, however, the tax credits have not been extended past these dates. Under present law, for projects that qualify, the production tax credits provide an income tax credit of 2.3 cents/kilowatt-hour for the production of electricity from utility-scale wind turbines. The EP Act of

Table of Contents

2005 also provides incentives for various forms of electric generation technologies. Governments from time to time may renew their policies that support renewable energy and consider actions to make the policies less conducive to the development and operation of renewable energy facilities.

EMPLOYEES

As of February 27, 2014, we had 295 employees, 189 in the United States and 106 in Canada. Of our Canadian employees, 67 are covered by two collective bargaining agreements. During 2013, we did not experience any labor stoppages or labor disputes at any of our facilities.

AVAILABLE INFORMATION

We make available, free of charge, on our website, www.atlanticpower.com, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Additionally, we make available on our website, our Canadian securities filings. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at www.sec.gov. We are not a foreign private issuer, as defined in Rule 3b-4 under the Exchange Act.

Information contained on our website or that can be accessed through our website is not incorporated into and does not constitute a part of this Annual Report on Form 10-K. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website.

ITEM 1A. RISK FACTORS

This section highlights specific risks that could affect our Company. You should carefully consider each of the following risks and all of the other information set forth in this Annual Report on Form 10-K. Based on the information currently known to us, we believe the following information identifies the most significant risk factors affecting our Company. However, the risks and uncertainties described below are not the only ones related to our business and are not necessarily listed in the order of their importance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business.

If any of the following risks and uncertainties develops into actual events or if the circumstances described in the risks and uncertainties occur or continue to occur, these events or circumstances could have a material adverse effect on our business, results of operations or financial condition. These events could also have a negative effect on the trading price of our securities.

Risks Related to Our Structure

We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities

We recognize that our important next steps include considering the relative merits of further debt reduction, identification of and investment in internal and external accretive growth opportunities, to the extent available, and other allocation of available cash while continuing to focus on how to best position the Company overall to maximize shareholder value. However, we may not generate sufficient

Table of Contents

cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities.

Our ability to make required payments under our outstanding indebtedness, including pursuant to the mandatory amortization feature of the New Senior Secured Credit Facilities (as defined herein), as well as the 50% cash sweep, or to prepay or redeem any such indebtedness, will depend on our financial and operating performance, including our ability to generate cash flow from operations in the future. To the extent a significant portion of our cash flow is used to pay dividends to our shareholders, any remaining cash flow may be insufficient to fund our debt service obligations or to repay or redeem any such indebtedness. As a result, we may be required to refinance such indebtedness and/or obtain third party financing in order to repay, redeem or refinance such indebtedness when it comes due. In particular, the Cdn$67.5 million aggregate principal amount of our 6.25% convertible debentures is due March 2017, the Cdn$80.5 million aggregate principal amount of our 5.60% convertible unsecured subordinated debentures is due June 2017 and the $460 million aggregate principal amount of our 9.0% notes is due in October 2018. There can be no assurance that our business will generate sufficient cash flow from operations or that future borrowings or refinancing opportunities will be available to us at an acceptable cost, in amounts sufficient, or at all, to enable us to service our debt obligations or to repay or redeem any such indebtedness at maturity, particularly because of our high levels of debt and the debt incurrence restrictions imposed by the various agreements governing our indebtedness. Steps taken to refinance our indebtedness or obtain other third party financing, if any, may not be successful and may not permit us to meet our scheduled debt service obligations, which could have a material adverse effect on our liquidity and financial condition.

In addition, a payout of a significant portion of our cash flow through any dividends, and/or to service our debt, including pursuant to the mandatory amortization feature of the New Senior Secured Credit Facilities, as well as the 50% cash sweep, may result in us not retaining a sufficient amount of cash to finance growth and reinvestment opportunities, including through the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us. As a result, we may have to forego growth and reinvestment opportunities that would otherwise be desirable, if we do not find alternative sources of financing for such opportunities or modify our dividend policy to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could also limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors. We cannot provide any assurance that we will be able to identify, finance or close any transactions associated with any such growth or reinvestment opportunities on acceptable terms or timing, or at all.

Further, if we are unable to generate sufficient cash flow from operations, our ability to support our liquidity needs, including, but not limited to the payment of any dividends, servicing our debt obligations, including pursuant to the mandatory amortization feature of the New Senior Secured Credit Facilities, as well as the 50% cash sweep, or financing internal or external growth opportunities, will depend on our ability to access the credit and capital markets, neither of which may be available to us on acceptable terms, or at all. Currently, because we no longer qualify as a "well-known seasoned issuer," which previously enabled us to, among other things, file automatically effective shelf registration statements, even if we were able to access the capital markets, any attempt to do so could be more expensive or subject to significant delays. Further, access to the credit and capital markets and the cost and availability of credit may be adversely affected by factors beyond our control, including turmoil in the financial services industry, volatility in securities trading markets and general economic conditions. We cannot provide any assurance that we will be able to access the credit or capital markets on acceptable terms or timing, or at all.

Table of Contents

We cannot provide any assurance regarding the outcome of evaluation of the broad range of potential options we are considering or the implications any such potential options may have on our business

As further discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Strategy Update", we are committed to evaluating a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options. Some or all of such options could potentially trigger change of control provisions in certain debt and other agreements to which we are a party or impose limitations on our ability to use our net operating losses in the future. However, certain of our projects are subject to transfer restrictions, which may prevent us from transferring such projects on economically favorable terms or at all. See " Risks Related to Our Business and Our Projects Our equity interests in certain projects may be subject to transfer restrictions." No assurance can be given as to how the evaluation of any such potential options may evolve or the actual or threatened impact any such options may have on our stock price. In addition, even if we choose to implement any such potential option, we may be unsuccessful in doing so or we may implement an option that yields unexpected results. The process of reviewing, and potentially executing, any such potential option, may be very costly and time-consuming and may distract our management and otherwise disrupt our operations, which could have an adverse effect on our business, financial condition and results of operations. Further, no assurance can be given that any such option, if and when identified, will be approved by our shareholders if such approval is required.

Future dividends are not guaranteed

Dividends to shareholders are paid at the discretion of our board of directors. Future dividends, if any, will depend on, among other things, the availability of cash flow from dividend payments rather than allocations of cash, the results of operations, working capital requirements, financial condition, restrictive covenants and our ability to satisfy such covenants, business opportunities, provisions of applicable law and other factors that our board of directors may deem relevant. See " We may not generate sufficent cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunitites or fund our operations" and " Our indebtedness and financing arrangements and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make dividend payments, acquisitions or investments or additional indebtedness, we would otherwise seek to do." Our board of directors may decrease the level of or entirely discontinue payment of dividends. In addition, if and for as long as we are in arrears on the declaration or payment of dividends on the 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares"), the 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares"), or the Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the Partnership, the Partnership will not be permitted to make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

Our New Senior Secured Credit Facilities contain certain terms, covenants and restrictions that could impact our available cash flow and results of operations and restrict our ability to make dividend payments, acquisitions or investments or issue additional indebtedness

Our New Senior Secured Credit Facilities contain certain terms, covenants and restrictions, including a mandatory amortization feature and customary prepayment provisions, including, among others, using 50% of the cash flow of the Partnership and its subsidiaries that remains after the application of funds, in accordance with customary priority, to certain items, including, but not limited to, the operations and maintenance expenses of the Partnership and its subsidiaries, debt service on the New Senior Secured Credit Facilities and other specified indebtedness and funding of a debt service

Table of Contents

reserve account. Such terms, covenants and restrictions may impact our available cash flow and limit our ability to retain sufficient amounts of cash to pay dividends, service our debt obligations or finance internal or external growth opportunities. Our New Senior Secured Credit Facilities are a primary source of our liquidity. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources".

The covenants under the New Senior Secured Credit Facilities include a requirement that the Partnership and its subsidiaries, maintain certain leverage and interest coverage ratios (each, as defined in the credit agreement governing the New Senior Secured Credit Facilities). The New Senior Secured Credit Facilities also contain customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds. Any such limitations could restrict our ability to, among other things, make dividend payments, acquisitions or investments or issue additional indebtedness.

Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make dividend payments, acquisitions or investments or issue additional indebtedness we otherwise would seek to do

The degree to which we are leveraged on a consolidated basis could have important consequences for our shareholders and other stakeholders, including:

- our ability to maintain our dividend payments at the current level if and when declared by our board of directors;
- our ability in the future to obtain additional financing for, among other things, the repayment or redemption of indebtedness and other debt service obligations and investment in internal and external growth opportunities, including the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us, or other purposes;
- our ability to refinance indebtedness on terms acceptable to us or at all;
- our ability to satisfy debt service and other obligations;
- our vulnerability to general adverse industry conditions and economic conditions, including but not limited to adverse changes in foreign exchange rates and commodity prices;
- the availability of cash flow to fund other corporate purposes and grow our business;
- our flexibility in planning for, or reacting to, changes in our business and the industry; and
- placing us at a competitive disadvantage to our competitors that are not as highly leveraged.

As of December 31, 2013, our consolidated long-term debt represented approximately 63% of our total capitalization, comprised of debt and balance sheet equity. As of February 27, 2014, giving effect to the New Senior Secured Credit Facilities and the related use of proceeds thereunder our consolidated long-term debt represented approximately 65% of our total capitalization.

