Pattern Energy Group Inc.
Form S-1
April 25, 2014
Table of Contents

As filed with the Securities and Exchange Commission on April 25, 2014

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

PATTERN ENERGY GROUP INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**4911**	**90-0893251**
(State or Other Jurisdiction of Incorporation or Organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

Pier 1, Bay 3

San Francisco, CA 94111

(415) 283-4000
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)

Daniel M. Elkort

General Counsel

Pattern Energy Group Inc.

Pier 1, Bay 3

San Francisco, CA 94111

(415) 283-4000

(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent For Service)

Copies to:

Richard D. Truesdell, Jr. **Davis Polk & Wardwell LLP** **450 Lexington Avenue** **New York, NY 10017** **(212) 450-4000**	**Jeffrey R. Lloyd** **Brendan D. Reay** **Blake, Cassels & Graydon LLP** **Suite 4000** **199 Bay Street** **Toronto, ON M5L 1A9** **(416) 863-2400**	**Shelley A. Barber** **Brenda K. Lenahan** **Vinson & Elkins L.L.P.** **666 Fifth Avenue** **New York, NY 10103** **(212) 237-0000**	**Philip D.A. Symmonds** **Rima Ramchandani** **Torys LLP** **Suite 3000** **79 Wellington Street West** **Toronto, ON M5K 1N2**

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ¨

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

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

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

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

CALCULATION OF REGISTRATION FEE[1]

Title Of Each Class Of Securities To Be Registered	Amount To Be Registered(1)(2)	Proposed Maximum Offering Price Per Unit(1)(2)(3)	Proposed Maximum Aggregate Offering Price(1)(2)(3)	Amount Of Registration Fee(3)
Class A common stock, $0.01 par value per share	16,564,638	$27.77	$459,999,997	$59,248

(1) Estimated solely for the purpose of computing the amount of the registration fee pursuant to Rule 457(a) under the Securities Act of 1933.
(2) Includes 2,160,604 additional shares of Class A common stock that may be purchased by the underwriters.
(3)

Estimated solely for the purpose of calculating the registration fee in accordance with Rule 457(a) promulgated under the Securities Act of 1933, as amended and is based upon the average of the high and low sales prices of the Class A common stock as reported on the NASDAQ Global Market on April 24, 2014.

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

Table of Contents

The information in this prospectus is not complete and may be changed. Neither we nor the selling shareholder may sell these securities until this registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and neither we nor the selling shareholder are soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED APRIL 25, 2014

PROSPECTUS

Shares

Pattern Energy Group Inc.

Class A Common Stock

Pattern Energy Group Inc. is offering shares of its Class A common stock. Pattern Energy Group LP, the selling shareholder, is offering an additional shares of Class A common stock. We will not receive any of the proceeds from the sale of the shares being sold by the selling shareholder.

Our Class A common stock is listed on the NASDAQ Global Market under the symbol PEGI and on the Toronto Stock Exchange under the symbol PEG. On , 2014, the last reported sale price of our Class A common stock on the NASDAQ Global Market was $ and on the Toronto Stock Exchange was C$.

Investing in our Class A common stock involves a high degree of risk. See Risk Factors beginning on page 26 of this prospectus for a discussion of certain risks that you should consider before investing.

	Per Class A Share	Total
Public offering price	$	$
Underwriters commissions	$	$
Net proceeds to us, before expenses	$	$
Net proceeds to the selling shareholder, before expenses	$	$

The underwriters may also purchase up to an additional shares of our Class A common stock from the selling shareholder named herein at the public offering price, less the underwriters commissions, within 30 days from the closing date of this offering to cover overallotments, if any. We will not receive any proceeds from the exercise of the underwriters overallotment option.

The underwriters expect to deliver the shares of Class A common stock to purchasers on , 2014.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

BMO Capital Markets **Morgan Stanley** **RBC Capital Markets**

The date of this prospectus is , 2014.

TABLE OF CONTENTS

Table of Contents

Subscriptions will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. We expect that delivery of our Class A shares will be made against payment therefor on or about the date specified on the cover page of this prospectus.

1

Table of Contents

NOTICE TO INVESTORS

We are a holding company with U.S. operating subsidiaries that are public utilities (as defined in the Federal Power Act, or FPA) and, therefore, subject to the jurisdiction of the U.S. Federal Energy Regulatory Commission, or FERC, under the FPA. As a result, the FPA places certain restrictions and requirements on the transfer of an amount of our voting securities sufficient to convey direct or indirect control over us. See Risk Factors Risks Related to this Offering and Ownership of our Class A Shares As a result of the FPA and FERC s regulations in respect of transfers of control, absent prior authorization by FERC, neither we nor Pattern Development can convey to an investor, nor will an investor in our company generally be permitted to obtain, a direct and/or indirect voting interest in 10% or more of our issued and outstanding voting securities, and a violation of this limitation could result in civil or criminal penalties under the FPA and possible further sanctions imposed by FERC under the FPA.

MARKET AND INDUSTRY DATA

We obtained the industry, market and competitive position data used throughout this prospectus from our own internal estimates as well as from industry publications and research, surveys and studies conducted by third parties, including the Global Wind Energy Council, the World Meteorological Organization, North American Electric Reliability Corporation, National Energy Technology Laboratory, the U.S. Department of Energy, the U.S. Energy Information Administration, the Federal Energy Regulatory Commission, the Electric Reliability Council of Texas, the Public Utility Commission of Texas, the Centre for Energy, Natural Resources Canada, Ontario Power Generation, Ontario Power Authority, the Government of Manitoba, the Chilean Ministry of Energy and Puerto Rico Electric Power Authority. Industry publications, studies and surveys generally state that they have been obtained from sources believed to be reliable, although they do not guarantee the accuracy or completeness of such information. While we believe our internal company research is reliable and the market definitions are appropriate, neither such research nor these definitions have been verified by any independent source. Estimates of historical growth rates in the markets where we operate are not necessarily indicative of future growth rates in such markets.

TRADEMARKS

This prospectus includes trademarks, such as the Pattern name and the Pattern logo, which are protected under applicable intellectual property laws and are our property and/or the property of our subsidiaries. This prospectus also contains trademarks, service marks, copyrights and trade names of other companies, which are the property of their respective owners. We do not intend our use or display of other companies trademarks, service marks, copyrights or trade names to imply a relationship with, or endorsement or sponsorship of us by, any other companies. Solely for convenience, our trademarks and tradenames referred to in this prospectus may appear without the ® or symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the right of the applicable licensor to these trademarks and tradenames. We have entered into an agreement with Pattern Development under which Pattern Development licenses us the name Pattern and the Pattern logo and also grants us a right to acquire the name and logo, subject to our granting Pattern Development a license to use the name Pattern and the Pattern logo after we acquire it.

CURRENCY AND EXCHANGE RATE INFORMATION

In this prospectus, references to C$ 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 stated.

Our historical consolidated financial statements that are included elsewhere or incorporated by reference in this prospectus are presented in U.S. dollars. The following chart sets forth for each of 2011, 2012 and 2013, and each completed month to date during 2014, the high, low, period average and period end noon buying rates of Canadian dollars expressed as Canadian dollars per US$1.00.

2

Table of Contents

	Canadian Dollars per US$ 1.00			
	High	Low	Period Average(1)	Period End
Year				
2011	C$ 1.0605	C$ 0.9448	C$ 0.9887	C$ 1.0168
2012	1.0417	0.9710	0.9995	0.9958
2013	1.0164	0.9348	0.9670	0.9402
Month				
January 2014	1.1148	1.0612	1.0940	1.1116
February 2014	1.1137	1.0952	1.1054	1.1075
March 2014	1.1251	1.1050	1.1107	1.1053
April 2014 (through April 18)	1.1035	1.0902	1.0981	1.1024

(1) The average of the noon buying rates on the last business day of each month during the relevant one-year period and, in respect of monthly information, the average of the noon buying rates on each business day for the relevant one-month period.

The noon buying rate in Canadian dollars on April 18, 2014 was US$1.00 = C$1.1024.

The above rates differ from the actual rates used in our consolidated historical financial statements and the calculation of cash available for distribution and dividends we declared and paid, if any, described elsewhere or incorporated by reference in this prospectus. Our inclusion of these exchange rates is not meant to suggest that the U.S. dollar amounts actually represent such Canadian dollar amounts or that such amounts could have been converted into Canadian dollars at any particular rate or at all.

For information on the impact of fluctuations in exchange rates on our operations, see Risk Factors Risks Related to Our Projects Currency exchange rate fluctuations may have an impact on our financial results and condition in our 2013 Form 10-K and Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure About Market Risk Foreign Currency Risk.

CAUTIONARY STATEMENT REGARDING THE USE OF NON-GAAP MEASURES

This prospectus, including documents incorporated by reference, contains references to Adjusted EBITDA, cash available for distribution before principal payments and cash available for distribution, which are not measures under generally accepted accounting principles in the United States, or U.S. GAAP, and, therefore, may differ from definitions of these measures used by other companies in our industry. We disclose Adjusted EBITDA, cash available for distribution before principal payments and cash available for distribution because we believe that these measures may assist investors in assessing our financial performance and the anticipated cash flow from our projects. None of these measures should be considered the sole measure of our performance and should not be considered in isolation from, or as a substitute for, the financial statements included elsewhere or incorporated by reference in this prospectus prepared in accordance with U.S. GAAP. For further discussion of the limitations of these non-U.S. GAAP measures and the reconciliations of net income to Adjusted EBITDA and net cash provided by (used in) operating activities to each of cash available for distribution before principal payments and cash available for distribution, see footnotes 1 and 2 to the table under the heading Summary Historical Consolidated Financial Data elsewhere in this prospectus.

3

Table of Contents

MEANING OF CERTAIN REFERENCES

Unless the context requires otherwise, any reference in this prospectus to:

Class A shares refers to shares of our Class A common stock, par value $0.01 per share;

Class B shares refers to shares of our Class B common stock, par value $0.01 per share;

our construction projects refers to the Grand, Panhandle 2 and El Arrayán projects, where we have commenced construction;

the Conversion Event refers to the later of December 31, 2014 and the date on which our South Kent project has achieved commercial operations;

El Arrayán or the El Arrayán project refers to the wind power project assets held by Parque Eólico El Arrayán SpA, a share company formed under the laws of Chile, which upon commencement of commercial operations will have an owned capacity of 36 MW;

FIT refers to feed-in-tariff regime;

Grand or the Grand project refers to the wind power project assets held by a 45/45/10 joint venture between us, Samsung and the Six Nations which has an owned capacity of 67 MW;

Gulf Wind or the Gulf Wind project refers to the wind power project assets held by Pattern Gulf Wind LLC, a limited liability company formed under the laws of the State of Delaware, which has an owned capacity of 113 MW;

Hatchet Ridge or the Hatchet Ridge project refers to the wind power project assets held by Hatchet Ridge Wind, LLC, a limited liability company formed under the laws of the State of Delaware, which has an owned capacity of 101 MW;

IPPs refers to independent power producers;

ISOs refers to independent system organizations, which are organizations that administer wholesale electricity markets;

ITCs refers to investment tax credits;

MW refers to megawatts;

MWh refers to megawatt hours;

OCC refers to our operations control center;

Ocotillo or the Ocotillo project refers to the wind power project assets held by Ocotillo Express LLC, a limited liability company formed under the laws of the State of Delaware, which has an owned capacity of 265 MW;

our operating projects refers to the Gulf Wind, Hatchet Ridge, St. Joseph, Spring Valley, Santa Isabel, Ocotillo and South Kent projects, where we have commenced commercial operations;

owned capacity of any particular project refers to the maximum, or rated, electricity generating capacity of the project in MW multiplied by our percentage ownership interest in the distributable cash flow of the project;

Table of Contents

our predecessor refers to our accounting predecessor, which consists of a combination of entities and assets contributed to us by Pattern Development concurrently with the IPO;

our projects, portfolio or project portfolio in each case refers to our operating projects together with our construction projects;

Panhandle or the Panhandle project refers to the Panhandle 1 and Panhandle 2 projects collectively.

Panhandle 1 or the Panhandle 1 project refers to the wind power project assets held by Pattern Panhandle Wind LLC, a limited liability company formed under the laws of the State of Delaware and a 100% owned subsidiary of Pattern Development.

Panhandle 2 or the Panhandle 2 project refers to the wind power project assets held by Pattern Panhandle Wind 2 LLC, a limited liability company formed under the laws of the State of Delaware, which we have agreed to acquire from Pattern Development and which, upon the completion of our acquisition, which we expect to occur in the fourth quarter of 2014, will have an owned capacity of 147 MW;

Pattern Development refers to Pattern Energy Group LP and, where the context so requires, its subsidiaries (excluding us);

Pattern Development-owned capacity of any particular project refers to the maximum, or rated, electricity generating capacity of the project in MW multiplied by Pattern Development s percentage ownership interest in the distributable cash flow of the project;

power sale agreements refers to PPAs and/or hedging arrangements, as applicable;

PPAs refers to power purchase agreements;

PTCs refers to production tax credits;

rated capacity refers to maximum electricity generating capacity in MW;

RECs refers to renewable energy credits;

RFP refers to a request for procurement;

RPS refers to Renewable Portfolio Standards;

Santa Isabel or the Santa Isabel project refers to the wind power project assets held by Pattern Santa Isabel LLC, a limited liability company formed under the laws of the State of Delaware, which has an owned capacity of 101 MW;

shares, common shares or common stock collectively refers to our Class A shares and Class B shares;

South Kent or the South Kent project refers to the wind power project assets held by South Kent Wind LP, a limited partnership formed under the laws of the Province of Ontario, which has an owned capacity of 135 MW;

Spring Valley or the Spring Valley project refers to the wind power project assets held by Spring Valley Wind LLC, a limited liability company formed under the laws of the State of Nevada, which has an owned capacity of 152 MW; and

St. Joseph or the St. Joseph project refers to the wind power project assets held by St. Joseph Windfarm Inc., a corporation formed under the laws of Canada, which has an owned capacity of 138 MW.

Table of Contents

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this prospectus from documents filed with the Securities and Exchange Commission (SEC) or similar authorities in the provinces and territories of Canada. Copies of the documents incorporated in this prospectus by reference may be obtained on request without charge from the Corporate Secretary of Pattern Energy at Pier 1, Bay 3, San Francisco, CA, telephone 415-283-4000. In addition, copies of the documents incorporated by reference herein may be obtained from the SEC through EDGAR at www.sec.gov or similar authorities in Canada through SEDAR at www.sedar.com. The following documents, filed with the SEC or similar authorities in the provinces and territories of Canada, are specifically incorporated by reference into and form an integral part of this prospectus:

- Our Annual Report on Form 10-K for the fiscal year ended December 31, 2013 filed with the SEC on February 28, 2014 (2013 Form 10-K);

- The information specifically incorporated by reference into the 2013 Form 10-K from our Definitive Proxy Statement on Schedule 14A filed with the SEC on April 23, 2014 (2014 Proxy Statement);

- The description of our Class A common stock contained in our Registration Statement on Form 8-A, filed with the SEC on September 24, 2013; and

- The description of our Class A common stock issued under our 2013 Equity Incentive Award Plan contained in our Registration Statement on Form S-8, filed with the SEC on October 9, 2013.

Notwithstanding the foregoing, we are not incorporating by reference any documents, portions of documents, exhibits or other information that is deemed to have been furnished to, rather than filed with, the SEC.

Table of Contents

BUSINESS SUMMARY

This summary highlights information contained elsewhere in, or incorporated by reference into, this prospectus. It does not contain all the information you need to consider in making your investment decision. You should read this entire prospectus carefully and should consider, among other things, the matters set forth under Risk Factors, along with the financial data and related notes and the other documents that we incorporate by reference into this prospectus before making your investment decision. See Documents Incorporated by Reference. Unless the context provides otherwise, references herein to (i) we, our, us, our company and Pattern Energy refer to Pattern Energy Group Inc., a Delaware corporation, together with its consolidated subsidiaries and (ii) Pattern Development refers to Pattern Energy Group LP and, where the context so requires, its subsidiaries (excluding us). For an explanation of certain terms used in this prospectus see Meaning of Certain References. For recent and historical exchange rates between Canadian dollars and U.S. dollars, see Currency and Exchange Rate Information.

Our Business

We are an independent power company focused on owning and operating power projects with stable long-term cash flows in attractive markets with potential for continued growth of our business. Including the pending acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to the satisfaction of customary closing conditions, in the fourth quarter of 2014, we own interests in ten wind power projects located in the United States, Canada and Chile that use proven, best-in-class technology and have a total owned capacity of 1,255 MW, consisting of seven operating projects and three construction projects. We expect our three construction projects will commence commercial operations prior to the end of 2014. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement with a creditworthy counterparty. Ninety-three percent of the electricity to be generated by our projects will be sold under these power sale agreements, which have a weighted average remaining contract life of approximately 18 years.

We have two classes of authorized common stock outstanding, Class A shares and Class B shares. The rights of the holders of our Class A and Class B shares are identical other than in respect of dividends and the conversion rights of our Class B shares. On December 31, 2014, which is the later of that date and the date on which our South Kent project achieved commercial operations (which occurred on March 28, 2014), and which we refer to as the Conversion Event, all of our outstanding Class B shares will automatically convert, on a one-for-one basis, into Class A shares. Our Class B shares, all of which are held by Pattern Development and members of management, have no rights to dividends. See Description of Capital Stock.

We intend to use a substantial portion of the cash available for distribution generated from our projects to pay regular quarterly dividends in U.S. dollars to holders of our Class A shares. On November 26, 2013, we announced the initiation of a quarterly common stock dividend and on January 30, 2014 we paid a dividend to each of our Class A common shareholders of $0.3125 per Class A share, or $1.25 per Class A share on an annualized basis. We also declared a dividend of the same amount per share payable on April 30, 2014 to our Class A common shareholders of record as of March 31, 2014. We established our quarterly dividend level based on a target payout ratio of approximately 80% after considering our expected 2014 and subsequently sustainable cash available for distribution to be generated from our projects, together with the impact of the Class A shares to be issued upon the Conversion Event. The declaration and amount of our future dividends, if any, will be subject to our actual earnings and capital requirements and the discretion of our Board of Directors, and will likely take into account any contribution to our expected sustainable cash available for distribution resulting from projects that we acquire from Pattern Development or third parties.

Pattern Development has granted us preferential rights to acquire projects that it owns and chooses to sell, including, among others, certain projects, or the Initial ROFO Projects, which are predominantly operational, in construction or construction ready and which we consider reasonably likely that we may have the opportunity to acquire at various times within the 18-month period following the completion of this offering. At the time of our initial public offering, or IPO, in October 2013, we identified six projects at Pattern Development with an aggregate owned capacity of 746 MW that comprised the Initial ROFO Projects, and we indicated we had initiated discussions with Pattern Development in connection with one of these originally identified Initial ROFO Projects, the Panhandle project, which we might acquire shortly after the closing of the IPO. Pattern Development subsequently increased the owned capacity of the Panhandle project by 78 MW, to a total of 326 MW, and split the project into the Panhandle 1 project, with a Pattern Development-owned capacity of 179 MW, and the Panhandle 2 project, with an owned capacity of 147 MW. Pattern Development also increased its estimated capacity of another of the originally identified Initial ROFO Projects, the Meikle project in British Columbia, by 10 MW, to 185 MW. In December 2013, we acquired one of the Initial ROFO Projects, the Grand project, with an owned capacity of 67 MW, and agreed to acquire the Panhandle 2 project, with such acquisition expected to be completed in the fourth quarter of 2014 at the time of that project s commencement of commercial operations. After accounting for Pattern Development s increase in the size of the Panhandle and Meikle projects, our acquisition of the Grand project and our agreement to acquire the Panhandle 2 project, the owned capacity of the remaining Initial ROFO Projects is 620 MW. See the table under Our Relationship with Pattern Development for more information about the remaining Initial ROFO Projects.

Based on our anticipated cash available for distribution and our initial quarterly dividend level, we believe that we will generate excess cash flow that we can use, together with our cash on hand and the proceeds of any potential future debt or equity issuances, to invest in accretive project acquisition opportunities, including the remaining Initial ROFO Projects. Considering our preferential rights to acquire the Initial ROFO Projects, at the time of our IPO, we established a three-year targeted annual growth rate in our cash available for distribution per Class A share of 8% to 10%.

Our Core Values and Financial Objectives

We intend to maximize long-term value for our shareholders in an environmentally responsible manner and with respect for the communities in which we operate. Our business is built around the core values of creating a safe, high-integrity and exciting work environment; applying rigorous analysis to all aspects of our business; and proactively working with our stakeholders to address environmental and community concerns.

Our financial objectives, which we believe will maximize long-term value for our shareholders, are to:

- produce stable and sustainable cash available for distribution;
- selectively grow our project portfolio and our dividend; and
- maintain a strong balance sheet and flexible capital structure.

Our Management Team

The executive officers who make up our management team have on average over 20 years of experience in all aspects of the independent power industry, including development, commercial contracting, finance, construction, operations and management, and are dedicated to protecting the long-term value of our projects. Almost all of the members of our and Pattern Development s management teams have worked together since 2002 and have a proven track record of successfully identifying new opportunities, investing, constructing projects and operating energy assets during periods of both favorable and challenging economic conditions. While working together at Pattern Development and prior to its formation, members of our management team were responsible for, and successfully financed and managed, over $12 billion of infrastructure assets, including over 3,000 MW of wind power projects (representing a wind business compound annual growth rate, or CAGR, of 34% from 2003 to 2014, measured by cumulative wind MW installed), several independent transmission projects and other conventional power assets. Since the formation of Pattern Development in 2009, the Pattern Development management team has acquired and developed the operational and in-construction wind power projects that comprise our owned capacity of 1,255 MW, representing a CAGR of 51%, and a more than 3,000 MW portfolio of development assets. We believe our management team, along with our talented staff, as well as the management team and staff at Pattern Development, provide our company with the depth of experience and breadth of skills to meet our financial objectives and successfully grow our business both domestically and internationally. In addition, we believe we are among the leaders in our industry in areas such as environmental mitigation, financing and commercial management, and we have built a team of highly skilled professionals dedicated to delivering high-quality, well-structured operating power projects.

Table of Contents

Our Projects

Including the pending acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to the satisfaction of customary closing conditions, in the fourth quarter of 2014, we own interests in ten wind power projects, consisting of seven operating projects and three construction projects. The following table provides an overview of our projects:

	Location and Start-up			Capacity (MW)		Power Sale Agree		
Projects	**Location**	**Construction Start(1)**	**Commercial Operations (2)**	**Rated (3)**	**Owned (4)**	**Type**	**Contracted Volume(5)**	**Counterparty**
Operating Projects								
Gulf Wind	Texas	Q1 2008	Q3 2009	283	113	Hedge(7)	~58%	Credit Suisse Energy I
Hatchet Ridge	California	Q4 2009	Q4 2010	101	101	PPA	100%	Pacific Gas & Electr
St. Joseph	Manitoba	Q1 2010	Q2 2011	138	138	PPA	100%	Manitoba Hydro
Spring Valley	Nevada	Q3 2011	Q3 2012	152	152	PPA	100%	NV Energy
Santa Isabel	Puerto Rico	Q4 2011	Q4 2012	101	101	PPA	100%	Puerto Rico Electric Power
Ocotillo(9)	California	Q3 2012	Q4 2012	223	223	PPA	100%	San Diego Gas & Elec
			Q2 2013	42	42	PPA	100%	San Diego Gas & Elec
South Kent	Ontario	Q1 2013	Q1 2014	270	135	PPA	100%	Ontario Power Autho
				1,310	1,005			
Construction Projects								
El Arrayán	Chile	Q3 2012	Q2 2014	115	36	Hedge(11)	~75%	Minera Los Pelambr
Grand	Ontario	Q3 2013	Q4 2014	149	67	PPA	100%	Ontario Power Autho
Panhandle 2(12)	Texas	Q4 2013	Q4 2014	182	147	Hedge(13)	~80%	Morgan Stanley
				446	250			
				1,756	1,255			

(1) Represents date of commencement of construction.

(2) Represents date of actual or anticipated commencement of commercial operations.

(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated will be less than its rated capacity. The amount of electricity generated may vary based on a variety of factors discussed elsewhere or incorporated by reference in this prospectus See Risk Factors in our 2013 Form 10-K.

(4) Owned capacity represents the maximum, or rated, electricity generating capacity of the project in MW multiplied by our percentage ownership interest in the distributable cash flow of the project.

(5) Represents the percentage of a project s total estimated average annual MWh of electricity generation contracted under power sale agreements.

(6) Reflects the counterparty s corporate credit ratings issued by S&P/Moody s as of April 23, 2014.
(7) Represents a 10-year fixed-for-floating power price swap. See Business Operating Projects Gulf Wind.
(8) Reflects the corporate credit ratings of the Province of Manitoba, which owns 100% of Manitoba Hydro-Electric.
(9) We initially commenced commercial operations on 223 MW of electricity generating capacity in the fourth quarter of 2012 and commenced commercial operations on the remaining 42 MW of electricity generating capacity from Ocotillo s additional 18 turbines in July 2013.
(10) Reflects the corporate credit ratings of the Province of Ontario, which owns 100% of the Ontario Power Authority.
(11) Represents a 20-year fixed-for-floating swap. See Business Construction Projects El Arrayán.
(12) The Panhandle project was separated into the Panhandle 1 project, with a Pattern Development-owned capacity of 179 MW, and the Panhandle 2 project, with an owned capacity of 147 MW; our acquisition of the Panhandle 2 project is pending and scheduled to close in the fourth quarter of 2014.
(13) Represents a 12.25 year fixed-for-floating swap. See Business Construction Projects Panhandle 2.

Each of our projects has gone through a rigorous vetting process in order to meet our investment and our lenders financing criteria. The development of each project was managed and overseen by our and Pattern Development s management teams over a period of several years and each project was designed to meet or exceed

Table of Contents

industry, environmental, community and safety standards applicable for industrial-scale power projects. As a result, our projects generally have the following characteristics: multi-year on-site wind data analysis; long-term contracts for our power sale, interconnection and real estate rights; fixed-price construction contracts with guaranteed completion dates; all necessary construction and operating permits; a comprehensive operations and maintenance service program; and safety, environmental and community programs.

For additional information regarding each of our projects, see Business Our Projects. Our ability to begin commercial operation of our construction projects and to achieve anticipated power output at our operating projects is subject to numerous risks and uncertainties as described under Risk Factors in our 2013 Form 10-K.

Our Strategy

We intend to make profitable investments in environmentally responsible power projects, while embracing a long-term commitment to the communities in which we operate. To achieve our financial objectives while adhering to our core values, we intend to execute the following business strategies:

- maintaining and increasing the value of our projects, by focusing on value-oriented project availability (by ensuring our projects are operational when the wind is strong and PPA prices are at their highest) and by regularly scheduled and preventative maintenance and by investing in our key personnel;

- completing our construction projects on schedule and within budget, by having our highly experienced construction team closely overseeing construction-contractor and turbine-vendor activities, which are subject to fixed-price contracts with guaranteed completion dates;

- maintaining a prudent capital structure and financial flexibility, by seeking to match our long-term assets with long-term liabilities, limiting exposure to commodity and interest rate risk and ensuring a prudent level of leverage in our business;

- working closely with our stakeholders, including suppliers, power sale agreement counterparties and the local communities where we are located to best support our projects; and

- selectively growing our business, by leveraging our management team s extensive relationships, experience and highly disciplined approach to evaluating and facilitating new business opportunities, including through collaboration with Pattern Development and other developers to advance their development pipelines, and by focusing on projects and regions where we believe we can add value.

For more information about our business strategy, see Business Our Strategy.

Our Competitive Strengths

We believe our key competitive strengths include:

our high-quality projects, which we believe provide the foundation for the stable long-term cash flows required to operate our business, service our debt and achieve our financial objectives;

our strong reputation in the industry, which we believe is derived from our integrity, expertise, solutions-oriented approach and record of success, which attracts talented people and opportunities;

our approach to project selection, which aims to deliver superior financial results and minimize long-term operating risks, by employing a highly disciplined, timely and comprehensive analysis of projects using our in-house experts;

our relationship with Pattern Development, which enhances our ability to operate our projects and provides us with access to a pipeline of acquisition opportunities, including the remaining Initial ROFO Projects (see Our Relationship with Pattern Development); and

our proven management team, which has extensive experience in all aspects of the independent power business, a demonstrated track record of successfully developing, constructing and operating wind power projects and a history of prudent financial and technological innovation in the power industry.

Table of Contents

For more information about our competitive strengths, see Business Competitive Strengths.

Market Opportunity

Wind power has been one of the fastest growing sources of electricity generation in North America and globally over the past decade. According to the Global Wind Energy Council, or GWEC, from 2003 through 2013, total net electricity generation from wind power in the United States and Canada grew at a CAGR of 25% and 38%, respectively. The growth in the industry is largely attributable to renewable energy s increasing cost competitiveness with other power generation technologies, the advantages of wind power over other renewable energy sources and growing public support for renewable energy driven by concerns regarding security of energy supply and the environment. As global demand for electricity generation from wind power has increased, technology enhancements supported by U.S. government incentives have reduced the cost of wind power by more than 90% over the last twenty years, according to the American Wind Energy Association, or AWEA.

The United States is the second largest market for wind power in the world by electricity generating capacity. According to the U.S. Department of Energy, or DoE, wind power was the second largest source of new electricity generating capacity in the United States after natural gas for six of the seven years between 2005 and 2011. According to AWEA, wind power became a leading source of new electricity generating capacity in the United States for the first time in 2012. The success of wind power in the United States is evidenced by over $90 billion in investments over the last five years, according to AWEA.

The Canadian wind power industry has also experienced dramatic growth in recent years. In 2013, Canada experienced approximately 1,600 MW of new installed wind power generating capacity, resulting in wind power generating capacity in Canada reaching approximately 7,800 MW as of January 2014. Ontario, one of our markets, is the national leader in installed capacity, with approximately 2.5 gigawatts, or GW, of wind power generating capacity, although recent changes to the Ontario government FIT regime may make future projects less attractive and PPAs more difficult to obtain. The EIA forecasts total wind power generating capacity in Canada to exceed 13 GW by 2020.

Chile, also one of our markets, has an abundant wind resource, which GWEC estimates could provide the potential for more than 40 GW of generating capacity. As of the end of 2013, Chile had approximately 355 MW of installed wind power generating capacity, representing approximately 2% of total electricity generating capacity and, according to GWEC, approximately 6,445 MW of wind projects under various stages of development, of which 450 MW of wind power projects were expected to come online in 2014 and a further 1,400 MW during 2015 to 2018.

Given supply diversity requirements, falling equipment costs, the inherent stability of the cost of wind power as an energy resource and an active market for the purchase and sale of power projects, we believe that our markets present a substantial opportunity for growth. We require a relatively small share of a very large market to meet our growth objectives and we believe we will achieve growth through the acquisition of operational and construction-ready projects from Pattern Development and other third parties.

While we currently operate solely in wind power markets, we expect to continue to evaluate other types of independent power projects for possible acquisition, including renewable energy projects other than wind power projects, non-renewable energy projects and transmission projects.

