First Wind Holdings Inc.
Form S-1/A
October 21, 2010

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As filed with the Securities and Exchange Commission on October 21, 2010

Registration No. 333-152671

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 9
to

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

First Wind Holdings Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**4911**	**26-2583290**
(State or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

179 Lincoln Street, Suite 500
Boston, MA 02111
617-960-2888
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant's Principal Executive Offices)

Paul Gaynor
Chief Executive Officer
First Wind Holdings Inc.
179 Lincoln Street, Suite 500
Boston, MA 02111
617-960-2888
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent For Service)

Copies to:

Paul H. Wilson, Jr. **Executive Vice President,** **General Counsel and Secretary** **First Wind Holdings Inc.** **179 Lincoln Street, Suite 500**	**Richard J. Sandler** **Joseph A. Hall** **Davis Polk & Wardwell LLP** **450 Lexington Avenue** **New York, NY 10017**	**Dennis M. Myers, P.C.** **Elisabeth M. Martin** **Kirkland & Ellis LLP** **300 North LaSalle** **Chicago, IL 60654**

Boston, MA 02111	**212-450-4000**	**312-862-2000**
617-960-2888		

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

If any 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, as amended (the "Securities Act"), check the following box. o

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

If this form is a post-effective amendment filed pursuant to Rule 462(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. o

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

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

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

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 or until this registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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

SUBJECT TO COMPLETION, DATED OCTOBER 21, 2010

12,000,000 Shares

First Wind Holdings Inc.

Class A Common Stock

We are offering 12,000,000 shares of our Class A common stock and we intend to use the net proceeds of this offering to repay debt and fund capital expenditures and for general corporate purposes.

We will be a holding company and our sole asset will be approximately 51.6% of the aggregate Membership Interests of First Wind Holdings, LLC. Concurrently with the completion of this offering, we will issue 12,760,860 and 23,239,140 shares of Class A and Class B common stock, respectively, to members of First Wind Holdings, LLC.

Before this offering there has been no public market for our Class A common stock. The initial public offering price of our Class A common stock is expected to be between $24.00 and $26.00 per share. We have applied to list our Class A common stock on the Nasdaq Global Market under the symbol "WIND."

The underwriters have an option to purchase up to 1,800,000 additional shares from us to cover over-allotments, if any.

Investing in our Class A common stock involves risks. See "Risk Factors" beginning on page 15.

	Price to Public	Underwriting Discounts and Commissions(1)	Proceeds to First Wind Holdings Inc.
Per share	$	$	$
Total	$	$	$

(1) We have agreed to reimburse the underwriters for certain out-of-pocket legal expenses incurred by them in connection with this offering up to a maximum of $100,000 and to pay certain consulting fees in connection with this offering. See "Underwriting."

Delivery of the shares of Class A common stock will be made on or about , 2010.

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.

Credit Suisse **Morgan Stanley** **Goldman, Sachs & Co.** **Deutsche Bank Securities**

RBS

Citi **Macquarie Capital** **Piper Jaffray** **KeyBanc Capital Markets** **SOCIETE GENERALE**

The date of this prospectus is , 2010.

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OPERATING PROJECTS

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We have not authorized anyone to provide any information or to make any representations other than those contained in this prospectus or in any free writing prospectuses we have prepared. We take no responsibility for, and can provide no assurance as to the reliability of, any information that others may give you. This prospectus is an offer to sell only the shares offered hereby, but only under circumstances and in jurisdictions where it is lawful to do so. The information contained in this prospectus is current only as of its date.

In this prospectus, unless the context otherwise requires, we refer to (i) First Wind Holdings Inc. and its subsidiaries, including First Wind Holdings, LLC, after giving effect to the reorganization described herein, as "*First Wind*," "*we*," "*us*," "*our*" or the "*company*"; (ii) entities in the D. E. Shaw group as "*the D. E. Shaw group*;" (iii) Madison Dearborn Capital Partners IV, L.P., as "*Madison Dearborn*;" and (iv) the D. E. Shaw group and Madison Dearborn collectively as "*our Sponsors*." We use the following electrical power abbreviations throughout this prospectus: "*kW*" means kilowatt, or 1,000 watts of electrical power; "*MW*" means megawatt, or 1,000 kW of electrical power; "*GW*" means gigawatt, or 1,000 MW of electrical power; "*TW*" means terawatt, or 1,000 GW of electrical power; and "*kWh*," "*MWh*," "*GWh*" and "*TWh*" mean an hour during which 1 kW, MW, GW or TW, as applicable, of electrical power has been continuously produced. Capacity refers to rated capacity. References in this prospectus to "*NCF*" mean net capacity factor, or the measure of a wind energy project's actual production expressed as a percentage of the amount of power the wind energy project could have produced running at full capacity for a particular period of time, and references to "*RECs*" mean renewable energy certificates or other renewable energy attributes, as the context requires. References to Series B Units in this prospectus are to First Wind Holdings, LLC's Series B Units, which were outstanding prior to the reorganization that will be effected immediately before completion of this offering. Unless otherwise indicated, the financial information in this prospectus represents the historical financial information of First Wind Holdings, LLC.

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PROSPECTUS SUMMARY

This summary highlights selected information from this prospectus but does not contain all information that you should consider before investing in our Class A common stock. You should read this entire prospectus carefully, including the information under "Risk Factors" beginning on page 15, and the consolidated financial statements included elsewhere in this prospectus.

First Wind Holdings Inc.

We are an independent wind energy company focused solely on the development, financing, construction, ownership and operation of utility-scale wind energy projects in the United States. Our projects are located in the Northeastern and Western regions of the continental United States and in Hawaii. We have focused on these markets because we believe they provide the potential for future growth and investment returns at the higher end of the range available for wind projects. These markets are characterized by relatively high electricity prices, a shortage of renewable energy and sites with good wind resources that can be built in a cost effective manner. Moreover, we have focused our efforts on projects and regions with significant expansion opportunities, often enabled by transmission solutions that we have developed and built.

As of September 30, 2010, we operated seven projects with combined rated capacity of 504 MW, and we owned two lines that connect projects to the electricity grid (generator leads) with transmission capacity of approximately 1,200 MW. In 2009, we doubled the number of projects in our operating fleet, adding three new projects with an aggregate capacity of 386 MW. Two of these projects, Milford I, which sells power from Utah into Southern California, and Stetson I, which sells power in New England, include wholly-owned generator leads we had built in anticipation of expanding these projects. In March 2010, we commenced commercial operations of our seventh project, Stetson II, an expansion project in Maine with 26 MW of capacity.

We manage our business with a team of professionals with experience in all aspects of wind energy development, financing, construction and operations. We have a track record of selecting projects from our development pipeline and converting them into operating projects that we believe will meet our financial return requirements. By the end of 2010, our goal is to have six additional projects with 268 MW of capacity operating or under construction. Four of these projects (totaling 232 MW) are currently under construction: Kahuku (30 MW) in Hawaii, Milford II (102 MW) in the West and Rollins (60 MW) and Sheffield (40 MW) in the Northeast.

We target having approximately 1,000 MW of projects operating or under construction by the end of 2011. Thereafter, we target adding approximately 200 to 400 MW of operating/under-construction capacity each year to achieve our goal of having an operating/under-construction fleet of approximately 1,900 MW by the end of 2014. Expansions of current operating and under-construction projects make up approximately 32% (measured by capacity) of our targeted 2011-2012 projects. See "Business Our Development Process" and "Business Our Portfolio of Wind Energy Projects."

We believe our development pipeline of approximately 4,000 MW should enable us to meet our 2014 goal of having an operating/under-construction fleet of approximately 1,900 MW. As of September 30, 2010, we had land rights for approximately 80% of our development pipeline and meteorological data for approximately 95% of our development pipeline, in the majority of cases covering at least three years. We have also conducted preliminary environmental screening for all of our projects. We are unlikely to complete all of the projects in our current development pipeline, while some of the projects we are likely to develop in the future are not in our current pipeline. From time to time we have abandoned projects on which we had started development work, or re-categorized projects to a less advanced stage than we had previously assigned them. Our ability to complete our projects and achieve anticipated generation capacities is subject to numerous risks and uncertainties as described under "Risk Factors."

Wind energy project returns depend mainly on the following factors: energy prices, transmission costs, wind resources, turbine costs, construction costs, financing costs and availability and government incentives. In applying our strategy, we take into account the combination of all of these factors and focus on margins, return on invested capital and value creation as opposed solely to project size. Some of our projects, while having high construction costs, still offer attractive returns because of favorable wind resources or energy prices. Additionally, in many cases, smaller, more profitable projects can create as much absolute value as do larger, lower-returning projects. We assess the profitability of each project by evaluating its net present value. We also evaluate a project on the basis of its Project EBITDA, as described under "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Measure Our Performance," including the ratio of Project EBITDA to project development and construction costs.

We closely manage our commodity price risk and generally construct wind energy projects only if we have put in place some form of a long-term power purchase agreement (PPA) and/or financial hedge. We have PPAs or hedges on all seven of our operating projects and we expect to have PPAs or hedges on all of our 2010 projects. As of September 30, 2010, approximately 90% of the estimated revenues through 2011 from our current operating projects were hedged. We plan to hedge approximately 90% of the estimated revenues for 2011 for the four projects currently under construction and the two projects we plan to have under construction in 2010. Most of the estimated aggregate revenues from our operating projects and 2010 projects is hedged through 2020. See "Business Revenues; Hedging Activities."

The United States is one of the largest and fastest growing wind energy markets, although capacity additions have slowed in 2010. As of the end of 2009, the United States was the leading wind energy market in terms of cumulative installed wind power capacity as capacity increased by almost 10 GW, accounting for 39% of all new U.S. electric generating capacity in 2009, according to the American Wind Energy Association (AWEA). Moreover, our markets are among the highest growth U.S. markets due to demand driven by state-mandated renewable portfolio standards (RPS), premium electricity pricing, a shortage of renewable energy and strong wind resources. Based on estimates of IHS Emerging Energy Research (IHS EER), we believe that states in our markets in the Northeast, West and Hawaii will need approximately 42 GW of incremental renewable energy capacity to be built by 2020, assuming a 30% average net capacity factor.

Achievements

We have achieved a number of milestones, including:

- ***Northeast.*** We completed two of the largest utility-scale wind energy projects in New England (Stetson I and Mars Hill in Maine) and obtained the first permit for a utility-scale wind energy project in Vermont since 1996, our Sheffield project, which is under construction. We built a 200 MW-rated 38-mile 115 kV generator lead in Washington County, Maine as part of our 57 MW Stetson I project. This provides sufficient excess capacity to accommodate up to 140 MW of our expansion projects, including our 26 MW Stetson II project, which commenced commercial operations in March 2010, and our 60 MW Rollins project, which began construction in September 2010. The generator lead interconnects to the ISO-NE market. For our Stetson II project, we have a long-term PPA with Harvard University to sell half of the electricity and RECs generated by the project. See "Business Our Regions Northeast."

- ***West.*** We entered into a long-term PPA with the Southern California Public Power Authority (SCPPA) to supply 20 years of power to the cities of Los Angeles, Burbank and Pasadena from Milford I, our 204 MW wind energy project in Utah. This project includes a 1,000 MW generator lead providing transmission to the electricity grid. Milford I commenced commercial operations in November 2009. Milford I is the first wind energy project to receive a grant of a right of way permit under the Bureau of Land Management's (BLM) new programmatic environmental impact statement for wind energy development. We have also started construction of Milford II (102 MW) and have capacity on our generator lead for future expansion projects. See "Business Our Regions West."

Hawaii. We successfully completed and are operating our Kaheawa Wind Power I (KWP I) project in Maui, the largest wind energy project in Hawaii. See "Business Our Regions Hawaii." In July 2010, we received from the U.S. Department of Energy (DOE) a $117 million loan guarantee under Section 1703 of the American Recovery and Reinvestment Act of 2009 (ARRA) to help finance construction of our Kahuku project in Oahu. This is the first DOE loan guarantee for a wind energy project. Construction of Kahuku started in July 2010. We also have signed a PPA for our Kaheawa Wind Power II (KWP II) expansion project that is subject to approval by the Hawaii Public Utilities Commission (Hawaiian PUC).

Financing and U.S. Treasury Grants. Since the beginning of 2009, in the midst of very difficult financial and credit markets, we have refinanced, raised or received approximately $2.5 billion for our company and projects in 20 refinancing and new capital-raising activities and customer prepayments. These activities included project debt financings, tax equity financings, intermediate holding company financings, government grants, Sponsor equity contributions and customer prepayments. In September 2009, we were among the first recipients of investment tax credit (ITC) cash grants from the U.S. Treasury under Section 1603 of the ARRA and have received approximately $254 million for four of our projects. See "Industry Drivers of U.S. Wind Energy Growth State and Federal Government Incentives American Recovery and Reinvestment Act of 2009 (ARRA)."

Revenues, Financing and Government Programs

We generate revenues from the sale of electricity and the sale of RECs from our operating projects:

Electricity sales. We typically sell the power generated by our projects (sometimes bundled with RECs) either pursuant to PPAs with local utilities or power companies or directly into the local power grid at market prices. Our PPAs have initial terms ranging from five to 20 years with fixed prices, market prices or a combination of fixed and market prices. We also seek to hedge a significant portion of the market component of our power sales revenue with financial swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Power Purchase Agreements and Financial Hedging."