The agreements governing our indebtedness limit, but do not prohibit, the incurrence of additional indebtedness. Our current or future borrowings could increase the level of financial risk to us and, to the extent that the interest rates are not fixed and rise, or that borrowings are refinanced at higher rates, our available cash flow and results of operations could be adversely affected. Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 95% of our debt, including our share of the project-level debt associated with equity

20

Table of Contents

investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

As of December 31, 2013, we had (i) no amount outstanding and $97.9 million was issued in letters of credit under our revolving credit facility, (ii) $405.2 million of outstanding convertible debentures, (iii) $398.6 million of outstanding non-recourse project-level debt, and (iv) $1.1 billion of unsecured debt. As of February 27, 2014, we had (i) no amount outstanding and $144.1 million in letters of credit outstanding under our New Revolving Credit Facility, (ii) $405.2 million of outstanding convertible debentures, (iii) $390.5 million of outstanding non-recourse project-level debt, and (iv) $1.3 billion of unsecured debt.

As previously disclosed in our Current Report on Form 8-K filed on January 30, 2014, due to the aggregate impact of the up-front costs resulting from the prepayments on certain of our indebtedness using the proceeds of New Term Loan Facility, including the make-whole payment and charges for unamortized debt discount and fee expenses (all such up-front costs, collectively, the "Prepayment Charges"), which will be reflected as charges to our 2014 first quarter results, we are no longer in compliance with the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing our 9.0% notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments. As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (as defined in the indenture governing our 9.0% notes) (approximately $61 million at December 31, 2013) until such time that we are in compliance with the fixed charge coverage ratio. For the year ended December 31, 2013, dividend payments to our shareholders totaled approximately Cdn$48 million for the full year, on a pro forma basis reflecting the lower Cdn$0.03333 per common share monthly dividend first declared in March 2013. The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, if we pursue further debt reduction, including the potential repurchase or redemption, by means of a tender offer or otherwise, of up to $150 million aggregate principal amount of our 9.0% notes, any similar prepayment charges incurred in connection with such debt reduction would also be reflected in the calculation of the fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense.

In addition, some of our projects currently have non-recourse term loans or other financing arrangements in place with various lenders. These financing arrangements are typically secured by all of the project assets and contracts as well as our equity interests in the project. The terms of these financing arrangements generally impose many covenants and obligations on the part of the borrower. For example, some of these agreements contain requirements to maintain specified historical, and in some cases prospective debt service coverage ratios before cash may be distributed from the relevant project to us, which would adversely affect our available cash flow. We have, in the past, failed to meet the cash flow coverage ratio tests at certain of our projects, which restricted those projects from making cash distributions. Although all of our projects with non-recourse loans are currently meeting their debt service requirements, we cannot provide any assurances that our projects will generate enough future cash flow to meet any applicable ratio tests in order to be able to make distributions to us.

In many cases, an uncured default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the particular project(s) to us and may entitle the lenders to demand repayment and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition,

Table of Contents

failure to comply with the terms, restrictions or obligations of any of our revolving credit facility, convertible debentures or unsecured notes, or the preferred shares of the Partnership, or any other financing arrangements, borrowings or indebtedness, or events of default thereunder, may entitle the lenders to demand repayment, accelerate related debt as well as any other debt to which a cross-default or cross-acceleration provision applies and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, if and for as long as we are in arrears on the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares. Additionally, if our lenders under our indebtedness demand payment, we may not, at that time, have sufficient cash and cash flows from operating activities to repay such indebtedness.

Our failure to refinance or repay any indebtedness when due could constitute a default under such indebtedness and restrict our ability to take certain actions, including paying dividends. In addition, any covenant breach or event of default could harm our credit rating and our ability to obtain additional financing on acceptable terms or at all. The occurrence of any of these events could have a material adverse effect on our business, results of operations, financial condition and liquidity.

Exchange rate fluctuations may adversely affect our available cash flow and results of operations

Our payments to shareholders, some of our corporate-level long-term debt and convertible debenture holders are denominated in Canadian dollars. Conversely, some of our projects' revenues and expenses are denominated in U.S. dollars. Our 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. As a result, we are exposed to currency exchange rate risks, against which we do not typically hedge our entire exposure. Any arrangements to mitigate this exchange rate risk may not be sufficient to fully protect against this risk. If hedging transactions do not fully protect against this risk, changes in the currency exchange rate between U.S. and Canadian dollars could adversely affect our available cash flow and results of operations.

A downgrade in our credit rating or in the credit rating of our outstanding debt securities, or any deterioration in 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 our credit rating, a downgrade in the credit rating of our outstanding debt securities, which we have recently experienced, or any deterioration in 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, restrict access to our revolving credit facility and/or trigger termination rights or enhanced disclosure requirements under certain contracts to which we are a party. Any downgrade of our corporate credit rating could cause counterparties to require us to post letters of credit or other additional collateral, make cash prepayments, or obtain a guarantee agreement, 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.

Table of Contents

Changes in our creditworthiness may affect the value of our common shares

Changes to our perceived creditworthiness and ability to meet our required covenants on an on-going basis may affect the market price or value and the liquidity of our common shares.

The future issuance of additional common shares could dilute existing shareholders

From time to time, we may decide to issue additional common shares, redeem outstanding debt for common shares, or repay outstanding principal amounts under existing debt by issuing common shares. We may also, from time to time, decide to issue common shares to meet strategic objectives or in connection with acquiring assets or pursuing broader strategic options. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Strategy Update". The issuance of additional common shares may have a dilutive effect on shareholders and may adversely impact the price of our common shares.

Volatile capital and credit markets may adversely affect our ability to raise capital on favorable terms and may adversely affect our business, results of operations, financial condition and cash flows

Disruptions in the capital and credit markets in the United States, Canada or abroad can adversely affect our ability to access the capital markets. Our access to funds under our credit facility is dependent on the ability of the banks that are parties to the facility to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Longer term disruptions in the capital and credit markets as a result of turmoil in the financial services industry, volatility in securities trading markets and general economic conditions could result in an inability to support our liquidity needs, including, but not limited to, the payment of any dividends, service of our debt obligations or financing of internal or external growth opportunities. Currently, because we no longer qualify as a "well-known seasoned issuer," which previously enabled us to, among other things, file automatically effective shelf registration statements, even if we were able to access the capital markets, any attempt to do so could be more expensive or subject to significant delays. See " We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities."

Our ability to arrange for financing on a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general industry, economic and capital market conditions;
- the availability of bank credit;
- investor confidence;
- our financial condition, performance and prospects as well as companies in our industry or similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available to us, either as a result of market conditions or our financial condition, we may not be able to pay dividends, service our debt obligations or finance internal or external growth opportunities, any of which would adversely affect our business, results of operations and financial condition.

Table of Contents

We have guaranteed the performance of some of our subsidiaries, which may result in substantial costs in the event of non-performance

We have issued certain guarantees of the performance of some of our subsidiaries in certain situations, which obligates us to perform in the event that the subsidiaries do not perform. In the event of non-performance by the subsidiaries, we could incur substantial cost to fulfill our obligations under these guarantees. Such performance guarantees could have a material impact on our business, results of operations, financial condition and cash flows. See Notes 10, 25 and 26 to the consolidated financial statements for information on our guarantee obligations.

We have anti-takeover protections that may discourage, delay or prevent a change in control that could benefit our shareholders.

The BCBCA and our Articles of Continuance contain provisions that could make it more difficult for a third party to acquire us without the consent of our Board of Directors ("Board"). These provisions include:

- As a notice of meeting is required to include certain particulars in the case where a shareholder meeting is being requisitioned by shareholders, our Board must be given advance notice regarding special business that is to be brought by such requisitioning shareholders before the shareholder meeting. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location;

- Under the BCBCA, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders, provided that such shareholders represent at least 1% of the voting shares of a company or such shares have a fair market value of at least Cdn$2,000. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities; and

- Casual vacancies on our Board can be approved prior to the next annual meeting of shareholders by the directors of our Board of Directors.

If we experience a change of control, unless we elect to make a voluntary prepayment of the term loan under the New Senior Secured Credit Facilities, the Partnership will be required to offer each electing lender to prepay such lender's term loans under the New Senior Secured Credit Facilities at a price equal to 101% of par. Additionally, a change in control will permit holders of our convertible debentures to require that we purchase the debentures upon the conditions set forth in the respective indenture governing the debentures, which may discourage, delay or prevent a change of control or the acquisition of a substantial block of our common shares. In addition, some of our PPAs or other commercial agreements may contain change of control provisions.

We have also adopted a shareholder rights plan that may delay or prevent a change of control or the acquisition of a substantial block of our common shares and may make any future unsolicited acquisition attempt more difficult. Under the rights plan:

- The rights will generally become exercisable if a person or group acquires 20% or more of Atlantic Power's outstanding common shares (unless such transaction is a "permitted bid" or a transaction to which the application of the shareholders rights plan has been waived pursuant to the terms of the plan) and thus becomes an "acquiring person." A "permitted bid" is an offer

Table of Contents

pursuant to which, among other things, such person or group agrees to hold the offer open to all shareholders for a period longer than the statutorily required period;

Each right, when exercisable, will entitle the holder, other than the "acquiring person," to acquire shares of Atlantic Power's common shares at a significant discount to the then-prevailing market price; and

As a result, the rights plan may cause substantial dilution to a person or group that becomes an "acquiring person" and may discourage or delay a merger or acquisition that shareholders may consider favorable, including transactions in which shareholders might otherwise receive a premium for their shares.