Our Relationship with Pattern Development

We were incorporated as a Delaware corporation by Pattern Development in October 2012 with the intent that we would own, operate and construct power projects and that Pattern Development would focus on its extensive development pipeline. Since it was formed, Pattern Development has been very active in developing project opportunities. We and Pattern Development have agreed that we will transfer Pattern Development s employees to our company, at no cost, once we reach $2.5 billion in total market capitalization, which we believe is a sufficient size to undertake development of future projects.

Table of Contents

Key members of our management team, together with certain other executives at Pattern Development and investment funds managed by Riverstone Holdings LLC, or Riverstone, formed Pattern Development in June 2009. Upon its formation, Pattern Development acquired a portfolio of development projects, but did not own any operating or construction projects. In late 2009, Pattern Development closed financing for its first construction project, Hatchet Ridge. In 2010, Pattern Development acquired the Gulf Wind project, completed construction of the Hatchet Ridge project, commenced construction of the St. Joseph project and formed a joint venture with a subsidiary of Samsung C&T Corporation, or Samsung, to develop at least 1,000 MW of wind power projects located in Ontario. Since 2010, Pattern Development also successfully completed construction and commenced operation of the St. Joseph, Spring Valley, Santa Isabel, Ocotillo and South Kent projects and commenced construction of the El Arrayán, Panhandle 1 and 2, Grand and K2 projects. Certain members of Pattern Development s management team who are not part of our management team, including John Calaway, Pattern Development s Senior Vice President Wind Development, and George Hardie and Colin Edwards, each a Vice President Development, intend to continue in their current roles at Pattern Development. These individuals have been key contributors to Pattern Development s success and to the more than 3,000 MW portfolio of development assets that includes the remaining Initial ROFO Projects.

Upon completion of this offering, Pattern Development will hold approximately % of our outstanding Class A shares and 99.1% of our outstanding Class B shares (or % and 99.1%, respectively, if the underwriters exercise their overallotment option in full), representing in the aggregate an approximate % voting interest in our company (or % if the underwriters exercise their overallotment option in full). The remaining 0.9% of our outstanding Class B shares are held by members of our management. Until the Conversion Event, neither Pattern Development nor the management holders of our Class B shares will be entitled to receive any dividends on their Class B shares.

We own, acquire and operate projects for which the development risks have been substantially reduced in order to generate stable long-term cash flows, and we expect that Pattern Development will invest in and deploy its staff to engage in higher-risk project development activities. Pattern Development holds a retained interest of approximately 27% in Gulf Wind, representing approximately 76 MW of Pattern Development-owned capacity, which we refer to as the Pattern Development retained Gulf Wind interest and interests in development projects with an expected total rated capacity of more than 3,000 MW, including wind power and solar power projects, as well as certain transmission development projects. Four of these development projects, together with the Pattern Development retained Gulf Wind interest, constitute the remaining Initial ROFO Projects, and are predominantly operational or construction ready.

						Capacity (MW)	
Remaining Initial ROFO Projects	**Status**	**Location**	**Construction Start(1)**	**Commercial Operations(2)**	**Contract Type**	**Rated(3)**	**Pattern Development Owned(4)**
Gulf Wind	Operational	Texas	2008	2009	Hedge	283	76
Panhandle 1	In Construction	Texas	2013	2014	Hedge	218	179
K2	In Construction	Ontario	2014	2015	PPA	270	90
Armow	Ready for Financing	Ontario	2014	2015	PPA	180	90
Meikle	Pre-Construction	British Columbia	2015	2016	PPA	185	185
						1,136	620

(1) Represents date of actual or anticipated commencement of construction.
(2) Represents date of actual or anticipated commencement of commercial operations.
(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated will be less than its rated capacity. The amount of electricity generated may vary based on a variety of factors.
(4) Pattern Development-owned capacity represents the maximum, or rated, electricity generating capacity of the project multiplied by Pattern Development s percentage ownership interest in the distributable cash flow of the project.

Our Purchase Rights

To promote our growth strategy, concurrent with the completion of our IPO, we entered into a purchase rights agreement with Pattern Development and its equity owners that provides us with three distinct avenues to grow our business through acquisitions:

- the right to acquire the Pattern Development retained Gulf Wind interest at any time between the first and second anniversary of the completion our IPO on October 2, 2013 at its then current fair market value, which we refer to as our Gulf Wind Call Right;

- a right of first offer with respect to any power project that Pattern Development decides to sell, including the Initial ROFO Projects, which we refer to as our Project Purchase Right; and

- a right of first offer with respect to Pattern Development itself, or substantially all of its assets, if the equity owners of Pattern Development decide to sell any material portion of the equity interests in Pattern Development or substantially all of its assets, which we refer to as our Pattern Development Purchase Right.

We refer to these rights as our Purchase Rights. Our Gulf Wind Call Right will commence on the first anniversary of the completion of the IPO, or October 2, 2014, and will terminate on the second anniversary of the completion our IPO, or October 2, 2015. Our Project Purchase Right and Pattern Development Purchase Right will terminate together upon the fifth anniversary of the completion our IPO, or October 2, 2018, but are subject to automatic five-year renewals unless either party dissents at the time of renewal. In addition, Pattern Development will have the right to terminate our Project Purchase Right and Pattern Development Purchase Right together upon the third occasion (within any five-year initial or renewal term) on which we have elected not to exercise our Project Purchase Right with respect to an operational or construction-ready project and following which Pattern Development has sold the project to an unrelated third party.

We have made a commitment to acquire the Panhandle 2 project from Pattern Development following the commencement of that project s commercial operations, which we expect to occur in the fourth quarter of this year. In addition, although we have no commitments to make any such acquisitions, we consider it reasonably likely that we may have the opportunity to acquire some or all of the remaining Initial ROFO Projects under our Purchase Rights at various times within the 18-month period following the completion of this offering. See Use of Proceeds and Certain Relationships and Related Party Transactions Our Relationship with Pattern Development Our Purchase Rights in our 2014 Proxy Statement.

Shareholder Approval Rights Agreement

We entered into a shareholder approval rights agreement, or the Shareholder Agreement, with Pattern Development concurrently with the completion of our IPO. Pursuant to the Shareholder Agreement, for so long as Pattern Development beneficially owns at least 33 1/3% of our shares, Pattern Development s consent will be necessary for us to take certain material corporate actions, including: (i) our consolidation with or merger into an unaffiliated entity; (ii) certain acquisitions of stock or assets of a third-party; (iii) our adoption of a plan of liquidation, dissolution or winding up; (iv) certain dispositions of our or our subsidiaries assets; (v) the incurrence of indebtedness in excess of a specified amount; (vi) a change in the size of our board of directors (subject to certain exceptions); and (vii) issuing equity securities with preferential rights to our Class A shares. See Certain Relationships and Related Party

Transactions Shareholder Agreement in our 2014 Proxy Statement.

13

Table of Contents

Non-Competition Agreement

We entered into a non-competition agreement, or the Non-Competition Agreement, with Pattern Development concurrently with the completion of our IPO. Pursuant to the Non-Competition Agreement, Pattern Development agreed that, for so long as any of our Purchase Rights are exercisable, it will not compete with us for acquisitions of power generation or transmission projects from third parties. Pattern Development will notify us of opportunities to acquire power generation or transmission projects that it wishes to pursue and, should we be interested in acquiring all or a portion of such projects, we may direct Pattern Development to forego such opportunities. We may also elect to collaborate with Pattern Development to jointly pursue acquisition opportunities from time to time. Riverstone is not subject to the Non-Competition Agreement.

Management Services Agreement and Shared Management

We intend to grow our assets until we have sufficient size and cash flow to undertake development activities. Until such time, we have contracted for certain services pursuant to the terms of a bilateral services agreement with Pattern Development, or the Management Services Agreement, that we entered into upon the completion of our IPO. However, under the terms of the Management Services Agreement, upon the completion of the first 20 consecutive trading day period during which our total market capitalization is no less than $2.5 billion, such event, the reintegration event, the employees of Pattern Development will become our employees, which we refer to as the employee reintegration.

Our project operations and maintenance personnel and executive officers are solely compensated by us and their employment with Pattern Development terminated concurrently with the completion of our IPO. These executives lead our business functions and rely on support from Pattern Development employees for certain administrative functions. Pattern Development retained only those employees whose primary responsibilities relate to project development or legal, financial or other administrative functions. The Management Services Agreement provides for us and Pattern Development to benefit, primarily on a cost-reimbursement basis, from the parties respective management and other professional, technical and administrative personnel, all of whom report to and are managed by our executive officers. In the event that Pattern Development is, or substantially all of its assets are, acquired by an unrelated third party, we have the unilateral right to terminate the Management Services Agreement.

Pursuant to the Management Services Agreement, certain of our executive officers, including our Chief Executive Officer, also serve as executive officers of Pattern Development and devote their time to both our company and Pattern Development as is prudent in carrying out their executive responsibilities and fiduciary duties. We refer to our employees who serve as executive officers of both our company and Pattern Development as the shared PEG executives. The shared PEG executives have responsibilities to both us and Pattern Development and, as a result, these individuals do not devote all of their time to our business. Under the terms of the Management Services Agreement, Pattern Development is required to reimburse us for an allocation of the compensation paid to such shared PEG executives reflecting the percentage of time spent providing services to Pattern Development.

Upon employee reintegration, we expect that our principal focus will continue to be owning operational and under construction power projects. However, reintegration is expected to enhance our long-term ability to independently develop projects and grow our business. Following the employee reintegration, we will continue to provide management services to Pattern Development (including services from the reintegrated departments of Pattern Development) to the extent required by Pattern Development s remaining development activities and the consideration for such services would continue to be paid primarily on a cost reimbursement basis. See Certain Relationships and Related Party Transactions Management Services Agreement and Shared Management in our 2014 Proxy Statement for a further discussion of the Management Services Agreement and the employee reintegration.

Initial Public Offering and Contribution Transactions

Concurrent with the completion of our IPO, pursuant to the terms of a contribution agreement between us and Pattern Development, which we refer to as the Contribution Agreement, we entered into a series of transactions with Pattern Development, or the Contribution Transactions. In connection with the Contribution Transactions, Pattern Development contributed to us all of our initial projects, including the related properties and other assets to be used in our business, together with liabilities and obligations to which such projects are subject.

Table of Contents

On October 2, 2013, we issued 16,000,000 shares of Class A common stock in an IPO generating net proceeds of approximately $317.0 million. Concurrent with our IPO, we issued 19,445,000 shares of Class A common stock and 15,555,000 shares of Class B common stock to Pattern Development and utilized approximately $232.6 million of the net proceeds of the IPO as a portion of the consideration to Pattern Development for the entities and assets contributed to us in the Contribution Transactions, consisting of interests in eight wind power projects, including six projects in operation (Gulf Wind, Hatchet Ridge, St. Joseph, Spring Valley, Santa Isabel and Ocotillo), and two projects under construction (El Arrayán and South Kent). In accordance with ASC 805-50-30-5, Transactions between Entities under Common Control, we recognized the assets and liabilities contributed by Pattern Development at their historical carrying amounts at the date of the Contribution Transactions. On October 8, 2013, our underwriters exercised in full their overallotment option to purchase 2,400,000 shares of Class A common stock from Pattern Development, the selling shareholder, pursuant to the overallotment option granted by Pattern Development.

In connection with the Contribution Transactions, we also assumed certain indemnities previously granted by Pattern Development for the benefit of the Spring Valley, Santa Isabel and Ocotillo project finance lenders. These indemnity obligations consist principally of indemnities that protect the project finance lenders from the potential effect of any recapture by the U.S. Department of the Treasury, or U.S. Treasury, of any amount of the ITC cash grants previously received by the projects. The indemnity obligations that we assumed are in amounts that are up to the greater of the respective cash grant loans or the amounts of any cash grant subsequently recaptured. Such maximum indemnity amounts are approximately $116 million, $80 million and $58 million for the Ocotillo, Spring Valley and Santa Isabel projects, respectively. In addition, we also assumed an indemnity that was granted by Pattern Development to our Ocotillo project finance lenders in connection with certain legal matters, which is limited to the amount of certain related costs and expenses. See Risk Factors We are subject to various indemnity obligations, in our 2013 Form 10-K, Business Legal Proceedings and Management s Discussion & Analysis of Financial Condition and Results of Operations Description of Credit Agreements Santa Isabel Senior Financing Agreement and Ocotillo Senior Financing Agreement in our 2013 Form 10-K.

Table of Contents

Our Ownership Structure

The following diagram summarizes our ownership structure upon completion of this offering.

(1) These funds and these employees hold indirect interests in Pattern Development.
(2) Pattern Development holds an interest of approximately 27% in Gulf Wind, representing Pattern Development-owned capacity of 76 MW.
(3) We have agreed to acquire Panhandle 2 from Pattern Development and expect to complete the acquisition in the fourth quarter of 2014, subject to the satisfaction of customary closing conditions.

Riverstone

Pattern Development was formed in June 2009 by the executive management team of Pattern Development and investment funds managed by Riverstone. Riverstone is an energy and power-focused private equity firm founded in 2000 with approximately $27.0 billion of equity capital raised across seven investment funds and related coinvestments, including the world s largest renewable energy fund. Riverstone conducts buyout and growth capital investments in the midstream, exploration & production, oilfield services, power and renewable sectors of the energy industry. With offices in New York, London and Houston, the firm has committed approximately $25.8 billion to 107 investments in North America, Latin America, Europe, Africa and Asia.

Corporate Information

Our principal executive offices are located at Pier 1, Bay 3, San Francisco, California 94111, and our telephone number is (415) 283-4000. Our website is www.patternenergy.com. We make our periodic reports and other information filed or furnished to the SEC or Canadian Securities Administrators available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC or Canadian Securities Administrators. Except as specifically noted, information on our website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

Table of Contents

THE OFFERING

Common stock offered by us	Class A shares.
Common stock offered by the selling shareholder	Class A shares
Class A common stock to be outstanding after this offering	Class A shares.
Total common stock to be outstanding after this offering (x)	Total Class A and Class B shares.
Class B common stock to be outstanding after this offering	15,555,000 Class B shares. The rights of the holders of our Class A and Class B shares are identical other than in respect of dividends and the conversion rights of the Class B shares. While each Class A and Class B share have one vote on all matters submitted to a vote of our shareholders, our Class B shares have no rights to dividends or distributions (other than upon liquidation). Upon the Conversion Event, on December 31, 2014, all of our outstanding Class B shares will automatically convert, on a one-for-one basis, into Class A shares. See Description of Capital Stock.
Conversion Event	Our amended and restated certificate of incorporation provides that all of our Class B shares will automatically convert into Class A shares on a one-for-one basis upon the later of December 31, 2014 and the date on which our South Kent project achieves Commercial Operations, which occurred on March 28, 2014.
Overallotment option	Pattern Development, or the selling shareholder, has granted the underwriters an option, exercisable within 30 days following the closing date of this offering, to purchase up to an additional Class A shares at the public offering price to cover overallotments, if any. We will not receive any proceeds from the exercise of the underwriters overallotment option. See Use of Proceeds.
Use of proceeds	We estimate we will receive net proceeds of approximately $ million from this offering, based on an assumed public offering price of $ per Class A share, which is the last reported sale price of our Class A common stock on the NASDAQ on the cover page of this prospectus, and after deducting underwriting commissions and estimated offering expenses payable by us. We intend to use the net proceeds from this offering for working capital and general corporate purposes, which may include investment in one or more acquisition opportunities which we are considering. See Use of Proceeds for additional information. We will not receive any proceeds from the sale of the shares being sold by the selling shareholder.
Pattern Development retained interest	Upon completion of this offering, Pattern Development will hold approximately % of our outstanding Class A shares and 99.1% of our outstanding Class B shares (or % and 99.1%, respectively, if the underwriters exercise their

overallotment option in full), representing in the aggregate an approximate % voting interest in our company (or % if the underwriters exercise their overallotment option in full). The remaining 0.9% of our outstanding Class B shares is held by members of our management. Until the Conversion Event, neither Pattern Development nor the management holders of our Class B shares will be entitled to receive any dividends on their Class B shares.

Dividends	On November 26, 2013, we announced the initiation of a quarterly common stock dividend and on January 30, 2014, we paid a dividend to each of our Class A common shareholders of $0.3125 per Class A share, or $1.25 per Class A share on an annualized basis. We have declared a dividend of the same amount per share payable on April 30, 2014 to our Class A common shareholders of record as of March 31, 2014.
U.S. Taxation of Dividends to Non-U.S. Holders	The distributions that we will make to our shareholders will be treated as dividends under U.S. tax law only to the extent that they will be paid out of our current or accumulated earnings and profits computed under U.S. tax principles, which we refer to herein as earnings and profits. Our earnings and profits, as calculated under U.S. tax principles, may be negative at times due to various deductions, for example, depreciation. If the cash dividends paid to our shareholders exceed our current and accumulated earnings and profits for a taxable year, the excess cash dividends would not be taxable as a dividend but rather would be treated as a return of capital for U.S. federal income tax purposes, which would result in a reduction in the adjusted tax basis of our shares to the extent thereof, and any balance in excess of adjusted basis would be treated as a gain for U.S. federal income tax purposes. For non-U.S. Holders (as defined under Material U.S. Federal Income Tax Considerations for Non-U.S. Holders of Our Class A Common Shares), cash dividends that are treated as dividends would normally be subject to U.S. federal withholding tax at the rate of 30% (or at a reduced rate under an applicable income tax treaty). Although distributions on our Class A common shares in any year likely will exceed our earnings and profits and thus some or all of such distributions will not constitute dividends for U.S. federal income tax purposes, the facts necessary to make a determination of the extent to which a distribution on our Class A common shares is treated as a dividend for such purpose may not be known at the time of the distribution, and therefore a non- U.S. holder should expect that a withholding agent will treat the entire amount of a distribution on our Class A common shares as a dividend for purposes of determining the amount required to be withheld on such distribution. If it is later determined that all or a portion of such distribution did not in fact constitute a dividend for U.S. federal income tax purposes, a non-U.S. holder may be entitled to a refund of any excess tax withheld, provided that the required information is timely furnished to the IRS. For more information, see Material U.S. Federal Income Tax Considerations for Non-U.S. Holders of Our Class A Common Shares.
Exchange listing	Our Class A shares are listed on the NASDAQ Global Market, or NASDAQ, under the symbol PEGI , and the Toronto Stock Exchange, or TSX, under the symbol PEG .
Canadian Taxation of Dividends to Canadian Resident Shareholders and Non-Canadian Resident Shareholders	Shareholders resident in Canada will generally be required to include in their income any dividends, including any amounts deducted for U.S. withholding tax, if any, received on the shares whether or not treated as dividends under U.S. tax law. Such shareholders may be eligible for a foreign tax credit or deduction in respect of any U.S. withholding tax in computing their Canadian tax liability. Dividends paid in respect of our shares to shareholders not resident in Canada

will not be subject to Canadian withholding tax or, generally, other Canadian income tax.

	For more information, see Material Canadian Federal Income Tax Considerations for Holders of Our Class A Common Shares.
FERC-Related Purchase Restrictions	As a result of the FPA and FERC s regulations in respect of transfers of control, consistent with the requirements for blanket authorizations granted under or exemptions from FERC s regulations, absent prior authorization by FERC, no purchaser in this offering will be permitted to purchase an amount of our Class A shares that would cause such purchaser and its affiliate and associate companies in aggregate to hold 10% or more of our common shares outstanding after this offering. See Risk Factors Risks Related to this Offering and Ownership of our Class A Shares As a result of the FPA and FERC s regulations in respect of transfers of control, absent prior authorization by FERC, neither we nor Pattern Development can convey to an investor, nor will an investor in our company generally be permitted to obtain, a direct and/or indirect voting interest in 10% or more of our issued and outstanding voting securities, and a violation of this limitation could result in civil or criminal penalties under the FPA and possible further sanctions imposed by FERC under the FPA.

(x) Includes (a) Class A shares offered by us to the public hereby and (b) 35,703,134 Class A shares outstanding prior to this offering, and excludes 2,295,270 Class A shares available for future issuance, or issuable pursuant to outstanding but unexercised awards, under our 2013 Equity Incentive Award Plan.

Table of Contents

SUMMARY HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table presents summary historical consolidated financial data as of the dates and for the periods indicated. The summary historical consolidated financial data as of December 31, 2011, 2012 and 2013 and for the years ended December 31, 2011, 2012 and 2013 have been derived from the audited historical consolidated financial statements incorporated by reference in this prospectus.

Our historical consolidated financial statements, from which the summary historical consolidated financial data have been derived, are presented in U.S. dollars and have been prepared in accordance with U.S. GAAP, which differ in certain material respects from International Financial Reporting Standards, or IFRS. For recent and historical exchange rates between Canadian dollars and U.S. dollars, see Currency and Exchange Rate Information.

You should read the following table in conjunction with Structure and Formation of Our Company, Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations, and the historical consolidated financial statements and the notes thereto included elsewhere or incorporated by reference in this prospectus.

	Year Ended December 31,		
	2013	**2012**	**2011**
	(U.S. dollars in thousands, except share and per share data and Operating Data)		
Statement of Operations Data:			
Revenue:			
Electricity sales	$ 173,270	$ 101,835	$ 108,770
Energy derivative settlements	16,798	19,644	9,512
Unrealized (loss) gain on energy derivative	(11,272)	(6,951)	17,577
Related party revenue	911		
Other Revenue	21,866		
Total revenue	201,573	114,528	135,859
Cost of revenue:			
Project expenses	57,677	34,843	31,343
Depreciation and accretion	83,180	49,027	39,424
Total cost of revenue	140,857	83,870	70,767
Gross profit	60,716	30,658	65,092
Total operating expenses	12,988	11,636	9,668
Operating income	47,728	19,022	55,424
Total other expense	(33,110)	(36,002)	(28,829)
Net income (loss) before income tax	14,618	(16,980)	26,595
Tax provision (benefit)	4,546	(3,604)	689

Net income (loss)		10,072		(13,376)		25,906
Net (loss) income attributable to noncontrolling interest		(6,887)		(7,089)		16,981
Net income (loss) attributable to controlling interest	$	16,959	$	(6,287)	$	8,925
Earnings per share information:						
Less: net income attributable to controlling interest prior to the IPO on October 2, 2013		(30,295)				
Net loss attributable to controlling interest subsequent to the IPO	$	(13,336)				
Weighted average number of shares:						
Basic and diluted Class A common stock		35,448,056				
Basic and diluted Class B common stock		15,555,000				
Earnings per share for period subsequent to the IPO						
Class A common stock:						
Basic and diluted loss per share	$	(0.17)				

Table of Contents

	Year Ended December 31,		
	2013	2012	2011
Class B common stock:			
Basic and diluted loss per share	$ (0.48)		
Unaudited pro forma net loss after tax:			
Net loss before income tax		*$ (16,980)*	
Pro forma tax provision		*818*	
Pro forma net loss		*$ (17,798)*	
Other Financial Data:			
Adjusted EBITDA(1)	$ 141,769	$ 75,248	$ 77,258
Cash available for distribution(2)	$ 42,621	$ 17,692	$ 18,530
Cash available for distribution before principal payments(2)	$ 85,450	$ 45,238	$ 40,860
Net cash provided by (used in):			
Operating activities	$ 78,152	$ 35,051	$ 46,930
Investing activities	$ 72,391	$ (638,953)	$ (340,977)
Financing activities	$ (63,401)	$ 573,167	$ 331,336
Operating Data:			
MWh sold(3)	2,258,811	1,673,413	1,568,022
Average realized electricity price ($/MWh)(4)	$ 84	$ 73	$ 75

	As of December 31,		
	2013	2012	2011
	(U.S. dollars in thousands)		
Balance Sheet Data:			
Cash	$ 103,569	$ 17,574	$ 47,672
Construction in progress	$	$ 6,081	$ 201,245
Property, plant and equipment, net	$ 1,476,142	$ 1,668,302	$ 784,859
Total assets	$ 1,903,631	$ 2,035,730	$ 1,390,426
Long-term debt	$ 1,249,218	$ 1,290,570	$ 867,548
Total liabilities	$ 1,335,627	$ 1,446,318	$ 943,728
Total equity before noncontrolling interest	$ 468,210	$ 514,111	$ 362,226
Noncontrolling interest	$ 99,794	$ 75,301	$ 84,472
Total equity	$ 568,004	$ 589,412	$ 446,698

(1) Adjusted EBITDA represents net income before net interest expense, income taxes and depreciation and accretion, including our proportionate share of net interest expense, income taxes and depreciation and accretion for joint venture investments that are accounted for under the equity method. Adjusted EBITDA also excludes the effect of certain mark-to-market adjustments and infrequent items not related to normal or ongoing operations, such as early payment of debt and realized derivative gain or loss from refinancing transactions, and gain or loss related to acquisitions or divestitures. We disclose Adjusted EBITDA, which is a non-U.S. GAAP measure,

because management believes this metric assists investors and analysts in comparing our operating performance across reporting periods on a consistent basis by excluding items that our management believes are not indicative of our core operating performance. We use Adjusted EBITDA to evaluate our operating performance. You should not consider Adjusted EBITDA as an alternative to net income (loss), determined in accordance with U.S. GAAP, or as an alternative to net cash provided by operating activities, determined in accordance with U.S. GAAP, as an indicator of our cash flows.

Adjusted EBITDA has limitations as an analytical tool. Some of these limitations are:

Adjusted EBITDA:

- does not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;

Table of Contents

does not reflect changes in, or cash requirements for, our working capital needs;

does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on our debt;

does not reflect our income tax expense or the cash requirement to pay our taxes; and

does not reflect the effect of certain mark-to-market adjustments and non-recurring items;

although depreciation and accretion are non-cash charges, the assets being depreciated and accreted will often have to be replaced in the future, and Adjusted EBITDA does not reflect any cash requirements for such replacements; and

other companies in our industry may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure.

Because of these limitations, Adjusted EBITDA should not be considered in isolation or as a substitute for performance measures calculated in accordance with U.S. GAAP.

The most directly comparable U.S. GAAP measure to Adjusted EBITDA is net income (loss). The following table is a reconciliation of our net income (loss) to Adjusted EBITDA for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
	(U.S. dollars in thousands)		
Net income (loss)	$ 10,072	$ (13,376)	$ 25,906
Plus:			
Interest expense, net of interest income	61,118	35,457	28,285
Tax provision (benefit)	4,546	(3,604)	689
Depreciation and accretion	83,180	49,027	39,424
EBITDA	158,916	67,504	94,304
Unrealized (gain) loss on energy derivative	11,272	6,951	(17,577)
Unrealized (gain) loss on interest rate derivatives	(15,601)	4,953	345
Interest rate derivative settlements	2,099		
Gain on transactions(a)	(5,995)	(4,173)	
Plus, our proportionate share in the following from our equity accounted investments:			
Interest expense, net of interest income	267	44	
Tax provision (benefit)	(172)	(65)	

Depreciation and accretion	20		186
Unrealized loss on interest rate and currency derivatives	(9,076)	27	
Realized gain on interest rate and currency derivatives	39		
Adjusted EBITDA	$ 141,769	$ 75,241	$ 77,258

(a) Represents transaction costs related to acquisitions and gain related to the sale of a portion of our investment in the El Arrayán project in 2012.

(2) Cash available for distribution represents cash provided by (used in) operating activities as adjusted to (i) add or subtract changes in operating assets and liabilities, (ii) subtract net deposits into restricted cash accounts, which are required pursuant to the cash reserve requirements of financing agreements, to the extent they are paid from operating cash flows during a period, (iii) subtract cash distributions paid to noncontrolling interests, which currently reflects the cash distributions to our joint venture partners in our Gulf Wind project in accordance with the provisions of its governing partnership agreement and may in the future reflect distribution to other joint-venture

partners, (iv) subtract scheduled project-level debt repayments in accordance with the related loan amortization schedule, to the extent they are paid from operating cash flows during a period, (v) subtract non-expansionary capital expenditures, to the extent they are paid from operating cash flows during a period, and (vi) add or subtract other items as necessary to present the cash flows we deem representative of our core business operations. Cash available for distribution before principal payments represents the sum of cash available for distribution and scheduled project-level debt repayments in accordance with the related loan amortization schedules, to the extent they are paid from operating cash flows during a period.

We disclose cash available for distribution before principal payments and cash available for distribution because management recognizes that they will be used as supplemental measures by investors and analysts to evaluate our liquidity. However, cash available for distribution before principal payments and cash available for distribution have limitations as analytical tools because they exclude depreciation and accretion, do not capture the level of capital expenditures necessary to maintain the operating performance of our projects, are not reduced for principal payments on our project indebtedness except, with respect to cash available for distribution, to the extent they are paid from operating cash flows during a period, and exclude the effect of certain other cash flow items, all of which could have a material effect on our financial condition and results from operations. Cash available for distribution before principal payments and cash available for distribution are non-U.S. GAAP measures and should not be considered alternatives to net income, net cash provided by (used in) operating activities or any other liquidity measure determined in accordance with U.S. GAAP, nor are they indicative of funds available to fund our cash needs. In addition, our calculations of cash available for distribution before principal payments and cash available for distribution are not necessarily comparable to cash available for distribution before principal payments and cash available for distribution as calculated by other companies. Investors should not rely on these measures as a substitute for any U.S. GAAP measure, including net income (loss) and net cash provided by (used in) operating activities.

The most directly comparable U.S. GAAP measure to both cash available for distribution before principal payments and cash available for distribution is net cash provided by (used in) operating activities. The following table is a reconciliation of our net cash provided by (used in) operating activities to both cash available for distribution before principal payments and cash available for distribution for the periods presented:

	Year Ended December 31,		
	2013	**2012**	**2011**
	(U.S. dollars in thousands)		
Net cash provided by (used in) operating activities	$ 78,152	$ 35,051	$ 46,930
Changes in current operating assets and liabilities	8,237	6,885	3,237
Network upgrade reimbursement (a)	1,854	6,263	
Use of operating cash to fund maintenance and debt reserves		(1,047)	(1,048)
Release of restricted cash to fund general and administrative cost	318		
Operations and maintenance capital expenditures	(819)	(623)	(1,101)
Less:			
Distributions to noncontrolling interests	(2,292)	(1,298)	(7,158)
Cash available for distribution before principal payments	85,450	45,231	40,860

Principal payments paid from operating cash flows	(42,829)	(27,546)	(22,330)
Cash available for distribution	$ 42,621	$ 17,685	$ 18,530

(a) During the construction of the Hatchet Ridge project, we funded the costs to construct interconnection facilities in order to connect to the utility s power grid and we will be reimbursed from the utility for those costs during the years 2013 to 2015. We carry a network upgrade reimbursements receivable in prepaid expenses and other current assets and other assets on our balance sheet.

Table of Contents

(3) For any period presented, MWh sold represents the amount of electricity measured in MWh that our projects generated and sold.
(4) For any period presented, average realized electricity price represents total revenue from electricity sales and energy derivative settlements divided by the aggregate number of MWh sold.

Table of Contents

RISK FACTORS

An investment in our shares involves a high degree of risk. You should carefully consider the following risks, together with other information provided to you in and incorporated by reference into this prospectus, in deciding whether to invest in our Class A shares. The selected risks presented below and the risks that are incorporated into this prospectus by reference to our 2013 Form 10-K are not our only risks, and additional risks and uncertainties that are not currently known to us or those we currently believe are immaterial may also materially adversely affect our business, financial condition, results of operations and liquidity. If any of the following risks, or those described in our 2013 Form 10-K, were to occur, our business, financial condition, results of operations and liquidity could be materially adversely affected. In that case, we might have to decrease, or may not be able to pay, dividends on our Class A shares, the trading price of our Class A shares could decline and you could lose all or part of your investment.