REC sales. The RECs associated with renewable electricity generation can be "unbundled" and sold as separate attributes. In some states, we sell RECs to entities that must either purchase or generate specific quantities of RECs to comply with state or municipal RPS programs. As of September 2010, 25 states and the District of Columbia have adopted RPS programs that operate in tandem with a credit trading system in which generators sell RECs for renewable power they generate.

We have generated substantial net losses and negative operating cash flows since our inception. See "Risk Factors Risks Related to Our Business and the Wind Energy Industry We have generated substantial net losses and negative operating cash flows since our inception and expect to continue to do so as we develop and construct new wind energy projects." In addition, the amount of revenue we generate is subject to fluctuation due to a variety of factors and risks. For example, approximately 10% of our estimated revenue through 2011 from our operating projects is unhedged and is therefore subject to market-price fluctuations. In addition, a significant, long-term decline in market prices for electricity in our markets would adversely affect our un-hedged revenues and make it more difficult for us to develop our projects. Furthermore, the production of wind energy depends heavily on suitable

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wind conditions and if wind conditions are unfavorable, our electricity production and revenue may be substantially below our expectations. See "Risk Factors Risks Related to Our Business and the Wind Energy Industry."

We finance our projects with various sources of funds, depending on a project's stage of development and other factors. We use equity, turbine supply loans, construction loans, non-recourse project financings, tax equity financings, term loans and, recently, grants from the U.S. Treasury and a construction and term loan facility guaranteed by the DOE under the ARRA. We are in a capital intensive business and rely heavily on the debt and equity markets to finance the development and construction costs of our projects, and we may not be able to finance the growth of our business. See "Risk Factors Risks Related to Our Financial Activities."

We benefit from U.S. government programs established to stimulate the economy and increase domestic investment in the wind energy industry. In February 2009, the ARRA went into effect and extended the federal production tax credit (PTC) for renewable energy generators until the end of 2012. In the past, we have monetized PTCs through tax equity financings as part of our project financing strategy. In these transactions, we receive up-front payments, and our tax equity investors receive most of the operating cash flow and substantially all of the PTCs and taxable income or loss generated by the project until they achieve their targeted investment returns and return of capital, which we typically expect to occur in ten years. As a result, a tax equity financing substantially reduces the cash distributions from the applicable project available to us for other uses. Also, the period during which the tax equity investors receive most of the cash distributions from electricity sales and related hedging activities may last longer than expected if our wind energy projects perform below our expectations.

The ARRA also made an investment tax credit available to wind energy projects in lieu of PTCs. Project owners can for the first time receive the cash equivalent of the ITC in the form of a grant paid by the U.S. Treasury representing 30% of ITC-eligible costs of building a wind energy project, namely, the costs of constructing energy-producing assets. In September 2009, our Cohocton and Stetson I projects were among the first recipients of such cash grants and have received approximately $254 million for four of our projects. We plan to apply for cash grants for our other 2010 projects. We have also applied for other federal government incentives, including loan guarantees from the DOE. In July 2010, we entered into a $117 million construction and term loan facility guaranteed by the DOE to help finance construction of our Kahuku project. See "Industry Drivers of U.S. Wind Energy Growth State and Federal Government Incentives American Recovery and Reinvestment Act of 2009 (ARRA)."

We depend heavily on these programs to finance the projects in our development pipeline. If any of these incentives are adversely amended, reduced or eliminated, or if federal departments fail to administer these programs in a timely and efficient manner, it would have a material adverse effect on our ability to obtain financing. Similarly, if governmental authorities stop supporting, or reduce their support for, the development of wind energy projects, our revenues may be adversely affected, our economic return on certain projects may be reduced, our financing costs may increase and it may become more difficult to obtain financing.

Strategy

Our business strategy is to build a diverse portfolio of operating projects and development opportunities. We seek opportunities where, if we are able to execute successfully, we will be able to generate attractive returns for our stockholders.

- ***Focus on development of projects in markets with strong demand for renewable energy.*** We focus on developing projects to serve markets where there is strong demand for renewable energy, including states with RPS programs.

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Develop our existing pipeline of projects and expand existing operating projects. We have identified and are developing a broad pipeline of projects in our markets, including expanding our operating projects in existing locations. We believe expansion projects have lower execution risks than other projects.

Continue to identify and create a new pipeline of diverse development project opportunities in financially attractive markets. Our team of developers focuses our prospecting and development efforts on identifying new opportunities in our markets and acquiring existing wind energy assets that we believe will meet our financial return requirements in these markets.

Implement transmission solutions to support development opportunities. We develop, own and operate generator leads connecting our projects to third-party electricity networks. Our Stetson generator lead has approximately 115 MW of capacity available for our future expansion projects and our Milford generator lead has approximately 750 MW of capacity available for our future expansion projects. Both of these generator leads are operating. We are building our Milford II and Rollins expansion projects using these leads, leaving 700 MW of additional capacity on these lines for our future expansion projects. Our generator lead assets and capabilities enable us to develop projects in areas that would otherwise present significant transmission challenges.

Focus on construction and operational control. We believe having control of the construction and operation of our projects enhances our credibility, allows us to make rapid decisions and strengthens our relationships with landowners, local communities, regulators and other stakeholders. For construction projects, we manage and mitigate budget and schedule risks through arrangements with contractors that have significant experience constructing wind energy projects.

Obtain stable revenues from our operating fleet. We manage exposure to market prices for electricity through long-term PPAs and hedging. We also seek to maximize the value of the RECs we generate by selling our electricity into markets that have higher RPS requirements and strong markets for RECs. We believe that stabilizing our revenue stream benefits us, our lenders and investors, and enhances our ability to obtain long-term, non-recourse financing for our projects on attractive terms.

Develop substantial local presence and community stakeholder involvement in our markets. We establish and maintain a local presence early in a project's development to work cooperatively with the communities where our projects are located to more fully understand each community's unique issues and concerns. We believe this helps us to better assess the feasibility of projects and enhances our ability to complete and operate them successfully.

Competitive Strengths

We intend to use the following strengths to capitalize on what we believe to be significant opportunities for growth in the U.S. wind energy industry in general and in our markets in particular:

Track record in developing complex wind energy projects. Our experienced management team has a track record of developing complex projects in each of our three markets. Our project development strategy sometimes includes the construction of generator leads, as in the case of Stetson I and Milford I, or the structuring and negotiation of creative financing and risk management solutions, as in our PPA with SCPPA for Milford I. In certain cases, as in KWP I, we took over projects from other developers who were unable to complete them.

Ability to finance multiple projects across our portfolio. Wind energy project development and construction are capital intensive and require access to a relatively constant stream of financing. As a result, our ability to access capital markets efficiently and effectively is crucial to our growth. The recent worldwide financial and credit crisis has reduced the availability of liquidity and credit.

However, since the beginning of 2009, we have refinanced, raised or received approximately $2.5 billion for our company and projects in 20 refinancing and new capital-raising activities and customer prepayments. These activities included project debt financings, tax equity financings, intermediate holding company financings, government grants, Sponsor equity contributions and customer prepayments. We expect to fund the development of our projects with a combination of cash flows from operations, debt financings, tax equity financings, government grants and capital markets transactions such as this offering. See "Business Project Financing."

Established platform in attractive markets with significant growth opportunities. We have a portfolio of projects in the Northeast, West and Hawaii where we believe we can generate attractive investment returns. These markets are characterized by high electricity prices, a shortage of renewable energy and sites with good wind resources that can be built on cost-effectively. Many of our projects have significant expansion opportunities, which in some cases will enable us to use our existing generator leads. Expansions of our current operating and under-construction projects make up approximately 32% (measured by capacity) of our targeted 2011-2012 projects.

Well positioned to benefit from over-capacity in the turbine markets because we have few turbine commitments. Because there is significant over-capacity in the turbine market, we have not entered into firm commitments to purchase turbines for projects in our development pipeline after 2010. We are engaged in a process of seeking requests for proposals from various turbine manufacturers for some of our 2011 and 2012 projects. We also have agreements in place that give us the right, but not the obligation, to purchase additional turbines after 2010, allowing us to cancel our turbine orders with the forfeiture of deposits. We believe this gives us flexibility to acquire turbines at attractive prices and on favorable terms.

Experienced management team that owns significant equity in the company. Our management team is experienced in all aspects of the wind energy business. Over the past two years, we have added several key personnel to our team, primarily in the areas of construction, operations and finance. We believe we can achieve our operating/under-construction fleet goal of approximately 1,900 MW by the end of 2014 without significant additions to headcount and overhead costs related to non-operating activities. In addition, members of our senior management team have a meaningful equity stake in our company.

Our ability to capitalize upon these strengths may be affected by a variety of factors, including competition for: suitable operating sites for projects; access to transmission and distribution networks; turbines and related components at affordable prices; employees with relevant experience; and the limited funds available for tax equity financing.

U.S. Market Opportunity

According to AWEA, wind energy capacity in the United States grew at a compound annual growth rate (CAGR) of 34% from 2000 through 2009, although capacity additions have slowed in 2010. Wind energy nonetheless accounted for only 1.8% of total U.S. electricity production in 2009 according to the Energy Information Administration (EIA). Based on data provided by IHS EER, we estimate that installed wind capacity in the United States will grow at a CAGR of 19% from 2009 through 2013. In certain U.S. markets, state-mandated RPS and similar voluntary programs, among other factors, have strengthened the demand for renewable energy.

We believe wind energy growth in the United States is being driven primarily by:

- decreasing costs in the U.S. wind industry supply chain;
- continuing improvements in wind-turbine technologies that increase turbine generating capacity;
- public concern about environmental issues, including climate change;

- favorable federal and state policies regarding climate change and renewable energy, exemplified by state RPS programs and the ARRA, that support the development of renewable energy;
- increasing obstacles for the construction of conventional power plants; and
- public concern over continued U.S. dependence on foreign energy imports.

Risk Factors

Our business is subject to numerous risks and uncertainties, including:

- those relating to our ability to build our pipeline of projects under development or acquire wind energy assets and turn them into operating projects;
- the impact of schedule delays, cost overruns, revenue shortfalls and lower-than-expected capacity for those projects we do place into operation;
- our substantial net losses and negative operating cash flows;
- government policies supporting renewable energy development;
- our dependence on suitable wind conditions;
- our ability to locate and obtain control of suitable operating sites;
- the need for ongoing access to capital to support our growth;
- our substantial indebtedness and its short-term maturities, which could limit our flexibility in operating our business and to plan for and react to unexpected events; and
- the potential for mechanical breakdowns.

You should carefully consider all of the information in this prospectus and, in particular, the information under "Risk Factors," prior to making an investment in our Class A common stock.

Class A Common Stock and Class B Common Stock

After completion of this offering, our outstanding capital stock will consist of Class A common stock and Class B common stock. Investors in this offering will hold shares of Class A common stock. See "Description of Capital Stock."

The Reorganization and Our Holding Company Structure

First Wind Holdings Inc. was formed for purposes of this offering and has only engaged in activities in contemplation of this offering. Upon completion of the offering, all of our business will continue to be conducted through First Wind Holdings, LLC, which is the holding company that has conducted all of our business to date. First Wind Holdings Inc. will be a holding company, whose principal asset will be its interest in First Wind Holdings, LLC. That interest will represent approximately 51.6% of the economic interests in our business, assuming the underwriters do not exercise their over-allotment option. First Wind Holdings Inc. will be the sole managing member of First Wind Holdings, LLC and will therefore control First Wind Holdings, LLC. Entities in the D. E. Shaw group and Madison Dearborn will collectively own substantially all of the balance of the economic interests in our business. As a holding company, our only source of cash flow from operations will be distributions from First Wind Holdings, LLC. See "The Reorganization and Our Holding Company Structure." After completion of this offering, First Wind Holdings Inc. will be a "controlled company" under the listing rules of the Nasdaq Stock Market (Nasdaq Listing Rules).

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The diagram below shows our organizational structure immediately after completion of this offering and related transactions, assuming no exercise of the underwriters' over-allotment option.

(1) Certain entities in the D. E. Shaw group will receive Class A common stock rather than Series B Membership Interests (and the corresponding shares of Class B common stock). As a result, the D. E. Shaw group will hold a combination of Series B Membership Interests, Class A common stock and Class B common stock. The Class A common stock held by the D. E. Shaw group will have 48.0% of the voting power, and 25.6% of the economic rights, in First Wind Holdings Inc. if the underwriters exercise their over-allotment option in full. On a combined basis, the Class A common stock and Class B common stock held by the D. E. Shaw group will represent combined voting power of 35.3% in First Wind Holdings Inc. (or 34.0% if the underwriters exercise their over-allotment option in full).

(2) The members of First Wind Holdings, LLC, other than us, will consist of our Sponsors and certain of our employees and current investors in First Wind Holdings, LLC.

(3) The Class A common stockholders will have the right to receive all distributions made on account of our capital stock. Each share of Class A common stock and Class B common stock is entitled to one vote per share. The Class A common stock held by public stockholders will have 27.7% of the voting power, and 52.0% of the economic rights, in First Wind Holdings Inc. if the underwriters exercise their over-allotment option in full.