Our common shares may not continue to be qualified investments under Canadian tax laws

There can be no assurance that our common shares will continue to be qualified investments under relevant Canadian tax laws for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax-free savings accounts. Canadian tax laws impose penalties for the acquisition or holding of non-qualified or ineligible investments.

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 hold a promissory note from our primary U.S. holding company (the "Intercompany Note") and are required to include, in computing our taxable income, interest on the Intercompany Note.

Canadian federal income tax laws and policies could be changed in a manner which adversely affects holders of our common shares

There can be no assurance that Canadian federal income tax laws and Canada Revenue Agency administrative policies respecting the Canadian federal income tax consequences generally applicable to us, to our subsidiaries, or to a U.S. or Canadian holder of common shares will not be changed in a manner which adversely affects holders of our common shares.

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 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 United States 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.

Table of Contents

We received advice from our U.S. tax counsel at the time of the issuance, 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. The Partnership has also 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. However, it is possible that the Internal Revenue Service (the "IRS") could successfully challenge these positions and assert that any of these arrangements should be treated as equity rather than debt for U.S. federal income tax purposes or that the interest on such arrangements is 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 respective 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.

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 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 under 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 each U.S. holding company's net interest expense (the interest paid by each U.S. holding company on all debt, including the Intercompany Note and the Partnership Financing Arrangements, less its interest income) exceeds 50% of its 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. In addition, 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 companies 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. 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

Table of Contents

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, including as a result of implementation of any of the broad range of potential options we are committed to evaluating, our ability to realize these benefits may be limited. See " We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities or fund our operations." 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.

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.

We are subject to significant pending civil litigation, which if decided against us, could require us to pay substantial judgments or settlements and incur expenses that could have a material adverse effect on our business, results of operations, financial condition and liquidity.

In addition to being subject to litigation in the ordinary course of business, we are party to numerous legal proceedings, including securities class actions, from time to time. On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints related to, among other things, claims that we made materially false and misleading statements and omissions regarding the sustainability of our common share dividend that artificially inflated the price of our common shares were filed in the United States District Court for the District of Massachusetts against us and certain of our current and former executive officers. On March 19, 2013 and April 2, 2013, two notices of action relating to purported Canadian securities class action claims were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, in the Ontario Superior Court of Justice in the Province of Ontario and on April 8, 2013, a similar claim, issued by alleged investors in Atlantic Power common shares, seeking to initiate a purported class action was filed in the Superior Court of Quebec in the Province of Quebec against us and certain of our current and former executive officers. On May 2, 2013, a statement of claim relating to the April 2, 2013 notice of action was filed with the Ontario Superior Court of Justice in the Province of Ontario. The allegations of these purported class actions are essentially the same as those asserted in the United States.

These litigations may be time consuming, expensive and distracting from the conduct of our daily business. Due to the nature of these proceedings, the lack of precise damage claims (other than in certain Canadian Actions, as defined in "Item 3. Legal Proceedings") and the type of claims we are subject to, we are unable to determine the ultimate or maximum amount of monetary liability or financial impact, if any, to us in these legal matters, which unless otherwise described in "Item 3. Legal Proceedings", seek damages from the defendants of material or indeterminate amounts. As a result, we are also unable to reasonably estimate the possible loss or range of losses, if any, arising from these litigations. Although we are unable at this time to estimate what our ultimate liability in these matters may be, it is possible that we will be required to pay substantial judgments or settlements and incur expenses that could have a material adverse effect on our business, results of operations, financial condition and liquidity. We intend to defend vigorously against these actions. For additional information with respect to these unresolved matters, see "Item 3. Legal Proceedings".

Table of Contents

Risks Related to Our Business and Our Projects

The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between August 2014 and December 2037. See Item 1. 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 may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. 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 and the value of the project may be impaired such that we would be required to record an impairment loss under applicable accounting rules. See " Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition".

For example, we are currently in negotiations with purchasers of power at our Selkirk and Tunis projects, whose PPAs expire in August 2014 and December 2014, respectively, and which represented 7.7% and 3.5% of our total Project Adjusted EBITDA for the year ended December 31, 2013, respectively. If Selkirk does not obtain a new PPA, this could result in 100% of the capacity at Selkirk not contracted and therefore sold at market power prices. With respect to Tunis, because it has not been in the first group for which recontracting discussion are currently underway with the Ontario government and the process for such discussions has not been transparent, the outcome of recontracting discussions at the project is uncertain and we expect that a new PPA, if any, at Tunis, would be on significantly less favorable terms than the project's existing PPA. Beyond the expiration of the Selkirk and Tunis PPAs in 2014, our next PPA expirations do not occur until year-end 2017 and are at our North Bay and Kapuskasing projects in Ontario. The loss of significant PPAs, our inability to secure new PPAs on favorable terms or at all, or the breach by the other parties to such contracts that prevents us from fulfilling our obligations thereunder, could have a material adverse impact on our business, results of operations and financial condition.

Our projects depend on their electricity and thermal energy customers and there is no assurance that these customers will perform their obligations or make required payments

Each of our projects relies 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. At times, we rely on a single customer or a limited number of customers to purchase all or a significant portion of a project's output. In 2013, the largest customers of our power generation projects, including projects recorded under the equity method of accounting, are OEFC, San Diego Gas & Electric, and BC Hydro which purchase approximately 27.7%, 14.4% and 10.1%, respectively, of the net electric generation capacity of our projects. If a customer stops purchasing output from our power generation projects or purchases less power than anticipated, such customer may be difficult to replace, if at all. Further concentration of our customers would increase our dependence on any one customer. Our cash flows and results of operations, including the amount of cash available to make payments on our indebtedness, are highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their contractual obligations or make required payments.

Further, our customers generally have investment-grade credit ratings, as measured by Standard & Poor's. Customers that have assigned ratings at the top end of the range have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the

Table of Contents

bottom end of the range have the weakest capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition

Those of our projects operating without a PPA or with 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, which may not be favorable. The open market wholesale prices for electricity are very volatile. Long and short-term power prices may fluctuate substantially due to other factors outside of our control, including:

- changes in generation capacity in the electricity markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation facilities, expansion or retirement of existing facilities or additional transmission capacity;
- electric supply disruptions, including plant outages and transmission disruptions;
- fuel transportation capacity constraints;
- weather conditions;
- changes in the demand for power or in patterns of power usage;
- development of new fuels and new technologies for the production or storage of power;
- development of new technologies for the production of natural gas;
- availability of competitively priced renewable fuel sources;
- available supplies of natural gas, crude oil and refined products, and coal;
- interest rate and foreign exchange rate fluctuation;
- availability and price of emission credits;
- geopolitical concerns affecting global supply of oil and natural gas;
- general economic conditions which impact energy consumption in areas where we operate; and

power market, fuel market and environmental regulation and legislation.

The market price for electricity is affected by changes in demand for electricity. Factors such as economic slowdown, worse than expected economic conditions, milder than normal weather, the growth of energy efficiency and efforts aimed at energy conservation, among others, could reduce energy demand or significantly slow the growth in demand for electricity, thereby reducing the market price for electricity. A reduction in demand could contribute to conditions that no longer support the continued operation of certain power generation projects, which could adversely affect our results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs, among others.

Table of Contents

We are also exposed to market power prices 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, approximately 56% of the facility's capacity is currently not contracted. The facility can generate and sell this excess capacity into the grid at market prices. If market prices do not justify the increased generation, the project has no requirement to sell any excess capacity. 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. The expiration of the current PPA at Selkirk is August 2014. If the project does not obtain a new PPA, this could result in an increase to 100% of the capacity not contracted and therefore sold at market power prices. As a result, fluctuations in the price of electricity may have a material adverse effect on the operating margins of these facilities and on our business, results of operations and financial condition.

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. 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. If our suppliers are unable to perform their contractual obligations or we are unable to renegotiate our fuel supply agreements, we may seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price. Changes in market prices for natural gas, biomass, coal and oil may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- additional generating capacity;
- disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil, refined products and coal production levels;
- changes in market liquidity;
- governmental regulation and legislation; and
- our creditworthiness and liquidity, and the willingness of fuel suppliers/transporters to do business with us.

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. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. To the extent possible, our projects attempt to match fuel cost setting mechanisms in supply agreements to energy payment formulas in the PPA and to provide for indexing or pass-through of fuel costs to 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. To the extent that costs are not matched well to PPA energy payments, pass through of fuel costs is not allowed or hedging strategies are unsuccessful, increases in fuel costs may adversely affect our results of operation. This may have a material adverse effect on our business, results of operations and financial condition. Our energy payments at our Orlando project are subject to fluctuations as the energy payments are comprised of a fuel component based on the cost of coal consumed at a nearby coal-fired generating station.