Risks Related to this Offering and Ownership of our Class A Shares

We are a holding company with no operations of our own, and we depend on our power projects for cash to fund all of our operations and expenses, including to make dividend payments.

Our operations are conducted entirely through our power projects and our ability to generate cash to meet our debt service obligations or to pay dividends is dependent on the earnings and the receipt of funds from our project subsidiaries through distributions or intercompany loans. Our power projects ability to generate adequate cash depends on a number of factors, including wind conditions, timely completion of our construction projects, the price of electricity, payments by key power purchasers, increased competition, foreign currency exchange rates, compliance with all applicable laws and regulations and other factors. See Risk Factors Risks Related to Our Projects in our 2013 Form 10-K. Our ability to declare and pay regular quarterly cash dividends is subject to our obtaining sufficient cash distributions from our project subsidiaries after the payment of operating costs, debt service and other expenses. We may lack sufficient available cash to pay dividends to holders of our Class A shares due to shortfalls attributable to a number of operational, commercial or other factors, including insufficient cash flow generation by our projects, as well as unknown liabilities, the cost associated with governmental regulation, increases in our operating or general and administrative expenses, principal and interest payments on our and our subsidiaries outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

Our cash available for distribution to holders of our Class A shares may be reduced as a result of restrictions on our subsidiaries cash distributions to us under the terms of their indebtedness.

We intend to declare and pay regular quarterly cash dividends on all of our outstanding Class A shares. However, in any period, our ability to pay dividends to holders of our Class A shares depends on the performance of our subsidiaries and their ability to distribute cash to us as well as all of the other factors discussed under Risks regarding our cash dividend policy. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness.

Restrictions on distributions to us by our subsidiaries under our revolving credit facility and the agreements governing their respective project-level debt could limit our ability to pay anticipated dividends to holders of our Class A shares. These agreements contain financial tests and covenants that our subsidiaries must satisfy prior to making distributions. If any of our subsidiaries is unable to satisfy these restrictions or is otherwise in default under such agreements, it would be prohibited from making distributions to us that could, in turn, limit our ability to pay dividends to holders of our Class A shares. The terms of our project-level indebtedness typically require commencement of commercial operations prior to our ability to receive cash distributions from a project. The terms of any such indebtedness also typically include cash management or similar provisions, pursuant to which revenues generated by projects subject to such indebtedness are immediately, or upon the occurrence of certain events, swept into an account for the benefit of the lenders under such debt agreements. As a result, project revenues typically only become available to us after the funding of reserve accounts for, among other things, debt service, taxes and insurance at the project level. In some instances, projects may be required to sweep cash to reserve funds intended to mitigate the results of pending litigation or other potentially adverse events. If our projects do not generate sufficient cash available for distribution, we may be required to fund dividends from working capital, borrowings under our revolving credit facility, proceeds from this and future offerings, the sale of assets or by obtaining other debt or equity financing, which may not be available, any of which could have a material adverse effect on the price of our

Table of Contents

Class A shares and on our ability to pay dividends at anticipated levels or at all. See Management s Discussion & Analysis of Financial Condition and Results of Operations Description of Credit Agreements in our 2013 Form 10-K.

Our ability to pay regular dividends on our Class A shares is subject to the discretion of our Board of Directors.

Our Class A shareholders have no contractual or other legal right to dividends. The payment of future dividends on our Class A shares will be at the discretion of our Board of Directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our Board of Directors deems relevant. Our Board of Directors has the authority to establish cash reserves for the prudent conduct of our business, and the establishment of or increase in those reserves could result in a reduction in cash available for distribution to pay dividends on our Class A shares at anticipated levels. Accordingly, we may not be able to make, or may have to reduce or eliminate, the payment of dividends on our Class A shares, which could adversely affect the market price of our Class A shares.

Our cash dividend policy is subject to risks and uncertainties.

We do not have a sufficient operating history as an independent company upon which to rely in evaluating whether we will have sufficient cash available for distribution and other sources of liquidity to allow us to pay dividends on our Class A shares at our initial quarterly dividend level on an annualized basis. While we believe that we will have sufficient available cash to enable us to pay quarterly dividends on our Class A shares for the year ending December 31, 2014, we may be unable to pay the quarterly dividend or any amount on our Class A shares during this or any subsequent period. Holders of our Class A shares have no contractual or other legal right to receive cash dividends from us on a quarterly or other basis and, while we currently intend to maintain our initial dividend and to grow our business and increase our dividend per Class A share over time, our cash dividend policy is subject to all the risks inherent in our business and may be changed at any time. Some of the reasons for such uncertainties in our stated cash dividend policy include the following factors:

Our $145 million revolving credit facility with a four-year term includes customary affirmative and negative covenants that will subject certain of our project subsidiaries to restrictions on making distributions to us. See Management s Discussion and Analysis of Financial Condition and Results of Operations Description of Credit Agreements Revolving Credit Facility in our 2013 Form 10-K. Our subsidiaries are also subject to restrictions on distributions under the agreements governing their respective project-level debt. Additionally, we may incur debt in the future to acquire new power projects, the terms of which will likely require commencement of commercial operations prior to our ability to receive cash distributions from such acquired projects. These agreements likely will contain financial tests and covenants that our subsidiaries must satisfy prior to making distributions. The current financial tests and covenants applicable to our subsidiaries are described in Management s Discussion and Analysis of Financial Condition and Results of Operations Description of Credit Agreements in our 2013 Form 10-K. If any of our subsidiaries is unable to satisfy these restrictions or is otherwise in default under our financing agreements, it would be prohibited from making distributions to us, which could, in turn, limit our ability to pay dividends to holders of our Class A shares at our intended level or at all.

Our Board of Directors has the authority to establish cash reserves for the prudent conduct of our business, and the establishment of or increase in those reserves would reduce the cash available to pay our dividends.

We may lack sufficient cash available for distribution to pay our dividends due to operational, commercial or other factors, some of which are outside of our control, including insufficient cash flow generation by our projects, as well as unexpected operating interruptions, insufficient wind resources, legal liabilities, the cost associated with governmental regulation, changes in governmental subsidies or regulations, increases in our operating or selling, general and administrative expenses, principal and interest payments on our and our subsidiaries outstanding debt, tax expenses, working capital requirements and anticipated cash reserve needs.

Table of Contents

We are an emerging growth company, and we cannot be certain if the reduced reporting requirements applicable to emerging growth companies will make our Class A shares less attractive to investors.

We are an emerging growth company. For as long as we are an emerging growth company, we may take advantage of exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002, or the Sarbanes-Oxley Act, certain reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and exemptions from the requirements of holding a non-binding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We could be an emerging growth company for up to five years, although circumstances could cause us to lose that status earlier, including if the market value of our shares held by non-affiliates exceeds $700 million as of any June 30 before that time, in which case we would no longer be an emerging growth company as of the following December 31. We cannot predict if investors will find our Class A shares less attractive because we may rely on these exemptions. If some investors find our Class A shares less attractive as a result, there may be a less active trading market for our Class A shares and our Class A share price may be more volatile.

Under the JOBS Act, emerging growth companies can also delay adopting new or revised accounting standards until such standards apply to private companies. In addition, Section 107 of the JOBS Act also provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the U.S. Securities Act of 1933, or the U.S. Securities Act, for complying with new or revised accounting standards that have different effective dates for public and private companies. In other words, an emerging growth company can delay the adoption of such accounting standards until the first to occur of the date the subject company (i) is no longer an emerging growth company or (ii) affirmatively and irrevocably opt outs of the extended transition period provided in U.S. Securities Act Section 7(a)(2)(B). We have elected to take advantage of the extended transition period provided in Section 7(a)(2)(B) of the U.S. Securities Act for complying with new or revised accounting standards that have different effective dates for public and private companies and, as a result, our financial statements may not be comparable to the financial statements of other public companies. In addition, we have availed ourselves of the exemption from disclosing certain executive compensation information in this prospectus pursuant to Title 1, Section 102 of the JOBS Act. We cannot predict if investors will find our Class A shares less attractive because we will rely on these exemptions. If some investors find our Class A shares less attractive as a result, there may be a less active trading market for our Class A shares and our Class A share price may be more volatile.

We are an SEC foreign issuer under Canadian securities laws and, therefore, are exempt from certain requirements of Canadian securities laws applicable to other Canadian reporting issuers.

Although we are a reporting issuer in Canada, we are an SEC foreign issuer under Canadian securities laws and are exempt from certain Canadian securities laws relating to continuous disclosure obligations and proxy solicitation if we comply with certain reporting requirements applicable in the United States, provided that the relevant documents filed with the SEC are filed in Canada and sent to our Class A shareholders in Canada to the extent and in the manner and within the time required by applicable U.S. requirements. In some cases the disclosure obligations applicable in the United States are different or less onerous than the comparable disclosure requirements applicable in Canada for a Canadian reporting issuer that is not exempt from Canadian disclosure obligations. Therefore, there may be less or different publicly available information about us than would be available if we were a Canadian reporting issuer that is not exempt from such Canadian disclosure obligations.

Pattern Development s general partner and its officers and directors have fiduciary or other obligations to act in the best interests of Pattern Development s owners, which could result in a conflict of interest with us and our

shareholders.

Pattern Development holds approximately 62.95% of our outstanding Class A shares and 99.1% of our outstanding B shares. Upon completion of this offering, Pattern Development will hold approximately % of our outstanding Class A shares and 99.1% of our outstanding Class B shares (or % and 99.1%, respectively, if the underwriters exercise their overallotment option in full), representing in the aggregate an approximate %

voting interest in our company (or % if the underwriters exercise their overallotment option in full). The remaining 0.9% of our outstanding Class B shares are held by members of our management. Until the Conversion Event, neither Pattern Development nor the management holders of our Class B shares will be entitled to receive any dividends on their Class B shares. We are party to the Management Services Agreement, pursuant to which each of our executive officers (including our Chief Executive Officer), with the exception of our Chief Financial Officer and Senior Vice President, Operations, are also shared PEG executives and devote their time to both our company and Pattern Development as needed to conduct our respective businesses. As a result, these shared PEG executives have fiduciary and other duties to Pattern Development. Conflicts of interest may arise in the future between our company (including our shareholders other than Pattern Development) and Pattern Development (and its owners and affiliates). Our directors and executive officers owe fiduciary duties to the holders of our shares. However, Pattern Development s general partner and certain of its officers and directors also have a fiduciary duty to act in the best interest of Pattern Development s limited partners, which interest may differ from or conflict with that of our company and our other shareholders.

Pattern Development s share ownership limits other shareholders ability to influence corporate matters.

Pattern Development or its affiliates hold approximately 62.95% of the combined voting power of our shares. Following this offering Pattern Development or its affiliates will hold approximately % of the combined voting power of our shares if the underwriters exercise their overallotment option in full, and this concentration of voting power limits other shareholders ability to influence corporate matters, and as a result, actions may be taken that shareholders other than Pattern Development may not view as beneficial. As a result of its ownership in our company, Pattern Development will continue to have significant influence over all matters that require approval by our shareholders, including the election of directors. As a result, Pattern Development or its affiliates have the ability to exercise substantial influence over our company, including with respect to decisions relating to our capital structure, issuing additional Class A shares or other equity securities, paying dividends on our Class A shares, incurring additional debt, making acquisitions, selling properties or other assets, merging with other companies and undertaking other extraordinary transactions. In any of these matters, the interests of Pattern Development and its affiliates may differ from or conflict with the interests of our other shareholders. Pursuant to the Shareholder Agreement, for so long as Pattern Development beneficially owns at least 33 1/3% of our shares, Pattern Development s consent will be necessary for us to take certain material corporate actions. Pattern Development may withhold its consent, which could adversely affect our business. See Certain Relationships and Related Party Transactions Share Ownership Shareholder Agreement in our 2014 Proxy Statement.

Certain of our executive officers have an economic interest in, as well as provide services to, Pattern Development, which could result in conflicts of interest.

Certain of our executive officers provide services to Pattern Development pursuant to the terms of the Management Services Agreement between our company and Pattern Development and, as a result, in some instances, have fiduciary or other obligations to Pattern Development. Additionally, our Chief Executive Officer, Executive Vice President, Business Development, Executive Vice President and General Counsel, Senior Vice President, Fiscal and Administrative Services and Senior Vice President, Engineering and Construction have economic interests in Pattern Development and, accordingly, the benefit to Pattern Development from a transaction between Pattern Development and our company will proportionately inure to their benefit as holders of economic interests in Pattern Development. Pattern Development is a related party under the applicable securities laws governing related party transactions and, as a result, any material transaction between our company and Pattern Development (except the occurrence of the reintegration event) will be subject to our corporate governance guidelines, which requires prior review of any such transaction by the conflicts committee, which is comprised solely of independent members of our Board of Directors, and a recommendation to the full Board of Directors in respect of such transaction. Those of our executive officers who have economic interests in Pattern Development may be conflicted when advising the conflicts committee or otherwise participating in the negotiation or approval of such transactions. These executive officers have significant project- and industry-specific expertise that could prove beneficial to the conflicts committee s decision-making process and the absence of such strategic guidance could have a material adverse effect on our company s ability to evaluate any such transaction and, in turn, on our business, financial condition and results of operations.

Riverstone is under no obligation to offer us an opportunity to participate in any business opportunities that it may consider from time to time, including those in the energy industry, and, as a result, Riverstone s existing and future portfolio companies may compete with us for investment or business opportunities.

Conflicts of interest could arise in the future between us, on the one hand, and Riverstone, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Riverstone is a private equity firm in the business of making investments in entities primarily in the energy industry. As a result, Riverstone s existing and future portfolio companies (other than Pattern Development, which will be subject to the Non-Competition Agreement) may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

Subject to the terms of the Non-Competition Agreement with, and our Purchase Rights granted to us by, Pattern Development (see Certain Relationships and Related Party Transactions in our 2014 Proxy Statement), we have expressly renounced any interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time presented to Riverstone or any of its officers, directors, agents, shareholders, members or partners or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling shareholder or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director or officer, any such business opportunity is expressly offered to such director or officer solely in his or her capacity as our director or officer. Riverstone has advised us that it does not have a formal policy regarding business opportunities presented to the investment funds managed or advised by it and their respective portfolio companies, but Riverstone s practice has been that any business opportunities may be pursued by any such fund or directed to any such portfolio company except when the business opportunity has been presented to an employee of Riverstone or its affiliates solely in his or her capacity as a director of a portfolio company.

As a result, Riverstone may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which it has invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunities. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to Riverstone could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours. See Description of Capital Stock Corporate Opportunity.

Our actual or perceived failure to deal appropriately with conflicts of interest with Pattern Development could damage our reputation, increase our exposure to potential litigation and have a material adverse effect on our business, financial condition and results of operations.

Our conflicts committee is required to review, and make recommendations to the full Board of Directors regarding, any future transactions involving the acquisition of an asset or investment in an opportunity offered to us by Pattern Development to determine whether the offer is fair and reasonable (including any acquisitions by us of assets of Pattern Development pursuant to our Purchase Rights). However, our establishment of a conflicts committee may not prevent holders of our shares from filing derivative claims against us related to these conflicts of interest and related party transactions. Regardless of the merits of their claims, we may be required to expend significant management time and financial resources on the defense of such claims. Additionally, to the extent we fail to appropriately deal with any such conflicts, it could negatively impact our reputation and ability to raise additional funds and the willingness of counterparties to do business with us, all of which could have a material adverse effect on our business, financial condition and results of operations.

Market interest and foreign exchange rates may have an effect on the value of our Class A shares.

One of the factors that influences the price of our Class A shares is the effective dividend yield of our Class A shares (i.e., the yield as a percentage of the market price of our Class A shares) relative to market interest rates. An increase in market interest rates, which are currently at low levels relative to historical rates, may lead prospective purchasers of our Class A shares to expect a higher dividend yield and, our inability to increase our dividend as a result of an increase in borrowing costs, insufficient cash available for distribution or otherwise, could result in selling pressure on, and a decrease in the market price of, our Class A shares as investors seek alternative investments with higher yield. Additionally, we pay quarterly dividends in U.S. dollars, and to the extent the value of the U.S. dollar decreases relative to Canadian dollars, the market price of our Class A shares in Canada could decrease.

Table of Contents

The price of our Class A shares may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our shares may prevent you from being able to sell your Class A shares at or above the price you paid for your shares. The market price of our Class A shares could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual results of operations or those of other companies in our industry;
- a change in interest rates or changes in currency exchange rates;
- the public s reaction to our press releases, our other public announcements and our filings with the Canadian securities regulators and the SEC;
- changes in, or failure to meet, earnings estimates or recommendations by research analysts who track our Class A shares or the stock of other companies in our industry;
- the failure of research analysts to cover our Class A shares;
- strategic actions by us, our power purchasers or our competitors, such as acquisitions or restructurings;
- new laws or regulations or new interpretations of existing laws or regulations applicable to our business;
- changes in accounting standards, policies, guidance, interpretations or principles;
- material litigation or government investigations;
- changes in applicable tax laws;
- changes in general conditions in the United States, Canadian and global economies or financial markets, including those resulting from war, incidents of terrorism or responses to such events;
- changes in key personnel;

- sales of Class A shares by us or members of our management team;

- termination of lock-up agreements with our management team and principal shareholders;

- the granting or exercise of employee stock options;

- volume of trading in our Class A shares; and

- the realization of any risks described under Risk Factors included herein or in our 2013 Form 10-K.

In addition, volatility in the stock markets has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our Class A shares could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce the share price of our Class A shares and cause you to lose all or part of your investment. Further, in the past, market fluctuations and price declines in a company s stock have led to securities class action litigation. If such a suit were to arise, it could have a substantial cost and divert our resources regardless of the outcome.

Table of Contents

If we fail to maintain proper and effective internal controls, our ability to produce accurate and timely financial statements could be impaired and investors views of us could be harmed.

U.S. securities laws require, among other things, that we maintain effective internal control over financial reporting and disclosure controls and procedures. In particular, once we are no longer an emerging growth company as defined in the JOBS Act, we must perform system and process evaluation and testing of our internal control over financial reporting to allow management to report on the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act. If we are not able to comply with these requirements in a timely manner, or if we identify deficiencies in our internal control over financial reporting that are deemed to be material weaknesses, the market price of our shares could decline and we could be subject to sanctions or investigations by the stock exchanges on which we list, the SEC, the Canadian Securities Administrators or other regulatory authorities, which would require additional financial and management resources. However, for as long as we remain an emerging growth company, we intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act. We may take advantage of these reporting exemptions until we are no longer an emerging growth company. We will remain an emerging growth company for up to five years from the time of our initial public offering, although if the market value of our shares that is held by non-affiliates exceeds $700 million as of any June 30 before that time, we would cease to be an emerging growth company as of the following December 31.

Our ability to successfully implement our business plan and comply with Section 404 of the Sarbanes-Oxley Act requires us to be able to prepare timely and accurate financial statements. Any delay in the implementation of, or disruption in the transition to, new or enhanced systems, procedures or controls, may cause our operations to suffer and we may be unable to conclude that our internal control over financial reporting is effective as required under Section 404 of the Sarbanes-Oxley Act. Moreover, we cannot be certain that these measures would ensure that we implement and maintain adequate controls over our financial processes and reporting in the future. Even if we were to conclude that our internal control over financial reporting provided reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP, because of its inherent limitations, internal control over financial reporting may not prevent or detect fraud or misstatements. This, in turn, could have an adverse impact on trading prices for our Class A shares, and could adversely affect our ability to access the capital markets.

We incur increased costs and demands upon management as a result of complying with the laws and regulations affecting public companies, which could harm our operating results, and such costs may increase when we cease to be an emerging growth company.

As a public company, we incur significant legal, accounting, investor relations and other expenses that we did not incur as a private company, including costs associated with public company reporting requirements. We also have incurred and will continue to incur costs associated with current corporate governance requirements, Section 404 and other provisions of the Sarbanes-Oxley Act and the Dodd-Frank Act of 2010, as well as rules implemented by the SEC, the Canadian Securities Administrators and the stock exchanges on which our Class A shares are traded.

Such costs may increase when we cease to be an emerging growth company. For as long as we remain an emerging growth company, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a non-binding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We may take advantage of these reporting exemptions until we are no longer an emerging growth company. We will remain an emerging growth company for up to five years unless we no longer qualify for such status prior to that time. We would cease to be an emerging growth company if we have more than $1.0 billion in annual revenues, have more than $700 million in market value of our shares held by non-affiliates or issue more than $1.0 billion of non-convertible debt over a three-year period. If the market value of our shares that is held by non-affiliates exceeds $700 million as of any June 30, before that time, we would cease to be an emerging growth company as of the following December 31. After we are no longer an emerging growth company, we expect to incur additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not emerging growth companies.

Table of Contents

The expenses incurred by public companies for reporting and corporate governance purposes have increased dramatically over the past several years. These rules and regulations have increased our legal and financial compliance costs substantially and has made some activities more time consuming and costly. We are currently unable to estimate these costs with a high degree of certainty. Greater expenditures may be necessary in the future with the advent of new laws and regulations pertaining to public companies. If we are not able to comply with these requirements in a timely manner, the market price of our Class A shares could decline and we could be subject to sanctions or investigations by the SEC, the Canadian Securities Administrators, the applicable stock exchanges or other regulatory authorities, which would require additional financial and management resources.

As a result of the FPA and FERC s regulations in respect of transfers of control, absent prior authorization by FERC, neither we nor Pattern Development can convey to an investor, nor will an investor in our company generally be permitted to obtain, a direct and/or indirect voting interest in 10% or more of our issued and outstanding voting securities, and a violation of this limitation could result in civil or criminal penalties under the FPA and possible further sanctions imposed by FERC under the FPA.

We are a holding company with U.S. operating subsidiaries that are public utilities (as defined in the FPA) and, therefore, subject to FERC s jurisdiction under the FPA. As a result, the FPA requires us or Pattern Development, as the case may be, either to (i) obtain prior authorization from FERC to transfer an amount of our voting securities sufficient to convey direct or indirect control over any of our public utility subsidiaries or (ii) qualify for a blanket authorization granted under or an exemption from FERC s regulations in respect of transfers of control. Similar restrictions apply to purchasers of our voting securities who are a holding company under the Public Utility Holding Company Act of 2005, or PUHCA, in a holding company system that includes a transmitting utility or an electric utility, or an electric holding company, regardless of whether our voting securities were purchased in our initial public offering, subsequent offerings by us or Pattern Development, in open market transactions or otherwise. A purchaser of our voting securities would be a holding company under the PUHCA and an electric holding company if the purchaser acquired direct or indirect control over 10% or more of our voting securities or if FERC otherwise determined that the purchaser could directly or indirectly exercise control over our management or policies (e.g., as a result of contractual board or approval rights). Under the PUHCA, a public-utility company is defined to include an electric utility company, which is any company that owns or operates facilities used for the generation, transmission or distribution of electric energy for sale, and which includes EWGs such as our U.S. operating subsidiaries. Accordingly, absent prior authorization by FERC or a general increase to the applicable percentage ownership under a blanket authorization, for the purposes of sell-side transactions by us or Pattern Development and buy-side transactions involving purchasers of our securities that are electric holding companies, no purchaser can acquire 10% or more of our issued and outstanding voting securities. A violation of these regulations by us or Pattern Development, as sellers, or an investor, as a purchaser of our securities, could subject the party in violation to civil or criminal penalties under the FPA, including civil penalties of up to $1 million per day per violation and other possible sanctions imposed by FERC under the FPA.

As a result of the FPA and FERC s regulations in respect of transfers of control, and consistent with the requirements for blanket authorizations granted thereunder or exemptions therefrom, absent prior authorization by FERC, no purchaser of our common shares in this offering, the open market, or subsequent offerings of our voting securities, will be permitted to purchase an amount of our securities that would cause such purchaser and its affiliate and associate companies to collectively hold 10% or more of our voting securities outstanding on a post-offering basis. Additionally, purchasers in this offering should manage their investment in us in a manner consistent with FERC s regulations in respect of obtaining direct or indirect control of our company. Accordingly, absent prior authorization by FERC, investors in our common shares that are electric holding companies are advised not to acquire a direct and/or indirect voting interest in 10% or more of our issued and outstanding voting securities, whether in connection with an offering by us or Pattern Development, open market purchases or otherwise.

Table of Contents

Provisions of our organizational documents and Delaware law might discourage, delay or prevent a change of control of our company or changes in our management and, as a result, depress the trading price of our Class A shares.

Our amended and restated certificate of incorporation and amended and restated bylaws contain provisions that could discourage, delay or prevent a change in control of our company or changes in our management that the shareholders of our company may deem advantageous. These provisions:

- authorize the issuance of blank check preferred stock that our Board of Directors could issue to increase the number of outstanding shares and to discourage a takeover attempt;
- prohibit our shareholders from calling a special meeting of shareholders if Pattern Development and its affiliates (other than our company) collectively cease to own more than 50% of our shares;
- prohibit shareholder action by written consent, which requires all shareholder actions to be taken at a meeting of our shareholders if Pattern Development and its affiliates (other than our company) collectively cease to own more than 50% of our shares;
- provide that the Board of Directors is expressly authorized to adopt, or to alter or repeal our bylaws; and
- establish advance notice requirements for nominations for election to our Board of Directors or for proposing matters that can be acted upon by shareholders at shareholder meetings.

These anti-takeover defenses could discourage, delay or prevent a transaction involving a change in control of our company. These provisions could also discourage proxy contests and make it more difficult for you and other shareholders to elect directors of your choosing and cause us to take corporate actions other than those you desire. See Description of Capital Stock.

Future sales of our shares in the public market could lower our Class A share price, and any additional capital raised by us through the sale of equity or convertible debt securities may dilute shareholders ownership in us and may adversely affect the market price of our Class A shares.

If we sell, or if Pattern Development sells, a large number of our Class A shares, or if we issue a large number of shares of our Class A common stock in connection with future acquisitions, financings, or other circumstances, the market price of our Class A shares could decline significantly. Moreover, the perception in the public market that we or Pattern Development might sell Class A shares could depress the market price of those shares. We, our officers and directors and the selling stockholders will enter into lock-up agreements in connection with this offering that will restrict transfers for a period of 90 days, subject to certain exceptions and to compliance with the applicable requirements under Rule 144 of the U.S. Securities Act. See Underwriting.

We cannot predict the size of future issuances of our Class A shares or the effect, if any, that future issuances or sales of our shares will have on the market price of our shares. Sales of substantial amounts of our shares (including sales pursuant to Pattern Development s registration rights and shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our Class A shares. See Certain Relationships and Related Party Transactions in our 2014 Proxy Statement and Shares Eligible for Future Sale.

Table of Contents

FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements. All statements other than statements of historical fact included in this prospectus are forward-looking statements. The words believe, expect, anticipate, intend, estimate and ot expressions that are predictions of or indicate future events and trends and that do not relate to historical matters identify forward-looking statements. You should not place undue reliance on these forward-looking statements. Although forward-looking statements reflect management s good faith beliefs, reliance should not be placed on forward-looking statements because they involve known and unknown risks, uncertainties and other factors, which may cause the actual results, performance or achievements to differ materially from anticipated future results, performance or achievements expressed or implied by such forward-looking statements. Forward-looking statements in this prospectus speak only as of the date of this prospectus. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changed circumstances or otherwise. These forward-looking statements are subject to numerous risks and uncertainties, including, but not limited to:

- our ability to complete construction of our construction projects and transition them into financially successful operating projects;
- our ability to complete the acquisition of power projects;
- fluctuations in supply, demand, prices and other conditions for electricity, other commodities and RECs;
- our electricity generation, our projections thereof and factors affecting production, including wind and other conditions, other weather conditions, availability and curtailment;
- changes in law, including applicable tax laws;
- public response to and changes in the local, state, provincial and federal regulatory framework affecting renewable energy projects, including the potential expiration or extension of the U.S. federal PTC, ITC, and the related U.S. Treasury grants and potential reductions in RPS requirements;
- the ability of our counterparties to satisfy their financial commitments or business obligations;
- the availability of financing, including tax equity financing, for our wind power projects;
- an increase in interest rates;

our substantial short-term and long-term indebtedness, including additional debt in the future;

competition from other power project developers;

our expectations regarding the time during which we will be an emerging growth company under the JOBS Act;

development constraints, including the availability of interconnection and transmission;

potential environmental liabilities and the cost and conditions of compliance with applicable environmental laws and regulations;

our ability to operate our business efficiently, manage capital expenditures and costs effectively and generate cash flow;

our ability to retain and attract executive officers and key employees;

our ability to keep pace with and take advantage of new technologies;

the effects of litigation, including administrative and other proceedings or investigations, relating to our wind power projects under construction and those in operation;

Table of Contents

- conditions in energy markets as well as financial markets generally, which will be affected by interest rates, currency exchange rate fluctuations and general economic conditions;

- the effective life and cost of maintenance of our wind turbines and other equipment;

- the increased costs of, and tariffs on, spare parts;

- scarcity of necessary equipment;

- negative public or community response to wind power projects;

- the value of collateral in the event of liquidation; and

- other factors discussed under Risk Factors.

We derive many of our forward-looking statements from our operating budgets and forecasts, which are based upon many detailed assumptions, including industry data referenced elsewhere or incorporated by reference in this prospectus. While we believe our assumptions are reasonable, we caution that it is very difficult to predict the impact of known factors, and it is impossible for us to anticipate all factors that could affect our actual results. Important factors that could cause actual results to differ materially from our expectations are disclosed under Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations included or incorporated by reference herein. All written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements in this prospectus as well as other cautionary statements that are made from time to time in our other filings with the SEC and applicable Canadian securities regulatory authorities or public communications. You should evaluate all forward-looking statements made in this prospectus in the context of these risks and uncertainties.

We caution you that the important factors referenced above may not contain all of the factors that are important to you. In addition, we cannot assure you that we will realize the results or developments we expect or anticipate or, even if those results or developments are substantially realized, that they will result in the consequences we anticipate or affect us or our operations in the way we expect.

Table of Contents

USE OF PROCEEDS

Excluding the offering by the selling shareholders from which we will not receive any of the proceeds, we estimate the net proceeds to us from this offering will be approximately $ million, based on the offering price of $ per Class A share, which is the last reported sale price of our Class A common stock on the NASDAQ Global Market as set forth on the cover page of this prospectus and after deducting underwriting commissions and estimated offering expenses payable by us.

We intend to use the net proceeds from this offering for working capital and general corporate purposes, including investment in one or more acquisition opportunities from Pattern Development and third parties, which we are considering.

The underwriters may also purchase up to an additional Class A shares from the selling shareholder at the public offering price, less the underwriting commissions, within 30 days from the closing date of this offering to cover overallotments, if any. We estimate that the net proceeds to the selling shareholder will be approximately $ million, based on an assumed public offering price of $ per Class A share, which is the last reported sale price of our common stock on the NASDAQ Global Market as set forth on the cover page of this prospectus, after deducting underwriting commissions and assuming the exercise in full of the underwriters overallotment option. We will not receive any proceeds from the exercise of the underwriters overallotment option. The selling shareholder will pay the underwriters commissions and the expenses of the offering applicable to the sale of shares pursuant to the exercise of the underwriters overallotment option.