(4) 46.7% of the voting power in First Wind Holdings Inc. if the underwriters exercise their over-allotment option in full.

(5) Series A Membership Interests and Series B Membership Interests will have the same economic rights in First Wind Holdings, LLC. Series A and Series B Membership Interests will have 53.3% and 46.7%, respectively, of the economic rights in our business through First Wind Holdings, LLC if the underwriters exercise their over-allotment option in full.

Corporate Information

We began developing wind energy projects in North America in 2002. First Wind Holdings Inc. was incorporated in Delaware in May 2008. Our principal executive offices are located at 179 Lincoln Street, Suite 500, Boston, Massachusetts 02111, and our telephone number is (617) 960-2888. Our website is *www.firstwind.com*. The information contained on or accessible through our website, or any other website referenced in this prospectus, is not part of this prospectus and you should not consider it in making an investment decision.

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The Offering

Class A common stock offered by us	12,000,000 shares.
Class A common stock to be outstanding after this offering	24,760,860 shares (assuming no exercise of the underwriters' over-allotment option).
Underwriters' over-allotment option	1,800,000 shares.
Class B common stock to be outstanding after this offering	23,239,140 shares. Shares of our Class B common stock will be issued in connection with, and in equal proportion to, issuances of Series B Membership Interests of First Wind Holdings, LLC. Each Series B Membership Interest of First Wind Holdings, LLC, together with a corresponding share of our Class B common stock, will be exchangeable for one share of Class A common stock as described under "The Reorganization and Our Holding Company Structure Limited Liability Company Agreement of First Wind Holdings, LLC."
Use of proceeds	We expect to receive net proceeds from the sale of Class A common stock offered hereby, after deducting estimated underwriting discounts and commissions and estimated offering expenses, of approximately $275.2 million, based on an assumed offering price of $25.00 per share (the midpoint of the range set forth on the cover of this prospectus). We are required under the terms of our Wind Acquisition Loan to make a principal payment estimated to be approximately $15 to $20 million as a result of this offering. Additionally, we intend to use approximately $78 million of net proceeds from this offering to retire the First Wind Term Loan in March 2011 in advance of its March 2013 maturity. We intend to use the remainder of the offering proceeds to fund a portion of our project development and construction costs for 2010-2013 and for general corporate purposes.
Voting rights	Each share of our Class A common stock and Class B common stock will entitle its holder to one vote on all matters to be voted on by stockholders. Holders of Class A common stock and Class B common stock will vote together as a single class on all matters presented to stockholders for their vote or approval, except as otherwise required by law. After completion of this offering, the D. E. Shaw group and Madison Dearborn will own 51.5% (48.0% if the underwriters exercise their over-allotment option in full) and 91.0%, respectively, of the total number of shares of our outstanding Class A common stock and Class B common stock and will have effective control over the outcome of votes on all matters requiring approval by our stockholders.
Dividend policy	We do not anticipate paying dividends. See "Dividend Policy."
Risk factors	For a discussion of certain factors you should consider before making an investment, see "Risk Factors."

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Proposed Nasdaq Global Market symbol	"WIND"

The number of shares to be outstanding after completion of this offering is based on 12,760,860 shares of Class A common stock and 23,239,140 shares of Class B common stock outstanding as of October 20 after giving effect to the reorganization described under "The Reorganization and Our Holding Company Structure." The number of shares to be outstanding after this offering excludes 5,500,000 additional shares of Class A common stock reserved for issuance under our long-term incentive plan.

Unless we specifically state otherwise, the information in this prospectus assumes:

- the implementation of the reorganization described in "The Reorganization and Our Holding Company Structure;" and
- no exercise of the underwriters' over-allotment option.

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Summary Financial and Operating Data

The following tables present summary consolidated financial data as of and for the dates and periods indicated below. The summary consolidated statement of operations data for the years ended December 31, 2007, 2008 and 2009 and the summary consolidated balance sheet data as of December 31, 2008 and 2009 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The summary consolidated statement of operations data for the nine months ended September 30, 2009 and 2010 and the summary consolidated balance sheet data as of September 30, 2010 are derived from our unaudited interim consolidated financial statements included elsewhere in this prospectus. The unaudited interim period financial information, in the opinion of management, includes all adjustments, which are normal and recurring in nature, necessary for the fair presentation of the periods shown.

The summary unaudited pro forma consolidated financial data for the year ended December 31, 2009 and for the nine months ended September 30, 2010 have been prepared to give pro forma effect to all of the reorganization transactions described in "The Reorganization and Our Holding Company Structure" and this offering as if they had been completed as of January 1, 2009 with respect to the unaudited consolidated pro forma statement of operations and as of September 30, 2010 with respect to the unaudited pro forma consolidated balance sheet data. These data are subject and give effect to the assumptions and adjustments described in the notes accompanying the unaudited pro forma financial statements included elsewhere in this prospectus. The summary unaudited pro forma financial data are presented for informational purposes only and should not be considered indicative of actual results of operations that would have been achieved had the reorganization transactions and this offering been consummated on the dates indicated, and do not purport to be indicative of statements of financial condition data or results of operations as of any future date or for any future period. Pro forma net loss per share is based on the weighted average common shares outstanding.

The summary consolidated financial data set forth below should be read in conjunction with the "Unaudited Pro Forma Financial Information," "Selected Historical Financial and Operating Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes included elsewhere in this prospectus. Our historical results may not be indicative of the operating results to be expected in any future period.

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	First Wind Holdings, LLC			First Wind Holdings Inc.	First Wind Holdings LLC		First Wind Holdings Inc.
	Year Ended December 31,				Nine Months Ended September 30,		
	2007	2008	2009	2009 Pro Forma As Adjusted	2009	2010	2010 Pro Forma As Adjusted
	(Dollars in thousands, except per share/unit amounts)						
Statement of Operations Data:							
Revenues:							
Revenues	$ 23,817	$ 28,790	$ 47,136	$ 47,136	$ 30,468	$ 62,805	$ 62,805
Cash settlements of derivatives	(1,670)	(4,072)	10,966	10,966	8,388	5,927	5,927
Fair value changes in derivatives	(9,801)	14,760	17,175	17,175	19,192	19,397	19,397
Total revenues	12,346	39,478	75,277	75,277	58,048	88,129	88,129
Cost of revenues:							
Project operating expenses	9,175	10,613	19,709	19,709	13,269	34,162	34,162
Depreciation and amortization of operating assets	8,800	10,611	34,185	34,185	23,445	35,678	35,678
Total cost of revenues	17,975	21,224	53,894	53,894	36,714	69,840	69,840
Gross income (loss)	(5,629)	18,254	21,383	21,383	21,334	18,289	18,289
Other operating expenses:							
Project development	25,861	35,855	35,895	35,895	32,694	32,889	32,889
General and administrative	13,308	44,358	39,192	39,192	28,599	24,974	24,974
Depreciation and amortization	1,215	2,325	3,381	3,381	2,443	3,443	3,443
Total other operating expenses	40,384	82,538	78,468	78,468	63,736	61,306	61,306
Income (loss) from operations	$ (46,013)	$ (64,284)	$ (57,085)	$ (57,085)	$ (42,402)	$ (43,017)	$ (43,017)
Risk management activities related to non-operating projects	$ (21,141)	$ 42,138	$	$	$	$	$
Net loss attributable per common unit (basic and diluted)(1)	$ (0.36)	$ (0.05)	$ (0.09)		$ (0.06)	$ (0.06)	
Weighted average number of common units (basic and diluted)(1)	189,161,855	278,288,518	649,681,382		649,681,382	649,681,382	
Pro forma net loss per share basic and diluted(1)				$ (1.24)			$ (0.95)
Shares used in computing pro forma net loss per share basic and diluted(1)				24,760,860			24,760,860
Other Financial Data:							
Net cash provided by (used in):							
Operating activities(2)	$ (26,370)	$ (41,589)	$ (54,478)	$ (54,478)	$ (40,288)	$ 203,464	$ 203,464
Investing activities	(334,007)	(477,268)	(253,533)	(253,533)	(325,894)	(39,278)	(39,278)
Financing activities	358,107	556,059	298,749	298,749	374,012	(129,043)	(129,043)
Selected Operating Data							
Rated capacity (end of period)	92 MW	92 MW	478 MW	478 MW	274 MW	504 MW	504 MW
Electricity generated	239,940 MWh	275,024 MWh	656,365 MWh	656,365 MWh	437,143 MWh	849,614 MWh	849,614 MWh
Average realized energy price(3)	$ 103/MWh	$ 97/MWh	$ 85/MWh	$ 85/MWh	$ 82/MWh	$ 78/MWh	$ 78/MWh
Project EBITDA(4)	$ 14,945	$ 15,589	$ 35,867	$ 35,867	$ 22,350	$ 33,723	$ 33,723

(1)

The basic net loss attributable per common unit for each of the annual periods ended December 31, 2007, 2008 and 2009 and the nine month periods ended September 30, 2009 and 2010 has been presented for informational and historical purposes only. After completion of this offering, as a result of the reorganization events that have taken place or that will take place immediately prior to completion of the offering as described in "The Reorganization and Our Holding Company Structure," the shares used in computing net earnings or loss per share will bear no relationship to these historical common units.

Pro forma basic and diluted net loss per share was computed by dividing the pro forma net loss attributable to our Class A common stockholders by the shares of Class A common stock that we will issue and sell in this offering, plus shares issued in connection with our initial capitalization, assuming that these shares of Class A common stock were outstanding for the entirety of each of the historical periods presented on a pro forma basis. No pro forma effect was given to the future potential exchanges of the Series B Membership Interests of our subsidiary, First Wind Holdings, LLC (and the equal number of shares of our Class B common stock), that will be outstanding immediately after the completion of this offering and the reorganization transactions for an equal number of shares of our Class A common stock because the issuance of shares of Class A common stock upon these exchanges would not be dilutive.

(2)

Operating cash flows for the nine months ended September 30, 2010 include a prepayment for energy for our Milford I project of approximately $232 million.

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(3)

Average realized energy price per MWh of energy generated is a metric that allows us to compare revenues from period to period, or on a project by project basis, regardless of whether the revenues are generated under a PPA, from sales at market prices with a financial swap, from sales at market prices or a combination of the three. Although average realized energy price is based, in part, on revenues recognized under accounting principles generally accepted in the United States (GAAP), this metric does not represent revenue per unit of production on a GAAP basis. We adjust GAAP revenues used to compute this metric in several respects:

Under GAAP, recognition of revenues from the sale of New England RECs is delayed due to regulations that limit their transfer to the buyer to quarterly trading windows that open two quarters subsequent to generation. To match New England REC revenue to the period in which the related power was generated, in calculating this metric, we add New England REC revenues attributable to generation during a period but not yet recognized under GAAP, and subtract New England REC revenue recognized under GAAP in the period but generated in a prior period.

In addition, in order to focus this metric on realized energy prices, we exclude the effects of mark-to-market adjustments on financial swaps.

Average realized energy price changes over time due to several factors. Historically, the most significant factor has been the growth of our business and the corresponding change in pricing mix. Each project has a different pricing profile, including varying levels of hedging in relation to electricity generation, and in certain cases, short periods of unhedged exposure to market price fluctuations as hedging agreements are put in place.

The table below shows the calculation of our average realized energy price for the periods presented:

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	**2008**	**2009**	**2009**	**2010**
Numerator (in thousands)					
Total revenue	$ 12,346	$ 39,478	$ 75,277	$ 58,048	$ 88,129
Add (subtract):					
New England REC timing(a)	2,461	1,947	2,060	1,239	(2,237)
Mark-to-market adjustments(b)	9,801	(14,760)	(21,322)	(23,339)	(19,397)
	$ 24,608	$ 26,665	$ 56,015	$ 35,948	$ 66,495
Denominator (MWh)					
Total energy production	239,940	275,024	656,365	437,143	849,614
Average realized energy price					
(numerator/denominator)	$ 103/MWh	$ 97/MWh	$ 85/MWh	$ 82/MWh	$ 78/MWh

(a)

New England REC timing represents the difference between: (i) New England RECs generated in earlier periods that qualified for GAAP revenue recognition in the applicable period and (ii) New England RECs generated in the applicable period and sold to a counterparty under a firm sales contract where revenue is deferred under GAAP until the applicable quarterly trading window occurs. The gross amounts of such New England RECs are as follows:

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	**2008**	**2009**	**2009**	**2010**
	(in thousands)				
New England RECs					
Included in revenues	$ (2,076)	$ (4,488)	$ (8,803)	$ (7,328)	$ (11,477)
Generated during the period	4,537	6,435	10,863	8,567	9,240
	$ 2,461	$ 1,947	$ 2,060	$ 1,239	$ (2,237)

(b)

The mark-to-market adjustments for the 2009 periods include the effect of a financial hedge modification fee of $4,147 in addition to market adjustments of $17,175 and $19,192 for the year and the nine months, respectively.