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, and that will in turn be available for any dividends paid to our shareholders, as debt service obligations, investments in internal or external growth opportunities or funding of our operations. There is a risk of equipment failure due to wear and tear, more frequent and/or larger than forecasted downtimes for equipment maintenance and repair, unexpected construction delays, latent defect, design error or operator error, or force majeure events, among other things, which could adversely affect revenues and cash flow. For example, we have previously experienced delays in achieving commercial operations at our Piedmont project as a result of repairs to the project's steam turbine from damage sustained during late-stage testing and are also currently disputing certain issues with the engineering, procurement and construction contractor of the project regarding the condition and performance of the project. Additionally, older equipment, even if maintained in accordance with good practices, is subject to operational failure, including events that are beyond our control, and may require unplanned expenditures to operate efficiently. Unplanned outages of generation facilities, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues or require us to incur significant costs as a result of obtaining replacement power from third parties in the open market to satisfy our obligations.

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. To the extent that we suffer disruptions of plant availability and power generation due to transformer failures or for any other reason, there could be a material adverse effect on our business, results of operations and financial condition and the amount of available cash flow may be adversely affected.

We provide letters of credit under our $210 million New 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.

The effects of weather and climate change may adversely impact our business, results of operations and financial condition

Our operations are affected by weather conditions, which directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal

Table of Contents

levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues. To the extent that weather is warmer in the summer or colder in the winter than assumed, we may require greater resources to meet our contractual commitments. These conditions, which cannot be accurately predicted, may have an adverse effect on our business, results of operations and financial condition by causing us to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

To the extent climate change contributes to the frequency or intensity of weather related events, our operations and planning process could be impacted, which may adversely impact our business, results of operations and financial condition.

Revenues from windpower projects are highly dependent on suitable wind and associated weather conditions and in the absence of such suitable conditions, our wind energy projects may not meet anticipated production levels, which could adversely affect our forecasted revenues

We own interests in five windpower projects, which are subject to substantial risks. 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 resources 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 acquiring or 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 revenues.

Revenues from hydropower projects are highly dependent on suitable precipitation and associated weather conditions and in the absence of such suitable conditions, our hydropower projects may not meet anticipated production levels, which could adversely affect our forecasted revenues.

We own interests in four hydropower projects, which are subject to substantial resource risks. The energy and revenues generated at a hydro energy project are highly dependent on climatic conditions, particularly precipitation patterns, which are variable and difficult to predict for any given year. We base our investment decisions with respect to each hydro energy project on the historical stream flow records for the area. However, actual climatic conditions in any given year may not meet the historical averages which would impair our ability to meet anticipated production levels, which could adversely affect our forecasted revenues.

U.S., Canadian and/or global economic conditions and uncertainty could adversely affect our business, results of operations and financial condition

Our business may be affected by changes in U.S., Canadian and/or global economic conditions, including inflation, deflation, interest rates, availability of capital, consumer spending rates and the effects of governmental initiatives to manage economic conditions. Uncertainty about global economic conditions may cause consumers to alter behaviors that may directly or indirectly reduce energy spending, which could have a material adverse effect on demand for our product. Volatility in the financial markets and the deterioration of national and global economic conditions may have a material adverse effect on our business, results of operations and financial condition.

Financial markets can also be, and have been in the past, affected by concerns over U.S. fiscal policy, as well as the U.S. federal government's debt ceiling, federal deficit and related budget and tax

Table of Contents

issues. These concerns continue to raise discussions relating to the stability of the long-term sovereign credit rating of the United States. Any actions taken by the U.S. federal government regarding the debt ceiling or the federal deficit or any action taken or threatened by ratings agencies, could significantly impact the global and U.S. economies and financial markets. Any such economic downturn could have a material adverse effect on our business, results of operations and financial condition.

Risks that are beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition

Man-made events, such as acts of terror and governmental responses to acts of terror, could adversely affect general economic conditions, which could have a material impact on our business, results of operations and financial condition. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Our projects may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of the ability of the projects to generate and/or transmit electricity. Any such environmental repercussions or other disruption could result in a decline in energy consumption and significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects could also be impacted by natural disasters, such as earthquakes, floods, lightning activity, hurricanes, tropical storms, winter storms, tornadoes, wind, seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive or otherwise disrupt our operations or compromise the physical or cyber security of our facilities, which could result in increased costs and could adversely affect our ability to manage our business effectively. We maintain standard insurance against catastrophic losses, which are subject to deductibles, limits and exclusions; however, our insurance coverage may not be sufficient to cover all of our losses. Additionally, future significant weather related events, natural disasters and other similar events that have an adverse effect on the economy could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition.

Our business faces significant operating hazards, natural disaster risks and other hazards such as fire and explosions and insurance may not be sufficient to cover all losses

Our business involves significant operating hazards related to the generation of electricity, including hazards related to acquiring, transporting and unloading fuel, operating large pieces of rotating equipment, structural collapse, machinery failure, and delivering electricity to transmission and distribution systems. In addition, we are exposed to natural disaster risks and other hazards such as fire and explosions. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, disruption of communication systems and technology, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being subject to various litigation matters, including regulatory and administrative proceedings, asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. While we believe that the projects maintain an amount of insurance coverage that is adequate and 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 or insured, nor that the amounts of insurance will

Table of Contents

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, results of operations, financial condition and future prospects.

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

Our business is subject to extensive Canadian and U.S. federal, state, provincial and local laws and regulations. Compliance with the requirements under these various regimes may cause us to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines and/or civil or criminal liability.

Generally, in the United States, our projects are subject to regulation by the 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 QF projects and the siting of the generation facilities. The majority of our generation is sold by QF projects under PPAs that required approval by state authorities.

The EP Act of 2005 also limited the requirement that electric utilities buy electricity from QFs 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.

If any project were to lose its status as a QF, it would lose its ability to make sales to utilities on favorable terms. Such project may no longer be entitled to exemption from provisions of PUHCA of 2005 or from certain provisions of the Federal Power Act and state law and regulations. Loss of QF status could also 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. In such event, our business, results of operations and financial condition could be negatively impacted.

Notwithstanding their status as QFs and EWGs, our facilities remain subject to numerous FERC regulations, including those relating to power marketer status, approval of mergers, acquisitions and investments relating to utilities, and mandatory reliability rules and regulations delegated to NERC. Any violation of these rules and regulations could subject us to significant fines and penalties and negatively impact our business, results of operations and financial condition.

The EP Act of 2005 and other federal and state programs also may provide incentives for various forms of electric generation technologies, which may subsidize our competitors. The U.S. regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale competition and the creation of incentives for the addition of large amounts of new renewable energy generation and, in some cases, transmission. These changes are ongoing and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism as well as proposals to re-regulate the markets. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, or new law or other future regulatory developments are introduced, our business, results of operations and financial condition could be negatively impacted.

Generally, in Canada, our projects are subject to energy regulation primarily by the relevant provincial authorities. In addition, our projects are subject to Canada's corporate, commercial and other laws of general application to businesses. Our projects require licenses, permits and approvals

Table of Contents

which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable licenses, permits and approvals, our business, results of operations and financial condition could be adversely affected.

Additionally, public policy mechanisms and favorable regulatory incentives in the United States and Canada, including production and investment tax credits, cash grants, loan guarantees, accelerated depreciation tax benefits, renewable portfolio standards, and carbon trading plans, impact the viability of our renewable energy projects. As a result of budgetary constraints, political factors or otherwise, governments from time to time may review their policies that support renewable energy and consider actions to make the policies less conducive to the development and operation of renewable energy facilities. Any reductions to, or the elimination of, governmental incentives that support renewable energy, or the imposition of additional taxes or other assessments on renewable energy, could result in a material adverse effect on our business, results of operations and financial condition.

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

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 the generation, transmission and distribution of electricity within British Columbia. Our projects in that province are subject to these laws. These 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.

The *Clean Energy Act*, which became law in British Columbia in 2010, sets out British Columbia's energy objectives, one of which is the generation of at least 94% of the electricity in British Columbia from clean or renewable resources. BC Hydro is required to submit resource plans outlining how it will meet these objectives and requires the province to be energy self-sufficient by 2016. 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 and/or the province's energy objectives could impact the market for electricity generated by our British Columbia projects although BC Hydro is currently limited by regulation to undertaking efficiency improvements at its existing facilities and only undertaking development of new generation facilities/projects with BCUC approval. 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 *Utilities Commission Act* governs the BCUC, which is responsible for the regulation of British Columbia's public energy utilities, which include publicly owned and investor owned utilities (*i.e.,* independent power producers). All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the 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. Consequently, power procurement is controlled by the BCUC and, as a result, our potential contracts with BC Hydro may be subject to terms that adversely affect us.

Table of Contents

(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 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. While all of our Ontario projects are currently licensed, the OEB has the authority to effectively modify the licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the 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. Thus, the OEB'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 IESO, Hydro One, the ESA, OEFC and OPA. All these agencies may affect our projects.

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

Many of 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 federal 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 or identified through self-certification, compliance audits, spot checking, self-reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submissions, exception reporting, and complaints. The penalty that could 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, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects are subject to significant environmental and other regulations

Our projects are subject to numerous and significant federal, state, provincial and local laws, including statutes, regulations, by-laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers' health and safety matters. Our facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, penalties and property damage. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters. We have implemented environmental, health and safety management programs designed to regularly improve environmental, health and safety performance, but there is no guarantee that such programs will fully and effectively eliminate the inherent risk of environmental, health and safety liabilities related to the operation of our projects.

Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In the United States, the Clean Air Act and related regulations and programs of the Environmental Protection Agency (the "EPA") extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds by power plants. In March 2005, the EPA promulgated the Clean Air Interstate Rule ("CAIR"), which requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through participation in a cap and trade system or more aggressive state-by-state emissions limits. Although implementation of the CAIR is underway, the EPA is subject to a court order to develop a more stringent replacement rule. Other more stringent EPA air emission regulations currently being implemented include the more stringent national ambient air quality standards for sulfur dioxide, issued in June 2010, and for fine particulate matter, issued in December 2012, and the new mercury and air toxics emissions standards for power plants, issued in December 2011. Meeting these new standards, when implemented, may have a material adverse impact on our business, results of operations and financial condition.

The U.S. Resource Conservation and Recovery Act 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 alternative 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 alternative 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 associated costs that may have a material adverse impact on our business, results of operations and financial condition.

Similar increasingly stringent environmental regulations also apply to our projects in British Columbia and Ontario.

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. Some of our projects' PPAs do not allow for the pass through of emissions allowance or emission reduction capital expenditure costs. 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, 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

Table of Contents

cannot be predicted and which could have a material adverse effect on our business, results of operations and financial condition.

If additional regulatory requirements are imposed on energy companies mandating limitations on greenhouse gas emissions or requiring efficiency improvements, such requirements may result in compliance costs that alone or in combination could make some of our projects uneconomical to maintain or operate

The EPA, other regulatory agencies, environmental advocacy groups and other organizations are focusing considerable attention on greenhouse gas emissions from power generation facilities and their potential role in climate change. We expect that additional EPA regulations, and possibly additional legislation and/or regulation by other regulatory authorities, may be issued, resulting in the imposition of additional limitations on greenhouse gas emissions or requiring efficiency improvements from fossil fuel-fired electric generating units.

There are also potential impacts on our natural gas businesses as greenhouse gas legislation or regulations may require greenhouse gas emission reductions from the natural gas sector and could affect demand for natural gas. Additionally, greenhouse gas requirements could result in increased demand for energy conservation and renewable products, as well as increase competition surrounding such innovation. Additionally, our reputation could be damaged due to public perception surrounding greenhouse gas emissions at our power generation projects. Any such negative public perception could ultimately result in a decreased demand for electric power generation or distribution. Several regions of the United States and Canada have moved forward with greenhouse gas emission regulation.

For example, the multi-state carbon dioxide ("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. The Western Climate Initiative 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 (the "CARB") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector) to reduce state-wide emissions of greenhouse gases to 1990 levels by 2020. Under the CARB regulations that took effect on January 1, 2013, electricity generators and certain other facilities are now subject to an allowance for greenhouse gas emissions, with allowances allocated by both formulas set by the CARB and auctions.

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 PPAs 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 ("MWh") associated with combined-cycle, gas turbine baseload generation, such as our North Island project.

In addition to the regional initiatives, President Obama has declared action addressing climate change to be a major priority for his second term, and the EPA has taken several recent actions for the regulation of greenhouse gas emissions.

The EPA's actions include its December 2009 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 required large sources, including power plants, to monitor and report greenhouse gas emissions to the EPA annually, which was required beginning in 2011, and its issuance in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, which under a phased-in approach 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. In addition, in September 2013, the EPA issued a new proposed rule regulating carbon emissions from new electric generating units. For existing electric generating units, the EPA is scheduled to issue a proposed rule regulating carbon emissions by June 2014, to issue a final rule by June 2015, and to require states to submit revisions to their implementation plans addressing the new rule by June 2016. In Canada, British Columbia and Ontario have implemented greenhouse gas reporting regulations and are developing additional programs to address greenhouse gas emissions.

Concerning our projects in British Columbia, regulatory restrictions stemming from the GGRTA and the GGRCTA, and financial commitments arising in connection with the requirements under the CTA, could affect our ability to operate our projects in British Columbia and affect our profitability.

All of our subject generating facilities have complied on a timely basis with the new EPA and Ontario greenhouse gas reporting requirements. Compliance with greenhouse gas emission reduction requirements may require increasing the energy efficiency of equipment at our natural gas projects, committing significant capital toward carbon capture and storage technology, purchase of allowances and/or offsets, fuel switching, and/or retirement of high-emitting projects and potential replacement with lower emitting projects. The cost of compliance with greenhouse gas emission legislation and/or regulation is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon capture and storage technology, and the selected compliance alternatives. We cannot estimate the aggregate effect of such requirements on our business, results of operations, financial condition or our customers. However, such expenditures, if material, could make our generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect our business, results of operations and financial condition.

Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition

As of December 31, 2013, we had approximately $296.3 million of goodwill, which represented approximately 9% of our total assets on our consolidated balance sheets. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. We could be required to, and have in the past, evaluated the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to, deterioration in general economic conditions or our operating or regulatory environment, increased competitive environment, an increase in fuel costs (particularly when we are unable to pass through the impact to customers), negative or declining cash flows, loss of a key contract or customer (particularly when we are unable to replace it on equally favorable terms), divestiture of a significant component of our business or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if any acquisitions we make do not perform as expected. See Note 7 to the consolidated financial statements included in this Annual Report on Form 10-K.

Long lived assets are initially recorded at fair value and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived

Table of Contents

assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

Increasing competition could adversely affect our performance and the performance of our project

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 PPAs, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. Further, changes in technology, including fuel cells, microturbines and solar cells, may facilitate the entrance of new competitors, increase the supply of electricity or reduce the cost of methods of producing power that we do not currently use. If these technologies became cost competitive, we could face increasing competition and the value of our generating facilities could be reduced. In addition, we continue to confront significant competition for acquisition and investment opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms, if at all. Increasing competition among participants in the power generation industry may adversely affect our performance and the performance of our projects. Further, a payout of a significant portion of our cash flow through dividends, and/or to service our debt, may result in us not retaining a sufficient amount of cash to finance acquisition or investment opportunities and make other capital and operating expenditures. See " Risk Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities."

We have limited control over management decisions at certain projects

Approximately one third of 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 CEM and PPMS) operate eight of our projects. As such, we must rely on the technical and management expertise of these third-party operators although typically we negotiate to obtain positions 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, our cash flow may be adversely affected. The approval of third-party operators also may be required for us to receive distributions of funds from projects or to transfer our interest in projects. Our inability to control fully certain projects could have an adverse effect on our business, results of operations and financial condition.

We may face significant competition for acquisitions and may not be able to finance our otherwise pursue, execute or successfully integrate acquisitions or new business initiatives

To the extent identification of and pursuit of acquisition opportunities forms a part of our strategy, 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 at all, or be sure that such acquisitions, if any, will be successfully integrated into our existing operations. In addition, a payout of a significant portion of our cash flow through dividends, and/or to service our debt obligations, may result in us not retaining a sufficient amount of cash to finance any acquisition or other growth opportunities, to the extent any such acquisition or other opportunities are available to us. As a result, we may have to forego such opportunities, even if they would otherwise be necessary or desirable, if we do not find alternative sources of financing for such opportunities or modify our dividend policy to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors. See "Risks Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities."

Although electricity demand is expected to grow, creating the need for more generation, such growth is expected to occur at a slower rate. The U.S. power industry is continuing to undergo consolidation and may offer attractive acquisition opportunities, but 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.

Any acquisition, investment or new business initiative 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, inadequate return on capital 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 or prior to launching an initiative or entering a market. We may not be indemnified for some or all these liabilities in an acquisition transaction. In addition, our funding requirements associated with acquisitions, integration and implementation costs may reduce the funds available to us to make any dividend payments.

Our equity interests in certain 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. For example, the sale of our Delta-Person project has required us to pursue transfer of certain permits in connection with the sale of the project. 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. See "Risks Related to Our Structure We are committed to evaluating a broad range of potential options and no assurance can be given as to how the evaluation of any such potential options may evolve or the implications of any such potential options."

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. These activities, though intended to mitigate price volatility, expose us to other risks. In the future, the project operators could recognize financial losses on these arrangements, including as a result of volatility in the market values of the underlying commodities, if a counterparty fails to perform under a contract or upon the failure or insolvency of a financial intermediary, exchange or clearinghouse used to enter, execute or clear the transactions. 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.

Table of Contents

Most of these contracts are recorded at fair value with changes in fair value recorded currently in the statement of operations, resulting in significant volatility in our income (loss) (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 (loss) (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 business, results of operations, financial condition 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 increases in natural gas prices, we have incurred income on these natural gas swaps. We execute these swaps only for the purpose of managing risks and not for speculative trading.

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our business, results of operations and financial condition may be improved or diminished based upon movement in commodity prices.

Certain employees are subject to collective bargaining

A number of our plant employees, from 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. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on our business, results of operations and financial condition.

Our Pension Plan may require additional future contributions

Certain of our employees in Canada are participants in a legacy defined benefit pension plan that we sponsor. As of December 31, 2013, our pension plan was fully funded on a going concern basis. The additional 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.

Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information, damage our reputation and otherwise have an adverse effect on our business, results of operations and financial condition

A cyber intrusion is considered to be any adverse event that threatens the confidentiality, integrity or availability of our information resources. More specifically, a cyber intrusion is an intentional attack or an unintentional event that can include gaining unauthorized access to systems to disrupt operations, corrupt data, steal confidential information, and impact our ability to make collections or otherwise impact our operations. We are dependent on various information technologies throughout our company to carry out multiple business activities. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. and/or Canadian bulk power system or our operations could view our computer systems, software or networks as attractive targets for cyber attack. In addition, our business requires that we collect and maintain confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack, such as unauthorized access, malicious software or other violations on the systems that control generation and transmission at our projects could severely disrupt business operations, diminish competitive advantages through reputation damages and increase operation costs. The breach of certain business systems could affect our ability to correctly record, process and report

Table of Contents

financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For these reasons, a significant cyber incident could materially and adversely affect our business, results of operations and financial condition.

Failure to comply with the U.S. Foreign Corrupt Practices Act and/or the Canadian Corruption of Foreign Public Officials Act could subject us to, among other things, penalties and legal expenses that could harm our reputation and have a material adverse effect on our business, results of operations and financial condition

We are subject to anti-corruption laws and regulations including the U.S. Foreign Corrupt Practices Act ("FCPA") and the Canadian Corruption of Foreign Public Officials Act (the "CFPOA"), which generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or keeping business and/or other benefits. In addition, the FCPA imposes accounting standards and requirements on U.S. publicly traded corporations and their foreign affiliates, which are intended to prevent the diversion of corporate funds to the payment of bribes and other improper payments, and to prevent the establishment of "off books" slush funds from which improper payments can be made (similar provisions have been proposed to be added to the CFPOA). The Securities and Exchange Commission has increased its enforcement of the FCPA during the past several years. In recent years, enforcement of the CFPOA in Canada has also increased and can be attributed, in part, to the establishment of the Royal Canadian Mounted Police's International Anti-Corruption Unit in 2008. Although we have implemented policies and procedures designed to ensure that we, our employees and other intermediaries comply with the FCPA and/or the CFPOA, there is no assurance that such policies or procedures will work effectively all of the time or protect us against liability under the FCPA and/or the CFPOA for actions taken by our employees and other intermediaries with respect to our business or any businesses that we may acquire. If we are not in compliance with the FCPA and/or the CFPOA, we may be subject to criminal penalties pursuant to the CFPOA and/or criminal and civil penalties and other remedial measures pursuant to the FCPA, including changes or enhancements to our procedures, policies and control, as well as potential personnel change and disciplinary actions, which could have an adverse impact on our business, results of operations and financial condition.

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 who have experience in our industry. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Further, an aging work force in the power industry necessitates recruiting, retaining and developing the next generation of leadership. A failure to attract and retain executives and other key employees with specialized knowledge in power generation could have an adverse impact on our business, results of operations and financial condition because of the difficulty of promptly finding qualified replacements.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We have included descriptions of the locations and general character of our principal physical operating properties, including an identification of the segments that use such properties, in "Item 1. Business," which is incorporated herein by reference. A significant portion of our equity interests in the entities owning these properties is pledged as collateral under our New Senior Secured Credit Facilities or under non-recourse operating level debt arrangements.

Our principal executive office is located at One Federal Street, 30th floor, Boston, Massachusetts under a lease that expires in 2023.

ITEM 3. LEGAL PROCEEDINGS

IRS Examination

In 2011, the IRS began an examination of our federal income tax returns for the tax years ended December 31, 2007 and 2009. On April 2, 2012, the IRS issued various Notices of Proposed Adjustments. The principal area of the proposed adjustments pertain to the classification of U.S. real property in the calculation of the gain related to our 2009 conversion from the previous income participating security structure to our current traditional common share structure. As of the date of this Annual Report on Form 10-K, the examination is before the IRS Office of Appeals. We continue to vigorously contest these proposed adjustments, including pursuing all administrative and judicial remedies available to us. We expect to be successful in sustaining our positions with no material impact to our financial results. We believe that an adjustment, if any, would be offset by net operating loss carry forwards. No accrual has been made for any contingency related to any of the proposed adjustments as of December 31, 2013.

Shareholder class action lawsuits

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our President and Chief Executive Officer and a Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Individual Defendants," and together with Atlantic Power, the "Defendants") (the "U.S. Actions").

The District Court complaints differ in terms of the identities of the Individual Defendants they name, as noted above, the named plaintiffs, and the purported class period they allege (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleges, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

Table of Contents

The parties to each District Court action have filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013, which the Court will consider (along with the motion papers discussed above) in deciding who will serve as lead plaintiff and lead counsel.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013 statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. This claim names the Company, Barry Welch and Terrence Ronan as defendants (the "Defendants"). The Plaintiffs seeks leave to commence an action for statutory misrepresentation under the Ontario Securities Act and asserts common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs seek to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

A schedule for the Plaintiffs' motions and the action was set on November 12, 2013.

Table of Contents

The Petitioner in the proposed class action in Quebec served and filed a motion to suspend those proceedings pending the Ontario proceedings. This motion was not granted. Nothing further has happened in the action.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously each of the actions.

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2013 that are expected to have a material impact on our financial position or results of operations or have been reserved for as of December 31, 2013.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information and Holders

The following table sets forth the price ranges of our outstanding common shares, as reported by the NYSE from the date on which our common shares were listed through December 31, 2013:

Period	High (US$)	Low (US$)
Quarter ended December 31, 2013	5.36	3.06
Quarter ended September 30, 2013	4.66	3.81
Quarter ended June 30, 2013	5.57	3.86
Quarter ended March 31, 2013	13.03	4.56
Quarter ended December 31, 2012	15.18	10.72
Quarter ended September 30, 2012	15.05	12.85
Quarter ended June 30, 2012	14.49	12.55
Quarter ended March 31, 2012	15.22	13.57

The following table sets forth the price ranges of our common shares, as applicable, as reported by the TSX for the periods indicated:

Period	High (Cdn$)	Low (Cdn$)
Quarter ended December 31, 2013	5.51	3.05
Quarter ended September 30, 2013	4.86	4.01
Quarter ended June 30, 2013	5.63	4.04
Quarter ended March 31, 2013	13.02	4.64
Quarter ended December 31, 2012	15.12	10.57
Quarter ended September 30, 2012	14.79	13.19
Quarter ended June 30, 2012	14.27	12.88
Quarter ended March 31, 2012	15.11	13.60

The number of holders of common shares was approximately 63,225 on February 27, 2014.

Dividends

Dividends declared per common share in 2013 and 2012 were as follows (Cdn$):

Month	2013	2012
	Amount	
January	$ 0.0958	$ 0.0958
February	0.0958	0.0958
March	0.0333	0.0958
April	0.0333	0.0958
May	0.0333	0.0958
June	0.0333	0.0958
July	0.0333	0.0958
August	0.0333	0.0958
September	0.0333	0.0958
October	0.0333	0.0958
November	0.0333	0.0958
December	0.0333	0.0958

Table of Contents

See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors That May Influence Our Results" for a discussion of certain non-recourse project-level debt that can restrict the ability of our projects to make cash distributions to us and Item 1A. "Risk Factors Risk Related to Our Structure Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make dividend payments, cash distributions, acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2013 regarding our Long-Term Incentive Plan. For the description of our Long-Term Incentive Plan, see Note 15, *Equity Compensation Plans* to the consolidated financial statements.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights[(1)]	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))[(1)]
	(a)	(b)	(c)
Equity compensation plans approved by security holders	511,325	$	212,353
Equity compensation plans not approved by security holders			
Total	511,325	$	212,353

(1) Number of securities to be issued upon exercise of outstanding awards and number of securities remaining available for future issuance reflects expected redemption of award one-third in cash and two-thirds in shares of our common stock. See Item 15. "Exhibits and Financial Statements Schedule" Note 2(r), Equity compensation plans.

Table of Contents

Performance Graph

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2008, through December 31, 2013, with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, or S&P 500 and the Standard & Poor's TSX Composite or S&P/TSX. Our common shares trade on the NYSE under the symbol "AT" and the TSX under the symbol "ATP". The performance graph shown below is being furnished and compares each period assuming that an investment was made on December 31, 2008, in each of our common shares, the stocks included in the S&P 500 and the stocks included in the S&P/TSX, and that all dividends were reinvested.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information for each of the periods indicated. The annual historical information for each of the years in the three-year period ended December 31, 2013 has been derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

You should read the following selected consolidated financial data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and the accompanying notes, which describe the impact of material acquisitions and dispositions that occurred in the three-year period ended December 31, 2013.

	Year Ended December 31,				
(in millions of U.S. dollars, except as otherwise stated)	**2013[(a)]**	**2012[(a)]**	**2011[(a)(b)]**	**2010[(a)]**	**2009[(a)]**
Project revenue	$ 551.7	$ 440.4	$ 93.9	$ 1.1	$
Project income (loss)	64.3	(29.4)	(3.6)	16.1	20.1
Loss from continuing operations	(17.6)	(114.2)	(69.9)	(26.7)	(63.9)
Income (loss) from discontinued operations, net of tax	(6.2)	13.9	34.3	22.9	25.4
Net loss attributable to Atlantic Power Corporation	(33.0)	(112.8)	(38.4)	(3.8)	(38.5)
Basic and diluted loss per share[(c)]					
Loss per share from continuing operations attributable to Atlantic Power Corporation	$ (0.23)	$ (1.09)	$ (0.94)	$ (0.45)	$ (1.06)
Income (loss) from discontinued operations, net of tax	(0.05)	0.12	$ 0.44	$ 0.37	$ 0.43
Net loss attributable to Atlantic Power Corporation	$ (0.28)	$ (0.97)	$ (0.50)	$ (0.08)	$ (0.63)
Per IPS distribution declared	$	$	$	$	$ 0.51
Per common share dividend declared	$ 0.51	$ 1.1	$ 1.11	$ 1.06	$ 0.46
Total assets	$ 3,395.0	$ 4,002.7	$ 3,248.4	$ 1,013.0	$ 869.6
Total long-term liabilities	$ 1,909.6	$ 2,280.8	$ 1,940.2	$ 518.3	$ 402.2

(a) The Florida Projects, Path 15 and Rollcast are classified as discontinued operations for the five years ended December 31, 2013. Prior periods have been reclassified to reflect the impact.