Upon completion of this offering, Pattern Development will hold approximately % of our outstanding Class A shares and 99.1% of our outstanding Class B shares (or % and 99.1%, respectively, if the underwriters exercise their overallotment option in full), representing in the aggregate an approximate % voting interest in our company (or % if the underwriters exercise their overallotment option in full). The remaining 0.9% of our outstanding Class B shares will be held by members of our management. Until the Conversion Event, neither Pattern Development nor the management holders of our Class B shares will be entitled to receive any dividends on their Class B shares.

Each $1.00 increase (decrease) in the assumed public offering price would increase (decrease) the net proceeds to us by approximately $ million, after deducting underwriting commissions and estimated offering expenses payable by us, assuming the number of Class A shares offered by us, as set forth on the cover page of this prospectus, remains the same.

Table of Contents

CAPITALIZATION

The following table sets forth the cash and cash equivalents and the capitalization as of December 31, 2013 on (i) a historical basis from our consolidated financial statements and (ii) as adjusted to give effect to this offering and the use of the proceeds therefrom as set forth under Use of Proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, our historical consolidated financial statements and the accompanying notes included elsewhere or incorporated by reference in this prospectus. You should also read this table in conjunction with Structure and Formation of Our Company, Use of Proceeds, Selected Consolidated Historical Financial Data and Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of December 31, 2013	
	Historical	Adjusted
	(U.S. dollars in thousands, except share data)	
Cash and cash equivalents	$ 103,569	
Long-term debt	$ 1,200,367	
Current portion of long term debt	48,851	
Revolving credit facility		
Total stockholders equity:		
Class A common stock, $0.01 par value per share: 500,000,000 shares authorized; 35,530,786 shares issued and outstanding at December 31, 2013, pro forma shares issued and outstanding(1)	355	
Class B common stock, $0.01 par value per share: 20,000,000 shares authorized; 15,555,000 shares issued and outstanding	156	
Additional paid-in capital	489,388	
Accumulated deficit	(13,336)	
Accumulated other comprehensive loss	(8,353)	
Noncontrolling interest	99,794	
Total equity	568,004	
Total capitalization	$ 1,817,222	

(1) Includes 35,703,134 Class A shares outstanding before this offering and Class A shares offered by us to the public hereby based on a public offering price of $ per Class A share (the last reported sale price of our common stock on the NASDAQ Global Market as set forth on the cover of this prospectus).

38

Table of Contents

TRADING PRICE AND VOLUME; DIVIDENDS

The Class A common shares began trading on the NASDAQ on September 27, 2013, under the trading symbol PEGI and on the TSX under the trading symbol PEG . From September 27, 2013 to December 31, 2013, the high and low reported prices for our Class A common stock on the NASDAQ were $30.81 and $22.26, respectively; and from January 1, 2014 to March 31, 2014, the high and low reported prices for our Class A common stock on the NASDAQ were $31.79 and $25.82, respectively.

The following tables show the monthly range of high and low prices of Class A common shares and the total volume of Class A common shares traded on the NASDAQ and the TSX during the indicated periods before the date of this prospectus. On April 24, 2014, being the last day on which the Class A common shares traded prior to the date of this prospectus; the last reported sale price of our Class A common stock was $27.77 on the NASDAQ and C$30.38 on the TSX.

NASDAQ:

Date	High	Low	Volume
September 27-30, 2013	$ 24.30	$ 22.81	10,915,856
October 2013	$ 23.64	$ 22.26	8,295,429
November 2013	$ 25.50	$ 22.32	5,118,980
December 2013	$ 30.81	$ 23.50	9,953,813
January 2014	$ 31.79	$ 26.72	7,328,178
February 2014	$ 28.71	$ 25.82	4,116,646
March 2014	$ 29.00	$ 26.25	4,052,980
April 2014 (through April 24)	$ 29.40	$ 26.67	3,201,253

The following table sets forth the range of high and low sale prices of the Class A common stock on the Toronto Stock Exchange.

TSX:

Date	High	Low	Volume
September 27-30, 2013	C$ 24.95	C$ 23.50	142,688
October 2013	C$ 24.27	C$ 23.10	260,713
November 2013	C$ 26.29	C$ 23.50	23,386
December 2013	C$ 32.30	C$ 26.02	13,353
January 2014	C$ 34.99	C$ 30.61	19,386
February 2014	C$ 31.00	C$ 28.83	16,962
March 2014	C$ 31.95	C$ 29.06	16,169
April 2014 (through April 24)	C$ 31.95	C$ 29.98	20,185

The following table sets forth the dividends declared on shares of Class A common stock for the periods indicated. We declared our first and second quarterly dividends on our Class A common stock, the only dividends declared to date, payable to shareholders of record as of December 31, 2013 and March 31, 2014, respectively. See Market Registrant s Common Equity and Related Stockholder Matters Cash Dividend Policy in our 2013 Form 10-K for further discussion of our cash dividend policy.

Period	Dividends Declared
Quarter ended December 31, 2013	$ .3125
Quarter ended March 31, 2014	$ .3125

Table of Contents

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table presents selected historical consolidated financial data as of the dates and for the periods indicated. The selected historical consolidated financial data as of December 31, 2011, 2012 and 2013 and the years ended December 31, 2011, 2012 and 2013 have been derived from the audited historical consolidated financial statements that are incorporated by reference in this prospectus.

Our historical consolidated financial statements, from which the selected historical consolidated financial data have been derived, are presented in U.S. dollars and have been prepared in accordance with U.S. GAAP, which differs in certain material respects from IFRS. For recent and historical exchange rates between Canadian dollars and U.S. dollars, see Currency and Exchange Rate Information.

You should read the following table in conjunction with Structure and Formation of Our Company, Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical consolidated financial statements and the notes thereto that are included elsewhere or incorporated by reference in this prospectus.

	Year ended December 31,		
	2013	2012	2011
	(U.S. dollars in thousands, except share and per share data)		
Statement of Operations Data:			
Revenue:			
Electricity sales	$ 173,270	$ 101,835	$ 108,770
Energy derivative settlements	16,798	19,644	9,512
Unrealized (loss) gain on energy derivative	(11,272)	(6,951)	17,577
Related party revenue	911		
Other Revenue	21,866		
Total revenue	201,573	114,528	135,859
Cost of revenue:			
Project expenses	57,677	34,843	31,343
Depreciation and accretion	83,180	49,027	39,424
Total cost of revenue	140,857	83,870	70,767
Gross profit	60,716	30,658	65,092
Operating expenses			
Development expenses		174	704
General and administrative	4,819	858	866
Related party general and administrative	8,169	10,604	8,098
Total operating expenses	12,988	11,636	9,668

Operating income	47,728	19,022	55,424
Other income (expense):			
Interest expense	(63,614)	(36,502)	(29,404)
Equity in earnings in unconsolidated investments	7,846	(40)	(205)
Interest rate derivative settlements	(2,099)		
Unrealized loss on derivatives	15,601	(4,953)	(345)
Net gain on transactions	5,995	4,173	
Related party income	665		
Other income, net	2,496	1,320	1,125
Total other expense	(33,110)	(36,002)	(28,829)
Net income (loss) before income tax	14,618	(16,980)	26,595
Tax provision (benefit)	4,546	(3,604)	689
Net income (loss)	10,072	(13,376)	25,906
Net (loss) income attributable to noncontrolling interest	(6,887)	(7,089)	16,981
Net income (loss) attributable to controlling interest	$ 16,959	$ (6,287)	$ 8,925
Earnings per share information:			
Less: Net income attributable to controlling interest prior to the IPO on October 2, 2013	(30,295)		

Table of Contents

	Year ended December 31,		
	2013	2012	2011
Net loss attributable to controlling interest subsequent to the IPO	$ (13,336)		
Weighted average number of shares:			
Basic and diluted- Class A common stock	35,448,056		
Basic and diluted-Class B common stock	15,555,000		
Earnings per share for period subsequent to the IPO			
Class A common stock:			
Basic and diluted loss per share	$ (0.17)		
Class B common stock:			
Basic and diluted loss per share	$ (0.48)		
Unaudited pro forma net loss after tax:			
Net loss before income tax		*$ (16,980)*	
Pro forma tax provision		*818*	
Pro forma net loss		*$ (17,798)*	
Other Data:			
Net cash provided by (used in):			
Operating activities	$ 78,152	$ 35,051	$ 46,930
Investing activities	$ 72,391	$ (638,953)	$ (340,977)
Financing activities	$ (63,401)	$ 573,167	$ 331,336

	As of December 31,		
	2013	2012	2011
	(U.S. dollars in thousands)		
Balance Sheet Data:			
Cash	$ 103,569	$ 17,574	$ 47,672
Construction in progress	$	$ 6,081	$ 201,245
Property, plant and equipment, net	$ 1,476,142	$ 1,668,302	$ 784,859
Total assets	$ 1,903,631	$ 2,035,730	$ 1,390,426
Long-term debt	$ 1,249,218	$ 1,290,570	$ 867,548
Total liabilities	$ 1,335,627	$ 1,446,318	$ 943,728
Total equity before noncontrolling interest	$ 468,210	$ 514,111	$ 362,226
Noncontrolling interest	$ 99,794	$ 75,301	$ 84,472
Total equity	$ 568,004	$ 589,412	$ 446,698

Table of Contents

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in Risk Factors, Forward-Looking Statements and other matters included elsewhere or incorporated by reference in this prospectus. The following discussion of our financial condition and results of operations should be read in conjunction with our historical financial statements and the notes thereto included elsewhere or incorporated by reference in this prospectus, as well as the information presented under Summary Historical Consolidated Financial Data, Selected Historical Financial Data, Material U.S. Federal Income Tax Considerations for Non-U.S. Holders of Our Class A Shares and Material Canadian Federal Income Tax Considerations for Holders of Our Class A Shares.

Overview

We are an independent power company focused on owning and operating power projects with stable long-term cash flows in attractive markets with potential for continued growth of our business. Including the pending acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to the satisfaction of customary closing conditions, in the fourth quarter of 2014, we hold interests in ten wind power projects located in the United States, Canada and Chile that use proven, best-in-class technology and have a total owned capacity of 1,255 MW, consisting of seven operating projects and three construction projects. We expect our three construction projects will commence commercial operations prior to the end of 2014. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement with a creditworthy counterparty. Ninety-three percent of the electricity to be generated by our projects will be sold under these power sale agreements, which have a weighted average remaining contract life of approximately 18 years.

We intend to maximize long-term value for our shareholders in an environmentally responsible manner and with respect for the communities in which we operate. Our business is built around the core values of creating a safe, high-integrity and exciting work environment; applying rigorous analysis to all aspects of our business; and proactively working with our stakeholders in addressing environmental and community concerns. Our financial objectives, which we believe will maximize long-term value for our shareholders, are to produce stable and sustainable cash available for distribution, selectively grow our project portfolio and our dividend and maintain a strong balance sheet and flexible capital structure.

Our growth strategy is focused on the acquisition of operational and construction-ready power projects from Pattern Development and other third parties that we believe will contribute to the growth of our business and enable us to increase our dividend per share over time. We expect our continuing relationship with Pattern Development, a leading developer of renewable energy and transmission projects, will be an important source of growth for our business.

Factors that Significantly Affect our Business

Our results of operations in the near-term as well as our ability to grow our business and revenue from electricity sales over time could be impacted by a number of factors, including those affecting our industry generally and those that could specifically affect our existing projects and our ability to grow.

Recent Transactions

Our IPO and the Contribution Transactions

On October 2, 2013, we issued 16,000,000 shares of Class A common stock in an initial public offering generating net proceeds of approximately $317.0 million. Concurrently with the completion of the initial public offering, we issued 19,445,000 shares of Class A common stock and 15,555,000 shares of Class B common stock to Pattern Development and utilized approximately $232.6 million of the net proceeds of the initial public offering as the cash portion of the consideration paid to Pattern Development for the Contribution Transactions and repaid a $56.0 million outstanding balance of our revolving credit facility. On October 8, 2013, our underwriters exercised in full their overallotment option to purchase 2,400,000 shares of Class A common stock from Pattern Development, the selling shareholder, pursuant to the overallotment option granted by Pattern Development in connection with the initial public offering.

Table of Contents

In connection with the Contribution Transactions, Pattern Development retained a 40% portion of the interest in Gulf Wind project previously held by it (equivalent to a 27% interest in the project) such that, following the completion of the IPO, we, Pattern Development and our joint venture partner hold interests of approximately 40%, 27% and 33%, respectively, of the distributable cash flow of Gulf Wind, together with certain allocated tax items.

Project Acquisitions

On December 20, 2013, we entered into agreements with Pattern Development to acquire its ownership interests in the Grand and Panhandle 2 wind projects. On that date, we acquired a 67 MW interest in the 149 MW Grand project for a cash purchase price of $79.5 million and we agreed to acquire a 147 MW interest in the 182 MW Panhandle 2 project upon the completion of its construction (the Panhandle 2 closing date) for a cash purchase price of $122.9 million, subject to certain price adjustments based on final project size, design and modeling assumptions, to be funded on the Panhandle 2 closing date. Both projects are currently under construction, and are expected to commence commercial operations in the fourth quarter of 2014.

The Panhandle 2 and Grand project interests represent a portion of the Initial ROFO Projects and are the first two acquisitions that we agreed to make from Pattern Development in connection with our Project Purchase Rights. At the time of our IPO, we identified six projects at Pattern Development with an aggregate owned capacity of 746 MW that comprised the Initial ROFO Projects, and we indicated we had initiated discussions with Pattern Development in connection with one of these originally identified Initial ROFO Projects, the Panhandle project, which we might acquire shortly after the closing of the IPO. Pattern Development subsequently increased the owned capacity of the Panhandle project by 78 MW, to a total of 326 MW, and split the project into the Panhandle 1 project, with a Pattern Development-owned capacity of 179 MW, and the Panhandle 2 project, with an owned capacity of 147 MW. Pattern Development also increased its estimated capacity of another of the Initial ROFO Projects, the Meikle project in British Columbia, by 10 MW, to 185 MW. After accounting for Pattern Development s increase in the size of the Panhandle and Meikle projects, our acquisition of the Grand project and our agreement to acquire the Panhandle 2 project, the owned capacity of the remaining Initial ROFO Projects is 620 MW. The status of the remaining Initial ROFO Projects is summarized in the table below:

						Capacity (MW)	
Remaining Initial ROFO Projects	**Status**	**Location**	**Construction Start (1)**	**Commercial Operations (2)**	**Contract Type**	**Rated (3)**	**Pattern Developm Owned (4)**
Gulf Wind	Operational	Texas	2008	2009	Hedge	283	76
Panhandle 1	In Construction	Texas	2013	2014	Hedge	218	179
K2	In Construction	Ontario	2014	2015	PPA	270	90
Armow	Ready for financing	Ontario	2014	2015	PPA	180	90
Meikle	Pre-Construction	British Columbia	2015	2016	PPA	185	185
						1,136	620

(1) Represents date of actual or anticipated commencement of construction.

(2) Represents date of actual or anticipated commencement of commercial operations.

(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated will be less than its rated capacity. The amount of electricity generated may vary based on a variety of factors.

(4) Pattern Development-owned capacity represents the maximum, or rated, electricity generating capacity of the project multiplied by Pattern Development s percentage ownership interest in the distributable cash flow of the project.

The project entity which owns the Grand project is fully financed with equity contributions from its owners, which were funded prior to our acquisition, and loan commitments from a consortium of commercial banks, which provided construction and term financing for the project. The project will sell all of its electrical output to the Ontario Power Authority.

The project entity which owns the Panhandle 2 project is fully financed with equity contributions from its owners, which were funded prior to our planned acquisition, and loan commitments from commercial lenders, which provided construction financing for the project. Pattern Development and three institutional tax equity investors for Panhandle 2 have agreed, subject to certain customary conditions precedent, which we expect will be satisfied, to provide equity contributions to the project holding company upon completion of construction. These contributions will be used to repay in full the then outstanding construction loan balances and the project entity will accordingly not have any term debt once these contributions are made following the commencement of commercial operations. The project will sell approximately 80% of its expected annual average electrical output to an affiliate of Morgan Stanley, under fixed-for-floating energy swaps with a term of 12.25 years, and the balance of its electrical output in the ERCOT spot market and will market its RECs separately.

Other Transactions and Events

In March 2014, we entered into an agreement to increase the size of our revolving credit facility by $25 million, to $145 million. In connection with this agreement, we added our interest in the Ocotillo project to the collateral pool that supports this loan facility.

On March 28, 2014, our South Kent construction project achieved the commercial operation date under its PPA with the Ontario Power Authority.

Trends Affecting our Industry

Wind and solar power have been among the fastest growing sources of electricity generation in North America and globally over the past decade. This rapid growth is largely attributable to wind and solar power s increasing cost competitiveness with other electricity generation sources, the advantages of wind and solar power over many other renewable energy sources and growing public support for renewable energy driven by concerns about security of energy supply and the environment. We expect these trends to continue to drive future growth in the wind power industry.

We believe that the key drivers for the long-term growth of wind power in North America include:

- overall and regional demand for new power plants resulting from regulatory or policy initiatives, such as state or provincial RPS programs, motivating utilities to procure electricity supply from renewable resources;

- efficiency and capital cost improvements in wind, solar and other renewable energy technologies, enabling wind and other forms of renewable energy to compete successfully in more markets;

- governmental incentives, including PTCs, which improve the cost competitiveness of renewable energy compared to traditional sources;

- environmental and social factors supporting increasing levels of wind, solar and other renewable technologies in the generation mix:

  - regulatory barriers increase the time, cost and difficulty of permitting new fossil fuel-fired facilities, notably coal, and nuclear facilities;

decommissioning of aging coal-fired and nuclear facilities is expected to leave a gap in electricity supply;

policy initiatives to include the cost of carbon pollution in conventional fossil fuel-fired electricity generation will increase costs of conventional generation; and

price volatility for natural gas used for electricity generation.

Table of Contents

Uncertainty related to the demand for power, generally, and thus the need for new power projects, and the expiration of U.S. federal incentives resulted in a reduction in the build rate of wind and solar power and other renewable energy projects in 2013, compared to 2012, and these trends may continue to dampen that build rate in 2014 and beyond. We expect these adverse effects to be partially or fully offset in certain markets by regional requirements for new power projects due to older power project retirements, passage of an extension or modification of the U.S. federal tax incentives or other government actions in support of new wind power projects, a potential return to higher natural gas prices, desire, on the part of regulatory commissions and ratepayers, for more stable power sale agreements such as those which wind and solar power projects are ideally suited to provide, and increased difficulty in permitting conventional power projects. In the long term, we believe that substantial growth potential remains in the U.S. market.

In addition, we continue to see more opportunities to acquire wind and solar projects in the North American market than has been typical for the past decade. Three factors are driving this accelerated activity level:

- We believe that many project developers have scaled back their wind project development teams and investment activity in reaction to the prior or anticipated potential expirations of PTC and ITC cash grant programs and continued uncertainty about federal, state and provincial energy policies and as a result of perceptions about slower market growth in the near term;

- A number of large European utilities that have been major participants in the U.S. wind power market appear to be strengthening their consolidated balance sheets due to their own home market issues by selling portions of their U.S. investment portfolios;

- The emergence of yieldcos has provided a new class of investors with an appetite for investment in contract-based renewable power projects.

In general we continue to believe that there will be additional acquisition opportunities in the United States in the short term and that the longer-term growth trend will resume following the determination of federal government policy. We have seen this occur in previous periods when tax credit extensions were uncertain, and we consider it likely to happen again in the coming years. We are a relatively small company involved in a large and somewhat fragmented market in which we believe our fully integrated approach to the business allows us to assess and execute on market opportunities quickly.

Our Outlook

Our projects are generally unaffected by the short-term trends discussed above, given that 93% of the electricity to be generated by our projects will be sold under our fixed-price power sale agreements, which have a weighted average remaining life of approximately 18 years, the geographic diversity of our projects and the limited impact that expiring U.S. federal incentives will have upon completion of our construction projects in the United States, Canada and Chile.

Our near-term growth strategy will focus on wind power projects, but will also include evaluation of solar power opportunities, and is largely insulated from the short-term trends. We expect that most of our short-term growth will come from opportunities to acquire the Initial ROFO Projects, including those located in Ontario, which have executed power sale agreements with terms substantially similar to our South Kent and Grand PPAs, Pattern Development s Panhandle projects, which have already qualified for PTCs and which have long-term power sales agreements in the form of energy hedge contracts, pursuant to our Project Purchase Right and the Pattern

Development retained Gulf Wind interest pursuant to our Gulf Wind Call Right.

We intend to use the net proceeds from this offering for working capital and general corporate purposes, including investment in one or more acquisition opportunities from Pattern Development and third parties, which we are considering.

Factors Affecting Our Operational Results

The primary factors that affect our financial results are (i) the timing of commencement of commercial operations at our construction projects, (ii) the amount and price of electricity sales by our operating projects, (iii) accounting for derivative instruments, (iv) acquisitions of new projects, (v) achievement of efficient project operations, and (vi) interest expense on our corporate- and project-level debt.

Timing of Commencement of Commercial Operations at Our Construction Projects

Including the pending acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to the satisfaction of customary closing conditions, in the fourth quarter of 2014, our construction projects include interests in three projects that we expect will contribute an additional operating capacity of 250 MW in 2014, for an aggregate owned capacity of 1,255 MW together with our operating projects. Our near-term operating results will, in part, depend upon our ability to transition these projects into commercial operations in accordance with our existing construction budgets and schedules. The following table sets forth each of our construction projects as well as their respective power capacities and our anticipated date of their commencement of commercial operations.

				MW	
Projects	**Location**	**Construction Start**	**Commercial Operations**	**Rated**	**Owned**
El Arrayan	Chile	Q3 2012	Q2 2014	115	36
Panhandle 2 (1)	Texas	Q4 2013	Q4 2014	182	147
Grand	Ontario	Q3 2013	Q4 2014	149	67
				446	250

(1) Commencement of commercial operations and the acquisition of Panhandle 2 are expected to occur in the fourth quarter of 2014.

We are constructing our projects under fixed-price and fixed-schedule contracts with major equipment suppliers and experienced balance-of-plant constructors. Under our management team s supervision, Pattern Development completed the construction of our Hatchet Ridge, St. Joseph, Spring Valley, Santa Isabel, Ocotillo and South Kent projects on time and within budget. Including their time together before forming Pattern Development, our management team has constructed and placed into service 26 wind power projects with an aggregate generating capacity of over 2,800 MW.

Electricity Sales and Energy Derivative Settlements of Our Operating Projects

Our electricity sales and energy derivative settlements are primarily determined by the price of electricity and any environmental attributes we sell under our power sale agreements and the amount of electricity that we produce, which is in turn principally the result of the wind conditions at our project sites and the performance of our equipment. Ninety-three percent of the electricity to be generated across our projects is currently committed under long-term, fixed-price power sale agreements with creditworthy counterparties, which have a weighted average remaining contract life of approximately 18 years.

Wind conditions and equipment performance represent the primary factors affecting our near-term operating results because these variables impact the volume of the electricity that we are able to generate from our operating projects.

Our revenue from electricity sales and energy derivative settlements during a period is primarily a function of the amount of electricity generated by our projects. The electricity generated from our power projects depends primarily on wind and weather conditions at each specific site and the performance of our equipment. We base our estimates of each project s capacity to generate electricity on the findings of our internal and external experts long-term meteorological studies, which includes on-site data collected from equipment on the property and relevant reference wind data from other sources, as well as specific equipment power curves and estimates for the performance of our equipment over time. Although wind conditions in 2013 were below the assumptions that drive our long-term production expectations, the longer term data continues to support our production forecast and we have not changed our expected annual average output from our existing projects.

Our wind analysis evaluates the wind s speed and prevailing direction, atmospheric conditions, and wake and seasonal variations for each project. The result of our meteorological analysis is a probabilistic assessment of a project s likely output. A P50 level of production indicates we believe a 50% probability exists that the electricity generated from a project will exceed a specified aggregate amount of electricity generation during a given period. While we plan for variability around this P50 production level, it generally provides the foundation for our base case expectation. The variability is measured in a spectrum of possible output levels such as a P75 output level, which indicates that over a specified period of time, such as one or ten years, the P75 output level would be exceeded 75% of the time. Similarly, the P25 output level would be exceeded 25% of the time. We often use P95, P90 and P75 production levels to plan ahead for low-wind years, while recognizing that we should also have corresponding high-wind years.

Table of Contents

In addition to annual P50 variability, we also expect seasonal variability to occur. Variability increases as the period of review shortens, so it is likely that we will experience more variability in monthly or quarterly production than we do for annual production. Therefore, our periodic cash flow and payout ratios will also reflect more variability during periods shorter than a year. As a result, we use cash reserves to help manage short term production and cash flow variability.

When analyzed together, a portfolio s probability of exceedance changes when all the projects are considered as a portfolio instead of on a stand-alone basis. Due to the geographical separation between our projects, the uncertainty variables and wind speed correlations are diverse enough across the portfolio to provide improvement in the overall uncertainty, which we refer to as the portfolio effect. For example, the sum of our individual projects P75 output levels is approximately 92% of the aggregate P50 output level (which is unaffected by the portfolio effect), while the P75 output level, when taking into account the portfolio effect, is approximately 95% of our aggregate P50 output level. On a portfolio basis, our P90 and P95 production estimates for the annual electricity generation of our ten projects, once they are all fully operational, are approximately 90% and 87%, respectively, of our estimated P50 output levels. The portfolio effect results in an improvement in the production stability across the portfolio. A greater diversity of projects in the portfolio has the effect of increasing the frequency of occurrences aggregated around the expected result (probability level). This is demonstrated in the following diagram:

Our electricity generation is also dependent on the equipment that we use. We have selected high-quality equipment with a goal of having a concentration of turbines from top manufacturers. We employ (or will employ) the Siemens 2.3 MW turbine at nine of our ten project sites and the Mitsubishi MWT95/2.4 at the tenth. With a combination of high-quality equipment and scale, we have structured our projects such that we may expect high availability and long-term production from the equipment, develop operating expertise and experience, which can be shared among our operators, obtain a high level of attention and focus from the manufacturers and maintain a shared spare parts inventory and common operating practices. Given our manufacturers global fleet sizes and strong balance sheets, the warranties that we secure for our turbines and our operating approach described below, we are confident in our expectations for reliable long-term turbine operation.

In May 2013, a blade separated from the turbine hub on one of the wind turbines at our Ocotillo project following which we shut down all of the SWT-2.3-108 turbines which were then utilized only at our Ocotillo and Santa Isabel projects, pending determination of the cause. Siemens completed, and we accepted, a root cause analysis, a remediation plan, including inspection, repair or replacement, and a return to service program for all of the SWT-2.3-108 blades. Our warranty arrangements with Siemens required that Siemens complete the remediation plan at its cost and pay liquidated damages to us in the event that turbine availability falls below specified thresholds. During 2013, we received warranty liquidated damages from Siemens with respect to our availability warranties. Depending on future performance of the equipment, we may receive additional liquidated damages from Siemens in 2014.

Accounting for Derivative Instruments

We have, and expect to continue to enter into, contracts to hedge against risks related to fluctuations in energy prices and interest rates on our project loans and foreign currency exchange rates. Except with respect to contracts for which we do not elect or do not qualify for hedge accounting, we recognize derivative instruments as assets or

47

liabilities at fair value in our consolidated balance sheets. Our method of accounting for a change in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated as part of a hedging relationship and, if so, on the type of hedging relationship. For derivative instruments that are not so designated, such as our energy derivatives and certain of our interest rate derivatives, changes in fair value are recorded as a component of net income on our consolidated statement of operations. For derivative instruments that are designated as cash flow hedges, the effective portion of the change in the fair value of the instrument is recorded as a component of other comprehensive income. Changes in the fair value of derivative instruments designated as cash flow hedges are subsequently reclassified into net income in the period that the hedged transaction affects earnings. The ineffective portion of changes in the fair value of designated hedges is also recorded as a component of current net income.

The fair value of a derivative is a function of a number of factors, including the duration and notional volume of the derivative and forward price curve for the product to which the derivative applies. In general, there is more volatility in the fair value of derivative instruments that are designed to protect long-dated risks, such as an 18-year loan amortization profile, than those with short durations, such as a two-year foreign currency fixed-for-floating swap. Where possible, we have sought to protect ourselves against electricity and interest rate exposures with a relatively longer term hedging strategy. We expect to hedge exposure to foreign currency exchange rates in the future over shorter periods of time. Accordingly, we have experienced in the past, and expect to record in the future, substantial volatility in the components of our net income that relate to the mark-to-market adjustments on our undesignated energy and interest rate derivatives.

We believe that mark-to-market adjustments that we make to the fair value of our derivative assets and liabilities are generally mirrored by changes in the economic value of the related operating or financial assets, such as our wind projects and our project loans, for which the application of U.S. GAAP does not permit us to record such economic gains and losses. For this reason, and because one of our principal financial objectives is to produce stable and sustainable cash available for distribution, we believe that the economic value to our shareholders reflected in these derivative instruments, outweighs the risk of volatility in net income that we expect to report. Accordingly, we believe it is useful to investors to consider supplemental financial measures that we report, such as Adjusted EBITDA, where we have subtracted and added back, as applicable, the unrealized gains and losses arising from mark-to-market adjustments on our derivative instruments, and cash available for distribution.

Project Operations

Our ability to generate electricity in an efficient and cost-effective manner is impacted by our ability to maintain the operating capacity of our projects. We use reliable and proven wind turbines and other equipment for each of our projects. For the years ended December 31, 2012 and 2011, our turbine availability across our projects was 97.6% and 96.2%, respectively, which is in line with industry standards for original investment projections reviewed by independent engineering firms. For the year ended 2013, our turbine availability across our projects was 88.3%, which was lower than our and industry standards due primarily to the blade issue at our Santa Isabel and Ocotillo projects. It was also affected by certain unrelated equipment issues at our Spring Valley project which are covered under manufacturer warranty, which may result in certain liquidated damages being received in 2014, and which are not expected to have a long-term impact on our project operating results. More importantly, we operate our projects to maximize our revenues rather than solely focusing on time-based availability or electricity generation volume. See Business Organization of Our Business Operations and Maintenance. To accomplish this, we provide forward-looking wind forecasts to each of our sites twice a day. Our site managers use this information to plan the maintenance activities for those days, in order to schedule maintenance during low wind periods, where impact to revenues is minimized. In addition, for sites with power prices that vary during different periods, we schedule work to avoid known or anticipated high price periods. For example, on the Hatchet Ridge project in the summer of 2012, we scheduled summer maintenance crews to start work at 5:00 AM and finish by 1:00 PM, in order to have all available turbines operating when peak PPA pricing started at 2:00 PM.

In addition, as a result of the importance we place on safety and implementation of a safety management program, our operating business has experienced no significant lost time events, worksite accidents, or other significant environmental, health or safety, or EHS, issues in 2013 or 2012. Certain contractors or subcontractors at our construction sites have had worksite accidents, and we continue to work with these third parties to improve their safety performance.

In 2013 and 2012, we took the following steps that should enable us to continue to improve our operating performance at our operating projects:

- We hired site management personnel six months prior to achieving commercial operations at our Spring Valley, Santa Isabel, Ocotillo and South Kent projects. This allows these individuals to go through an organized training program, which includes time in our Houston office to meet with the operations team, training at one of our existing operating projects, vendor and third-party external training, and focused time setting up project operational and compliance programs before arrival at site. After arrival at site, this time also allows the site management to be intimately involved in the project commissioning process and operational preparations. We also include regular visits from our management, safety, and turbine specialists during this pre-operational period to ensure smooth coordination of start-up.