(4) We evaluate the performance of our operating projects on the basis of their Project EBITDA, which is a non-GAAP financial measure. We use Project EBITDA to assess the performance of our operating projects because we believe it is a measure that allows us to: (i) more accurately evaluate the operating performance of our projects based on the energy generated during each period (through the exclusion of mark-to-market adjustments and the effects of New England REC timing, for which the GAAP accounting treatment does not correspond to the energy generated during the period) and (ii) assess the ability of our projects to support debt and/or tax equity financing (through the exclusion of depreciation and amortization that is not indicative of capital costs that would be expected over the term of the financing and general and administrative expenses that are not incurred at the project level). Our ability to raise debt and/or tax equity financing for our projects is a key requirement of our development plan as described in " Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Financing Requirements." We believe it is important for investors to understand the factors that we focus on in managing the business, and therefore we believe Project EBITDA is useful for investors to understand. In addition, as long as investors consider Project EBITDA in combination with the most directly comparable GAAP measure, gross income (loss), we believe it is useful for investors to have information about our operating

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performance on a period-by-period basis, without giving effect to GAAP requirements that require the recognition of income or expense that does not correspond to actual energy production in a given period, and we believe it is useful for investors to consider a measure that does not include project-related depreciation and amortization. Because lenders and providers of tax equity financing frequently disregard the non-cash charges and GAAP timing differences noted above when determining the financeability of a project, we believe that presenting information in this manner can help give investors an understanding of our ability to secure financing for our projects. Project EBITDA can be reconciled to gross income (loss), which we believe to be the most directly comparable financial measure calculated and presented in accordance with GAAP, as follows (in thousands):

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
Gross income (loss)	$ (5,629)	$ 18,254	$ 21,383	$ 21,334	$ 18,289
Add (subtract):					
Depreciation and amortization of operating assets	8,800	10,611	34,185	23,445	35,678
New England REC timing	2,461	1,947	2,060	1,239	(2,237)
Mark-to-market adjustments(a)	9,801	(14,760)	(21,322)	(23,339)	(19,397)
KWP I property tax assessment(b)	(488)	(463)	(439)	(329)	1,390
Project EBITDA	$ 14,945	$ 15,589	$ 35,867	$ 22,350	$ 33,723

(a) The mark-to-market adjustments for the 2009 periods include the effect of a financial hedge modification fee of $4,147 in addition to market adjustments of $17,175 and $19,192 for the year and the nine months, respectively.

(b) In June 2010, the County of Maui, Hawaii retroactively assessed property taxes for our KWP I project totaling approximately $1.4 million plus penalties and interest for 2007, 2008 and 2009. We have appealed these retroactive assessments as well as the amount then billed by the county for 2010. The KWP I property tax assessment adjustment reflects these retroactive assessments in the periods to which they relate.

Project EBITDA does not represent funds available for our discretionary use and is not intended to represent or to be used as a substitute for gross income (loss), net income or cash flow from operations data as measured under GAAP. We use Project EBITDA to assess the performance of our operating projects and not as a measure of our liquidity. Investors should consider cash flow from operations, and not Project EBITDA, when evaluating our liquidity and capital resources. The items excluded from Project EBITDA are significant components of our statement of operations and must be considered in performing a comprehensive assessment of our overall financial performance. Project EBITDA and the associated period-to-period trends should not be considered in isolation.

The following table presents summary consolidated balance sheet data as of the dates indicated:

- on an actual basis;
- on a pro forma basis as of September 30, 2010 to give effect to all of the reorganization transactions described in "The Reorganization and Our Holding Company Structure"; and
- on a pro forma as adjusted basis as of September 30, 2010 to give further effect to our sale of 12,000,000 shares of common stock in this offering at an assumed initial public offering price of $25.00 per share, the midpoint of the range set forth on the cover of this prospectus, after deducting estimated underwriting discounts and commissions and estimated offering expenses.

	First Wind Holdings, LLC				First Wind Holdings Inc.	
	As of December 31,			As of September 30,	Pro Forma As of September 30,	Pro Forma As Adjusted September 30,
	2007	2008	2009	2010	2010	2010
	(in thousands)					
Balance Sheet Data:						
Property, plant and equipment, net	$ 192,076	$ 187,316	$ 950,610	$ 838,165	$ 838,165	$ 838,165

Construction in progress	346,320	571,586	472,526	559,541	559,541	559,541
Total assets	770,666	1,311,591	1,698,154	1,712,269	1,712,269	1,968,669
Long-term debt, including debt with maturities less than one year	465,449	532,441	632,046	561,381	561,381	542,631
Members' capital/ stockholders' equity	147,876	653,092	849,373	792,172	792,857	1,068,007

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RISK FACTORS

You should consider carefully each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in our Class A common stock. If any of the following risks materializes, our business, financial condition and results of operations may be materially adversely affected. In that event, the trading price of our Class A common stock could decline, and you could lose some or all of your investment.

This prospectus also contains forward-looking statements that involve risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements as a result of various factors, including the risks described below and elsewhere in this prospectus. See "Cautionary Statement Regarding Forward-Looking Statements."

Risks Related to Our Business and the Wind Energy Industry

If we cannot continue to build our pipeline of projects under development and turn them into operating projects, our business will not grow and we may have significant write-offs.

We may be unable to meet our target of having approximately 1,900 MW of operating/under-construction capacity by 2014, because we will need to add new projects to our pipeline on an ongoing basis, including projects we acquire from others. In addition, we may have difficulty in converting our development pipeline into operating projects or may be unable to find suitable projects to add to our pipeline. These circumstances could prevent those projects from commencing operations or from meeting our original expectations about how much energy they will generate or the returns they will achieve. Since completing the projects in or added to our development pipeline as anticipated or at all involves numerous risks and uncertainties, some projects in our portfolio will not progress to construction or may be substantially delayed. From time to time we have abandoned projects on which we had started development work, or re-categorized projects to a less advanced stage than we had previously assigned them, representing in the aggregate approximately 145 MW of potential capacity. This resulted in $3.5 million, $3.1 million and $2.5 million of write-offs in 2008, 2009 and the nine months ended September 30, 2010, respectively. Abandonment or re-categorization of our projects may make it difficult for us to achieve our capacity goals by our target dates. As we increase our development activities and the number of projects in our pipeline, such discontinuations and re-categorizations and the corresponding write-offs may increase. In addition, those projects that are constructed and begin operations may not meet our return expectations due to schedule delays, cost overruns or revenue shortfalls or they may not generate the capacity that we anticipate or result in receipt of revenue in the originally anticipated time period or at all. An inability to maintain and add to our development pipeline or to convert projects into financially successful operating projects would have a material adverse effect on our business, financial condition and results of operations.

We have generated substantial net losses and negative operating cash flows since our inception and expect to continue to do so as we develop and construct new wind energy projects.

We have generated substantial net losses and negative operating cash flows from operating activities since our operations commenced. We had accumulated losses of approximately $233.0 million from our inception through September 30, 2010. For the year ended December 31, 2009 and the nine months ended September 30, 2010, we generated net losses of $61.0 million and $52.0 million, respectively. In addition, our operating activities used cash of $54.5 million for the year ended December 31, 2009 and $28.5 million (excluding the $232.0 million prepayment for energy for our Milford I project) for the nine months ended September 30, 2010.

We expect that our net losses will continue and our cash used in operating activities will grow during the next several years, as compared with prior periods, as we increase our development activities and construct additional wind energy projects. Wind energy projects in development typically incur operating losses prior to commercial operation at which point the projects begin to generate positive operating cash flow. We also expect to incur additional costs, contributing to our losses and operating uses of cash, as we incur the incremental costs of operating as a public company. Our costs may also increase due to such factors as higher than anticipated financing and other costs; non-performance by third-party suppliers or subcontractors; increases in the costs of labor or materials; and major incidents or catastrophic events. If any of those factors occurs, our net losses and accumulated deficit could increase significantly and the value of our common stock could decline.

We depend heavily on federal, state and local government support for renewable energy, especially wind projects.

We depend heavily on government policies that support renewable energy and enhance the economic feasibility of developing wind energy projects. The federal government and several of the states in which we operate or into which we sell power provide incentives that support the sale of energy from renewable sources, such as wind.

The Internal Revenue Code provides a production tax credit (PTC) for each kWh of energy generated by an eligible resource. Under current law, an eligible wind facility placed in service prior to the end of 2012 may claim the PTC. The PTC is a credit claimed against the income of the owner of the eligible project.

PTC eligible projects are also eligible for an investment tax credit (ITC) of 30% of the eligible cost-basis, which is in lieu of the PTC. The same placed-in-service deadline of December 31, 2012 applies for purposes of the ITC. The ITC is a credit claimed against the income of the owner of the eligible project.

The American Recovery and Reinvestment Act of 2009 (ARRA) created a grant administered by the U.S. Treasury that provides for a cash payment of the amount an eligible project whose construction began in 2010 would otherwise be able to claim under the ITC. In addition, there are various programs for loan guarantees. See "Industry Drivers of U.S. Wind Energy Growth State and Federal Government Incentives."

In addition to federal incentives, we rely on state incentives that support the sale of energy generated from renewable sources, including state adopted renewable portfolio standards (RPS) programs. Such programs generally require that electricity supply companies include a specified percentage of renewable energy in the electricity resources serving a state or purchase credits demonstrating the generation of such electricity by another source. However, the legislation creating such RPS requirements usually grants the relevant state public utility commission the ability to reduce electric supply companies' obligations to meet the RPS requirements in certain circumstances. If the RPS requirements are reduced or eliminated, this could result in our receiving lower prices for our power and in a reduction in the value of our RECs, which could have a material adverse effect on us. See "Industry Drivers of U.S. Wind Energy Growth State and Federal Government Incentives."

We depend heavily on these programs to finance the projects in our development pipeline. If any of these incentives are adversely amended, eliminated, subjected to new restrictions, not extended beyond their current expiration dates, or if funding for these incentives is reduced, it would have a material adverse effect on our ability to obtain financing. A delay or failure by governmental authorities to administer these programs in a timely and efficient manner could have a material adverse effect on our financing.

While certain federal, state and local laws, programs and policies promote renewable energy and additional legislation is regularly being considered that would enhance the demand for renewable energy, they may be adversely modified, legislation may not pass or may be amended and governmental support of renewable energy development, particularly wind energy, may not continue or may be reduced. If governmental authorities do not continue supporting, or reduce or eliminate their support

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for, the development of wind energy projects, our revenues may be adversely affected, our economic return on certain projects may be reduced, our financing costs may increase, it may become more difficult to obtain financing, and our business and prospects may otherwise be adversely affected.

Most of our revenue comes from sales of electricity and RECs, which are subject to market price fluctuations, and there is a risk of a significant, sustained decline in their market prices. Such a decline may make it more difficult to develop our projects.

We may not be able to develop our projects economically if there is a significant, sustained decline in market prices for electricity or RECs without a commensurate decline in the cost of turbines and the other capital costs of constructing wind energy projects. Electricity prices are affected by various factors and may decline for many reasons that are not within our control. Those factors include changes in the cost or availability of fuel, regulatory and governmental actions, changes in the amount of available generating capacity from both traditional and renewable sources, changes in power transmission or fuel transportation capacity, seasonality, weather conditions and changes in demand for electricity. In addition, other power generators may develop new technologies or improvements to traditional technologies to produce power that could increase the supply of electricity and cause a sustained reduction in market prices for electricity and RECs. If governmental action or conditions in the markets for electricity or RECs cause a significant, sustained decline in the market prices of electricity or those attributes, without an offsetting decline in the cost of turbines or other capital costs of wind energy projects, we may not be able to develop and construct our pipeline of development projects or achieve expected revenues, which could have a material adverse effect on our business, financial condition and results of operations.

The production of wind energy depends heavily on suitable wind conditions. If wind conditions are unfavorable or below our estimates, our electricity production, and therefore our revenue, may be substantially below our expectations.

The electricity produced and revenues generated by a wind energy project depend heavily on wind conditions, which are variable and difficult to predict. Operating results for projects vary significantly from period to period depending on the windiness during the periods in question. We base our decisions about which sites to develop in part on the findings of long-term wind and other meteorological studies conducted in the proposed area, which measure the wind's speed, prevailing direction and seasonal variations. Actual wind conditions, however, may not conform to the measured data in these studies and may be affected by variations in weather patterns, including any potential impact of climate change. Therefore, the electricity generated by our projects may not meet our anticipated production levels or the rated capacity of the turbines located there, which could adversely affect our business, financial condition and results of operations. In recent years and in the first quarter of 2010, the wind resources at our operating projects, while within the range of our long-term estimates, varied from the averages we expected. If the wind resources at a project are below the average level we expect, our rate of return for the project would be below our expectations and we would be adversely affected. Projections of wind resources also rely upon assumptions about turbine placement, interference between turbines and the effects of vegetation, land use and terrain, which involve uncertainty and require us to exercise considerable judgment. We or our consultants may make mistakes in conducting these wind and other meteorological studies. Any of these factors could cause us to develop sites that have less wind potential than we expected, or to develop sites in ways that do not optimize their potential, which could cause the return on our investment in these projects to be lower than expected.

If our wind energy assessments turn out to be wrong, our business could suffer a number of material adverse consequences, including:

- our energy production and sales may be significantly lower than we predict;

- our hedging arrangements may be ineffective or more costly;

- we may not produce sufficient energy to meet our commitments to sell electricity or RECs and, as a result, we may have to buy electricity or RECs on the open market to cover our obligations or pay damages; and

- our projects may not generate sufficient cash flow to make payments of principal and interest as they become due on our project-related debt, and we may have difficulty obtaining financing for future projects.