(b) The acquisition of the Partnership was completed on November 5, 2011.

(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 each of the five years ended December 31, 2013, 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 included elsewhere in this Form 10-K for information relating to the number of shares used in calculating basic and diluted earnings (loss) per share for the periods presented.

Table of Contents

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with our audited consolidated financial statements included in this Annual Report on Form 10-K. All dollar amounts discussed below are in millions of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

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

Overview of Our Business

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of December 31, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,948 megawatts ("MW") in which our aggregate ownership interest is approximately 2,026 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012, which we expect to close in 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer in Seattle, Washington. Twenty-two of our projects are wholly owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from August 2014 to December 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

The majority of our natural gas, coal and biomass power generation projects have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is 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 twenty-one of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including CEM and PPMS. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Strategy Update

As we have previously disclosed, we have been focused on initiatives aimed at, among other things, improving our financial flexibility and addressing our near-term maturities. We believe that the execution of the New Term Loan Facility and the use of the funds therefrom to address debt maturities in 2014, 2015 and 2017 and for possible further debt reduction, as discussed in more detail in " Liquidity and Capital Resources", are important steps toward achieving these goals. The 50% cash sweep and amortization features of the New Term Loan Facility are expected to reduce leverage over time. The additional flexibility, liquidity and maturity extension associated with the New Revolving

Table of Contents

Credit Facility is also a meaningful achievement with respect to these goals. We believe that these steps should improve our ability to continue with efforts to strengthen our balance sheet and optimize our assets. In addition, as previously disclosed, due to the aggregate impact of certain prepayment charges associated with the prepayments on our indebtedness described above, we are no longer in compliance with the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing our 9.0% notes. For additional information about the fixed charge coverage ratio test and its possible impact on our ability to pay dividends, if and when declared by our board of directors, see " Liquidity and Capital Resources."

We recognize that our important next steps include considering the relative merits of further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash while continuing to focus on how to best position the Company overall to maximize shareholder value. Consistent with these objectives, we are also committed to evaluating a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options. No assurance can be given as to how the evaluation of any such potential options may evolve.

Significant Events

Amendment to Our Prior Credit Facility

In August 2013, we entered into an amendment to our prior credit facility (the "Prior Credit Facility") with our lenders primarily to obtain more favorable financial covenant ratios. The amendment included changes to our borrowing capacity, financial ratios and certain other customary representations, warranties, terms and conditions and covenants. On February 26, 2014 we terminated the Prior Credit Facility in conjunction with the funding of the New Senior Secured Credit Facilities, as further described below. For a description of these changes, see " Liquidity and Capital Resources" and Note 10 to the consolidated financial statements included in this Annual Report on Form 10-K

New Senior Secured Credit Facilities

On February 24, 2014, the Partnership, our wholly-owned indirect subsidiary, entered into a new senior secured term loan facility (the "New Term Loan Facility"), comprising of $600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "New Revolving Credit Facility') with a capacity of $210 million (collectively, the "New Senior Secured Credit Facilities") with its lenders. On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and letters of credit in an aggregate face amount of $144 million were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service (approximately $15.8 million), and (ii) to support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries have used the proceeds from the New Term Loan Facility to:

- prepay or redeem in whole, at a price equal to par plus accrued interest and applicable make-whole premium, (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

- pay transaction costs and expenses; and

Table of Contents

make a distribution to us in the range of approximately $120 million to $125 million, which we may use for any corporate purpose, including, in our discretion, additional debt reduction which may, taking into account available funds, market conditions and other relevant factors, include steps to repurchase or redeem, by means of a tender offer or otherwise, up to $150 million aggregate principal amount of our 9.0% senior unsecured notes due 2018 and up to Cdn$46 million of our 6.50% convertible debentures due October 31, 2014.

The foregoing description of the New Senior Secured Credit Facilities is qualified in its entirety by reference to the full text of the credit agreement governing the Senior Secured Credit Facilities, which is attached to this Annual Report on Form 10-K as Exhibit 10.1 and is incorporated herein by reference. For a description of the New Senior Secured Credit Facilities and use of proceeds thereunder, see " Liquidity and Capital Resources" and Note 10 to the consolidated financial statements included in this Annual Report on Form 10-K.

Sale of Rollcast

In November 2013, we completed the sale of our 60% interest in Rollcast to the other shareholders. As consideration for the sale, we were assigned asset management contracts for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont bringing our total ownership to 100%. In return, we paid $0.5 million to the minority owner and forgave an outstanding $1.0 million loan that was provided by us to Rollcast to fund working capital during 2013. Rollcast's net loss is recorded as loss from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

Goodwill Impairment

During the second quarter of 2013, based on a prolonged decline in our market capitalization we determined that it was appropriate to initiate a test of goodwill to determine if the fair value of each of our reporting units' goodwill does not exceed their carrying amounts. We concluded the test during the three months ended September 30, 2013 and determined that goodwill was impaired at the Kenilworth, Naval Station, Naval Training Center and North Island ("Naval reporting units") reporting units. The total non-cash impairment charge recorded was $34.9 million.

The $30.8 million impairment at Kenilworth was due to lower forecasted capacity and energy prices compared to the assumptions at the time of the acquisition in November 2011. When performing our two-step quantitative analysis, the increase in the intangible value associated with the new Energy Service Agreement ("ESA") entered into in July 2013 resulted in a lower implied goodwill value. At the time of its acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Kenilworth project were valued assuming a merchant basis for the period subsequent to the expiration of the project's original PPA in July 2012. These forecasted energy revenues on a merchant basis were higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the new ESA. The $4.1 million impairment at the Naval reporting units was primarily due to increased uncertainty, not assumed at the time of the reporting unit's acquisition in 2011, in our ability to extend two of the projects lease and steam agreements upon their expiration. In addition, lower currently forecasted capacity and energy prices in California after the expiration of the PPAs compared to the forecast at the time of the acquisition in 2011 result in a lower business enterprise value which resulted in a lower implied goodwill value.

During the three months ended June 30, 2013, we recorded a $3.5 million impairment of goodwill at Rollcast, which is designated as discontinued operations. We determined, based on the results of the two-step process, that the carrying amount of goodwill exceeded the implied fair value of goodwill. We also wrote-off $1.4 million of capitalized development costs at Rollcast related to the Greenway

Table of Contents

development project. The determination to impair goodwill and write-off the capitalized development costs was based on the reduced expectation of the Greenway project being further developed.

Administration and Development Reductions

In July 2013, we implemented changes in several areas that are expected to result in an approximate $8.0 million reduction to administration and development expenses relative to our previous 2014 budget for those items. The expected expense reductions are targeted to occur in three broad areas, which are, in order of significance: (1) reduction in the development budget, both for personnel and third-party expenses, consistent with de-emphasizing early-stage development projects; (2) consolidation of accounting and finance functions in two offices, down from three; and (3) additional synergies from full integration of areas such as health care, plant insurance, IT, travel and other functions. Most of the one-time costs incurred to implement these changes were recorded in 2013. The savings are expected to be realized beginning in 2014.

Piedmont Commercial Operations, Receipt of Grant Proceeds, and Term Convert

Piedmont achieved commercial operation under its PPA with Georgia Power Company at a declared capacity of 53.5 MW on April 19, 2013. Piedmont and its engineering, procurement and construction ("EPC") contractor, Zachry Industrial, Inc. ("Zachry"), are disputing certain issues under the EPC agreement including the condition and performance of the project, and are currently engaged in arbitration proceedings. An arbitration hearing has been tentatively scheduled in the later part of 2014 in connection with such dispute, during which time Piedmont is withholding the amount still retained under the EPC agreement.

In May 2013, Piedmont submitted an application under the federal 1603 grant program. In July, the grant was approved and $49.5 million was received from the U.S. Treasury. With the proceeds received and a $1.5 million contribution from Atlantic Power to cover the shortfall created by the U.S. federal budget sequestration, the project's outstanding $51.0 million bridge loan was fully repaid in July 2013. During the three months ended June 30, 2013 we contributed an additional $2.7 million equity investment to fund the project's working capital.

On February 14, 2014, we contributed an additional $14.2 million equity investment to Piedmont. With the contribution, the project paid down $8.1 million of the outstanding $76.6 million Piedmont project debt and converted the remaining $68.5 million principal to a term loan maturing in August 2018. We will pay interest at rate of LIBOR plus an applicable margin of 3.5% to 4.0% over the life of the term loan. The project used the remaining $6.1 million equity investment to fund various reserves required under the term loan and pay for fees associated with the term loan conversion.