- At our projects nearing the end of their original turbine manufacturer warranty periods, which includes Hatchet Ridge in October 2012 and St. Joseph in early 2013, we conduct extensive third-party end-of-warranty inspections to identify any potential equipment or service issues that can be remedied by the manufacturer pursuant to their warranty contractual obligations and ensure the sites start their post-warranty periods with reliably functioning equipment. We believe these thorough inspections also provide a solid baseline for equipment condition to drive future maintenance planning. These same end-of-warranty dates on most projects also mark the end of the manufacturer s service contracts, and we conduct competitive solicitations between both the manufacturers as well as top-tier third-party independent service providers for conducting the turbine service and maintenance in the post-warranty period. At Hatchet Ridge, this solicitation resulted in the selection of leading independent service provider Duke Energy Services, LLC at a significant cost savings, while still ensuring quality of service.

- We implemented a robust NERC compliance program consisting of a suite of policies and procedures, employee training and record keeping systems. This program is run by a full-time in-house regulatory compliance specialist. In August 2012, we completed our first full NERC audit for the Gulf Wind project. The audit was successful, with no findings of any violations, and we were commended by the auditors for our strong regulatory compliance culture.

Debt Financing

We intend to use a portion of our revenue from electricity sales to cover our subsidiaries interest expense and principal payments on borrowings under their respective project financing facilities. In the near-term, our interest expense primarily reflects (i) imputed interest on the lease financing of our Hatchet Ridge project, (ii) periodic interest on the term loan financing arrangements at our other operating projects and (iii) interest on short-term loan facilities, including any borrowings under our revolving credit facility.

We believe that our projects have been financed on average with stronger coverage ratios than is typical in our industry. A debt service coverage ratio is generally defined as a project s operating cash flows divided by scheduled payments of principal and interest for a period. While we believe that the commercial bank market generally seeks a minimum average annual debt service coverage ratio for wind power projects, based on P50 output levels, of between 1.4 and 1.5 to 1.0, our projects, on a portfolio basis, have an expected average annual debt service coverage ratio over the remaining scheduled loan amortization periods of approximately 1.7 to 1.0.

Key Metrics

We regularly review a number of financial measurements and operating metrics to evaluate our performance, measure our growth and make strategic decisions. In addition to traditional U.S. GAAP performance and liquidity measures, such as revenue, cost of revenue, net income and cash provided by (used in) operating activities, we also consider MWh sold, average realized electricity price and Adjusted EBITDA in evaluating our operating performance and cash available for distribution as supplemental liquidity measures. Each of these key metrics is discussed below.

Table of Contents

MWh Sold and Average Realized Electricity Price

The number of MWh sold and the average realized price per MWh sold are the operating metrics that determine our revenue. For any period presented, average realized electricity price represents total revenue from electricity sales and energy derivative settlements divided by the aggregate number of MWh sold.

Adjusted EBITDA

We define Adjusted EBITDA as net income before net interest expense, income taxes and depreciation and accretion, including our proportionate share of net interest expense, income taxes and depreciation and accretion of joint venture investments that are accounted for under the equity method, and excluding the effect of certain other items that our company does not consider to be indicative of its ongoing operating performance such as mark-to-market adjustments and infrequent items not related to normal or ongoing operations, such as early payment of debt and realized derivative gain or loss from refinancing transactions, and gain or loss related to acquisitions or divestitures. In calculating Adjusted EBITDA, we exclude mark-to-market adjustments to the value of our derivatives because we believe that it is useful for investors to understand, as a supplement to net income and other traditional measures of operating results, the results of our operations without regard to periodic, and sometimes material, fluctuations in the market value of such assets or liabilities. Adjusted EBITDA is a non-U.S. GAAP measure.

The following table reconciles net income (loss) to Adjusted EBITDA for the periods presented and is unaudited (U.S. dollars in thousands):

	Year ended December 31,		
	2013	**2012**	**2011**
	(U.S. dollars in thousands)		
Net income (loss)	$ 10,072	$ (13,376)	$ 25,906
Plus:			
Interest expense, net of interest income	61,118	35,457	28,285
Tax provision (benefit)	4,546	(3,604)	689
Depreciation and accretion	83,180	49,027	39,424
EBITDA	158,916	67,504	94,304
Unrealized loss (gain) on energy derivative	11,272	6,951	(17,577)
Unrealized (gain) loss on interest rate derivatives	(15,601)	4,953	345
Interest rate derivative settlements	2,099		
Gain on transactions	(5,995)	(4,173)	
Plus, our proportionate share in the following from our equity accounted investments:			
Interest expense, net of interest income	267	44	
Tax benefit	(172)	(65)	
Depreciation and accretion	20		186
Unrealized (gain) loss on interest rate and currency derivatives	(9,076)	27	

Realized loss on interest rate and currency derivatives	39		
Adjusted EBITDA	$ 141,769	$ 75,241	$ 77,258

Cash Available for Distribution

We define cash available for distribution as net cash provided by operating activities as adjusted for certain other cash flow items that we associate with our operations. It is a non-U.S. GAAP measure of our ability to generate cash to service our dividends. Cash available for distribution represents cash provided by (used in) operating activities as adjusted to (i) add or subtract changes in operating assets and liabilities, (ii) subtract net deposits into restricted cash accounts, which are required pursuant to the cash reserve requirements of financing agreements, to the extent they are paid from operating cash flows during a period, (iii) subtract cash distributions

Table of Contents

paid to noncontrolling interests, which currently reflects the cash distributions to our joint venture partners in our Gulf Wind project in accordance with the provisions of its governing partnership agreement and will in the future reflect distribution to other joint venture partners, (iv) subtract scheduled project-level debt repayments in accordance with the related loan amortization schedule, to the extent they are paid from operating cash flows during a period, (v) subtract non-expansionary capital expenditures, to the extent they are paid from operating cash flows during a period, and (vi) add or subtract other items as necessary to present the cash flows we deem representative of our core business operations.

	Year ended December 31,		
	2013	2012	2011
	(U.S. dollars in thousands)		
Net cash provided by operating activities	$ 78,152	$ 35,051	$ 46,930
Changes in current operating assets and liabilities	8,237	6,885	3,237
Network upgrade reimbursement	1,854	6,263	
Use of operating cash to fund maintenance and debt reserves		(1,047)	(1,048)
Release of restricted cash to fund general and administrative costs	318		
Operations and maintenance capital expenditures	(819)	(623)	(1,101)
Less:			
Distributions to noncontrolling interests	(2,292)	(1,298)	(7,158)
Principal payments paid from operating cash flows(1)	(42,829)	(27,546)	(22,330)
Cash available for distribution	$ 42,621	$ 17,685	$ 18,530

(1) Excludes $7,495 of principal pre-payments on our Ocotillo project which were paid from ITC cash grant proceeds in 2013

Results of Operations

The following discussion and analysis of financial condition and results of operations relate to our company and its predecessor presented as a single entity from the beginning of the earliest period presented. For periods prior to October 2, 2013, the Contribution Transaction date, our company was a shell company, with expenses of less than $10,000 for 2013 and 2012.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following table provides selected financial information for the periods presented (U.S. dollars in thousands, except percentages):

	Year ended December 31,			
	2013	2012	$ Change	% Change
Revenue	$ 201,573	$ 114,528	$ 87,045	76%
Project expense	57,677	34,843	22,834	66
Depreciation and accretion	83,180	49,027	34,153	70
Total cost of revenue	140,857	83,870	56,987	68
Gross profit	60,716	30,658	30,058	98
Development expense		174	(174)	(100)
General and administrative	4,819	858	3,961	462
Related party general and administrative	8,169	10,604	(2,435)	(23)
Total operating expenses	12,988	11,636	1,352	12
Operating income	47,728	19,022	28,706	151
Total other expense	(33,110)	(36,002)	2,892	8
Net income (loss) before income tax	14,618	(16,980)	31,598	186
Tax provision (benefit)	4,546	(3,604)	8,150	(226)
Net income (loss)	10,072	(13,376)	23,448	175
Net loss attributable to noncontrolling interest	(6,887)	(7,089)	202	3
Net income (loss) attributable to controlling interest	$ 16,959	$ (6,287)	$ 23,246	370%

Table of Contents

MWh sold and average realized electricity price. We sold 2,258,811 MWh of electricity in the year ended December 31, 2013 as compared to 1,673,413 MWh sold in the year ended December 31, 2012. This increase in MWh sold during 2013 as compared to 2012 was primarily attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. Our average realized electricity price was approximately $84 per MWh in the year ended December 31, 2013 as compared to approximately $73 per MWh in the year ended December 31, 2012. The average realized electricity price in 2013 was higher than the comparable period in 2012 because the pricing terms under the Spring Valley, Santa Isabel and Ocotillo project PPAs are each higher than our overall average realized price applicable in 2012. Although our electricity production was up 35% over the same period last year, it was lower than our expected long term average in 2013. After adjusting for equipment downtime which is reimbursable by the vendor, our electricity production was about 9% below the expected production based on long-term average wind conditions. The 2013 wind conditions are, however, within the range of variability that has been measured in our six operating wind regions over the last 35 years and, after considering these measured results, we have not changed our long-term wind forecast. Particularly noteworthy was the low average wind in the western United States in 2013 which was partly the result of a high pressure zone towards the end of 2013.

Revenue. Revenue for the year ended December 31, 2013 was $201.6 million compared to $114.5 million for the year ended December 31, 2012, an increase of $87.1 million, or approximately 76%. This increase in revenue during 2013 as compared to 2012 was the result of an increase of $71.5 million in electricity sales primarily attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. Also during the year ended December 31, 2013, we recorded other revenue of $21.9 million related to warranty settlement payments we received from a turbine supplier during the period as a result of the turbines at the Ocotillo and Santa Isabel projects being off line for a portion of the period. The increase in electricity sales in 2013 as compared to 2012 was offset by a decrease of $4.3 million in period-over-period revenue due to energy derivative valuation. In 2013, we recorded a $11.3 million unrealized loss on energy derivative compared to a $7.0 million unrealized loss in 2012. The value of our energy derivative, and the amount of unrealized gain or loss we record, increases and decreases due to our monthly derivative settlements and changes in forward electricity prices, which are derived from and impacted by changes in forward natural gas prices.

Cost of revenue. Cost of revenue for the year ended December 31, 2013 was $140.9 million compared to $83.9 million for the year ended December 31, 2012, an increase of $57.0 million, or approximately 68%. The increase in cost of revenue during 2013 as compared to 2012 was primarily attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012 with depreciation and accretion contributing $34.2 million of the $57.0 million increase in 2013 as compared to 2012. As each new project commences commercial operations, we incur new incremental and ongoing costs for maintenance and services agreements, property taxes, insurance, land lease and other costs associated with managing, operating and maintaining the facility, including adding site employees and operations center staff.

General and administrative expense. General and administrative expense for the year ended December 31, 2013 was $4.8 million compared to $0.9 million for the year ended December 31, 2012, an increase of $3.9 million, or approximately 462%. After the Contribution Transactions and the initial public offering, our company has direct payroll costs and employee-related, audit and consulting expenses costs, and other administrative costs that were previously allocated to our company from Pattern Development and which were reflected in related party general and administrative expense. In addition, our company has additional general and administrative costs related to being a public company, such as directors fees.

Related party general and administrative expense. Related party general and administrative expense for the year ended December 31, 2013 was $8.2 million compared to $10.6 million for the year ended December 31, 2012, a decrease of $2.4 million, or approximately 23%, resulting primarily from lower cash bonus expense in 2013, as compared to 2012, offset by the increased staffing and overhead costs related to commercial operations commencing at Spring Valley, Santa Isabel and Ocotillo as well as our ownership in El Arrayán and South Kent as construction on these projects advanced in 2013.

Other expense. Other expense for the year ended December 31, 2013 was $33.1 million compared to $36.0 million for the year ended December 31, 2012. The decrease of $2.9 million in other expense during 2013, as compared to 2012, was primarily related to a $7.9 million increase in equity in earnings in unconsolidated investments, which was primarily attributable to interest rate swaps that were entered into during 2013, which were deemed to be derivatives and not designated as hedges. The gain on these interest rate swaps was attributable to an increase in the forward interest rate curve after these interest rate swaps were entered into. In addition, there was a $20.6 million increase in unrealized gain on derivatives as a portion of our interest rate swaps on the Ocotillo project are not designated as hedges and there was an increase in the forward interest rate curve, which decreases our liability under these interest rate swaps and increases our unrealized gain on derivatives. During the year ended December 31, 2013 we also recorded a $7.2 million gain on the sale of Puerto Rico tax credits at the Santa Isabel project and $1.2 million of transaction expense related to our acquisition of the Grand and Panhandle 2 projects as compared to a $4.2 million gain on the sale of a portion of the El Arrayán project in 2012. Offsetting these gains was a $27.1 million increase in interest expense in 2013 attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012 and the resultant cessation of interest capitalization and treatment of interest as expense under the related facilities.

Tax provision. The tax provision was $4.5 million for the year ended December 31, 2013 compared to a $3.6 million benefit for the year ended December 31, 2012. The 2012 benefit was principally the result of the Santa Isabel project holding company being subject to U.S. income taxes and the impact of receipt of a U.S. Treasury cash grant by the Santa Isabel project on a stand-alone basis in 2012, which then required a valuation allowance in 2013 as the Santa Isabel project is included in our company s consolidated U.S. income tax return as a result of the Contribution Transactions.

Noncontrolling interest. The allocation to noncontrolling interest was a $6.9 million loss for the year ended December 31, 2013 compared to $7.1 million of loss for the year ended December 31, 2012. The noncontrolling interest income or loss calculation is based on the hypothetical liquidation at book value method of accounting for the earnings attributable to the noncontrolling interests ownership in Gulf Wind.

Adjusted EBITDA. Adjusted EBITDA for the year ended December 31, 2013 was $141.8 million compared to $75.2 million for the year ended December 31, 2012, an increase of $66.6 million. The increase in Adjusted EBITDA during 2013 as compared to 2012 was primarily attributable to the commencement of operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. For a reconciliation of net income to Adjusted EBITDA, see Key Metrics Adjusted EBITDA.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

The following table provides selected financial information for the periods presented (U.S. dollars in thousands, except percentages):

	Year ended December 31,			
	2012	**2011**	**$ Change**	**% Change**
Revenue	$ 114,528	$ 135,859	($ 21,331)	16%
Project expense	34,843	31,343	3,500	11
Depreciation and accretion	49,027	39,424	9,603	24
Total cost of revenue	83,870	70,767	13,103	19
Gross profit	30,658	65,092	(34,434)	(53)

Development expense	174	704	(530)	(75)
General and administrative	858	866	(8)	(1)
Related party general and administrative	10,604	8,098	2,506	31
Total operating expense	11,636	9,668	1,968	20
Operating income	19,022	55,424	(36,402)	(66)
Total other expenses	(36,002)	(28,829)	(7,173)	25
Net (loss) income before income tax	(16,980)	26,595	(43,575)	(164)
Tax (benefit) provision	(3,604)	689	(4,293)	623
Net (loss) income	(13,376)	25,906	(39,282)	(152)
Net (loss) income attributable to noncontrolling interest	(7,089)	16,981	(24,070)	(142)
Net (loss) income attributable to controlling interest	($ 6,287)	$ 8,925	($ 15,212)	(170)%

Table of Contents

MWh sold and average realized electricity price. We sold 1,673,413 MWh of electricity in the year ended December 31, 2012 as compared to 1,568,022 MWh in the year ended December 31, 2011. This increase in MWh sold during 2012 as compared to 2011 was primarily attributable to a full year of operations at St. Joseph as compared to a partial year in 2011 as St. Joseph commenced commercial operations in April 2011. In 2012, we also began commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. These increases were offset by lower production at our Gulf Wind and Hatchet Ridge projects primarily due to lower winds in 2012 compared to 2011. Our average realized electricity price was approximately $73 per MWh in the year ended December 31, 2012 as compared to approximately $75 per MWh in the year ended December 31, 2011.

Revenue. Revenue for the year ended December 31, 2012 was $114.5 million compared to $135.9 million for the year ended December 31, 2011, a decrease of $21.4 million, or approximately 16%. The decrease in revenue during 2012 as compared to 2011 was attributable to a net decrease of $16.8 million due to lower spot electricity prices applicable to Gulf Wind and a decrease of $24.6 million due to energy derivative valuation, offset by an increase of approximately $20.0 million in revenue from other projects. The Gulf Wind project received higher spot market electricity prices in 2011 than in 2012, including unusually high prices which exceeded $2,000 per MWh for a total of approximately 24 hours during 2011. The lower spot prices in 2012 reduced our electricity sales at the Gulf Wind project by approximately $26.9 million and increased our energy derivative settlements by approximately $10.1 million, for a net reduction of approximately $16.8 million in 2012. In addition, in 2012, we recorded a $7.0 million unrealized loss on energy derivative compared to a $17.6 million unrealized gain in 2011, resulting in a decrease in year-over-year revenue of $24.6 million in 2012. The value of our energy derivative, and the amount of unrealized gain or loss we record, increases and decreases due to our monthly derivative settlements and changes in forward electricity prices, which are derived from and impacted by changes in forward natural gas prices. These revenue decreases in 2012 were partially offset by increased electricity sales of approximately $20.0 million resulting from a full year of electricity sales at St. Joseph in 2012, which commenced commercial operations in April 2011, and electricity sales at Spring Valley, which commenced commercial operations in August 2012, and at Santa Isabel and Ocotillo, which both commenced commercial operations in December 2012.

Cost of revenue. Cost of revenue for the year ended December 31, 2012 was $83.9 million compared to $70.8 million for the year ended December 31, 2011, an increase of $13.1 million, or approximately 19%. The increase in cost of revenue during 2012 as compared to 2011 was attributable to a full year of costs at St. Joseph following the commencement of commercial operations in April 2011 and costs attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. As each new project commences commercial operations, we incur new incremental and ongoing costs for maintenance and services agreements, property taxes, insurance, land lease and other costs associated with managing, operating and maintaining the facility, including adding site employees and operations center staff.

Development expenses. Development expenses for the year ended December 31, 2012 were $0.2 million compared to $0.7 million for the year ended December 31, 2011, a decrease of $0.5 million, or approximately 71%. The decrease in development expenses was primarily attributable to our determination that development expenses related to El Arrayán should be capitalized starting in the first quarter of 2012.

Related party general and administrative expense. Related party general and administrative expense for the year ended December 31, 2012 was $10.6 million compared to $8.1 million for the year ended December 31, 2011, an increase of $2.5 million, or approximately 31%, resulting primarily from the increased staffing and overhead costs related to commercial operations commencing at Spring Valley, Santa Isabel and Ocotillo as well as our ownership in El Arrayán and South Kent as construction and development, respectively, on the projects advanced in 2012.

Other expense. Other expense for the year ended December 31, 2012 was $36.0 million compared to $28.8 million for the year ended December 31, 2011. The increase in other expense during 2012 as compared to 2011 was primarily attributable to a $7.1 million, or approximately 25%, increase in interest expense in 2012 reflecting a full year of interest expense at St. Joseph following the commencement of commercial operations in April 2011 and interest expense attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. In 2012, we also had a $4.6 million increase in unrealized loss on derivatives as a portion of our interest rate swaps on the Ocotillo project are not designated as hedges and, during the period after the closing of the Ocotillo financing and entering into these interest rate swaps in October 2012, there was a decrease in the forward interest rate curve which increases our liability under these interest rate swaps and increases our unrealized loss on derivatives. These increased costs in 2012 were offset by a $4.2 million gain on the sale of a portion of our investment in El Arrayán in 2012.

Tax provision. The tax provision was a $3.6 million benefit for the year ended December 31, 2012 compared to $0.7 million for the year ended December 31, 2011. This was principally the result of the Santa Isabel project holding company being subject to U.S. income taxes at the end of 2012 but not during 2011.

Noncontrolling interest. The net loss attributable to noncontrolling interest was a $7.1 million for the year ended December 31, 2012 compared to a $17.0 million of income for the year ended December 31, 2011. The noncontrolling interest income or loss calculation is based on the hypothetical liquidation at book value method of accounting for the earnings attributable to the noncontrolling interest s ownership in Gulf Wind, and 2011 was favorably impacted by unusually high power prices during the year.

Adjusted EBITDA. Adjusted EBITDA for the year ended December 31, 2012 was $75.2 million compared to $77.3 million for the year ended December 31, 2011, a decrease of $2.1 million. The decrease in Adjusted EBITDA during 2012 as compared to 2011 was primarily attributable to higher spot electricity prices at our Gulf Wind project in 2011, including unusually high prices which exceeded $2,000 per MWh for approximately 24 hours during 2011 (contrasted with an average spot-market electricity price of $25.31/MWh received at Gulf Wind in 2012) and which were not repeated in 2012; the absence of this unexpected incremental electricity revenue in 2012 was partially offset by additional revenue, net of project expense, that was earned following commencement of operations at our Spring Valley, Santa Isabel and Ocotillo projects in 2012 and from a full year of operations at our St. Joseph project. For a reconciliation of net income to Adjusted EBITDA, see Key Metrics Adjusted EBITDA.

Liquidity and Capital Resources

Our business requires substantial capital to fund (i) equity investments in our construction projects, (ii) current operational costs, (iii) debt service payments, (iv) dividends to our shareholders, (v) potential investments in new acquisitions (vi) modifications to our projects, (vii) unforeseen events and (viii) other business expenses. As a part of our liquidity strategy, we plan to retain a portion of our cash flows in above-average wind years in order to have additional liquidity in below-average wind years. Our sources of liquidity include cash generated by our operations, ITC cash grants, cash reserves, borrowings under our corporate and project-level credit agreements and further issuances of equity and debt securities.

The principal indicators of our liquidity are our restricted and unrestricted cash balances and availability under our credit agreements. As of December 31, 2013, our available liquidity was $301.9 million, including restricted cash on hand of $32.6 million, unrestricted cash on hand of $103.6 million, $75.2 million available under our revolving credit agreements and $90.5 million available under project financings for post construction use.

We believe that throughout 2014, we will have sufficient liquid assets, cash flows from operations, and borrowings available under our revolving credit facility to meet our financial commitments, debt service obligations, contingencies and anticipated required capital expenditures for at least the next 24 months, without taking into account capital required for additional project acquisitions. Additionally, we believe that our construction projects have been sufficiently capitalized such that we will not need to seek additional financing arrangements in order to complete construction and achieve commercial operations at these projects. Our acquisition of Panhandle 2 is contingent on funding by the tax equity investors so no further project financing is required. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce a corresponding adverse effect on our borrowing capacity. In connection with our future capital expenditures and other investments, including any project acquisitions that we may make in addition to our acquisition of Grand and Panhandle 2, we may, from time to time, issue debt or equity securities.

Cash Flows

We use traditional measures of cash flow, including net cash provided by operating activities, net cash used in investing activities and net cash provided by financing activities as well as cash available for distribution to evaluate our periodic cash flow results.

Table of Contents

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Net cash provided by operating activities was $78.2 million for the year ended December 31, 2013 as compared to $35.1 million for the year ended December 31, 2012. Electricity sales were $71.5 million higher during 2013 as compared to 2012, which was primarily attributable to the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012. Also during the year ended December 31, 2013, we recorded other revenue of $21.9 million related to non-refundable warranty settlement payments we received from a turbine supplier during the period as a result of the turbines at the Ocotillo and Santa Isabel projects being off line for a portion of the period. Offsetting these increases in electricity sales and other revenue is an $8.7 million increase in the period-over-period reduction of cash flow provided by operations related to an increase in trade receivables consistent with our terms under the power sales agreements, a period-over-period increase of $19.4 million in project expenses, and a period-over-period increase in cash interest expense of $22.8 million.

Net cash provided by investing activities was $72.4 million for the year ended December 31, 2013, which consisted of $173.4 million of ITC grant proceeds at Ocotillo and Santa Isabel, $14.3 million of proceeds from the sale of investments and tax credits, and a net reduction in our reimbursable interconnection receivable of $49.7 million, offset by $123.5 million of capital expenditures primarily at Ocotillo and Santa Isabel and a funding of restricted cash primarily at Ocotillo under the credit agreement. Net cash used in investing activities was $639.0 million for the year ended December 31, 2012, which consisted of $641.4 million of capital expenditures at Spring Valley, Santa Isabel and Ocotillo, $22.4 million of investments in our unconsolidated investments, and $47.1 million in net payments for interconnection network upgrades primarily at our Ocotillo project offset by ITC cash grant proceeds of $79.9 million.

Net cash used in financing activities for the year ended December 31, 2013 was $63.4 million, which was attributable to $317.9 million of net initial public offering proceeds, $138.6 million of loan proceeds primarily at Santa Isabel and Ocotillo and $32.7 million of capital contributions prior to the initial public offering offset by $232.6 million of distributions to Pattern Development in conjunction with the Contribution Transactions, $49.4 million related to the acquisition of Grand from Pattern Development, repayment of $114.1 million of construction and bridge loans at Santa Isabel and Ocotillo, $98.9 million of capital distributions prior to our initial public offering, and $50.3 million of long-term debt repayments. Net cash provided by financing activities for the year ended December 31, 2012 was $573.2 million which was primarily attributable to $281.5 million of capital contributions, $497.2 million of loan borrowings at Spring Valley, Santa Isabel and Ocotillo, offset by $80.9 million of loan repayments and $114.2 million of capital distributions.

Cash available for distribution was $42.6 million for the year ended December 31, 2013 as compared to $17.7 million for the year ended December 31, 2012, an increase of $24.9 million. This increase in cash available for distribution was the result of higher electricity sales of $71.5 million, which was primarily attributable to the commencement of commercial operations at Spring Valley in August 2012, and at Santa Isabel and Ocotillo in December 2012. Also, during the year ended December 31, 2013, we recorded other revenue of $21.9 million related to warranty settlement payments we received from a turbine supplier during the period as a result of the turbines at the Ocotillo and Santa Isabel projects being off line for a portion of the period. Offsetting these increases in electricity sales and other revenue is a period-over-period increase of $19.4 million in project expenses, a period-over-period increase in cash interest expense of $22.8 million, a $15.3 million increase in principal payments from operating cash flows as the additional projects commenced operations in late 2012 and a $4.4 million increase in network upgrade reimbursements. For a reconciliation of net cash provided by operating activities to cash available for distribution, see Key Metrics Cash Available for Distribution.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Net cash provided by operating activities was $35.1 million for the year ended December 31, 2012 as compared to $46.9 million for the year ended December 31, 2011. This decrease in cash provided by operating activities was primarily the result of lower revenue in 2012 at our Gulf Wind project as a result of receiving higher spot market electricity prices in 2011 than in 2012, including unusually high prices which exceeded $2,000 per MWh for approximately 24 hours during 2011. The lower revenue at Gulf Wind during 2012 as compared to 2011 was partially offset by increased electricity sales from a full year of operations at St. Joseph following its commencement of commercial operations in April 2011 and electricity sales following the commencement of commercial operations at Spring Valley in August 2012 and at Santa Isabel and Ocotillo in December 2012.

Net cash used in investing activities was $639.0 million for the year ended December 31, 2012, which consisted of $641.4 million of capital expenditures at Spring Valley, Santa Isabel and Ocotillo, $22.4 million of investments in our unconsolidated investments, and $47.1 million in net payments for interconnection network upgrades primarily at our Ocotillo project offset by ITC cash grant proceeds of $79.9 million. Net cash used in investing activities was $341.0 million for the year ended December 31, 2011, which consisted of $392.2 million of capital expenditures at St. Joseph, Spring Valley, Santa Isabel and Ocotillo and offset by the collection on our $80.3 million notes receivable at Hatchet Ridge.

Net cash provided by financing activities for the year ended December 31, 2012 was $573.2 million, which was primarily attributable to $281.5 million of capital contributions, $497.2 million of loan borrowings at Spring Valley, Santa Isabel and Ocotillo, offset by $80.9 million of loan repayments and $114.2 million of capital distributions. Net cash provided by financing activities for the year ended December 31, 2011 was $331.3 million, which was primarily attributable to $260.8 million of loan proceeds related to construction of St. Joseph, Spring Valley and Santa Isabel and $232.3 million of capital contribution, offset by $121.4 million of capital distributions.

Cash available for distribution was $17.7 million for the year ended December 31, 2012 as compared to $18.5 million for the year ended December 31, 2011. This decrease in cash available for distribution was primarily the result of higher spot electricity prices at our Gulf Wind project in 2011, including unusually high prices which exceeded $2,000 per MWh for approximately 24 hours during 2011 and which were not repeated in 2012; the loss of this unexpected incremental electricity revenue was partially offset by additional revenue, net of project expense, that was earned following commencement of operations at our Spring Valley, Santa Isabel and Ocotillo projects in 2012 and from a full year of operations at our St. Joseph project, $6.3 million of network upgrade reimbursements in 2012 and a decrease of $5.9 million in distributions to our noncontrolling interest in 2012 as compared to 2011. For a reconciliation of net cash provided by operating activities to cash available for distribution, see Key Metrics Cash Available for Distribution.

Capital Expenditures and Investments

We currently own only those projects that we acquired through the Contribution Transactions and those which we additionally acquired or agreed to acquire from Pattern Development in December 2013. Each of the acquired project entities has secured all of the required project equity needed to complete the construction and achieve commercial operations at our construction projects and funding for all remaining planned construction costs, including contingency allowances, is available under financing commitments from project lenders. All capital expenditures and investments in 2013 have either been funded by Pattern Development or are available from project finance lenders under project-level credit facilities. For 2013, total capital expenditures were $123.5 million. For 2014, we do not expect to make capital expenditures at our construction projects as these projects are held in joint ventures for which we use the equity method of accounting.

We expect to make investments in additional projects. Although we have no commitments to make any such acquisitions, other than the acquisition of Panhandle 2, we consider it reasonably likely that we may have the opportunity to acquire certain Pattern Development near-term projects under our Project Purchase Rights within the 24 month period following December 31, 2013. We have agreed to make a cash payment to Pattern Development in the amount of $122.9 million, subject to certain price adjustments based on final project size, design and modeling assumptions, at the time of the Panhandle 2 acquisition, which we expect to occur in the fourth quarter of 2014. We believe that we will have sufficient cash and revolving credit facility capacity to complete the Panhandle 2 acquisition, but this may be affected by any other acquisitions or investments that we make prior to the Panhandle 2 acquisition. To the extent that we make any such investments or acquisitions, we will evaluate capital markets and other corporate financing sources available to us at the time.

In addition, we will make investments from time to time at our operating projects. Operational capital expenditures are those capital expenditures required to maintain our long-term operating capacity. Capital expenditures for the projects are generally made at the project level using project cash flows and project reserves, although funding for major capital expenditures may be provided by additional project debt or equity. Therefore, the distributions that we receive from the projects may be made net of certain capital expenditures needed at the projects.

For the year ending December 31, 2014, we have budgeted $0.9 million for operational capital expenditures and $1.9 million for expansion capital expenditures.