Natural events may reduce energy production below our expectations.

A natural disaster, severe weather or an accident that damages or otherwise adversely affects any of our operations could have a material adverse effect on our business, financial condition and results of operations. Lightning strikes, blade icing, earthquakes, tornados, extreme wind, severe storms, wildfires and other unfavorable weather conditions or natural disasters could damage or require us to shut down our turbines or related equipment and facilities, impeding our ability to maintain and operate our facilities and decreasing electricity production levels and our revenues. Operational problems, such as degradation of turbine components due to wear or weather or capacity limitations on the electrical transmission network, can also affect the amount of energy we are able to deliver. Any of these events, to the extent not fully covered by insurance, could have a material adverse effect on our business, financial condition and results of operations.

Operational problems may reduce energy production below our expectations.

Spare parts for wind turbines and key pieces of electrical equipment may be hard to acquire or unavailable to us. Sources for some significant spare parts and other equipment are located outside of North America. If we were to experience a shortage of or inability to acquire critical spare parts, we could incur significant delays in returning facilities to full operation. In addition, we generally do not hold spare substation main transformers. These transformers are designed specifically for each wind energy project, and the current lead time to receive an order for this type of equipment is over eight months. For example, operations at our Stetson I project were temporarily interrupted in February 2010 due to a transformer malfunction. If we had to replace any of our substation main transformers, we could be unable to sell electricity from the affected wind energy project until a replacement is installed. That interruption to our business might not be fully covered by insurance.

One of our key turbine suppliers, Clipper Windpower Plc, has experienced certain technical issues with its wind turbine technology and may continue to experience similar issues.

Clipper, one of our two turbine suppliers in our existing operating fleet, entered the wind turbine market in 2007. Clipper's first prototype wind turbine, the 2.5 MW Liberty, was placed in service in April 2005. We now operate 116 Liberty turbines (290 MW) and plan to install 34 Liberty turbines in 2010 (85 MW). We have entered into agreements which provide us the right but not the obligation to acquire up to 253 Liberty turbines (633 MW) for installation during 2011-2015. We deployed the first eight commercially produced Liberty turbines at our Steel Winds I project, which commenced commercial operations on June 1, 2007. Since our initial deployment, Clipper has announced and remediated three defects affecting the Liberty turbines deployed by us and other customers that resulted in prolonged downtime for turbines at various projects, including our Steel Winds I and Cohocton projects. Among issues adversely affecting Liberty turbine performance were drive trains that incorporated a supplier-related deficiency, a design deficiency resulting in separation of bonding materials in the blades of several turbines and minor defects in the blade skin resulting from a defective manufacturing process. At present, all such items affecting our installed Clipper fleet have been remediated and average availability of the Liberty turbines in our fleet through 2010 is within warranted levels.

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The Liberty turbines, however, may not perform in accordance with Clipper's specifications for their anticipated useful life or may require additional warranty or non-warranty repairs. In addition, the initial failure of performance has adversely affected our ability to arrange and close turbine supply loans, tax equity financing transactions and construction loans involving Liberty turbines. Moreover, Clipper may not be able to fund its obligations to us and its other customers under its outstanding warranty agreements.

A failure of Clipper to produce Liberty turbines that perform within design specifications would preclude us from completing projects that could otherwise incorporate Clipper technology and likely result in our determination to elect not to purchase any or all Liberty turbines that we have the right but not the obligation to acquire from 2011 through 2015.

We have paid Clipper approximately $60 million in deposits and progress payments towards turbine purchases from 2011 2015 and intend to pay approximately $30 million more in deposits and progress payments through January 15, 2011. If we elect for any reason not to acquire any additional turbines from Clipper, we will forfeit the pro rata portion of these deposits and progress payments corresponding to the schedule of future turbine purchases: $38.6 million for turbines scheduled to be purchased in 2011, $17.9 million for 2012, $10.7 million for 2013, $13.4 million for 2014 and $8.9 million for 2015.

We have no commitments from turbine manufacturers other than Clipper for projects we plan to have in construction after 2010.

A portion of our revenues from the sale of RECs is not hedged, and we are exposed to volatility of commodity prices with respect to those sales.

REC prices are driven by various market forces, including electricity prices and the availability of electricity from other renewable energy sources and conventional energy sources. We are unable to hedge a portion of our revenues from RECs in certain markets where conditions limit our ability to sell forward all of our RECs. Our ability to hedge RECs generated by our Northeast projects is limited by the unbundled nature of the RECs and the relative illiquidity of this market, and revenues associated with these RECs account for a majority of the unhedged revenue stream from our existing operating fleet. We are exposed to volatility of commodity prices with respect to the portion of RECs that are unhedged, including risks resulting from changes in regulations, including state RPS targets, general economic conditions and changes in the level of renewable energy generation. We expect to have quarterly variations in our revenues from the sale of unhedged RECs.

We have a limited operating history and our rapid growth may make it difficult for us to manage our business efficiently.

Since we began our business in 2002 and began commercial operation of our first wind energy project in 2006, there is limited history to use to evaluate our business. You should consider our prospects in light of the risks and uncertainties growing companies encounter in rapidly evolving industries such as ours. Also, our rapid growth may make it difficult for us to manage our business efficiently, effectively manage our capital expenditures and control our costs, including general and administrative costs. These challenges could have a material adverse effect on our business, financial condition and results of operation.

We rely on a limited number of key customers.

There are a limited number of possible customers for electricity and RECs produced in a given geographic location. As a result, we do not have many choices about the buyers of our electricity, which limits our ability to negotiate the terms under which we sell electricity. Also, since we depend on sales of electricity and RECs to certain key customers, our operations are highly dependent upon these customers' fulfilling their contractual obligations under our power purchase agreements (PPAs) and other material sales contracts. For example, 45% of our revenues were generated from sales of electricity under PPAs with four customers in the year ended December 31, 2009. Our customers may not comply with their contractual payment obligations or may become subject to insolvency or liquidation proceedings during the term of the relevant contracts. In addition, the credit support we received from such customers to secure their payments under the PPAs may not be sufficient to cover our losses if they fail to perform. To the extent that any of our customers are, or are controlled by, governmental entities, they may also be subject to legislative or other political action that impairs their contractual performance. Failure by any key customer to meet its contractual commitments or insolvency or liquidation of our customers could have a material adverse effect on our business, financial condition and results of operations.

We face competition primarily from other renewable energy sources and, in particular, other wind energy companies.

We believe our primary competitors are developers and operators focused on renewable energy generation, and specifically wind energy companies. Renewable energy sources, including wind, biomass, geothermal and solar, currently benefit from various governmental incentives such as PTCs, ITCs, cash grants, loan guarantees, RPS programs and accelerated tax depreciation. Changes in any of these incentives could significantly disadvantage wind energy generators including us, compared with other renewable energy sources. Further, the energy industry is rapidly evolving and highly competitive. A reduction in demand for energy from renewable sources or our failure to identify and adapt to new technologies could have a material adverse effect on our business, financial condition and results of operations.

We compete with other wind energy companies primarily for sites with good wind resources that can be built in a cost-effective manner. We also compete for access to transmission or distribution networks. Because the wind energy industry in the United States is at an early stage, we also compete with other wind energy developers for the limited pool of personnel with requisite industry knowledge and experience. Furthermore, in recent years, there have been times of increased demand for wind turbines and their related components, causing turbine suppliers to have difficulty meeting the demand. If these conditions return in the future, turbine and other component manufacturers may give priority to other market participants, including our competitors, who may have resources greater than ours.

We compete with other renewable energy companies (and energy companies in general) for the financing needed to pursue our development plan. Once we have developed a project and put a project into operation, we may compete on price if we sell electricity into power markets at wholesale market prices. Depending on the regulatory framework and market dynamics of a region, we may also compete with other wind energy companies, as well other renewable energy generators, when we bid on or negotiate for a long-term PPA.

We also compete with traditional energy companies.

We also compete with traditional energy companies. For example, depending on the regulatory framework and market dynamics of a region, we also compete with traditional electricity producers when we bid on or negotiate for a long-term PPA. Furthermore, technological progress in traditional forms of electricity generation (including technology that reduces or sequesters greenhouse gas emissions) or the discovery of large new deposits of traditional fuels could reduce the cost of electricity generated from those sources or make them more environmentally friendly, and as a consequence reduce the demand for electricity from renewable energy sources or render existing or future wind energy projects uncompetitive. Any of these developments could have a material adverse effect on our business, financial condition and results of operations.

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The growth of our business depends on locating and obtaining control of suitable operating sites.

Wind energy projects require wind conditions that are found in limited geographic areas and, within these areas, at particular sites. These sites must also be suitable for construction of a wind energy project, including related roads and operations and maintenance facilities. Further, projects must be interconnected to electricity transmission or distribution networks. Once we have identified a suitable operating site, obtaining the requisite land rights (including access rights, setbacks and other easements) requires us to negotiate with landowners and local government officials. These negotiations can take place over a long time, are not always successful and sometimes require economic concessions not in our original plans. The property rights necessary to construct and interconnect our projects must also be insurable and otherwise satisfactory to our financing counterparties. In addition, our ability to obtain adequate property rights is subject to competition from other wind energy developers. If a competitor or other party obtains land rights critical to our project development efforts that we are unable to resolve, we could incur losses as a result of development costs for sites we do not develop, which we would have to write off. If we are unable to obtain adequate property rights for a project, including its interconnection, that project may be smaller in size or potentially unfeasible. Failure to obtain insurable property rights for a project satisfactory to our financing counterparties would preclude our ability to obtain third-party financing and could prevent ongoing development and construction of that project.

Negative public or community response to wind energy projects in general or our projects specifically can adversely affect our ability to develop our projects.

Negative public or community response to wind energy projects in general or our projects specifically can adversely affect our ability to develop, construct and operate our projects. This type of negative response can lead to legal, public relations and other challenges that impede our ability to meet our development and construction targets, achieve commercial operations for a project on schedule, address the changing needs of our projects over time and generate revenues. Some of our projects are and have been the subject of administrative and legal challenges from groups opposed to wind energy projects in general or concerned with potential environmental, health or aesthetic impacts, impacts on property values or the rewards of property ownership, or impacts on the natural beauty of public lands. We expect this type of opposition to continue as we develop and construct our existing and future projects. An increase in opposition to our requests for permits or successful challenges or appeals to permits issued to us could materially adversely affect our development plans. If we are unable to develop, construct and operate the production capacity that we expect from our development projects in our anticipated timeframes, it could have a material adverse effect on our business, financial condition and results of operations.

We need governmental approvals and permits, including environmental approvals and permits, to construct and operate our projects. Any failure to procure and maintain necessary permits would adversely affect ongoing development, construction and continuing operation of our projects.

The design, construction and operation of wind energy projects are highly regulated, require various governmental approvals and permits, including environmental approvals and permits, and may be subject to the imposition of related conditions that vary by jurisdiction. In some cases, these approvals and permits require periodic renewal. We cannot predict whether all permits required for a given project will be granted or whether the conditions associated with the permits will be achievable. The denial of a permit essential to a project or the imposition of impractical conditions would impair our ability to develop the project. In addition, we cannot predict whether the permits will attract significant opposition or whether the permitting process will be lengthened due to complexities and appeals. For example, permit challenges delayed the start of construction of our Rollins and Sheffield projects. Delay in the review and permitting process for a project can impair or delay our ability to develop that project or increase the cost so substantially that the project is no longer attractive to us.

We have experienced delays in developing our projects due to delays in obtaining non-appealable permits and may experience delays in the future. If we were to commence construction in anticipation of obtaining the final, non-appealable permits needed for that project, we would be subject to the risk of being unable to complete the project if all the permits were not obtained. If this were to occur, we would likely lose a significant portion of our investment in the project and could incur a loss as a result. Any failure to procure and maintain necessary permits would adversely affect ongoing development, construction and continuing operation of our projects.

Our development activities and operations are subject to numerous environmental, health and safety laws and regulations.

We are subject to numerous environmental, health and safety laws and regulations in each of the jurisdictions in which we operate. These laws and regulations require us to obtain and maintain permits and approvals, undergo environmental impact assessments and review processes and implement environmental, health and safety programs and procedures to control risks associated with the siting, construction, operation and decommissioning of wind energy projects. For example, to obtain permits we could be required to undertake expensive programs to protect and maintain local endangered species. If such programs are not successful, we could be subject to penalties or to revocation of our permits. In addition, permits frequently specify permissible sound levels.

If we do not comply with applicable laws, regulations or permit requirements, we may be required to pay penalties or fines or curtail or cease operations of the affected projects. Violations of environmental and other laws, regulations and permit requirements, including certain violations of laws protecting migratory birds and endangered species, may also result in criminal sanctions or injunctions.

Environmental, health and safety laws, regulations and permit requirements may change or become more stringent. Any such changes could require us to incur materially higher costs than we currently have. Our costs of complying with current and future environmental, health and safety laws, regulations and permit requirements, and any liabilities, fines or other sanctions resulting from violations of them, could adversely affect our business, financial condition and results of operations.

Our ownership and operation of real property and our disposal of hazardous waste could result in our being liable for environmental issues.