Canadian Hills Tax Equity

In May 2013, we syndicated our $44.0 million tax equity investment in Canadian Hills to an institutional investor and received cash proceeds of $42.1 million. The cash proceeds received were based on our initial tax equity investment of $44.1 million less distributions received from Canadian Hills resulting in an immaterial loss on the sale. During this short-term ownership as a tax equity investor in the project, we generated approximately $3.0 million of production tax credits and approximately $10.9 million of net operating losses, which we will be able to use to offset against future taxable income. The syndication of our interest completes the sale of 100% of Canadian Hills' $269.0 million of tax equity interests. The cash proceeds will be held for general corporate purposes. We continue to own 99% of the project and consolidate it in our consolidated financial statements. Income (loss) and distributions attributable to the tax investors are recorded as a component of noncontrolling interests.

Table of Contents

Sale of Gregory

In April 2013, we and the other owners of Gregory entered into a purchase and sale agreement with an affiliate of NRG Energy, Inc. to sell our 17% interest in the project for approximately $274.2 million including working capital adjustments. We received net cash proceeds from our ownership interest of approximately $34.7 million in the aggregate, after repayment of project-level debt and transaction expenses. Approximately $5.0 million of these proceeds will be held in escrow for up to one year after the closing date. We intend to use the net proceeds from the sale for general corporate purposes. The sale of Gregory closed on August 7, 2013 resulting in a gain of $30.4 million and was recorded in gain on sale of equity investments in the consolidated statements of operations for the year ended December 31, 2013.

Sale of Path 15

On March 11, 2013 we entered into a purchase and sale agreement with Duke-American Transmission Company, a joint venture between Duke Energy Corporation and American Transmission Co., to sell our interests in Path 15. The sale closed on April 30, 2013 and we received net cash proceeds from the sale, including working capital adjustments, of approximately $52 million, plus a management agreement termination fee of $4.0 million, for a total sale price of approximately $56 million. The cash proceeds will be used for general corporate purposes. All project level debt issued by Path 15, totaling $137.2 million, transferred with the sale. Path 15 was accounted for as an asset held for sale in the consolidated balance sheets at December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

Sale of Florida Projects

On January 30, 2013, we entered into a purchase and sale agreement for the sale of the Florida Projects, for approximately $140 million, with working capital adjustments. The sale closed on April 12, 2013 and we received net cash proceeds of approximately $117 million in the aggregate, after repayment of project-level debt at Auburndale and settlement of all outstanding natural gas swap agreements at Lake and Auburndale. This includes approximately $92 million received at closing and cash distributions from the projects of approximately $25 million received since January 1, 2013. We used a portion of the net proceeds from the sale to fully repay our Prior Credit Facility, which had an outstanding balance of approximately $64.1 million on the closing date. The Florida Projects were accounted for as assets held for sale in the consolidated balance sheets at December 31, 2012 and are a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

Factors That May Influence Our Results

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 for 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 flows 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:

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between August 2014 and December 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. For example, the current PPA at Selkirk (which represented 7.7% of our Project Adjusted EBITDA for the year ended December 31, 2013) expires in August 2014. If the project does not obtain a new PPA, this could result in 100% of the capacity at Selkirk not contracted and therefore sold at market power prices. Similarly, the PPA at Tunis (which represented 3.5% of our Project Adjusted EBITDA for the year ended December 31, 2013) expires in December 2014. Because Tunis has not been in the first group for which recontracting discussions are currently underway with the Ontario government and the process for such discussions has not been transparent, the outcome of recontracting discussions at the project are uncertain and we expect that a new PPA, if any, at Tunis, would be on significantly less favorable terms than the project's existing PPA. Beyond the expiration of the Selkirk and Tunis PPAs in 2014, our next PPA expirations do not occur until year end 2017 and are at our North Bay and Kapuskasing projects in Ontario. See "Risk Factors Risks Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition."

While approximately 31% of our power generation revenue in 2013 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. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging arrangements.

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. The current PPA at Selkirk expires in August 2014, which could result in an increase to 100% of capacity not contracted and therefore sold at market power prices. 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. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition."

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. If re-contracted, the degree of the expected decline in cash flows from operations is

Table of Contents

subject to market conditions when we execute new PPAs for these projects and is difficult to estimate at this time. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition." These projects will be free of debt when their PPAs expire, which we expect to provide 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. Although all projects are currently meeting these debt service requirements, we cannot provide any assurances that these projects will generate enough future cash flow to meet any applicable ratio tests and be able to make distributions to us. See "Liquidity and Capital Resources Project-level debt" and Item 1A. "Risk Factors Risks Related to Our Structure Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make dividend payments, acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

The performance of our projects is impacted by a variety of operational and other factors, including planned and unplanned outages and maintenance requirements, delays in start-up, sourcing of fuel from suppliers and wind, water and waste heat levels, among others. For example, delays in the start-up of our Piedmont project and subsequent unplanned outages have resulted in increased costs and lost revenue and have affected our results. For additional details regarding the various operational and other risks that we face, see "Risk Factors Risks Related to Our Business and Our Projects."

Non-cash gains and losses on derivatives instruments

In the ordinary course of our business, we execute natural gas purchase agreements and natural gas swap contracts to manage our exposure to fluctuations in commodity prices, foreign currency forward 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 Item 7A. "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. A portion of 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.

Table of Contents

Current Trends in Our Business

Macroeconomic impacts

The 2008-2009 recession caused significant decreases in both peak electricity demand and consumption that varied by region. The recovery from the recession continues on a slow path with a low economic growth rate leading to a slower recovery in employment. While summer and winter peak electricity demand is also greatly influenced by weather, summer and winter peak electricity demand is projected to steadily increase over the next ten years. However, such increase in summer and winter peak electricity demand is dependent on the speed of the economic recovery. As electricity peak demand recovers, base load (plants that typically operate at all times) and peaking plants (those that only operate in periods of very high demand) will be impacted more than mid-merit plants (those that operate for a portion of most days, but not at night or in other lower demand periods). Base load plants may be called on for increased levels of off-peak generation and peaking plants may be called on more 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.

Increased renewable power projects

The combination of federal stimulus and other tax provisions in the United States 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. The American Taxpayer Relief Act, enacted in January 2013 extended production tax credits ("PTC") and investment tax credits for projects that started construction prior to January 1, 2014 and extended bonus depreciation for projects that are placed in service prior to January 1, 2014. The PTC provided an income tax credit of 2.3 cents/kilowatt-hour for the production of electricity from utility-scale wind turbines. Although the PTC has not yet been extended, further investment in renewable power remains a priority for the current U.S. administration.

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 United States. 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 also have an adverse impact on development of new renewable projects whose owners are attempting to negotiate PPAs at favorable levels to support the financing and construction of the projects.

Retirement of fossil-fired generation

The increase of gas and renewable capacity will be offset by large-scale retirements of coal-fired generation plants. NERC projects a net 35.1 GW reduction of coal-fired generation in the United States and Canada by 2023, with over 90% retiring by 2017 primarily due to existing and potential federal environmental regulations and low natural gas prices.

Table of Contents

Consolidated Overview and Results of Operations by Segment

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as the result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the years ended December 31, 2013, 2012 and 2011 have been presented to reflect these changes in operating segments. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss. Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment.

Significant non-cash items included in the following discussion, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Item 7A. 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.

Performance highlights

	Year Ended December 31,		
	2013	**2012**	**2011**
Project income (loss)	$ 64.3	$ (29.4)	$ (3.6)
Loss from continuing operations	$ (17.6)	$ (114.2)	$ (69.9)
(Loss) income from discontinued operations	$ (6.2)	$ 13.9	$ 34.3
Net loss attributable to Atlantic Power Corporation	$ (33.0)	$ (112.8)	$ (38.4)
Loss per share from continuing operations attributable to Atlantic Power Corporation basic and diluted	$ (0.23)	$ (1.09)	$ (0.94)
Earnings (loss) per share from discontinued operations basic	(0.05)	0.12	$ 0.44
Loss per share attributable to Atlantic Power Corporation basic and diluted	$ (0.28)	$ (0.97)	$ (0.50)
Project Adjusted EBITDA[1]	$ 270.5	$ 227.6	$ 86.8
Cash Available for Distribution[1]	$ 108.8	$ 131.6	$ 79.0

(1) See reconciliation and definition below under Supplementary Non-GAAP Financial Information.

Table of Contents

2013 compared to 2012

The following table and discussion summarizes our consolidated results of operations:

	Years Ended December 31,			
	2013	**2012**	**$ change**	**% change**
Project revenue:				
Energy sales	$ 304.2	$ 217.0	$ 87.2	40%
Energy capacity revenue	168.8	154.9	13.9	9%
Other	78.7	68.5	10.2	15%
	551.7	440.4	111.3	25%
Project expenses:				
Fuel	198.7	169.1	29.6	18%
Operations and maintenance	152.4	122.8	29.6	24%
Development	7.2		7.2	NM
Depreciation and amortization	167.1	118.0	49.1	42%
	525.4	409.9	115.5	28%
Project other income (expense):				
Change in fair value of derivative instruments	49.5	(59.3)	108.8	NM
Equity in earnings of unconsolidated affiliates	26.9	15.2	11.7	77%