Table of Contents

Credit Agreements

See Management s Discussion & Analysis of Financial Condition and Results of Operations Description of Credit Agreements in our 2013 Form 10-K for a further discussion of the terms of our credit agreements.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2013 (U.S. dollars in thousands):

Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long term debt principal payments	$ 1,249,218	$ 48,851	$ 119,330	$ 128,118	$ 952,919
Long term debt interest payments	532,719	57,236	106,949	96,811	271,722
Purchase commitments	4,128	4,128			
Land leases	110,500	3,713	7,442	7,469	91,876
Turbine operations and maintenance	25,109	16,465	6,033	2,020	591
Asset retirement obligations	20,834				20,834
Panhandle 2 acquisition commitment	122,900	122,900			
Total	$ 2,065,408	$ 253,293	$ 239,754	$ 234,418	$ 1,337,942

Off-Balance Sheet Arrangements

We are not a party to any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on our consolidated historical financial statements that are incorporated by reference from our 2013 Form 10K, which have been prepared in accordance with U.S. GAAP. In applying the critical accounting policies set forth below, our management uses its judgment to determine the appropriate assumptions to be used in making certain estimates. These estimates are based on management s experience, the terms of existing contracts, management s observance of trends in the wind power industry, information provided by our power purchasers and information available to management from other outside sources, as appropriate. These estimates are subject to an inherent degree of uncertainty.

We use estimates, assumptions and judgments for certain items, including the depreciable lives of property, plant and equipment, impairment of long-lived assets, asset retirement obligations, derivatives, income taxes, revenue recognition, certain components of cost of revenue and exemptions, stock-based compensation and reduced reporting requirements provided by the JOBS Act. These estimates, assumptions and judgments are derived and continually evaluated based on available information, experience and various assumptions we believe to be reasonable under the circumstances. To the extent these estimates are materially incorrect and need to be revised, our operating results may be materially adversely affected.

Property, Plant and Equipment

Property, plant and equipment represents the costs of completed and operational projects transferred from construction in progress as well as land, computer equipment and software, furniture and fixtures, leasehold improvements and other equipment. Property, plant and equipment are stated at cost, less accumulated depreciation. Depreciation is calculated using the straight-line method over the assets useful lives. Wind power projects are depreciated over 20 years and the remaining assets are depreciated over three to five years. Land is not depreciated. Improvements to
Property, plant and equipment represents the costs of completed and operational projects transferred from construction
in property, plant and equipment deemed to extend the useful economic life of an asset are capitalized. Repair and maintenance costs are expensed as incurred.

Derivatives

We have, and we intend to, enter into derivative transactions for the purpose of reducing exposure to fluctuations in interest rates, electricity prices and foreign currency exchange rates. We entered into fixed for floating interest rate swap agreements and have designated these derivatives as qualified cash flow hedges of its expected interest payments on variable rate debt. We have also entered into interest rate caps.

Table of Contents

We recognize our derivative instruments at fair value in the consolidated balance sheet. Accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether the derivative instrument has been designated as part of a hedging relationship and on the type of hedging relationship.

For derivative instruments that are designated as cash flow hedges the effective portion of change in fair value of the derivative is reported as a component of other comprehensive income. The ineffective portion of change in fair value is recorded as a component of net income on the consolidated statement of operations.

For undesignated derivative instruments their change in fair value is reported as a component of net income on the consolidated statement of operations.

An interest rate cap is an instrument used to reduce exposure to future variable interest rates when the related debt is expected to be refinanced. We entered into an interest rate cap in 2010. The cap remains in place as of December 31, 2013.

We entered into an electricity price arrangement, which qualifies as a derivative, that fixes the price of approximately 58% of the electricity generation expected to be produced and sold by Gulf Wind through April 2019, and which reduces our exposure to spot electricity prices.

Our interest rate cap and energy derivative agreement do not qualify for hedge accounting.

Income Taxes

Prior to October 2, 2013, our predecessor did not provide for income taxes as it was treated as a pass-through entity for U.S. federal and state income tax purposes, except for several specific circumstances involving its Canadian entities, which are subject to Canadian income taxes, its Chilean entities, which are subject to Chilean income taxes, a U.S. entity that is subject to Puerto Rican taxes and a U.S. entity which became subject to U.S. income taxes in 2012. Federal and state income taxes were assessed at the owner level and each owner was liable for its own tax payments. Certain consolidated entities are corporations or have elected to be taxed as corporations. In these circumstances, income tax was accounted for under the asset and liability method.

Subsequent to October 2, 2013, following the Contribution Transactions, we account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. We recognize deferred tax assets to the extent that we believe these assets are more likely than not to be realized. In making such a determination, we consider all available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning and results of recent operations. If we determine that we would be able to realize deferred tax assets in the future in excess of their net recorded amount, we would make an adjustment to the deferred tax asset valuation allowance, which would reduce the provision for income taxes. We record uncertain tax positions in accordance with ASC 740 on the basis of a two-step process whereby (1) we determine whether it is more likely than not that the tax positions will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, we recognize the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with the related tax authority. We have a policy to classify interest and penalties associated with uncertain tax positions together with the related liability, and the expenses incurred related to such accruals, if any are included in the provision for income taxes.

Revenue Recognition

We sell the electricity we generate under the terms of our power sale agreements or at spot market prices. Revenue is recognized based upon the amount of electricity delivered at rates specified under the contracts, assuming all other revenue recognition criteria are met. We evaluate our PPAs to determine whether they are in substance leases or derivatives and, if applicable, recognize revenue pursuant to Accounting Standards Codification (ASC) 840 Leases and ASC 815 Derivatives and Hedging, respectively. As of December 31, 2013, there were no PPAs that are accounted for as leases or derivatives.

We also generate renewable energy credits as we produce electricity. Certain of these energy credits are sold independently in an open market and revenue is recognized at the time title to the energy credits is transferred to the buyer.

We acquired a ten-year energy derivative instrument under the terms of our acquisition of Gulf Wind, which fixes approximately 58% of our expected electricity sales at Gulf Wind through April 2019. The energy derivative instrument reduces exposure to changes in commodity prices by allowing us to lock in a fixed price per MWh for a specified amount of annual electricity production. The monthly settlement amounts under the energy hedge are accounted for as energy derivative settlements in the consolidated statements of operations. The change in the fair value of the energy hedge is classified as energy derivative revenue in the consolidated statements of operations.

Cost of Revenue

Our cost of revenue is comprised of direct costs of operating and maintaining our power projects, including labor, turbine service arrangements, land lease royalties, depreciation, amortization, property taxes and insurance.

Stock-Based Compensation

We account for stock-based compensation related to stock options granted to employees by estimating the fair value of the stock-based awards using the Black-Scholes option-pricing model. The fair value of the stock options granted are amortized over the applicable vesting period. The Black-Scholes option pricing model includes assumptions regarding dividend yields, expected volatility, expected option term, expected forfeiture rate and risk-free interest rates. We estimate expected volatility based on the historical volatility of comparable publicly traded companies for a period that is equal to the expected term of the options. The risk-free interest rate is based on the U.S. treasury yield curve in effect at the time of grant for a period commensurate with the estimated expected life. The expected term of options granted is derived using the simplified method as allowed under the provisions of the ASC 718 Compensation Stock Compensation, and represents the period of time that options granted are expected to be outstanding.

We account for stock-based compensation related to restricted stock award grants by amortizing the fair value of the restricted stock award grants, which is the grant date market price, over the applicable vesting period.

JOBS Act

In April 2012, the JOBS Act was enacted. Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the U.S. Securities Act for complying with new or revised accounting standards. In other words, an emerging growth company can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We are electing to delay such adoption of new or revised accounting standards, and as a result, we may not comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for other companies.

Additionally, we regularly evaluate the benefits of relying on other exemptions and reduced reporting requirements provided by the JOBS Act. We may choose to take advantage of some but not all of these reduced burdens. For so long as we are an SEC foreign issuer under Canadian securities laws, we will be exempt from the continuous disclosure requirements of Canadian securities laws, subject to limited exceptions, if we comply with the reporting requirements applicable in the United States, including certain provisions of the JOBS Act.

Subject to certain conditions set forth in the JOBS Act and Canadian securities laws, as an emerging growth company, we intend to rely on certain of these exemptions, including, without limitation, providing an auditor s attestation report on our system of internal controls over financial reporting pursuant to Section 404 and complying with any requirement that may be adopted regarding mandatory audit firm rotation or a supplement to the auditor s report providing additional information about the audit and the financial statements (auditor discussion and analysis). These exemptions will apply for a period of five years following our initial public offering; although, if the market value of our shares that are held by non-affiliates exceeds $700 million as of any June 30 before that time, we would cease to be an emerging growth company as of the following December 31.

60

Table of Contents

Recent Accounting Pronouncements

We have evaluated recent accounting pronouncements and their adoption has not had or is not expected to have a material impact on our financial statements.

Quantitative and Qualitative Disclosure about Market Risk

We have significant exposure to commodity prices, interest rates and foreign currency exchange rates, as described below. To mitigate these market risks, we have entered into multiple derivatives. We have not applied hedge accounting treatment to all of our derivatives, therefore we are required to mark some of our derivatives to market through earnings on a periodic basis, which will result in non-cash adjustments to our earnings and may result in volatility in our earnings, in addition to potential cash settlements for any losses.

Commodity Price Risk

We manage our commodity price risk for electricity sales through the use of long-term power sale agreements with creditworthy counterparties. Our financial results reflect approximately 308,000 MWh of electricity sales in the year ended December 31, 2013 that were not subject to power sale agreements and were subject to spot market pricing. A hypothetical increase or decrease of $3.04 per MWh (or an approximately 10% change) in these spot market prices would have increased or decreased earnings by $0.9 million, respectively, for the year ended December 31, 2013.

Interest Rate Risk

We use a variety of derivative instruments to manage our exposure to fluctuations in interest rates, including interest rate swaps and interest rate caps, primarily in the context of our project-level indebtedness. We generally match the tenor and amount of these instruments to the tenor and amount, respectively, of the related debt financing. We also will have exposure to changes in interest rates with respect to our revolving credit agreement to the extent that we make draws under that facility. A hypothetical increase or decrease in short-term interest rates by 1% would not have changed our earnings for the year ended December 31, 2013.

Foreign Currency Risk

We manage our foreign currency risk through the consideration of forward exchange rate derivatives. Certain of our power sale agreements are U.S. dollar denominated and others are Canadian dollar denominated. We did not enter into forward exchange rate derivatives to manage our exposure to Canadian dollar denominated revenues at our St. Joseph project in the past. Our financial results include approximately $40.3 million of revenue that was earned pursuant to Canadian dollar denominated power sale agreements. A hypothetical increase of US$0.10 per Canadian dollar would have increased our earnings by $0.3 million for the year ended December 31, 2013, and a hypothetical decrease of US$0.10 per Canadian dollar would have decreased our earnings by $0.3 million for the year ended December 31, 2013.

Table of Contents

INDUSTRY

Overview of the Electricity Generation Industry

According to the U.S. Energy Information Administration, or EIA, International Energy Outlook 2013, global net electricity generation is expected to grow at a CAGR of 2.8% from 2010 to 2020. Although the 2008-2009 global economic recession slowed the rate of growth in global demand for electricity, demand returned in 2010, led by strong recoveries in non-Organisation for Economic Co-operation and Development, or OECD, countries. The EIA expects net electricity generation in non-OECD countries to grow at a CAGR of 4.3% from 2010 to 2020, led by non-OECD Asia (including China and India), which is expected to grow at a CAGR of 5.5%. In contrast, total net electricity generation in OECD countries is expected to grow at a CAGR of 1.1% over the same period. In all of these markets, transmission infrastructure expansion will be required to transmit electricity from new power generation projects to areas of customer demand.

Renewable energy is generated using naturally-replenishing resources such as water, wind, sunlight, plant and wood waste, and geothermal energy. In many parts of the world, increasing concerns regarding manufacturing jobs, security of energy supply and the environmental consequences of greenhouse gas emissions as well as the outlook for fossil-fuel prices have resulted in governmental policies that support an increase in electricity generation from renewable energy. Over the period from 2010 to 2020, the EIA expects net electricity generation from renewable energy to be the fastest growing source of net electricity generation at a CAGR of 4.5%. The significant growth in electricity generation from renewable energy is principally the result of an improvement in the cost competitiveness of renewable energy technologies and support from governments to increase the contribution of electricity generation from renewable energy. According to the EIA, net electricity generation from renewable energy accounted for 20.6% of global net electricity generation in 2010, making it the third largest contributor after coal and natural gas. By 2020, net electricity generation from renewable energy is projected to account for 24.4% of global net electricity generation. While wind and solar resources are intermittent, depending on the time of day and climatic conditions, improving storage technology and the dispersing of wind power and solar power projects over wide geographic areas can mitigate these concerns.

Natural gas is expected to be the third fastest growing source of electricity generation. An increase in unconventional natural gas resources, in particular, in North America, is expected to result in growth in net electricity generation from natural gas at a CAGR of 2.3% from 2010 to 2020.

The EIA expects net electricity generation from nuclear power to increase at a CAGR of 3.3% from 2010 to 2020. However, there is still considerable uncertainty regarding the future of nuclear power, which suggests that the EIA s expectations for the addition of new nuclear power generating capacity may not be fully realized. Further, the EIA expects approximately 98% of the increase in net electricity generating capacity from nuclear power to occur in non-OECD countries, with China, Russia and India accounting for the largest growth through 2020.

Future net electricity generation from renewable energy, natural gas, and, to a lesser extent, nuclear power is largely expected to displace net electricity generation from coal, although coal is expected to remain the largest source of global net electricity generation through 2020.

Table of Contents

Global Net Electricity Generation by Energy Source

Source: International Energy Outlook 2013   U.S. Energy Information Administration

Over the period from 2010 to 2020, the EIA expects 45% and 34% of the increase in net electricity generation from renewable energy to be from hydro power and wind power, respectively. While hydro power represented 81.5% of global net electricity generation from renewable energy in 2010, its contribution is expected to decline to approximately 68.4% by 2020 as projects utilizing other renewable energy technologies, including wind power and solar power, come online. Net electricity generation from wind power is expected to increase at a CAGR of 12.8% from 2010 to 2020, increasing its contribution to global net electricity generation from renewable energy from 8.2% in 2010 to 17.5% in 2020.

Global Net Electricity Generation from Renewable Energy by Energy Source

Source: International Energy Outlook 2013   U.S. Energy Information Administration

Regulatory Frameworks

The regulatory frameworks applicable to the electricity industry vary between regions.

Table of Contents

United States

Electricity markets in the United States are subject to regulation at both the federal and state levels. Federal law provides for the exclusive jurisdiction over the sale of electricity at wholesale and the transmission of electricity in interstate commerce, while state regulators review individual utilities electricity supply requirements and have oversight over the ability of public utilities to pass through to their ratepayers the costs associated with power purchases from IPPs. Federal regulatory filings are required for renewable energy projects in the United States that sell energy at wholesale, but state and local approvals (such as siting and permitting approvals) typically require more time to secure.

FERC regulates the sale of electricity at wholesale and the transmission of electricity pursuant to its regulatory authority under the Federal Power Act. FERC s jurisdiction includes, among other things, authority over the rates, charges and other terms for the sale of electricity at wholesale by public utilities (entities that own or operate projects subject to FERC jurisdiction) and for transmission services. In most cases, FERC does not set specific rates for the sale of electricity at wholesale by generating companies (such as our U.S. project companies) that qualify for market-based rate authority, enabling companies to price based upon negotiated rates reflecting market conditions. In order to be eligible for market-based rate authority, and to maintain exemptions from certain FERC regulations, our projects must request market based rate authorization from FERC. With respect to its regulation of the transmission of electricity, FERC requires transmission providers to provide open access transmission services, which supports the development of non-utility power generators and competitive power markets by assuring non-discriminatory access of non-utility generators to the transmission grid. FERC has also encouraged the formation of regional transmission operators, or RTOs, to allow non-utility generators greater access to transmission services and certain competitive wholesale markets administered by RTOs.

In 2005, the U.S. federal government enacted the Energy Policy Act of 2005, or EPACT 2005, conferring new authority for FERC to act to limit wholesale market power if required and strengthening FERC s criminal and civil penalty authority (including the power to assess fines of up to $1 million per day per violation), and adding certain disclosure requirements. EPACT 2005 also directed FERC to develop regulations to promote the development of transmission infrastructure, which provides incentives for transmitting utilities to serve renewable energy projects and expanded and extended the availability of U.S. federal tax credits to a variety of renewable energy technologies, including wind power.

In addition, PUHCA provides FERC and state regulatory commissions with access to the books and records of holding companies and other companies in holding company systems, and it also provides for the review of certain costs. Companies that are holding companies under PUHCA solely with respect to one or more EWGs, qualifying facilities , or foreign utilities are exempt from these books and records requirements. Each of our U.S. projects must request EWG or qualifying facility status, as applicable, and file updates to ensure they maintain the applicable status and are not treated as a holding company under PUHCA. Given that our operating projects in the U.S. are all EWGs, we are exempt from regulation under PUHCA.

While federal law provides the utility regulatory framework for our sales of electricity at wholesale in interstate commerce, there are also important areas in which state regulatory actions over traditional public utilities that fall under state jurisdiction may have an effect on our U.S. projects. For example, the regulated electric utility buyers of electricity from our projects are generally required to seek state public utility commission approval for the pass through in retail rates of costs associated with PPAs entered into with a wholesale seller, such as one of our U.S. projects. Certain states, such as New York, regulate to some extent the transfer of wholesale power projects and financing activities by the owners of such projects. California, one of our markets, requires compliance with certain operations and maintenance reporting requirements for wholesale generators. In addition, states and other local agencies require a variety of environmental and other permits.

Canada

In Canada, provincial governments have jurisdiction over their respective intra-provincial electricity markets and the Canadian federal government has jurisdiction over inter-provincial and international transmission and export permitting. Significant regional diversity of the sources of supply and market structures exists among provinces. In addition, the pace and extent of electricity market deregulation varies among, and reflects the unique circumstances and challenges faced by, each province. In recent years there has been a shift to retail and wholesale competition in Alberta and to a much lesser extent in Ontario, and some other provinces have undertaken varying degrees of sector unbundling through the granting of PPAs to IPPs and greater access to transmission and distribution networks. As a result, the number of IPPs active across Canada has increased. Some provinces are experiencing supply adequacy challenges during demand peaks and are focused on immediate generation and transmission investments for both short-term reliability and long-term security of supply, while surplus baseload generation is presently occurring in Ontario.

Chile

Energy policy in Chile is founded on the principles of free market competition between private companies, the regulation of natural monopolies and the limited role of the state. Chile has two major electricity grids, the Central Interconnected System, or the SIC, and the Northern Interconnected System, or the SING. Each of these two main grids has its own independent system operator and market administrator, a Centro de Despacho Económico de Carga, or CDEC , and is subject to the oversight of La Comisión Nacional de Energía, or CNE. The CDECs functions include ensuring an adequate supply of electricity into the system and providing efficient and economical dispatch of power projects.

Power Markets

U.S. State Power Markets

In the United States, power prices vary across regions and states. The price of electricity varies based on supply and demand dynamics, generation mix, fuel-supply costs and other inputs required to generate electricity and relevant environmental laws and regulations.

California

California ranked second in the United States in terms of electricity generating capacity, which stood at approximately 68 GW as of the end of 2011. Electricity in California is principally sold by load-serving utilities which buy the majority of their required electricity supply from IPPs. Load-serving entities within the state include investor-owned utilities, including Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, and municipal utilities, including Los Angeles Department of Water and Power, Sacramento Municipal Utilities District, and the Imperial Irrigation District. The market clearing price of electricity in California is highly correlated with the price of natural gas as natural gas-fired projects are the marginal cost electricity generators. The average retail electricity price in California was approximately 14 cents/kWh in 2012. Much of the California power grid is operated by the CAISO, which operates and controls the bulk transmission grid and also administers a competitive bulk power market. Approximately 80% of California s load falls within the footprint of the CAISO, with the remaining 20% served by irrigation districts and municipal utilities, which have chosen not to join the CAISO.

Texas

Texas had approximately 109 GW of electricity generating capacity as of the end of 2011, ranking first nationally. The provision of transmission and distribution service in Texas remains regulated by the Public Utility Commission of Texas, or PUCT. Population growth, an improving economy and extreme temperatures have resulted in record electricity demand during recent summer and winter seasons in ERCOT. The market clearing, real-time settlement-point price of electricity within ERCOT is highly correlated with the price of natural gas as natural gas-fired projects are the marginal cost electricity generators in Texas for most of the on-peak hours. The average retail electricity price in Texas was approximately 9.0 cents/ kWh in 2012.

The Texas power market is deregulated, with competition in wholesale electricity generation and retail electricity sales. Most of Texas is within the ERCOT NERC region, with the balance included in the Southwest Power Pool, or SPP, and SERC Reliability Council regions. ERCOT is an ISO that serves approximately 85% of Texas electricity load and is subject to oversight by the PUCT. ERCOT is a self-contained market on a standalone grid with only approximately 1,100 MW of transfer capability through direct current ties with the SPP and the Comision Federal de Electricidad in Mexico. Nearly 95% of ERCOT transactions are bilateral, with only 5% of market operations conducted in the real-time energy market. In December 2010, ERCOT replaced its zonal market design with a nodal market. The nodal system was designed to mitigate congestion costs with a greater number of settlement points and improve wind power dispatch efficiency, given more frequent and specific instructions to controllable generation. The nodal market continues to support bilateral agreements, such as long-term power sale agreements, designated at settlement points.

In order to address curtailment issues that have historically impacted wind power projects in the western and northwestern areas of the State of Texas, the PUCT over the past several years has implemented a project to construct over $6 billion of new transmission facilities to serve those installations, or the CREZ Transmission Lines. The primary CREZ Transmission Lines have all been certificated and constructed.

Nevada

Nevada had approximately 11,646 MW of electricity generating capacity as of the end of 2011. In 1997, Nevada began to deregulate its power markets, but this plan was suspended in 2001. Electricity is regulated in the state by the Public Utility Commission of Nevada. The Nevada market is primarily served by NV Energy, Inc., or NV Energy, an integrated utility holding company, with natural gas as its primary fuel for electricity generation. The average retail electricity price in Nevada was approximately 9.0 cents/kWh in 2012.

Puerto Rico

PREPA is a public corporation and governmental instrumentality of Puerto Rico. PREPA transmits and distributes virtually all of the electricity consumed in Puerto Rico. As of June 30, 2012, PREPA owned and had entered into power sale agreements for approximately 4,878 MW and 1,000 MW of electricity generating capacity, respectively. Imported heavy distillate oil and residual oil are the primary fuels utilized for electricity generation in Puerto Rico. The average retail electricity price in Puerto Rico was approximately 27.8 cents/kWh in the 12-month period ended June 30, 2012.

Canadian Provincial Power Markets

Similar to the United States, power prices in Canada vary across regions and provinces. The price of electricity varies based on supply and demand dynamics, generation mix, fuel supply costs and other inputs required to generate electricity and relevant environmental laws and regulations.

Ontario

Ontario ranks second in Canada in terms of electricity generating capacity, which stood at approximately 37 GW as of the end of 2012. Ontario s electricity market is structured around the five entities that resulted from the break-up of Ontario Hydro in 1999, namely: the Ontario Electricity Financial Corporation, Ontario Hydro s legal successor with the mandate to manage and retire Ontario Hydro debt and contractual obligations with certain IPPs; Ontario Power Generation, or OPG, the electricity generating company, which generated approximately 60% of the electricity in Ontario in 2012; Hydro One Inc., the transmission and rural distribution company; the IESO, the grid operator that ensures security of supply, operates the spot market providing open access to regulated transmission systems; and the Electrical Safety Authority, with responsibility to oversee electrical safety in Ontario. In addition, in 2005, the Ontario government established the OPA, which awards and enters into PPAs for the supply of new electricity generation in Ontario.

Manitoba

Manitoba had approximately 5,927 MW of electricity generating capacity as of the end of 2012, which consists predominantly of hydro power. Manitoba Hydro is a Crown Corporation of the Province of Manitoba and generates, transmits and distributes virtually all of the electricity consumed in the province. Manitoba is a net exporter of electricity, mainly to Saskatchewan, Ontario and certain midwestern states of the United States. To date, the province has successfully utilized its large hydro power resources to satisfy its internal demand for electricity while exporting the balance.

Chilean Power Markets

Chile had approximately 18.3 GW of electricity generating capacity as of November 2012. Chile s Ministry of Energy expects electricity consumption in Chile to increase at an annual rate of approximately 6% to 7% from 2011 to 2020. According to the Ministry of Energy, 63% of Chile s electricity generation is generated from fossil fuel-fired sources, the majority of which is imported, 34% from domestic hydro power and only 3% from renewable

Table of Contents

energy, including wind power, small-scale hydro power and biomass. According to figures published by the OECD, electricity prices in Chile posted a four-fold increase between 1998 and 2011 due in large part to its dependence on foreign energy sources and a reduction in natural gas supply from Argentina. To satisfy this expected increase in demand, Chile s Ministry of Energy estimates that approximately 8,000 MW of additional electricity generating capacity would be required.

Overview of the Wind Industry

Wind power has been one of the fastest growing sources of electricity generation in North America and globally over the past decade. According to GWEC, from 2003 to 2013, net electricity generation from wind power in the United States and Canada grew at a CAGR of 25% and 38%, respectively. According to AWEA, wind was the number one source of new U.S. generating capacity in 2012. However, uncertainty related to the demand for new power projects in general and the potential expiration of U.S. federal incentives on December 31, 2012 resulted in a reduction in the build rate of wind power and other renewable energy projects in 2013 and potentially 2014 from a high of 13,124 MW installed in 2012, according to AWEA. According to Wood Mackenzie, 8%, or 97 GW, of the U.S. and Canadian power supply is estimated to come from wind by 2020. This rapid growth is largely attributable to renewable energy s increasing cost competitiveness with other power generation technologies, the advantages of wind power over other renewable energy sources, and growing public support for renewable energy driven by concerns regarding security of energy supply and the environment. As global demand for electricity generation from wind power has increased technology enhancements supported by U.S. government incentives have reduced the cost of wind power by more than 90% over the past 20 years, according to AWEA.

Wind power projects have a longstanding history of being able to secure long-term PPAs with creditworthy counterparties. Counterparties to PPAs, which are typically electric utilities, enter into these agreements to satisfy their requirements for electricity generating capacity, interest in diversifying their power sources, interests of their customers, or governmental mandates requiring a portion of their electricity supply to come from renewable energy sources. By entering into long-term, fixed-price PPAs, utilities are able to insulate themselves from the volatility in wholesale electricity prices that are typically passed on to ratepayers in their jurisdictions. Wind power generating capacity is typically sourced through a RFP, which is a solicitation by electric utilities for bids to provide a fixed generation amount, or a FIT program, which offers project operators fixed prices under long-term contracts for electricity typically generated from renewable energy sources. However, there are numerous cases of PPAs being negotiated on a bilateral basis with utilities and IPPs, such as Pattern Development.

United States

The United States is the second largest market for wind power in the world by electricity generating capacity. According to the DoE, wind power was the second largest source of new electricity generating capacity in the United States after natural gas for six of the seven years between 2005 and 2011. According to AWEA, wind power became a leading source of new electricity generating capacity in the United States for the first time in 2012. The success of wind power is evidenced by approximately $90 billion in investments over the last five years, according to the AWEA. In 2013, wind power generating capacity grew to a total of 61 GW, equivalent to powering over 15.3 million homes. As of the end of 2013, 39 of the 50 U.S. states and Puerto Rico had utility-scale wind projects, and 16 states had more than 1,000 MW of wind power generating capacity. Texas and California, two of our markets, represent the first- and second-ranked states in terms of wind power generating capacity, as of the end of 2013. Despite this growth, wind power represented only 4.1% of electricity generating capacity in the United States as of the end of 2013. Based on the percentage of electricity generated by wind power in other developed countries, we believe that, despite a reduction in the build rate of wind power and other renewable energy projects in 2013 and potentially 2014, as a result of the uncertainty related to the demand for new power projects in general, substantial growth potential remains in the

U.S. market over the long-term.

Table of Contents

U.S. Wind Power Generating Capacity by State 2013

Source: American Wind Energy Association, U.S. Wind Industry Fourth Quarter 2013 Market Report

California

As of December 31, 2013, California ranked second nationally in terms of overall wind installations, after Texas, with 5,812 MW of wind power generating capacity. In 2013, 6.6% of electricity in the state was generated from wind power, equivalent to powering approximately 1.9 million homes. The wind power installed in California avoids over 7.8 million metric tons of carbon dioxide annually. According to the National Renewable Energy Laboratory, or NREL, the California wind resource could meet 40% of the state s current electricity needs.

Texas

As of December 31, 2013, Texas ranked first nationally in terms of overall wind installations with 12,355 MW of wind power generating capacity and was the first state to reach 10 GW of wind power generating capacity. It is home to six of the nation s largest ten wind power projects. In 2013, 8.3% of electricity generated in the state was generated by wind power, equivalent to powering over 3.3 million homes. The wind power installed in Texas avoids over 22 million metric tons of carbon dioxide annually. According to NREL, the Texas wind resource could meet 18 times the state s current electricity needs. AWEA ranks the state s wind resource as the first in the United States.

Nevada

Our Spring Valley project was the first commercial-scale wind power project commissioned in Nevada, and the output from Spring Valley is currently being sold to NV Energy under a long-term PPA. According to NREL, the Nevada wind resource could meet nearly 60% of the state s current electricity needs.

Puerto Rico

Our Santa Isabel project was the first commercial-scale wind power project to achieve commercial operations in Puerto Rico.

Table of Contents

Canada

The Canadian wind power industry has also experienced dramatic growth in recent years. In 2013, Canada experienced approximately 1,600 MW of new installed wind power generating capacity. In 2013, new wind power projects were built in Prince Edward Island, Nova Scotia, Quebec, Ontario, British Columbia and Saskatchewan, resulting in wind power generating capacity in Canada reaching approximately 7,800 MW as of January 2014. Ontario, one of our markets, is the national leader in installed capacity, with approximately 2.5 GW of wind power generating capacity, although recent changes to the Ontario government FIT regime may make future projects less attractive and PPAs more difficult to obtain. The EIA forecasts total wind power generating capacity in Canada to exceed 13 GW by 2020.

Canadian Wind Power Generating Capacity by Province 2013

Source: Canadian Wind Energy Association

Ontario

Ontario is the current provincial leader, with approximately 2,740 MW of wind power generating capacity. Our South Kent project, representing 135 MW of owned capacity, achieved commercial operation in the second quarter of 2014.

Manitoba

Manitoba has 259 MW of wind power generating capacity, including our St. Joseph project, which commenced commercial operations in 2011 and represents 138 MW of electricity generating capacity.

Chile

Chile has an abundant wind resource, which GWEC estimates could provide the potential for more than 40 GW of electricity generating capacity, including within the south-central zone where approximately 80% of Chile s population resides. As of the end of 2013, Chile had approximately 335 MW of wind power generating capacity, representing approximately 2% of total electricity generating capacity. According to GWEC, as of the end of 2013, Chile had approximately 6,445 MW of wind projects under various stages of development, of which 450 MW of wind power projects were expected to come online in 2014 and a further 1,400 MW during 2015 to 2018.