Certain environmental laws impose liability on current and previous owners and operators of real property for the cost of removal or remediation of hazardous substances. These laws often impose liability even if the owner or operator did not know of, or was not responsible for, the release of such hazardous substances. They can also assess liability on persons who arrange for hazardous substances to be sent to disposal or treatment facilities when such facilities are found to be contaminated. Such persons can be responsible for cleanup costs even if they never owned or operated the contaminated facility. In addition to actions brought by governmental agencies, private plaintiffs may also bring claims arising from the presence of hazardous substances on a property or exposure to such substances. Our liabilities arising from past or future releases of, or exposure to, hazardous substances may adversely affect our business, financial condition and results of operations.

We often rely on transmission lines and other transmission facilities that are owned and operated by third parties. We are exposed to transmission facility development and curtailment risks, which may delay and increase the costs of our projects or reduce the return to us on those investments.

We often depend on electric transmission lines owned and operated by third parties to deliver the electricity we generate. Some of our projects have limited access to interconnection and transmission capacity because there are many parties seeking access to the limited capacity that is available. We may not be able to secure access to this limited interconnection or transmission capacity at reasonable prices or at all. Moreover, a failure in the operation by third parties of these transmission facilities could

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result in our losing revenues because such a failure could limit the amount of electricity we deliver. In addition, our production of electricity may be curtailed due to third-party transmission limitations or limitations on the grid's ability to accommodate intermittent energy sources, reducing our revenues and impairing our ability to capitalize fully on a particular project's potential. Such a failure or curtailment at levels significantly above which we expect could have a material adverse effect on our business, financial condition and results of operations.

In certain circumstances, we have developed and in the future will develop our own generator leads from our projects to available electricity transmission or distribution networks when such facilities do not already exist. In some cases, these facilities may cover significant distances. To construct such facilities, we need approvals, permits and land rights, which may be difficult or impossible to acquire or the acquisition of which may require significant expenditures. We may not be successful in these activities, and our projects that rely on such generator lead development may be delayed, have increased costs or not be feasible. Our failure in operating these generator leads could result in lost revenues because it could limit the amount of electricity we are able to deliver. In addition, we may be required by law or regulation to provide service over our facilities to third parties at regulated rates, which could constrain transmission of our power from the affected facilities, or we could be subject to additional regulatory risks associated with being considered the owner of a transmission line.

We may be unable to construct our wind energy projects on time, and our construction costs could increase to levels that make a project too expensive to complete or make the return on our investment in that project less than expected.

There may be delays or unexpected developments in completing our wind energy projects, which could cause the construction costs of these projects to exceed our expectations. We may suffer significant construction delays or construction cost increases as a result of a variety of factors, including:

- failure to receive turbines or other critical components and equipment, including batteries, that meet our design specifications and can be delivered on schedule;
- failure to complete interconnection to transmission networks;
- failure to obtain all necessary rights to land access and use;
- failure to receive quality and timely performance of third-party services;
- failure to secure and maintain environmental and other permits or approvals;
- appeals of environmental and other permits or approvals that we obtain;
- failure to obtain capital to develop our pipeline;
- shortage of skilled labor;
- inclement weather conditions;
- adverse environmental and geological conditions; and
- *force majeure* or other events out of our control.

Any of these factors could give rise to construction delays and construction costs in excess of our expectations. This could prevent us from completing construction of a project, cause defaults under our financing agreements or under PPAs that require completion of project construction by a certain time, cause the project to be unprofitable for us, or otherwise impair our business, financial condition and results of operations.

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Demand for wind turbines and related components may increase in the future. In that case, we may face difficulties in obtaining turbines and related components at affordable prices, in a timely manner or in sufficient quantities.

While the turbine market currently has significant over-capacity, there have been times when the demand for wind turbines and their related components has exceeded supply. Turbine suppliers have at times had difficulty meeting the demand, leading to significant supply backlogs, increased prices, higher up-front payments and deposits and delivery delays. These market conditions may prevail again and if they do, may result in prices that are higher than the costs we expect, less favorable payment terms or may result in insufficient available supplies to sustain our growth. Delays in the delivery of ordered turbines and components could delay the completion of our projects under development.

Warranties from suppliers of turbines, which protect us against turbine non-performance, may be limited by the ability of the vendor to satisfy its obligations under the warranty. In addition, the warranties have time limits and if we are not ready for turbine installation at the time we receive a turbine, that warranty protection can be lost.

When we purchase turbines, we also enter into warranty agreements with the manufacturer. However, there can be no assurance that the supplier will be able to fulfill its contractual obligations. In addition, these warranties generally expire within two to five years after the turbine delivery date or the date the turbine is commissioned. We may lose all or a portion of the benefit of a warranty if we take delivery of a turbine before we are able to deploy it, as we have in the past. If we seek warranty protection and the vendor is unable or unwilling to perform its obligations under the warranty, whether as a result of the vendor's financial condition or otherwise, or if the term of the warranty has expired, we may suffer reduced warranty availability for the affected turbines, which could have a material adverse effect on our business, financial condition and results of operations. Also, under such warranties, the warranty payments by the manufacturer are typically subject to an aggregate maximum cap that is a portion of the total purchase price of the turbines. Losses in excess of these caps would be our responsibility.

Our use and enjoyment of real property rights for our wind energy projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to us.

Our wind energy projects generally are and are likely to be located on land we occupy pursuant to long-term easements and leases. The ownership interests in the land subject to these easements and leases may be subject to mortgages securing loans or other liens (such as tax liens) and other easement and lease rights of third parties (such as leases of oil or mineral rights) that were created prior to our easements and leases. As a result, our rights under these easements or leases may be subject, and subordinate, to the rights of those third parties. We perform title searches and obtain title insurance to protect ourselves against these risks. Such measures may, however, be inadequate to protect us against all risk of loss of our rights to use the land on which our projects are located, which could have a material adverse effect on our business, financial condition and results of operations.

Many of our operating projects are, and other future projects may be, subject to regulation by the Federal Energy Regulatory Commission under the Federal Power Act or other regulations that regulate the sale of electricity, which may adversely affect our business.

Some of our current operating projects are "Qualifying Facilities" (QFs) and/or "Exempt Wholesale Generators" (EWGs) that are exempt from regulation as public utilities by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA). Many of our operating projects are, however, subject to rate regulation by FERC under the FPA, and certain of our under-construction and development projects may be subject to such rate regulation in the future. Our

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projects that are subject to rate regulation are required to obtain FERC acceptance of their rate schedules for wholesale sales of energy, capacity and ancillary services. FERC may revoke or revise an entity's authorization to make wholesale sales at market-based rates if FERC subsequently determines that such entity can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions or market manipulation. In addition, public utilities are subject to FERC reporting requirements that impose administrative burdens and that, if violated, can expose the company to criminal and civil penalties or other risks.

Any market-based rate authority that we have or will obtain will be subject to certain market behavior rules. If we are deemed to have violated these rules, we will be subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of our market-based rate authority, as well as potential criminal and civil penalties. If we were to lose market-based rate authority for a project, we would be required to obtain FERC's acceptance of a cost-based rate schedule and could become subject to, among other things, the burdensome accounting, record keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules. This could have an adverse effect on the rates we charge for power from our projects and our cost of regulatory compliance.

For our operating projects with more than 75MW of capacity, we are also subject to the reliability standards of the North American Electric Reliability Corporation (NERC). If we fail to comply with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Although the sale of electric energy has been to some extent deregulated, the industry is subject to increasing regulation and even possible re-regulation. Due to major regulatory restructuring initiatives at the federal and state levels, the U.S. electric industry has undergone substantial changes over the past several years. We cannot predict the future design of wholesale power markets or the ultimate effect ongoing regulatory changes will have on our business. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the movement towards competitive markets. If deregulation of the electric power markets is reversed, discontinued or delayed, our business, financial condition and results of operations could be adversely affected.

Current or future litigation or administrative proceedings could have a material adverse effect on our business, financial condition and results of operations.

We have been and continue to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of business. Individuals and interest groups may sue to challenge the issuance of a permit for a wind energy project or seek to enjoin construction of a wind energy project. For example, proceedings have been instituted against us challenging the issuance of some of our permits. In addition, we may be subject to legal proceedings or claims contesting the construction or operation of our wind energy projects. For example, some residents near our Mars Hill project have commenced litigation against us based on our construction and operation of the project, including complaints relating to sound levels. Unfavorable outcomes or developments relating to these proceedings, such as judgments for monetary damages, injunctions or denial or revocation of permits, could have a material adverse effect on our business, financial condition and results of operations. In addition, settlement of claims could adversely affect our financial condition and results of operations. See "Business Legal Proceedings."

Acquisition of existing wind energy assets involves numerous risks.

Our strategy includes acquiring wind energy assets at various stages of development. The acquisition of existing wind energy assets involves numerous risks. They include: difficulty in developing the assets into operating projects; unanticipated costs and exposure to liabilities; difficulty in integrating the acquired assets; and, if the assets are in new markets, the risks of entering markets where we have limited experience. A failure to achieve the financial returns we expect when we acquire wind energy assets could have an adverse effect on our business.

We are not able to insure against all potential risks and may become subject to higher insurance premiums.

Our business is exposed to the risks inherent in the construction and operation of wind energy projects, such as breakdowns, manufacturing defects, natural disasters, terrorist attacks and sabotage. We are also exposed to environmental risks. We have insurance policies covering certain risks associated with our business. Our insurance policies do not, however, cover losses as a result of *force majeure*, natural disasters, terrorist attacks or sabotage, among other things. We generally do not maintain insurance for certain environmental risks, such as environmental contamination. In addition, our insurance policies are subject to annual review by our insurers and may not be renewed at all or on similar or favorable terms. A serious uninsured loss or a loss significantly exceeding the limits of our insurance policies could have a material adverse effect on our business, financial condition and results of operations.

The loss of one or more members of our senior management or key employees may adversely affect our ability to implement our strategy.

We depend on our experienced management team and the loss of one or more key executives could have a negative impact on our business. We also depend on our ability to retain and motivate key employees and attract qualified new employees. Because the wind industry is relatively new, there is a scarcity of top-quality employees with experience in the wind industry. If we lose a member of the management team or a key employee, we may not be able to replace him or her. Integrating new employees into our management team and training new employees with no prior experience in the wind industry could prove disruptive to our operations, require a disproportionate amount of resources and management attention and ultimately prove unsuccessful. An inability to attract and retain sufficient technical and managerial personnel could limit or delay our development efforts, which could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Our Financial Activities

We may not be able to finance the growth of our business, including the development and construction of our wind energy projects and the growth of our organization.

We are in a capital intensive business and rely heavily on the debt and equity markets to finance the development and construction costs of our projects and other projected capital expenditures. Completion of our projects requires significant capital expenditures and construction costs. Recovery of the capital investment in a wind energy project generally occurs over a long period of time. As a result, we must obtain funds from equity or debt financings, including tax equity transactions, or from government grants to develop and construct our existing project pipeline, to finance the acquisition of turbines, to identify and develop new projects and to pay the general and administrative costs of operating our business. The cost of turbines has historically represented approximately 70% of the total cost of an average wind energy project. The significant disruption in credit and capital markets generally that began in the fall of 2008 and has persisted has made it difficult to obtain financing on acceptable terms or, in some cases, at all. If we are unable to raise additional funds when needed, we could delay development and construction of projects, reduce the scope of projects or abandon or sell some or all of our development projects, or default on our contractual commitments to buy turbines in the future, any of which would adversely affect our business, financial condition and results of operations.

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Our substantial amount of indebtedness maturing in less than one year may adversely affect our ability to operate our business, remain in compliance with debt covenants and make payments on our indebtedness.

As of September 30, 2010, we had outstanding indebtedness of approximately $582.2 million, which represented approximately 36.1% of our total debt and equity capitalization of $1,610.6 million (after giving effect to this offering and giving effect to the pro forma as adjusted assumptions set forth under "Capitalization"), including:

- $161.4 million of debt under turbine supply loans;
- $362.0 million of holding company and project term debt; and
- $58.8 million of other debt used to fund development, construction and general and administrative expenses.

Of this amount, approximately $112.0 million matures prior to October 1, 2011. We do not have available cash or short-term liquid investments sufficient to repay all of this indebtedness and we have not obtained commitments for refinancing all of this debt. Therefore, we may not be able to extend the maturity of this indebtedness or to otherwise successfully refinance current maturities. If we are unable to repay or further extend the maturity on the $94.1 million of turbine supply loans ($161.4 million total at September 30, 2010, less $67.3 million repaid with proceeds from the Milford II construction loan, which closed on October 20, 2010) included in this current indebtedness, we would be in default on these loans. In that event, we may be forced to sell the collateral securing the loans or surrender the collateral to the lender, which would result in a loss for financial reporting purposes and could have an adverse effect on our longer term operations, including a potential delay in completion of one or more of our Tier 1 projects.

The initial report of our independent registered public accounting firm, dated April 30, 2009, on our consolidated financial statements as of and for the year ended December 31, 2008, contained an explanatory paragraph regarding our ability to continue as a going concern. After April 30, 2009, we obtained additional funding that removed the substantial doubt about whether we would continue as a going concern through December 31, 2009. The report of our independent registered public accounting firm dated March 24, 2010, on our consolidated financial statements as of and for the year ended December 31, 2009, does not contain such an explanatory paragraph; however, there may be in the future circumstances that raise substantial doubt about our ability to continue as a going concern. If doubts about our ability to continue as a going concern are raised in the future notwithstanding the additional funding we have obtained and the funding we will obtain from this offering, our stock price could drop and our ability to raise additional funds, to obtain credit on commercially reasonable terms or to remain in compliance with our covenants with lenders may be adversely affected.

In addition, the assets of some of our subsidiaries collateralize their indebtedness, and in certain cases the assets of certain subsidiaries collateralize the indebtedness of other subsidiaries. This cross-collateralization means that a default by one subsidiary could trigger adverse consequences for other subsidiaries, including possible defaults under their debt agreements, which could have a material adverse effect on our business, financial condition and results of operations.

Our substantial indebtedness could have important consequences. For example, it could:

- make it difficult for us to satisfy our obligations with respect to our indebtedness, and failure to comply with these obligations could result in an event of default under those agreements, which could be difficult to cure, or result in our bankruptcy;
- require us to dedicate an even greater portion of our cash flow to pay principal and interest on our debt, reducing the funds available to us and our ability to borrow to operate and grow our business;
- limit our flexibility to plan for and react to unexpected opportunities;

make us vulnerable to adverse changes in general economic, credit and capital markets, industry and competitive conditions and adverse changes in government regulation; and

place us at a disadvantage compared with competitors with less debt.

Any of these consequences could materially and adversely affect our business, financial condition and results of operations. If we do not comply with our obligations under our debt instruments, we may be required to refinance all or part of our existing debt, borrow additional amounts or sell securities, which we may not be able to do on favorable terms, or at all. In addition, increases in interest rates and changes in debt covenants may reduce the amounts that we can borrow, reduce our net cash flow and increase the equity investment we may be required to make to complete development and construction of our projects. These increases could cause some of our projects to become economically unattractive. If we are unable to raise additional capital or generate sufficient operating cash flow to repay our indebtedness, we could be in default under our lending agreements and could be required to delay development and construction of our wind energy projects, reduce overhead costs, reduce the scope of our projects or abandon or sell some or all of our development projects, all of which could have a material adverse effect on our business, financial condition and results of operations.

If our subsidiaries default on their obligations under their debt instruments, we may need to make payments to lenders to prevent foreclosure on the collateral securing the debt, which would cause us to lose certain of our wind energy projects.

Our subsidiaries incur various types of debt. Non-recourse debt is repayable solely from the applicable project's revenues and is secured by the project's physical assets, major contracts, cash accounts and, in many cases, our ownership interest in the project subsidiary. Limited recourse debt is debt where we have provided a limited guarantee and recourse debt is debt where we have provided a full guarantee, which means if our subsidiaries default on these obligations, we will be liable directly to those creditors, although in the case of limited recourse debt only to the extent of our limited recourse obligations. To satisfy these obligations, we may be required to use amounts distributed by our other subsidiaries as well as other sources of available cash, reducing the cash available to execute our business plan. In addition, if our subsidiaries default on their obligations under non-recourse financing agreements, we may decide to make payments to prevent the creditors of these subsidiaries from foreclosing on the relevant collateral. Such a foreclosure would result in our losing our ownership interest in the subsidiary or in some or all of its assets. The loss of our ownership interest in one or more of our subsidiaries or some or all of their assets could have a material adverse effect on our business, financial condition and results of operations.

Our hedging activities may not adequately manage our exposure to commodity and financial risk, may result in significant losses or require us to use cash collateral to meet margin requirements, each of which could adversely affect our results of operations and cash flow. Liquidity constraints could impair our ability to execute favorable financial hedges in the future.

Our ownership and operation of wind energy projects exposes us to volatility in market prices of electricity and RECs.

In an effort to stabilize our revenue from electricity sales, we evaluate the electricity sale options for each of our development projects, including the appropriateness of entering into a PPA or a financial swap, or both. If we sell our electricity into an independent system operator (ISO) market without a PPA, we may enter into a financial swap to stabilize all or a portion of our estimated revenue stream. Under the terms of our existing financial swaps, we are not obligated to physically deliver or purchase electricity. Instead, we receive payments for specified quantities of electricity based on a fixed price and are obligated to pay our counterparty the market price for the same quantities of electricity. These financial swaps cover quantities of electricity that we estimate we are highly likely to produce. As a result, gains or losses under the financial swaps are designed to be offset by decreases or increases in our revenues from spot sales of electricity in liquid ISO markets. However, the actual amount of electricity we generate from operations may be materially different from our estimates for a variety of reasons, including variable wind conditions and turbine availability. If a project does not generate the volume of electricity covered by the associated swap contract, we could incur significant losses if electricity prices in the market rise substantially above the fixed price provided for in the swap. If a project generates more electricity than is contracted in the swap, the excess production will not be hedged and the revenues we derive will be exposed to market price fluctuations.

We would also incur financial losses as a result of adverse changes in the mark-to-market values of the financial swaps or if the counterparty fails to make payments. We could also experience a reduction in operating cash flow if we are required to post margin in the form of cash collateral. We often are required to post cash collateral and issue letters of credit, which fluctuate based on changes in commodity prices, to backstop our obligations under our hedging arrangements. These actions reduce our available borrowing capacity under the credit facilities under which these letters of credit are issued. We have been and expect in the future to be required to post additional cash collateral or issue additional letters of credit if electricity and oil prices rise. We may be exposed to counterparty credit risk, and may suffer losses, if we enter into hedges with entities that are not creditworthy or we obtain credit support that is inadequate with respect to a counterparty.

We enter into PPAs when we sell our electricity into non-ISO markets or where we believe it is otherwise advisable. Under a PPA, we contract to sell all or a fixed proportion of the electricity generated by one of our projects, sometimes bundled with RECs and capacity, to a customer, often a utility. We do this to stabilize our revenues from that project. We are exposed to the risk that the customer will fail to perform under a PPA, with the result that we will have to sell our electricity at the market price, which could be disadvantageous in the case of fixed-price PPAs. We also in some instances commit to sell minimum levels of generation. If the project generates less than the committed volumes, we may be required to buy the shortfall of electricity on the open market or make payments of liquidated damages.

We often seek to sell forward a portion of our RECs to fix the revenues from those attributes and hedge against future declines in prices of RECs. If our projects do not generate the amount of electricity required to earn the RECs sold forward or if for any reason the electricity we generate does not produce RECs for a particular state we may be required to make up the shortfall of RECs through purchases on the open market or make payments of liquidated damages. Further, current market conditions may limit our ability to hedge sufficient volumes of our anticipated RECs, leaving us exposed to the risk of falling prices for RECs. Future prices for RECs are also subject to the risk that regulatory changes will adversely affect prices.

We are subject to credit and performance risk from third parties under service and supply contracts.

We enter into contracts with vendors to supply equipment, materials and other goods and services for the development, construction and operation of wind projects as well as for other business operations. If vendors do not perform their obligations, we may have to enter into new contracts with other vendors at a higher cost or may have schedule disruptions.

We rely on tax equity financing arrangements to realize the benefits provided by PTCs and accelerated tax depreciation. These arrangements may limit the cash distributions we receive and restrict the manner in which we conduct our business.

Through September 30, 2010, we have entered into four tax equity financing transactions in which we received an aggregate of $388 million ($146.3 million in two transactions in 2007, $19.7 million in 2008 and $222.1 million in 2009) from tax equity investors in return for investments in our projects. The 2009 amount of $222.1 million consisted of an equity investment of $102.1 million and a redeemable interest of $120 million. We repaid the redeemable interest in March 2010 with the proceeds from an ARRA cash grant. The tax equity investors are entitled to most of the applicable project's operating cash flow from electricity sales and related hedging activities, and substantially all of the PTCs and taxable income or loss until they achieve their respective agreed rates of return, which we expect to occur in 10 years.

As a result, a tax equity financing substantially reduces the cash distributions from the applicable project available to us for other uses, and the period during which the tax equity investors receive most of the cash distributions from electricity sales and related hedging activities may last longer than expected if our wind energy projects perform below our expectations.

Our ability to enter into tax equity arrangements in the future depends on the extension of the expiration date or renewal of the PTC, without which the market for tax equity financing would likely cease to exist. Moreover, there are a limited number of potential tax equity investors, they have limited funds and wind energy developers compete with other renewable energy developers and others for tax equity financing. In addition, conditions in financial and credit markets generally may result in the contraction of available tax equity financing. As the renewable energy industry expands, the cost of tax equity financing may increase and there may not be sufficient tax equity financing available to meet the total demand in any year. If we are unable to enter into tax equity financing agreements with attractive pricing terms or at all, we may not be able to use the tax benefits provided by PTCs and accelerated tax depreciation, which could have a material adverse effect on our business, financial condition and results of operations.

Our tax equity financing agreements provide our tax equity investors with various approval rights with respect to the applicable project or projects, including approvals of annual budgets, indebtedness, incurrence of liens, sales of assets outside the ordinary course of business and litigation settlements. These approval rights may restrict how we conduct our business.

We have had material weaknesses and significant deficiencies in our internal control over financial reporting. Any material weaknesses or significant deficiencies in our internal controls could result in a material misstatement in our financial statements as well as result in our inability to file periodic reports timely as required by federal securities laws, which could have a material adverse effect on our business and stock price.

We are required to design, implement and maintain effective controls over financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of a company's annual or interim financial statements will not be prevented or detected on a timely basis.

We have had material weaknesses in our internal control over financial reporting that related to the adequacy of our financial and accounting organization support for our financial accounting and reporting needs. These weaknesses mainly resulted from a lack of sufficient personnel, and contributed to significant deficiencies related to: (1) effective policies and procedures designed to ensure certain costs are capitalized in accordance with generally accepted accounting principles and captured in the appropriate accounting period; (2) an effective process to ensure the completeness of accounts payable and accrued expenses; and (3) an effective review, approval and communications process for journal entries.

While we are implementing procedures designed to remediate these weaknesses and deficiencies, we cannot be certain that we will not in the future have material weaknesses or significant deficiencies in our internal control over financial reporting, or that we will successfully remediate any that we find. If, in the future, we have weaknesses or deficiencies in our internal controls, that could result in a material misstatement in our annual or interim consolidated financial statements or cause us to fail to meet our obligations to file periodic financial reports with the SEC. We also may not be able conclude on an ongoing basis that we have effective internal control over financial reporting as contemplated by Section 404 of the Sarbanes-Oxley Act of 2002 or our independent registered public accounting firm

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may issue an adverse opinion on the effectiveness of our internal control over financial reporting. Any of these failures could result in adverse consequences that could materially and adversely affect our business, including potential action by the SEC against us, possible defaults under our debt agreements, stockholder lawsuits, delisting of our stock and general damage to our reputation.

Risks Related to Our Structure

We are a holding company and our only material asset after completion of the reorganization and this offering will be our interest in First Wind Holdings, LLC, and accordingly we are dependent upon distributions from First Wind Holdings, LLC to pay taxes and other expenses.

We will be a holding company and will have no material assets other than our ownership of Series A Membership Interests of First Wind Holdings, LLC. We will have no independent means of generating revenue. First Wind Holdings, LLC will be treated as a partnership for U.S. federal income tax purposes and, as such, will not itself be subject to U.S. federal income tax. Instead, its taxable income will generally be allocated to its members, including us, pro rata according to the number of membership units each member owns. Accordingly, we will incur income taxes on our proportionate share of any net taxable income of First Wind Holdings, LLC and also will incur expenses related to our operations. We intend to cause First Wind Holdings, LLC to distribute cash to its members in an amount at least equal to the amount necessary to cover their tax liabilities, if any, with respect to their allocable share of the net income of First Wind Holdings, LLC. To the extent that we need funds to pay our tax or other liabilities or to fund our operations, and First Wind Holdings, LLC is restricted from making distributions to us under applicable agreements, laws or regulations or does not have sufficient cash to make these distributions, we may have to borrow funds to meet these obligations and operate our business and our liquidity and financial condition could be materially adversely affected.

We will be required to pay certain holders of Series B Membership Interests most of the tax benefit of any depreciation or amortization deductions we may claim as a result of the tax basis step up we receive in connection with future exchanges of Series B Membership Interests.

We expect that any future exchanges of Series B Membership Interests (together with an equal number of shares of our Class B common stock) for shares of our Class A common stock will result in increases in the tax basis in the tangible and intangible assets of First Wind Holdings, LLC. Any such increases in tax basis would reduce the amount of tax that we would otherwise be required to pay in the future. We will be required to pay a portion of the cash savings we actually realize from such increase to certain holders of the Series B Membership Interests, which include our Sponsors and certain of our employees and current investors, pursuant to a tax receivable agreement. See "The Reorganization and Our Holding Company Structure Tax Receivable Agreement."