Wind Power Fundamentals

Wind power harnesses the kinetic energy of moving air. Electricity is generated from the energy of wind flows exerted on the blades of a wind turbine, which activates an electric generator. Wind turbines are equipped with a control system that optimizes electricity generation output. In addition, wind power projects can be monitored and operated remotely to respond to changing weather conditions, including shutting down during heavy lightning storms and rotating to adjust to shifts in wind direction.

The amount of energy that the wind transfers to the turbine depends on the blades surface area and the wind speed. The amount of energy captured by a wind turbine increases as a square-function of an increase in blade size. For example, doubling the surface area of the blades quadruples the wind energy captured. The speed of the wind has an even greater effect. As wind speed doubles, the available energy increases by a factor of eight. Stronger winds are also able to drive larger turbine blades. In order to maximize the efficiency of the transfer of energy from wind to electricity, blade size must be chosen to capture the most wind energy the highest proportion of the time.

As a result of these factors, manufacturers have developed wind turbines to increase blade size in order to increase the swept area of a turbine, thereby increasing the electricity generation of the turbine and simultaneously decreasing the cost of electricity generated. In addition, manufacturers have successfully increased the height of towers in order to benefit from greater wind speeds at higher elevations (e.g., shear) in many wind regions. According to AWEA, a typical wind turbine today generates approximately 15 times more electricity than a typical turbine in 1990 and can generate electricity equivalent to powering approximately 500 homes.

Not only has technological evolution increased a wind turbine s ability to generate electricity, it has also increased the accuracy with which wind is forecast. New meteorological technology dispatched to a potential project site can measure wind at a higher hub height and rotor swept area with greater accuracy than previously possible. Additionally, improvements and new analytical methods have been incorporated into the prediction models. This improvement in forecasting has increased the predictability of the electricity generation of wind power projects, which, in turn, has increased their ability to attract long-term debt financing.

Wind Power Project Electricity Generation

Wind is a source of energy that is naturally variable; wind generally does not blow at a constant speed throughout a given day nor month-to-month. As a result, the amount of electricity generated on a daily or monthly basis is also variable or intermittent. However, long-term historical site-specific measurements for wind power allow for an annual average or mean wind speed, enabling the use of statistical analyses to estimate electricity generation.

There are a number of factors that preclude a wind turbine from operating at its maximum theoretical electricity generation, but the primary factor is wind speed. As a result of the variance in wind speed at any given project, a turbine will be operating for significant periods of time at levels less than its maximum electricity generating capacity. Other factors also affect the capacity factor but are generally much less significant, including scheduled annual maintenance of electricity-generating equipment and unscheduled non-operation resulting from equipment failure. In general, wind power projects have capacity factors, defined as the percentage of electricity that an electricity-generating source is expected to generate relative to the maximum theoretical electricity generation in a given period of time, ranging from 20% to 60%, depending on various site and equipment-specific factors.

Advantages of Wind Power

Low Operating Costs

Wind power projects do not have any fuel costs and typically use remote monitoring systems, which enable off-site operation and supervision. In addition, improvements in wind turbine technology have increased the efficiency and reliability of wind power projects. As a result, operating expenses for wind power projects are generally lower than those of comparably-sized fossil fuel-fired power projects such as natural gas or coal.

Simple Construction

Wind power projects are relatively simple to construct relative to conventional power projects. We believe that 50 MW and 200 MW wind power projects can be constructed within approximately six and 12 months, respectively,

Table of Contents

while constructing large-scale hydro power, natural gas, nuclear power or coal projects typically requires a longer timeframe. As a result, wind power projects are susceptible to far fewer risks associated with construction delays and cost over-runs.

Environmentally Responsible

Wind power projects do not emit any greenhouse gases or contribute to acid rain, both of which have significant negative impacts on the environment. Electricity generation from wind power does not result in thermal, chemical, radioactive, water or air pollution that is typically associated with fossil fuel-fired and nuclear power projects. According to GWEC, collectively, U.S. wind power projects can potentially account for 31% of the required emissions reductions between 2005 and 2020, avoiding 385 million tons of carbon dioxide in 2020 alone. Wind power projects can have an adverse impact on birds and bats, as well as plants and animals. However, a well-designed and operated wind power project can minimize these impacts and have a significantly lower environmental impact relative to most environmentally-responsible conventional power projects.

Technological Improvements

Technological improvements resulting in greater power efficiency are decreasing the cost of electricity generated from wind toward parity with the cost of other energy sources, such as natural gas. The diagram below exemplifies how, at specified wind speeds, new turbine technology that we believe can be deployed in 2014 is able to produce 50% to 100% more power for most North American wind locations than the technology that was available in 2009.

Power Efficiency Improvements

Limited Use of Land

Wind power projects require only a small percentage of the land they occupy for road access and foundations for wind turbines. The remainder of a wind power project site is available for other uses such as agriculture, industry and recreation. We believe a typical wind power project uses only 2% to 5% of the land area leased to or owned by the project.

Table of Contents

Key Drivers of Demand for Wind Power

We believe the following factors have driven, and will continue to drive, the growth of wind power in North America:

Requirements for New Electricity Generating Capacity

As stated above, from 2010 to 2020, the EIA expects global net electricity generation to grow at a CAGR of 2.8%; however, OECD countries are expected to grow at a CAGR of 1.1% over the same period. In the United States and Canada, in addition to the new electricity generating capacity associated with this growth, further capacity additions will be required to replace aging fossil fuel-fired and nuclear power projects. With the current low natural gas price environment and increased sensitivity regarding environmental concerns, it is expected that natural gas and renewable energy, including wind power, will be the future choice for new electricity generating capacity.

Governmental Incentives

Increasing concerns regarding manufacturing jobs, security of energy supply and consequences of greenhouse gas emissions as well as the outlook for fossil-fuel prices have resulted in support for governmental policies at the federal and state or provincial level that support electricity generation from wind power and other renewable energy sources. The state and provincial RPS as well as FIT programs have been and will continue to be the most important governmental policies supporting wind power. In order to promote employment in the manufacturing sector, jurisdictions are implementing domestic content requirements for renewable energy projects. For example, the FIT program in Ontario requires wind power projects greater than 10 KW and all solar projects to include a minimum amount of Ontario-based content. Minimum domestic content of 50% is required for projects that achieve commercial operations in Ontario after January 1, 2012. The minimum domestic content was lowered for FIT contracts issued after August 2013, for example minimum domestic content of 20% is required for on-shore wind projects under Ontario s current FIT program.

Continued Improvements in Wind Power Technologies

Wind turbine technology has evolved significantly over the last 20 years and technological advances are expected to continue in the future. The cost of electricity generation from wind projects has dropped over 90% over the last 20 years, we believe, as a result of technological advances, which have included:

- advances in wind turbine blade aerodynamics and development of variable speed generators to improve conversion of wind energy to electricity over a range of wind speeds, resulting in higher capacity factors and increased capacity per turbine;

- advances in turbine height resulting in the ability to benefit from greater wind speeds at higher elevations;

- advances in remote operation and monitoring systems;

- improvements in wind monitoring and forecasting tools, allowing for more accurate prediction of electricity generation and availability and for better system management and reliability; and advances in turbine maintenance, resulting in longer turbine lives.

Growing Environmental Concerns

The growing concern over the environmental consequences of greenhouse gas emissions has contributed to the growth of wind power generation. According to the World Meteorological Organization, 2013 tied with 2007 as the sixth warmest since global records began in 1850, and thirteen of the fourteen warmest years on record have all occurred in the twenty-first century. As one of the largest emitters of greenhouse gases in the world, the United States has experienced growing awareness of climate change and other effects of greenhouse gas emissions, which has resulted in increased demand for emissions-free electricity generation. As an emissions-free electricity source, wind power is an attractive alternative that is capable of addressing these growing environmental concerns.

Outlook for Energy Prices

We expect that increased demand for electricity coupled with a finite supply of fossil fuels, and capacity and distribution constraints, including volatility in fossil-fuel prices, will result in continued increases and volatility in electricity prices. Current natural gas prices are low; however, they are expected to increase in coming years. Additionally, electricity generation from natural gas is either exposed to volatility in natural gas prices or is priced at a premium for medium-term, fixed-price gas supply contracts. Wind power projects, in contrast, typically contract for long periods (e.g., 20 years) at fixed prices. As a result and given the lack of fuel costs associated with wind power projects, we believe that wind power has become cost competitive with conventional power projects and that this cost competitiveness will contribute to further growth in wind power.

Increasing Obstacles for Conventional Power Projects

Growing environmental concerns have made it increasingly difficult to construct new or expand existing fossil fuel-fired electricity generation projects. For example, according to industry sources, only 41 of the approximately 150 coal plants proposed in the United States between 2000 and 2006 were built or were under construction by the end of 2013. Nuclear power projects have also faced significantly increasing capital costs and steep environmental hurdles associated with, among other things, complications relating to the disposal of spent nuclear fuel and concerns over operational safety. Wind power, in contrast, does not create solid waste by-products, emit greenhouse gases or deplete non-renewable resources, and, as a result, is an attractive alternative to fossil fuel-fired power projects.

Dependence on Foreign Energy Sources

According to the EIA, the net import share of total U.S. energy consumption was 28% in 2012. In addition, many of the regions rich in energy supply are politically unstable, raising public concerns regarding the dependence of the United States on foreign energy imports and related threats to U.S. national security. The potential for future growth in U.S. wind power generating capacity is supported by the large amount of land available for turbine installations and the availability of significant wind resources. According to the DoE, wind power industry experts estimate that the United States has more than 10,500 GW of available land-based wind resources that can be captured economically, assuming 80 meter turbine heights and a capacity factor of at least 30%. Increased public awareness of the dependence of the United States on foreign energy sources has generated momentum to diversify the energy supply within the United States. We believe that wind power, which supplied only 4.1% of the total net electricity generation in the United States in 2013, according to the AWEA, is a viable domestic alternative to decrease the dependence of the United States on foreign energy sources and satisfy a portion of the expected increased demand for electricity in the United States.

Mechanisms to Promote Wind Power and Other Renewable Energy Sources

Generally, there has been broad support from governments to facilitate growth in electricity generation from renewable energy through the development of mechanisms that encourage the adoption of renewable energy, including wind power.

United States

Federal Government Support for Renewable Energy

Presently under U.S. law, the PTC provides a tax credit of 2.3 cents/kWh for projects that begun construction on or before December 2013. Although the tax credit expired for projects beginning construction after December 2013, the U.S. Senate approved adding language to a tax extenders package in April 2014 that would revive the PTC for two years. For projects placed into service on or before December 31, 2012, for which construction began on or after January 1, 2009 and before the end of 2011, project owners were permitted to elect to receive an ITC cash grant equivalent to 30% of the capital cost of qualified equipment. On March 4, 2013, the U.S. Treasury announced that the automatic federal spending reductions occurring across most U.S. government programs, known as sequestration, would apply to ITC cash grants. Awards made through the remainder of the government s fiscal year (September 30, 2013) were reduced by 8.7%. Alternatively, project owners were permitted to elect to claim an ITC equal to 30% of the capital cost of qualified equipment for wind projects placed in service on or after January 1, 2009 for which construction began before January 1, 2014. Given that many of the factors that gave rise to the initial establishment of the U.S. federal incentives remain, including strong public support for the continued expansion of renewable energy, we believe new U.S. federal incentives may be enacted, although the form and timing of any potential future incentives remain uncertain.

State Government Support for Renewable Energy

U.S. state RPS and targets have been a key driver of the expansion of wind power and will continue to drive wind power installations in many areas of the United States. As of March 2013, 29 states and the District of

Table of Contents

Columbia have RPS in place, and eight other states have non-binding goals supporting renewable energy. California, one of our markets, has been a leader in RPS with one of the highest state targets. In 2011, the governor of California signed into law legislation that increased the state s RPS from 20% to 33% by 2020. Texas, another of our markets, has surpassed its mandated RPS of 5,880 MW by 2015 as well as its target of 10,000 MW by 2025, but is completing a large expansion of the electricity grid in Texas principally to facilitate the development of additional wind power generating capacity.

Renewable Portfolio Standards and Targets by State March 2013

Source: Database of State Incentives for Renewables & Efficiency, U.S. Department of Energy

California. California has one of the most aggressive RPS in the United States with a target of 33% of electricity to be generated from renewable energy sources by 2020. Load-serving entities in California satisfy their RPS requirements, in part, by issuing requests for proposals for new renewable energy PPAs. The success of bringing currently contracted projects into operation will impact future demand for renewable energy in California.

Texas. While the Texas RPS requires 5,880 MW of renewable energy generating capacity by 2015 and Texas has a target of 10,000 MW by 2025, both of these levels have already been met.

Nevada. Under Nevada s RPS, NV Energy is required to utilize renewable energy sources to supply a minimum percentage of the electricity it sells in the state, which was set at 6% in 2005, increasing by 3% every two years to 20% by 2015 and to 25% by 2025. Both of NV Energy s operating subsidiaries, Nevada Power Company and Sierra Pacific Power Company, surpassed the minimum requirement of 18% in 2013, delivering 20.4% and 34.7%, respectively. NV Energy satisfies its RPS requirements, in part, by issuing requests for proposals for new renewable energy PPAs.

Puerto Rico. Under Puerto Rico s RPS, PREPA is required to meet targets for electricity generation from renewable energy sources as a percentage of electricity sales as follows: 12% by 2015; 15% by 2020; and 20% by 2035. In the 12-month period ended June 30, 2012, less than 1% of electricity generation in Puerto Rico was generated from renewable energy sources. PREPA primarily satisfies its RPS requirements by entering into power sale agreements for new electricity generation from renewable energy. As of June 30, 2012, PREPA had signed a total of more than 40 power sale agreements representing approximately 1,000 MW of renewable energy projects. Should these projects achieve commercial operation, PREPA expects that, collectively, they will generate approximately 4%, 8% and 11% of electricity generation in 2013, 2015 and 2017, respectively, in all years below the relevant RPS targets.

Table of Contents

Canada

Federal Government Support for Renewable Energy

While provincial governments have jurisdiction over their respective intra-provincial electricity markets, from 2007 to 2011, the Canadian federal government supported the development of renewable energy through its ecoENERGY for Renewable Power program, or ecoEnergy federal incentive , which resulted in a total of 104 projects qualifying for funds, including our St. Joseph project, and will represent cash incentives of approximately C$1.4 billion over 14 years and encouraged an aggregate of approximately 4,500 MW of new renewable energy generating capacity. The program is now fully subscribed, and the Canadian federal government has not signaled an intention to renew it.

Provincial Government Support for Renewable Energy

Provincial governments have been active in promoting renewable energy in general and wind power in particular through RPS as well as through RFPs and FIT programs for renewable energy. Several provinces are currently preparing new RFPs for renewable energy. Current provincial targets for renewable energy in those provinces with stated targets are outlined below.

Ontario. In 2009, the Green Energy and Green Economy Act, 2009 was passed into law and the OPA launched its FIT program, which offers stable prices under long-term contracts for electricity generation from renewable energy, including biomass, wind, solar photovoltaic and hydro power. In November 2010, the Ministry of Energy, or MoE, released the draft Supply Mix Directive and Long Term Energy Plan, or LTEP. Ontario, one of our markets, has been a leader in supporting the development of renewable energy through the LTEP, which calls for 10,700 MW of renewable energy generating capacity (excluding small-scale hydro power) by 2021. In addition, Ontario was the first jurisdiction in North America to introduce a FIT program, which has resulted in contracts being executed for approximately 4,541 MW of electricity generating capacity as of March 31, 2013. These new contract awards under the FIT program along with previously-awarded PPAs suggests Ontario is close to meeting its current RPS by 2015, provided that all of the currently-contracted projects are successfully developed, financed and constructed.

In April and July of 2012, the OPA implemented version 2.0 of the FIT program, which, among other things, reduced contract prices for new wind power and solar power projects, limited the acceptance of applications to specific application windows, and prioritized projects based upon project type (community participation, Aboriginal participation, public infrastructure participation), municipal and Aboriginal support, project readiness and electricity system benefit. The revisions to the FIT program do not affect FIT contracts issued prior to October 31, 2011, including our South Kent project and the Grand, K2 and Armow projects. Prices under the FIT program will be reviewed annually, with prices established in November that will take effect January 1st of the following year. Such price changes do not affect previously issued FIT contracts but, rather, only FIT contracts to be entered into subsequent to the price change. The revisions may, however, make project economics less attractive (because of the PPA price reduction) and by granting priority points or status to certain types of projects, may make it more difficult to obtain PPAs in the future.

In October 2013, the OPA issued version 3.0 of the FIT program, with new price schedules. Version 3.0 of the FIT program generally limits the size of eligible renewable energy projects to 500 kW. In the fall of 2013, the OPA announced that it would begin developing a process for procuring larger renewable energy projects, i.e. those greater than 500 kW in capacity, that will take into account local needs and considerations. This Large Renewable Procurement program is currently in the draft request for qualifications stage and will ultimately lead to a request for proposals for larger renewable energy projects.

Manitoba. The Manitoba government and Manitoba Hydro independently undertook studies to determine the potential of wind power generation in the province of Manitoba. As a result of such studies, in November 2005, the Manitoba government announced that it was targeting plans to add approximately 1,000 MW of new wind power generating capacity by 2016, a portion of which is expected to be procured from IPPs. To date, it has awarded three PPAs for electricity generating capacity in excess of 250 MW, including our St. Joseph project.

Other Provinces. Provincial support for renewable energy in other provinces includes the following objectives:

British Columbia: To achieve energy self-sufficiency by 2016 with at least 93% of net electricity generation from clean or renewable sources;

New Brunswick: To generate 10% of net electricity generation from new renewable sources by 2016;

Nova Scotia: To generate 25% and 40% of net electricity generation from new (post-2001) sources of renewable energy by 2015 and 2020, respectively;

Prince Edward Island: To acquire 30% of electricity from wind power over the next few years;

Québec: To develop 4,000 MW of wind power generating capacity by 2015; and

Saskatchewan: To generate approximately 29% of electricity from sources of renewable energy by 2016.

Chile

In 2008, the Chilean government enacted the Renewable and Non-Conventional Energy Law (law 20.257), which required power generation companies who sell directly to end-use customers, to source 5% of their electricity from renewable energy sources by 2010, which such percentage gradually increasing each year until it reaches 20% in 2024. As of the end of 2011, renewable energy accounted for approximately 3% of total electricity generation in Chile.

Table of Contents

BUSINESS

Overview

We are an independent power company focused on owning and operating power projects with stable long-term cash flows in attractive markets with potential for continued growth of our business. Including the acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to the satisfaction of customary closing conditions, in the fourth quarter of 2014, we own interests in ten wind power projects located in the United States, Canada and Chile that use proven, best-in-class technology and have a total owned capacity of 1,255 MW, consisting of seven operating projects and three construction projects. We expect our three construction projects will commence commercial operations prior to the end of 2014. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement with a creditworthy counterparty. Ninety-three percent of the electricity to be generated by our projects will be sold under these power sale agreements, which have a weighted average remaining contract life of approximately 18 years.

We have two classes of authorized common stock outstanding, Class A shares and Class B shares. The rights of the holders of our Class A and Class B shares are identical other than in respect of dividends and the conversion rights of our Class B shares. On December 31, 2014, which is the later of that date and the date on which our South Kent project achieved commercial operations (which occurred on March 28, 2014), and which we refer to as the Conversion Event, all of our outstanding Class B shares will automatically convert, on a one-for-one basis, into Class A shares. Our Class B shares, all of which are held by Pattern Development and members of management, have no rights to dividends. See Description of Capital Stock.

We intend to use a substantial portion of the cash available for distribution generated from our projects to pay regular quarterly dividends in U.S. dollars to holders of our Class A shares. On November 26, 2013, we announced the initiation of a quarterly common stock dividend and on January 30, 2014 we paid a dividend to each of our Class A common shareholders of $0.3125 per Class A share, or $1.25 per Class A share on an annualized basis. We have also declared a dividend of the same amount per share payable on April 30, 2014 to our Class A common shareholders of record on March 31, 2014. We established our quarterly dividend level based on a target payout ratio of approximately 80% after considering our expected 2014 and subsequently sustainable cash available for distribution to be generated from our projects, together with the impact of the Class A shares to be issued upon the Conversion Event. The declaration and amount of our future dividends, if any, will be subject to our actual earnings and capital requirements and the discretion of our Board of Directors, and will likely take into account any contribution to our expected sustainable cash available for distribution resulting from projects that we acquire from Pattern Development or third parties.

Our growth strategy is focused on the acquisition of operational and construction-ready power projects from Pattern Development or third parties that we believe will contribute to the growth of our business and enable us to increase our dividend per Class A share over time. We expect that our continuing relationship with Pattern Development, a leading developer of renewable energy projects, will be an important source of growth for our business.

Our Core Values and Financial Objectives

We intend to maximize long-term value for our shareholders in an environmentally responsible manner and with respect for the communities in which we operate. Our business is built around three core values:

- creating a safe, high-integrity, exciting work environment for our employees;
- applying rigorous analysis to all aspects of our business in a timely, disciplined and functionally integrated manner to understand patterns in wind regimes, technology developments, market trends and regulatory, financial and legal constraints; and
- proactively working with our stakeholders to address environmental and community concerns, which we believe is a socially responsible approach that also benefits our business by reducing operating risks at our projects.

Our financial objectives, which we believe will maximize long-term value for our shareholders, are to:

- produce stable and sustainable cash available for distribution;
- selectively grow our project portfolio and our dividend; and
- maintain a strong and flexible capital structure.

Table of Contents

Our Projects

The following table provides an overview of our projects:

Projects	Location	Location and Start-up Construction Start(1)	Commercial Operations (2)	Capacity (MW) Rated (3)	Owned (4)	Type	Contracted Volume(5)	Power Sale Agree Counterparty
Operating Projects								
Gulf Wind	Texas	Q1 2008	Q3 2009	283	113	Hedge(7)	~58%	Credit Suisse Energy I
Hatchet Ridge	California	Q4 2009	Q4 2010	101	101	PPA	100%	Pacific Gas & Electr
St. Joseph	Manitoba	Q1 2010	Q2 2011	138	138	PPA	100%	Manitoba Hydro
Spring Valley	Nevada	Q3 2011	Q3 2012	152	152	PPA	100%	NV Energy
Santa Isabel	Puerto Rico	Q4 2011	Q4 2012	101	101	PPA	100%	Puerto Rico Electric Power
Ocotillo(9)	California	Q3 2012	Q4 2012	223	223	PPA	100%	San Diego Gas & Elec
			Q2 2013	42	42	PPA	100%	San Diego Gas & Elec
South Kent	Ontario	Q1 2013	Q1 2014	270	135	PPA	100%	Ontario Power Autho
				1,310	1,005			
Construction Projects								
El Arrayán	Chile	Q3 2012	Q2 2014	115	36	Hedge(11)	~74%	Minera Los Pelambr
Grand	Ontario	Q3 2013	Q4 2014	149	67	PPA	100%	Ontario Power Autho
Panhandle 2(12)	Texas	Q4 2013	Q4 2014	182	147	Hedge(13)	~80%	Morgan Stanley
				446	250			
				1,756	1,255			

(1) Represents date of commencement of construction.
(2) Represents date of actual or anticipated commencement of commercial operations.
(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated will be less than its rated capacity. The amount of electricity generated may vary based on a variety of factors discussed elsewhere in this prospectus. See Risk Factors in our 2013 Form 10-K.
(4) Owned capacity represents the maximum, or rated, electricity generating capacity of the project in MW multiplied by our percentage ownership interest in the distributable cash flow of the project.
(5) Represents the percentage of a project s total estimated average annual MWh of electricity generation contracted under power sale agreements.
(6) Reflects the counterparty s corporate credit ratings issued by S&P/Moody s as of April 23, 2014.
(7) Represents a 10-year fixed-for-floating power price swap. See Business Operating Projects Gulf Wind.
(8) Reflects the corporate credit ratings of the Province of Manitoba, which owns 100% of Manitoba Hydro-Electric.
(9)

We initially commenced commercial operations on 223 MW of electricity generating capacity in the fourth quarter of 2012 and commenced commercial operations on the remaining 42 MW of electricity generating capacity from Ocotillo s additional 18 turbines in July 2013.

(10) Reflects the corporate credit ratings of the Province of Ontario, which owns 100% of the Ontario Power Authority.

(11) Represents a 20-year fixed-for-floating swap. See Business Operating Projects El Arrayán.

(12) The Panhandle project was separated into the Panhandle 1 project, with a Pattern Development-owned capacity of 179 MW, and the Panhandle 2 project, with an owned capacity of 147 MW; acquisition of the Panhandle 2 project is pending, and scheduled to close in the fourth quarter of 2014, subject to satisfaction of customary closing conditions.

(13) Represents a 12.25 year fixed-for-floating swap. See Business Construction Projects Panhandle 2.

Each of our projects has gone through a rigorous vetting process in order to meet our investment and our lenders financing criteria. The development of each project was managed and overseen by our management team over a period of several years and each project was designed to meet or exceed industry, environmental, community and safety standards applicable for industrial-scale power projects. As a result, our projects generally have the following characteristics:

multi-year on-site wind data analysis tied to one or more long-term wind energy reference sources. Pattern Development employs a full-time, five-person meteorological team that manages and verifies third party wind analysis. Our wind analysis is carefully vetted through detailed studies by internal and independent experts in meteorology and statistics to derive an expected production profile based on daily and seasonal wind patterns, structural interference, topography and atmospheric conditions. Our average on-site wind data collection is over four years (or approximately seven years including post-construction data collection);

long-term power sale agreement designed to ensure a predictable revenue stream. As is typical in our industry, we sell our electricity at a fixed price on a contingent, as-produced basis such that only the electricity that we generate is sold to and must be purchased by the counterparty at the agreed price. Our power sale agreements have a weighted average remaining contract life of approximately 18 years;

contractually secured real estate property and easement rights for a period well in excess of the project s expected useful life and contractual obligations. Each of our projects has land rights for 30 years or more;

a firm right to interconnect to the electricity grid through interconnection agreements, which defines the cost allocation and schedule for interconnection, as well as any upgrades required to connect the project to the transmission system. Our interconnection agreements allow our projects to connect to the electricity transmission system. Market rules and protocols generally govern dispatch of our electricity generation and allow it to flow freely into the grid as it is produced, except in very limited circumstances where our projects can be curtailed, for example during system emergencies. To date, our projects have on average been curtailed less than 1% per year;

long-term, limited-recourse, amortizing project financing designed to match the long-lived nature of our power projects and the related power sales agreements. The interest rates on our long-term loans are fixed for the tenor of the loans or are subject to fixed-for-floating swaps that match the amortization schedules of the debt;

all necessary construction and operating permits and other requisite federal, state or provincial and local permits, and regulatory approvals secured, which critical permits typically include federal aviation, state or provincial environmental approvals and local zoning and land-use permits and are designed to protect the community, cultural resources, plants, animal and other affected resources at or near the facility;

fixed-price turbine supply and construction contracts with guaranteed completion dates to ensure that our projects are completed on time and within the estimated budget. The construction period for our projects has typically been less than one year, although in certain instances circumstances warrant a longer construction period;

an operations and maintenance service program based on our own on-site personnel and central operations management as well as equipment warranties and service arrangements with qualified contractors experienced in wind project maintenance. We have existing equipment warranties for approximately 92% of our operating turbine units; and

safety, environmental and community programs to support our existing projects and relationships in the communities in which we operate.

Our ability to transition each of our construction projects to commercial operations and achieve anticipated power output at all of our operating projects is subject to numerous risks and uncertainties.

Our Strategy

We intend to make profitable investments in environmentally responsible power projects, while embracing a long-term commitment to the communities in which we operate. To achieve our financial objectives while adhering to our core values, we intend to execute the following business strategies:

Maintaining and Increasing the Value of Our Projects

We intend to efficiently operate our projects to meet projected revenues and cash available for distribution. We expect to maximize the long-term value of our projects by focusing on value-oriented project availability (by ensuring our projects are operational when the wind is strong and PPA prices are at their highest) and by regularly scheduled and preventative maintenance. We believe that good operating performance begins with a long-term maintenance program for our equipment. We also seek to improve performance or lower operating costs by working closely with our equipment vendors and considering contracting with third parties, if appropriate.

We believe it is important to employ our own personnel in aspects of our business that we deem critical to the value of our projects but to contract with reliable third parties for on-going major maintenance of our turbines and similar specialized services such as repairs on our substations or transmission lines. As a result, we have and expect to continue to employ on-site personnel, maintain a 24/7 OCC to monitor our projects and control all critical aspects of commercial asset management. We also believe it is important to invest in our employees to give our operating personnel the tools to pursue our objectives through regular training, performance incentives, integrating teams of different experts, use of advanced software programming and regular upgrading of our automated systems. See Business Organization of Our Business.

Completing Our Construction Projects on Schedule and Within Budget

We intend to promote the success of our business by completing our construction projects on schedule and within budget, transitioning projects under construction to commercial operation on a timely basis and efficiently operating our projects to maximize project revenues and minimize operating costs. Including the pending acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to the satisfaction of customary closing conditions, in the fourth quarter of 2014, our construction projects consist of interests in three projects that we expect will contribute an additional owned capacity of 250 MW in 2014, for an aggregate of 1,255 MW together with our currently operating projects.

We utilize experienced, creditworthy contractors and proven technology to build high-quality power projects. In addition, over the past 11 years, our management team has overseen the construction and commencement of commercial operations of 26 wind power projects, and our project and construction management capabilities are well respected throughout our industry. By capitalizing on these significant construction and operational resources available to us, including those available to us through the Management Services Agreement, we intend to complete the construction and commence commercial operations at our construction projects in accordance with construction schedules and within budget.

Maintaining a Prudent Capital Structure and Financial Flexibility

We intend to maintain a conservative approach to our capital structure to protect our ability to pay regular dividends and fund investments to provide for future growth. Power projects by their nature require significant up front capital investment and as a result we believe it prudent to match these long-lived assets with long-term debt and/or equity. The average maturity of our project-level debt is approximately 13 years and we have an expected average annual debt service coverage ratio over the remaining scheduled loan amortization periods of approximately 1.7 to 1.0. This prudent capital structure coupled with our predictable price for our electricity and our standard operations and maintenance programs help to achieve a stable cash flow profile.

Consistent with our existing indebtedness, we expect to typically utilize fixed-rate indebtedness (or swapping any variable rate indebtedness) with strong debt service coverage ratios to finance projects. We believe this approach, together with a strategic consideration of project-level financial restructuring and recapitalization opportunities, will contribute to our ability to maintain and, over time, increase our cash available for distribution.

Working Closely With Our Stakeholders

We believe that close working relationships with our various stakeholders, including suppliers, power sales agreement counterparties, regulators, the local communities where we are located and environmental organizations and with Pattern Development and other developers enable us to best support our existing projects and will help us access attractive, construction-ready projects. For example, by working closely with the regulatory agencies and the community, we believe that we create an environment within which if problems are identified we can work constructively and efficiently to resolve the problems and minimize the impact to our operations.

Selectively Growing Our Business

Our strategy for growth is focused on the acquisition of operational and construction-ready power projects from Pattern Development and other third parties that we believe will contribute to the growth of our business and enable

Table of Contents

us to increase our dividend per Class A share over time. We expect that projects we may acquire in the future will represent a logical extension of our existing business and be consistent with our risk profile, and that any incremental assumption of risk will require commensurate expectations of higher returns. As a result, our near-term growth strategy will remain focused on largely contracted cash flows with creditworthy counterparties and operating or in-construction projects.

We expect that new opportunities will arise from our relationship with Pattern Development, which provides us with the opportunity to acquire projects that it successfully develops and efficiently complete construction and achieve commercial operations at these projects. At the time of our initial public offering, we identified six projects at Pattern Development with an aggregate owned capacity of 746 MW as the Initial ROFO Projects. Pattern Development subsequently increased the owned capacity of the Panhandle projects by 78 MW to 326 MW, which includes the Panhandle 1 project, with a Pattern Development-owned capacity of 179 MW, and the Panhandle 2 project, with an owned capacity of 147 MW. We agreed in December 2013 to acquire two of the Initial ROFO Projects, Grand and Panhandle 2, with an aggregate owned capacity of 214 MW. The remaining Initial ROFO Projects represent a total Pattern Development-owned capacity of 620 MW, and our Gulf Wind Call Right and Project Purchase Right will provide us the initial opportunity to purchase these projects, as well as any other of the currently owned and future construction-ready power projects that Pattern Development intends to sell.

Our management team will rigorously review and analyze new market opportunities and selectively consider opportunities offered by Pattern Development as well as those offered by other third parties, either independently or jointly with Pattern Development. We believe our management team provides us with the experience to bring both currently owned and subsequently acquired domestic and international power projects online.

Reintegration of Pattern Development Employees

Under the terms of the Management Services Agreement, upon the completion of the first 20 consecutive trading day period during which our total market capitalization is no less than $2.5 billion, the employees of Pattern Development will become our employees. We refer to this event as the employee reintegration. For the purposes of determining the employee reintegration date, total market capitalization will be determined by multiplying the number of our issued and outstanding Class A shares (assuming all of our then outstanding Class B shares had converted into Class A shares prior to such date) and the closing price of our Class A shares as reported on the then primary stock exchange on which our Class A shares are listed. We will not be required to make any payments to Pattern Development upon the occurrence of the employee reintegration, other than the payment of any statutory severance payments that may as a result be due and payable to Canadian and Chilean employees who may be employed at that time. The employee reintegration will result in our complete internalization of the administrative, technical and other services that were initially provided to us by Pattern Development under the Management Services Agreement. The occurrence of the employee reintegration will neither alter our Purchase Rights nor the terms of the Management Services Agreement.

Upon the employee reintegration, we expect that our principal focus will continue to be owning operational and under-construction power projects. However, the employee reintegration is expected to enhance our long-term ability to independently develop projects and grow our business. Following the employee reintegration, we will continue to provide management services to Pattern Development (including services from the reintegrated departments of Pattern Development) to the extent required by Pattern Development s remaining development activities, and Pattern Development will continue to pay us for those services primarily on a cost reimbursement basis.

Competitive Strengths

We believe our key competitive strengths include:

Our High-Quality Projects

We believe our high-quality projects are better positioned to generate stable long-term cash flows compared to typical projects in the industry and will generate available cash in excess of our initial dividend level, providing us the financial resources for investing in new opportunities. Having high-quality projects also provides us access to low-cost project-level debt and strong stakeholder relationships. The key attributes and strengths of our projects are:

Long-Term, Fixed-Price Power Sale Agreements. We believe our long-term, fixed-price power sale agreements with nine distinct creditworthy counterparties will deliver stable long-term revenues, although we note on February 10, 2014 the credit rating of PREPA, the Puerto Rican counterparty, was downgraded. Our power sale agreements cover 93% of the electricity to be generated across our projects with a weighted average remaining contract life of approximately 18 years.

Table of Contents

Geographically Diverse Markets and Wind Regimes. Our geographically diverse projects are located across regions generally characterized by high demand for renewable energy, documented reliable wind resources, deregulated energy markets and favorable renewable energy policies. The geographic diversity of our projects from California to Puerto Rico, and Manitoba to Chile helps insulate us against regional wind fluctuations as well as adverse regulatory conditions in any one jurisdiction.

State-of-the-Art Wind Turbine Technologies. Our projects utilize state-of-the-art, proven, reliable wind turbine technologies. Our projects utilize Siemens 2.3 MW, and Mitsubishi MWT95/2.4 wind turbines, some of the most reliable and proven turbine technologies available in the market. The wind turbines were in each case specifically selected for the site conditions to ensure optimal performance and longevity of the machines. Our turbines have an average asset age of less than two and a half years.

Our Strong Reputation in the Industry

We believe the success of our team has created a highly respected organization which attracts talented people and new opportunities. Our integrity, expertise, and solutions-oriented approach is attractive to stakeholders and parties providing services to our existing projects as well as those who are looking for buyers of their assets.

Our Spring Valley project received the Wind Project of the Year Award in 2012 from POWER-GEN International (the publisher of Power Engineering and Renewable Energy World), which we believe is considered among the most prestigious awards in the renewable energy industry. Our El Arrayán project won two Chilean International Renewable Energy Awards, presented at the Chilean International Renewable Energy Congress (CIREC) 2012 annual conference in Santiago. The awards were the Best Renewable Energy Project in 2012 (Mejor proyecto de Energía Renovable de 2012) and the Best Renewable Energy Joint Venture (Mejor colaboración entre dos empresas). In 2013, our Ocotillo project received an award for its outstanding environmental analysis and documentation from the California Association of Environmental Professionals and also received the Renewable Project Finance Deal of the Year award from Power Finance & Risk published by Power Intelligence. Also in 2013, our Santa Isabel project won the Outstanding Project of the Year Award in Land Surveying and Environmental Engineering from the Professional College of Engineers and Land Surveyors of Puerto Rico.

Our Approach to Project Selection

Our approach to project selection aims to deliver superior financial results and minimize long-term operating risks by focusing on the acquisition of projects that are operational or construction-ready and have long-term power sales agreements with creditworthy counterparties. Once we identify an attractive opportunity, we apply rigorous analysis in a timely, disciplined and functionally integrated manner to evaluate the wind regime, technology options, site design improvement, regional market trends and regulatory, financial and legal constraints. The most attractive projects offer the proper combination of land accessibility, power transmission capacity, attractive power sales markets and favorable and dependable winds. We believe the members of our management team are recognized by their industry peers as skilled in identifying, analyzing and executing successful power project acquisitions.

Our approach to project selection has also enabled us to successfully execute new projects in a complex renewable energy market characterized by economic, political and regulatory changes that affect energy investment opportunities. Examples include the cyclical nature of U.S. federal incentives and the challenge of realizing the full value of these incentives, increasing environmental and permitting concerns, reduced PPA opportunities that are influenced by changing power markets, a cyclical wind turbine supply environment that alternates between tight and loose supply constraints, changes in wind turbine technology, changes in availability of debt markets, and changes in electricity market structure. Our management team has had success in identifying and executing attractive acquisitions through all of these changing circumstances. For example, through our innovative approach to our business, we developed a financial structure to realize value for PTCs, implemented ground-breaking radar technology to protect bird and bat populations, became one of the first IPPs to capture value from a number of newly deregulated markets and found long-term debt solutions even when the debt markets were highly constrained.

Table of Contents

As a fundamental principle, we seek to acquire projects that will contribute measurable improvements in our Adjusted EBITDA and our cash available for distribution and that will have a risk profile consistent with our current business objectives. In addition, we view projects as long-term partnerships with all stakeholders, and the benefits that we pledge to the community are fundamental to creating a positive environment for a project s long-term success. This has frequently resulted in community benefits on some of our projects that exceed market expectations and occasionally in decisions to cancel projects where our management team felt that we could not adequately address stakeholder concerns.

Our Relationship with Pattern Development

Our continuing relationship with Pattern Development provides us with access to a pipeline of acquisition opportunities. We believe Pattern Development s ownership position in our company incentivizes Pattern Development to support the successful execution of our objectives and business strategy, including through the preparation of projects to the stage where they are construction-ready. Pattern Development has a dedicated development team of professionals with significant experience across the spectrum of power project development:

- site selection;
- meteorological and market analysis;
- land acquisition;
- transmission rights;
- power contract negotiation;
- project financing;
- construction management;
- government relations;
- community outreach; and
- environmental permitting.

Pattern Development also has teams devoted to engineering, legal and project financing that enable it to develop and construct projects through to commercial operations. We believe Pattern Development s focus on project development combined with our Project Purchase Right will complement our acquisition strategy, which focuses on the identification and acquisition of operational and construction-ready power projects.

Our Proven Management Team

Our proven management team has extensive experience in all aspects of the independent power business, a demonstrated track record of success in power project investment management, operation and construction. Our and Pattern Development s management teams include professionals who have a history of financial and technological innovation in the power industry as well as a proven track record in managing energy assets during both periods of growth and economic challenge. While working together at Pattern Development and prior to its formation, members of our management team were responsible for, and successfully financed and managed, over $12 billion of infrastructure assets, including over 3,000 MW of wind power projects (representing a wind business compound annual growth rate, or CAGR of 34% from 2003 to 2014, measured by cumulative wind MW installed), several independent transmission projects and other conventional power assets. Before forming Pattern Development in 2009, our and Pattern Development s management teams developed, financed, constructed or acquired and operated 2,100 MW of wind power projects, as well as transmission projects and other power projects. Since the formation of Pattern Development in 2009, the Pattern Development management team has acquired and developed the operational and in-construction wind power projects that comprise our owned capacity of 1,255 MW, representing a CAGR of 51%, and more than a 3,000 MW portfolio of development assets, which we will have preferential rights to acquire. Additionally, our and Pattern Development s management teams have extensive acquisition, finance and commodity-hedging expertise, allowing us to react to opportunities, optimize our capital structure and manage risk.

Table of Contents

We believe our and Pattern Development s management teams extensive experience and involvement in bringing domestic and international power and infrastructure projects, from the initial development stage through financing to on-going operations and maintenance, positions us to operate our projects efficiently and generate strong cash available for distribution.

Organization of Our Business

Our business is organized around our current projects. In the future, we expect that our business will include additional operating and construction-ready projects acquired from Pattern Development and other third parties. In addition to our executive officers, we employ 40 full-time staff in two key functional areas associated with operations and maintenance and commercial management. We rely on some services to be performed by third parties, including Pattern Development, but have all the core functions required for overseeing constructing, operating and managing of our projects.

Operations and Maintenance

Our operations team s objective is to maximize revenues from each of our projects rather than focus solely on technical plant performance metrics. In order for us to maximize our revenues, we seek to operate and maintain our equipment so that we can ensure our equipment is productive during times of optimal wind resources and power prices. Our approach to achieving efficient operations involves the following key strategic objectives;

Safety. We believe that the safety of our workers, our contractors, our visitors and the community is paramount and takes precedence over all other aspects of operations. To date, we have not experienced any serious lost-time incident or worksite accidents at any of our sites. We achieve this through promoting a strong safety culture, implementing a formal safety management program, employing a full time in-house safety program manager and conducting annual site safety audits.

Equipment reliability and fleet management. We have selected high-quality equipment with a goal of having a concentration of equipment from top manufacturers. We employ (or will employ) the Siemens 2.3 MW turbine at nine of our ten project sites, and the Mitsubishi MWT95/2.4 at the tenth. With a combination of high-quality equipment and scale, we have structured our fleet such that we may:

expect high availability and long-term production from the equipment;

develop operating expertise and experience, which can be shared among our operators;

obtain a high level of attention and focus from the manufacturer; and maintain a shared spare parts inventory and common operating practices.

Table of Contents

Long-term service and maintenance. Good operating performance begins with a long-term maintenance approach to the equipment. While approximately 92% of our operating turbine units remain under warranty, on-going maintenance and replacement of parts is essential to equipment longevity. All of our wind turbines are managed under service agreements that ensure regular repair and replacement of parts. In some situations, we conduct competitive solicitations between the manufacturers as well as top-tier, third-party, independent service providers for conducting wind turbine service and maintenance. As a matter of operating practice, our turbine service program typically does not require shut down of the entire facility and is performed around the project s production profile to minimize lost revenue.

Inspection. As our warranty contracts and service arrangements expire, we conduct extensive third-party end of warranty inspections to identify any potential equipment or service issues which can be remedied by the manufacturer pursuant to their contractual obligations under the warranty and ensure the projects start their post-warranty periods with reliably functioning equipment.

Staff training. We employ highly experienced personnel from a variety of power generation sectors. In addition, we bring into the organization a broad base of best industry practices. After hiring, we provide our operators with on-going training, in-house and from manufacturers and from third parties, to keep them current on latest industry practices and experiences.

Focus on our value-added capabilities. In order to maximize efficiencies, we concentrate our resources on our core operating areas. In particular, we believe it is critical to have on-site management personnel that are our employees and provide oversight of all site activities to assure our safety and financial objectives have priority. We contract with third parties, often the turbine manufacturer, for on-going major maintenance of the turbines and similar specialized services such as repairs on our substations or transmission lines.

Maximize structural efficiencies. Our operating resources are allocated across three key areas, site operations, our 24/7 OCC and other central support services.

Site-operators. All of our projects have on-site operators, which allows for direct management of the projects and all contractors working on site. In addition, these individuals also strive for a high level of involvement in the communities we serve, including with respect to our power purchasers, the regulatory agencies and local communities. Each of our projects has the latest, state-of-the-art supervisory control and data acquisition systems that help us efficiently assess operating faults and plan preventative maintenance.

24/7 Operations Control Center. Our OCC, located in Houston, Texas, focuses on monitoring and controlling each wind turbine to prevent downtime, monitoring regional and local climate, tracking real time market prices and, for some of our projects, monitoring certain environmental activities. In addition, the OCC supports various other central activities such as safety, power marketing, and regulatory compliance and maintains constant communications with each of our site operators, which frees our site operators to concentrate on day-to-day equipment and safety activities.

Central Support Services. In addition to our OCC, our Houston office also hosts the balance of our operations organization which provides critical support to the operating projects. This team includes our operations management team and specialists in safety, environmental management, regulatory compliance, contract management, turbine specialists and asset administration.

Equipment improvements. We believe that our foundation of reliable and proven equipment allows us to make further operating improvements over time. We continuously evaluate new technologies to identify promising solutions which will improve our projects performance and increase our electricity generation.

Table of Contents

Commercial Management

Our commercial management group is tasked with protecting the long-term value of our projects commercial arrangements. We have adopted a commercial strategy of managing our projects and other assets with an in-house commercial management group acting as owner s representatives. The role of the commercial management group is to oversee contract management, environmental management, community relations, power marketing and finance and to closely monitor the performance of each project from an owner s point of view in order to maximize financial performance and minimize risk. Although the commercial management group manages the day-to-day aspects of commercial management, functional and managerial expertise is often brought in to support key areas such as legal, finance and power marketing.

Contract Management. With a group of seasoned managers, our commercial management group optimizes the commercial performance of our assets, services the project debt, manages project agreements and compliance with relevant laws, regulations and rules and has ultimate responsibility for the financial performance of each project. The team also manages our real estate obligations as well as our corporate insurance program, local government obligations, home office, remote facilities and mobile assets. Our commercial management group also facilitates a seamless transfer of responsibilities from the development team through construction to commercial operations in order to ensure all contractual and regulatory obligations are clearly captured and tracked in a formal compliance program.

Environmental Management and Community Relations. Adaptive environmental management is increasingly the standard by which power projects are managed and our company has been a leader in adopting strategies to minimize environmental impacts, such as bird and bat fatalities. Each project has different circumstances so our environmental and community programs range from hiring of local personnel and historical preservation to use of advanced radar systems to monitor birds and bats and presence of on-site biologists to assist in species recognition and mitigation management. By proactively addressing the concerns of the regions, our environmental management and community relations program seeks to minimize additional costs and burdens from a potential increase in regulations or law suits.

Power Marketing. A crucial element of a successful project is assuring revenue from the sale of power and other environmental attributes. We manage the risk associated with fluctuations in electricity prices across our business by seeking to commit the electricity we generate under long-term, fixed-price power sale agreements and have been able to secure 93% of our electricity sales under such arrangements. Our uncontracted power and renewable attributes are sold in the spot market or under shorter term contracts to optimize revenue realization. We believe this management philosophy will result in a steady, predictable source of revenue for each of our projects.

Finance. Our projects are typically funded with construction financing during the construction phase which converts to long-term financing when the project commences commercial operations. Debt at each individual project is project financed, which means that, with very limited exceptions, the lenders have no or only limited recourse to other assets of the company other than the assets that are being financed. Debt for our projects is typically provided by commercial banks and institutional lenders that have the expertise to evaluate the risks associated with the construction and operation of a wind power project, including evaluation of the equipment technology, construction, operations and wind resources. These lenders provide construction financing for many sizable industrial and infrastructure projects. Since debt comprises a significant portion of total project capitalization, achievement of construction financing is a general indication that lenders and their independent consultants have carefully evaluated the project and find it viable for long-term financing. Given the complexity involved in financing large infrastructure assets, projects are often completed with a syndicate of lenders, and the credibility we have established among the financial community allows lenders to have confidence in the quality of our projects and enables us to secure competitive financing terms and other financing efficiencies for our projects. Over the years our team has developed close relationships with many of the active renewable energy lenders.

Table of Contents

Engineering and Construction

The key leadership in our engineering and construction group resides within our company, which provides us with the in-house capabilities required to evaluate a project s design and construction process. We rely as necessary upon additional personnel from third-party sources and Pattern Development, with respect to the construction of our projects. We also typically enter into fixed-price construction contracts for our projects construction with a guaranteed completion date to encourage completion on time and within budget.

Project design involves close and frequent communication with both field development personnel as well as the construction contractor in order to develop a project that conforms to local geotechnical and topographic characteristics while accommodating permitting and real estate restrictions. The developer also strives to integrate experience obtained from operating projects in order to design projects with optimal maintenance and equipment-availability profiles. During construction, we are responsible for overseeing the construction contractor and turbine-vendor activities to ensure that the construction schedule is met. Collaboration among engineers and managers on each of our projects and with our major equipment suppliers allows us to efficiently transition from construction to commercial operations and to identify and process technical improvements over the life-cycle of each project.

Our engineering and construction team is comprised of highly experienced project and construction managers and includes personnel who have supervised the design and completion of construction of 26 wind power projects representing over 2,800 MW over the last eleven years. We set, and ensure compliance with, design specifications and take an active role in supervising field work, safety compliance, quality control and adherence to project schedules. Each project has a dedicated resident construction manager, and other engineering and construction functions are centralized, which allows the group to efficiently scale its resources to support our developing global platform and growth strategy.

Investing

We are organized in a manner that will allow us to independently and comprehensively evaluate investments in new projects. Key members of our management team, including Messrs. Garland, Armistead, Elkort, Lyon, and Pedersen, have spent extensive periods of their careers in the investment advisory, principal investment and finance field. While working together at Pattern Development and prior to its formation, members of our management team were responsible for, and successfully financed and managed, over $12 billion of infrastructure assets, including over 3,000 MW of wind projects, several independent transmission projects and other conventional power projects.

As a major part of our growth strategy, we intend to seek to acquire projects that would contribute measurable amounts to our Adjusted EBITDA and our cash available for distribution. Our approach to project selection is focused on projects (i) with strong economics that will support our long-term financial goals, as determined by intensive analysis and in-depth due diligence, (ii) in which we can add value and which have characteristics that are strategically compatible with our other projects and overall business, and (iii) which meet our core values, including our commitments to environmental stewardship and being a good neighbor in the communities in which our projects are located. To achieve proper investment management, we have implemented processes to ensure rigorous analysis and proper internal approval controls, including preparing formal investment approval documentation, maintaining strict limits on delegation of authority for making capital commitments, and vetting our assumptions with independent technical experts and advisors. In addition, we believe that alignment and independence is critical to successful investing. As a result, we require that certain of our executive officers maintain a minimum ownership interest in our company and have structured our Board of Directors to include a conflicts committee to review specific matters that the Board of Directors believes may involve conflicts of interest, primarily acquisitions from Pattern Development or its affiliates.

We view projects as long-term partnerships with all the stakeholders, and the benefits that we pledge to the community are fundamental to creating a positive environment for a project s long-term success.

Our Projects

Including the pending acquisition of the Panhandle 2 project from Pattern Development, which we expect to complete, subject to satisfaction of customary closing conditions, in the fourth quarter of 2014, we own interests in ten wind power projects, consisting of seven operating projects and three construction projects. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement with a creditworthy counterparty. We expect any project we acquire in the future will be party to a similar agreement, but we may acquire projects with greater levels of uncontracted capacity.

Table of Contents

Operating Projects

Gulf Wind

Gulf Wind is a 283 MW project located on the Gulf Coast in Kenedy County, Texas. The project consists of 118 2.4 MW Mitsubishi MWT95/2.4 turbines and commenced commercial operations in 2009. Pattern Development acquired this operational project in March 2010. Gulf Wind is held by a tax equity partnership with MetLife. We, Pattern Development and MetLife currently own approximately 40%, 27% and 33% of Gulf Wind, respectively.

The project is located in the South Zone of the ERCOT market and sells 100% of its power output into the ERCOT market, receiving the locational marginal price, or LMP. Approximately 58% of the project s expected annual electricity generation has been hedged under a 10-year fixed-for-floating swap with Credit Suisse Energy LLC. This financial hedging agreement settles using the South Trading Hub hourly LMP weighted by the settlement volume in each hour. The hourly notional settlement volume varies to match the project s hourly average production profile. Gulf Wind s obligations under the hedge are secured by a first priority lien on substantially all of the assets of Gulf Wind and a first priority lien on the membership interests in the operating project entity up to approximately $73 million, both of which are first in priority relative to the second priority liens associated with the debt financing up to approximately $250 million and which are second in priority over the third-priority liens in favor of Credit Suisse Energy LLC in excess of the first and second lien caps.

The project is connected to the Electric Transmission Texas 345 kV transmission system and is located on approximately 9,600 acres in Kenedy County, TX and is entirely on land owned by a single private landowner. Gulf Wind entered into an easement agreement with a single landowner on May 9, 2007 for an initial term of 30 years and with an option to extend for an additional 10 years. The land, which is primarily grassland and dunes, is part of a very large ranch. In addition to our wind operations, the ranch is also used for cattle raising, oil & gas production, and private hunting outings. Due to the afternoon sea breeze effect along the coast, Gulf Wind benefits from an average daily wind production profile that generally follows the typical electricity demand load profile, which is heaviest during the daytime.

Hatchet Ridge

Hatchet Ridge is a 101 MW project located in Burney, California. The project consists of 44 2.3 MW Siemens turbines and commenced commercial operations in December 2010. The project is connected to the PG&E transmission system.

The project sells 100% of its electricity generation, including environmental attributes, to PG&E under a 15-year PPA that expires in 2025. The price under the PPA is a stated price per MWh, adjusted by seasonal time of day multipliers, with no escalation. Hatchet Ridge is required to post performance security in the amount of $21.2 million to secure damages under the PPA. The PPA also contains customary termination and event of default provisions. Under the terms of the PPA, Hatchet Ridge is required to pay liquidated damages for failure to produce a certain amount of energy in each of two consecutive years.

The project, located along a gentle ridge top, spans an area of roughly 2,700 acres in Shasta County, CA and is entirely on land owned by two private landowners, subject to 30-year wind power ground lease agreements.

St. Joseph

St. Joseph is a 138 MW project located near St. Joseph, Manitoba, just north of the U.S. border. The project consists of 60 2.3 MW Siemens turbines and commenced commercial operations in April 2011. The project is connected to the Manitoba Hydro transmission system. St. Joseph was the second commercial wind power project, and is the largest, in Manitoba.

The project sells 100% of its electricity generation, including environmental attributes, to Manitoba Hydro under a 27-year PPA that expires in 2039. The price under the PPA is a stated price per MWh at inception of the PPA, with approximately 20% of the stated price escalating annually at the consumer price index for Canada, or Canadian CPI. The project will additionally receive the ecoEnergy federal incentive of C$10/MWh for approximately ten years for up to 423,108 MWh of production per year. Under the PPA, if there is a sale of the project, Manitoba Hydro has a right of first offer to purchase the St. Joseph project for a fixed minimum purchase price on terms specified by us. In addition to customary termination and event of default provisions, the PPA will terminate upon the exercise by Manitoba Hydro of its right of first offer to purchase the St. Joseph project, and St. Joseph will trigger an event of default, if after the first three contract years, it fails to supply at least 80% of certain minimal energy obligations for two consecutive years.

The project is located on approximately 125 square kilometers of agricultural land in the Rural Municipalities of Montcalm and Rhineland, Province of Manitoba. The project is constructed on privately owned lands pursuant to right-of-way agreements with 64 private landowners, with 40-year terms and all on substantially the same form of agreement covering all of turbine sites, collection lines, roads and an operations and maintenance building for the project. In addition, the project purchased a small parcel of property for the project substation.

Spring Valley

Spring Valley is a 152 MW project located in White Pine County, Nevada. The project consists of 66 2.3 MW Siemens turbines and commenced commercial operations in August 2012. The project is connected to the NV Energy transmission system. Spring Valley was Nevada s first commercial wind power project.

The project sells 100% of its electricity generation, including environmental attributes, to NV Energy, under a 20-year PPA that expires in 2032. The price under the PPA is a stated price per MWh escalating at 1.0% per year. Spring Valley is required to reimburse NV Energy for replacement costs for any annual energy shortfall and post operating security in the amount of $6.3 million for the performance of its obligations under the PPA. The PPA also contains customary termination and event of default provisions. In connection with the PPA and subject to certain pricing conditions, NV Energy was granted an option to acquire up to 50% of the equity membership interests in Spring Valley held by our project-level operating subsidiary, which option expires in August 2014. NV Energy s right to acquire the equity membership interests is subject to negotiation of terms and conditions that are acceptable to us. If we fail to agree on terms within 120 days of commencing negotiations, we have the right to terminate the option. In any event, if the option is exercised, the exercise price for the option is up to 50% of the fair market value of the Spring Valley project based on its assets and liabilities at the time of exercise and assuming a 25-year life of the Spring Valley project, provided that in no event will the agreed price result in a book loss to us.

The project is located on approximately 7,680 acres in White Pine County, NV on federal land administered by the Bureau of Land Management. Spring Valley was granted a right-of-way from the Bureau of Land Management with a 30-year term, which terminates on December 31, 2040.

Santa Isabel

Santa Isabel is a 101 MW project located on the south coast of Puerto Rico. The project consists of 44 2.3 MW Siemens turbines and commenced commercial operations during the fourth quarter of 2012. The project is connected to the Puerto Rico Electric Power Authority, or PREPA, transmission system. Santa Isabel is Puerto Rico s first commercial wind power project and is reflective of the Puerto Rican government s efforts to diversify its energy sources away from fossil fuels by fostering local renewable energy projects.

The project sells 100% of its electricity generation including environmental attributes to PREPA under a 20-year PPA, expiring in 2030, with automatic 5-year extensions unless terminated at the end of any term or extension by us, and PREPA may terminate after year 25 if there is a liquid spot market for electricity or the agreement has been in effect for 30 years. Under the PPA, PREPA has agreed to purchase electricity from us subject to a 75 MW per hour cap, with such cap increasing to 95 MW during certain hours of certain months. If the project is capable of generating electricity in excess of the applicable cap, PREPA has the option, but not the obligation, to purchase any such surplus electricity actually generated at the PPA price. The price for energy under the PPA and the price for RECs under a separate purchase agreement are both a stated price per MWh. Each price escalates at 1.5% per year. In the case that project electricity generation exceeds a threshold multiple of contractual electricity generation in a given year, the price for energy under the PPA reduces until output drops below contractual output for such year. Santa Isabel is required to post operating security in the amount of $3.0 million for the performance of its obligations under the PPA. In addition to customary termination and event of default provisions, the PPA may terminate if Santa Isabel fails to generate a threshold energy output during any 12 consecutive months.

Table of Contents

The project is located on approximately 5,500 acres of land owned by the Puerto Rico Land Authority, or PRLA, which is actively farmed by private operations under land leases with the PRLA. The project entered into a deed of lease, easements and restrictive covenants with the PRLA on October 6, 2011, with a 30-year initial term, together with up to 45 years in renewal options, comprising substantially all project infrastructure, including all turbine sites, collection lines, roads, substation and operations and maintenance buildings for the project. The project also has entered into transmission line leases for the transmission line corridor from the project substation to the point of interconnection with PREPA with four private landowners.

Ocotillo

Ocotillo is a 265 MW project located in western Imperial County, California. The project consists of 112 2.37 MW Siemens turbines. We initially commenced commercial operations on 223 MW of Ocotillo s electricity generating capacity during the fourth quarter of 2012 and commenced commercial operations on the remaining 42 MW of electricity generating capacity from Ocotillo s additional 18 turbines in July 2013. The project connects to the San Diego Gas & Electric, or SDG&E, 500 kV transmission system and has a large generator interconnection agreement with SDG&E and CAISO.

The project sells 100% of its electricity generation, including capacity and environmental attributes, to SDG&E under a 20-year PPA. The PPA has a stated price per MWh with no escalation. Ocotillo is required to post performance security in the amount of $26.7 million to secure damages. The PPA also contains customary termination and event of default provisions. Under the PPA, Ocotillo is required to pay liquidated damages for failure to produce a certain amount of energy in the two previous years.

Ocotillo is the subject of active lawsuits brought by a variety of project opponents. See Legal Proceedings.

The project is located on approximately 12,500 acres in Imperial County, CA and is almost entirely on federal land administered by Bureau of Land Management. The project was granted a right-of-way from the Bureau of Land Management with a 30-year term, which terminates on December 31, 2041. All the project s turbine sites, a substation and an operations and maintenance building are located on land administered by the Bureau of Land Management. The project has entered into collection and distribution line easements with two private landowners for a portion of the underground collection system. In addition, the project has purchased a small parcel of land for a portion of the underground collection system. The project also has a lease agreement in place with a private landowner for an additional 26 acres of private land.

South Kent

South Kent is a 270 MW project located in the municipality of Chatham-Kent in southern Ontario. The project consists of 124 2.3 MW Siemens turbines that have been de-rated to a range from 1.903 MW to 2.221 MW in order to facilitate permitting compliance. The project connects to the Hydro One Networks, Inc., or HONI, 230 kV transmission system at the existing Chatham switching station. The South Kent project commenced construction in the first quarter of 2013 and achieved commercial operations in March 2014.

The project sells 100% of its electricity generation, including environmental attributes, to the OPA under a 20-year PPA. The PPA has a stated price, which indexes at Canadian CPI from September 2009 until the December 31 of the year prior to commencement of commercial operations; thereafter 20% of the PPA price escalates at Canadian CPI. The PPA was granted in connection with the Green Energy Investment Agreement, an agreement among Samsung, Korea Electric Power Corporation and the Province of Ontario. This agreement supports growth in domestic renewable energy through both jobs creation and support of wind power and solar power projects.

The project is a 50/50 joint venture between us and Samsung, with shared development and financing responsibilities. Samsung has customary rights to purchase our interest in South Kent upon any subsequent sale of the project by us.

The project is located on approximately 165 distinct private land parcels and includes a conglomeration of multiple acquired wind power projects and greenfield acquired lands. The project has renegotiated and standardized each of the land agreements that were assumed along with the acquired projects. All land parcels containing project infrastructure are contracted under registered right-of-way agreements, providing for real estate interests in favor of the project in the form of easements-in-gross in respect of each land parcel, enforceable for a term of not less than 40 years.