We intend to enter into a tax receivable agreement with certain current members of First Wind Holdings, LLC and certain future holders of the Series B Membership Interests, pursuant to which we will pay them 85% of the amount of the cash savings, if any, in U.S. federal, state and local income tax that we realize (or are deemed to realize in the case of an early termination payment by us, or a change in control, as discussed below) as a result of these possible future increases in tax basis. Any actual increases in tax basis, as well as the amount and timing of any payments under the tax receivable agreement cannot be predicted reliably at this time. The amount of any such increases will vary depending upon a number of factors, including the timing of exchanges, the price of our Class A common stock at the time of the exchanges, the extent to which such exchanges are taxable, the amount and timing of our income and the tax rates then applicable. As a result of the size and increases in our share of the tax basis in the tangible and intangible assets of First Wind Holdings, LLC attributable to our interest therein, the payments that we may be required to make pursuant to the tax receivable agreement could be substantial for periods in which we generate taxable income. However, because we have not generated taxable income to date and do not expect to generate taxable income in the near-term, it is difficult to predict when and if we will make payments under the tax receivable agreement. Assuming no material changes in the relevant tax law and based on our current operating plan and other assumptions, including our estimate of the tax basis of our assets as of December 31, 2009, if all of the Series B Membership Interests were acquired by us in taxable transactions at the time of the closing of this offering for a price of $25.00 (the midpoint of the range on the cover of this prospectus) per Series B Membership Interest, we estimate that the amount that we would be required to pay under the tax receivable agreement could be approximately $45.0 million. The actual amount may materially differ from this hypothetical amount, as potential future payments will be calculated using the market value of our Class A shares and the prevailing tax rates at the time of relevant exchange and will be dependent on us generating sufficient future taxable income to realize the benefit.

If the Internal Revenue Service successfully challenges the tax basis increases described above, we will not be reimbursed for any payments made under the tax receivable agreement. As a result, in certain circumstances, we could be required to make payments under the tax receivable agreement in excess of our cash tax savings.

If we are deemed to be an investment company under the Investment Company Act, our business would be subject to applicable restrictions under that Act, which could make it impracticable for us to continue our business as contemplated.

We believe our company is not an investment company under the Investment Company Act because we are the managing member of First Wind Holdings, LLC and we are primarily engaged in a non-investment company business. We intend to conduct our operations so that we will not be an investment company. However, if we are deemed an investment company, restrictions imposed by the Investment Company Act, including limitations on our capital structure and our ability to transact with affiliates, and changes in financial reporting and regulatory disclosure requirements as a result of being an investment company, could make it impractical for us to continue operating our business as contemplated.

Risks Related to this Offering and Our Class A Common Stock

We will continue to be controlled by our Sponsors after the completion of this offering, which will limit your ability to influence corporate activities and may adversely affect the market price of our Class A common stock.

Upon completion of the offering, the D. E. Shaw group and Madison Dearborn will own or control outstanding common stock representing, in the aggregate, an approximately 70.6% voting interest in us, or approximately 68.1%, if the underwriters exercise their over-allotment option in full. As a result of this ownership, our Sponsors will have effective control over the outcome of votes on all matters requiring approval by our stockholders, including the election of directors, the adoption of amendments to our certificate of incorporation and bylaws and approval of a sale of the company and other significant corporate transactions. Our Sponsors can also take actions that have the effect of delaying or preventing a change in control of us or discouraging others from making tender offers for our shares, which could prevent stockholders from receiving a premium for their shares. These actions may be taken even if other stockholders oppose them. Prior to the completion of this offering we and our Sponsors will enter into a nominating and voting agreement pursuant to which we will agree to nominate individuals designated by our Sponsors to the board of directors and the Sponsors will agree to vote all of the shares of Class A common stock and Class B common stock held by them together on certain matters submitted to a vote of our common stockholders, as described under "The Reorganization and Our Holding Company Structure Nominating and Voting Agreement."

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The interests of our Sponsors may conflict with the interests of our other stockholders.

The interests of our Sponsors, or entities controlled by them, may not coincide with the interests of the holders of our Class A common stock. For example, our Sponsors could cause us to make acquisitions or engage in other transactions that increase the amount of our indebtedness or the number of outstanding shares of Class A common stock or sell revenue-generating assets. Additionally, our Sponsors are in the business of trading securities of, and/or investing in, energy companies, including wind energy producers, and related products, including derivatives, commodities and power, and may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. Our Sponsors may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us.

Conflicts of interest may arise because some of our directors are representatives of our controlling stockholders.

Messrs. Aube, Eilers, Martin and Raino, who are representatives of our Sponsors, serve on our board of directors. As discussed above, our Sponsors and entities controlled by them may hold equity interests in entities that directly or indirectly compete with us, and companies in which they currently invest may begin competing with us. As a result of these relationships, when conflicts between the interests of our Sponsors, on the one hand, and the interests of our other stockholders, on the other hand, arise, these directors may not be disinterested. Although our directors and officers have a duty of loyalty to us under Delaware law and our certificate of incorporation, transactions that we enter into in which a director or officer has a conflict of interest are generally permissible so long as (1) the material facts relating to the director's or officer's relationship or interest as to the transaction are disclosed to our board of directors and a majority of our disinterested directors, or a committee consisting solely of disinterested directors, approves the transaction, (2) the material facts relating to the director's or officer's relationship or interest as to the transaction are disclosed to our stockholders and a majority of our disinterested stockholders approves the transaction or (3) the transaction is otherwise fair to us. Under our certificate of incorporation, representatives of our Sponsors are not required to offer to us any transaction opportunity of which they become aware and could take any such opportunity for themselves or offer it to other companies in which they have an investment, unless such opportunity is offered to them solely in their capacity as a director of ours.

We have limited the liability of, and have agreed to indemnify, our Sponsors, their affiliates and their subsidiaries, as well as our directors and officers, which may result in these parties assuming greater risks.

The liability of our Sponsors, their affiliates and their subsidiaries, as well as of our directors and officers, is limited, and we have agreed to indemnify each of these parties to the fullest extent permitted by law. This may lead such parties to assume greater risks when making investment-related decisions than they otherwise would.

Under our certificate of incorporation and bylaws, the liability of our directors, officers and employees is limited. Similarly, First Wind Holdings, LLC's limited liability company agreement contains provisions limiting its managing member's, members', officers' and their respective affiliates', including our Sponsors', liability to First Wind Holdings, LLC and its unit holders. Because First Wind Holdings, LLC is a limited liability company, the exculpation and indemnification provisions in its limited liability company agreement are not subject to the limitations set forth in the Delaware General Corporation Law with respect to the indemnification that may be provided by a Delaware corporation to its directors and officers. In addition, we have contractually agreed to indemnify our directors to the fullest extent permitted by law. These protections may result in the indemnified parties' tolerating greater risks when making investment-related decisions than otherwise would be the case, for example when determining whether to use leverage in connection with investments. The indemnification

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arrangements may also give rise to legal claims for indemnification that are adverse to us and holders of our common stock.

We will be a "controlled company" within the meaning of Nasdaq Listing Rules and, as a result, will qualify for, and rely on, applicable exemptions from certain corporate governance requirements.

After completion of this offering we will be a "controlled company" under the listing rules of the Nasdaq Stock Market (Nasdaq Listing Rules). Under these rules, a company of which more than 50% of the voting power is held by a group is a "controlled company" and may elect not to comply with certain corporate governance requirements under the Nasdaq Listing Rules, including (1) the requirement that a majority of the board of directors consist of independent directors, (2) the requirement that the nominating committee be composed entirely of independent directors, (3) the requirement that the compensation committee be composed entirely of independent directors and (4) the requirement for an annual performance evaluation of the nominating and corporate governance and compensation committees. We intend to rely on this exemption to the extent it is applicable, and therefore we will not have a majority of independent directors or nominating and compensation committees consisting entirely of independent directors. Accordingly, you will not have the same protections afforded to stockholders of companies that are not deemed "controlled companies."

The market price of our Class A common stock could decline due to the large number of shares of Class A common stock eligible for future sale upon the exchange of Series B Membership Interests.

The market price of our Class A common stock could decline as a result of sales of a large number of shares of our Class A common stock eligible for future sale upon the exchange of Series B Membership Interests (together with an equal number of shares of our Class B common stock), or the perception that such sales could occur. These sales, or the possibility that these sales may occur, also may make it more difficult for us to raise additional capital by selling equity securities in the future, at a time and price that we deem appropriate.

After completion of this offering, approximately 23,239,140 Series B Membership Interests of First Wind Holdings, LLC will be outstanding. Each Series B Membership Interest, together with a share of Class B common stock, will be exchangeable for one share of Class A common stock as described under "The Reorganization and Our Holding Company Structure Limited Liability Company Agreement of First Wind Holdings, LLC." We will enter into a registration rights agreement with our current investors pursuant to which we will grant such investors registration rights with respect to shares of Class A common stock.

Requirements associated with being a public company will increase our costs significantly, as well as divert significant company resources and management attention.

Before this offering, we have not been subject to the reporting requirements of the Exchange Act or the other rules and regulations of the SEC or any stock exchange relating to publicly-held companies. We are working with our legal, independent auditing and financial advisors to identify those areas in which changes should be made to our financial and management control systems to manage our growth and fulfill our obligations as a public company. These areas include corporate governance, corporate controls, internal audit, disclosure controls and procedures, financial reporting and accounting systems. We have made, and will continue to make, changes in these and other areas. However, the expenses that will be required in order to prepare adequately for being a public company could be material. Compliance with the various reporting and other requirements applicable to public companies will also require considerable management time and attention.

In addition, being a public company could make it more difficult or more costly for us to obtain certain types of insurance, including directors' and officers' liability insurance, and we may be forced to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage.

Our certificate of incorporation, bylaws and Delaware law contain provisions that could discourage another company from acquiring us, may prevent attempts by our stockholders to replace or remove our current management and could negatively affect our stock price.

Some provisions of our certificate of incorporation, bylaws and Delaware law may have the effect of delaying, discouraging or preventing a merger or acquisition that our stockholders may consider favorable, including transactions in which stockholders may receive a premium for their shares. In addition, these provisions may frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace or remove our board of directors. Our certificate of incorporation and bylaws:

- authorize the issuance of "blank check" preferred stock that could be issued by our board of directors to thwart a takeover attempt without further stockholder approval;

- prohibit cumulative voting in the election of directors, which would otherwise allow holders of less than a majority of stock to elect some directors;

- require super majority ($66^2/_3$%) voting to effect amendments to provisions of our certificate of incorporation or bylaws regarding board composition, renouncement of business opportunities and other amendments to our certificate of incorporation or bylaws described above;

- state that as long as the Class A common stock and the Class B common stock held by our Sponsors and their affiliates, portfolio companies and designated members of our board of directors constitutes more than 50% of the total voting power of all of our capital stock, any action required or permitted to be taken at any annual or special meeting of stockholders may be taken by written consent of stockholders without a meeting; and

- state that only our board of directors, the Chairman of the board of directors, our Chief Executive Officer and, if the Class A common stock and the Class B common stock held by our Sponsors and their affiliates, portfolio companies and designated members of our board of directors constitutes more than 50% of our total voting power, holders of such Class A common stock and Class B common stock (treated as a single class), are permitted to call a special meeting of stockholders.

Upon completion of this offering at an assumed initial public offering price of $25.00 per share (the midpoint of the range set forth on the cover of this prospectus), assuming no exercise of the underwriters' over-allotment option, our Class B common stockholders will own 48.4% of our total voting power.

These provisions could limit the price that investors are willing to pay in the future for shares of our Class A common stock. These provisions may also discourage a potential acquisition proposal or tender offer, even if the acquisition proposal or tender offer is at a premium over the then-current market price for our Class A common stock.

Our Class A common stock has not traded publicly before this offering, and we expect the price of our Class A common stock to fluctuate substantially.

There has not been a public market for our Class A common stock before this offering. A trading market for our Class A common stock may not develop or be liquid. If you purchase shares of our Class A common stock in this offering, you will pay a price that was not established in the public trading markets. The initial public offering price was determined by negotiations between the underwriters and us. You may not be able to resell your shares above the initial public offering price and may suffer a loss of some or all of your investment.

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Broad market and industry factors may adversely affect the market price of our Class A common stock, regardless of our actual operating performance. Other factors that could cause fluctuations in our stock price may include, among other things, the numerous risks and uncertainties as described under "Risk Factors" and under "Cautionary Statement Regarding Forward-Looking Statements."

Factors over which we have little or no control may cause our operating results to vary widely from period to period, which may cause our stock price to decline.

Our operating results may fluctuate from period to period depending on several factors, including varying weather conditions; changes in regulated or market electricity prices; electricity demand, which follows broad seasonal demand patterns; changes in market prices for RECs; marking to market of our hedging arrangements; and unanticipated development or construction delays. Thus, a period-to-period comparison of our operating results may not reflect long-term trends in our business and may not prove to be a relevant indicator of future earnings. These factors may harm our business, financial condition and results of operations and may cause our stock price to decline.

We currently do not intend to pay dividends on our Class A common stock. As a result, your only opportunity to achieve a return on your investment is if the price of our Class A common stock appreciates.

We currently do not expect to declare or pay dividends on our Class A common stock. Our debt agreements currently limit our ability to pay dividends on our Class A common stock, and we may also enter into other agreements in the future that prohibit or restrict our ability to declare or pay dividends on our Class A common stock. As a result, your only opportunity to achieve a return on your investment will be if the market price of our Class A common stock appreciates and you sell your shares at a profit.

You may experience dilution of your ownership interest due to the future issuance of additional shares of our Class A common stock.

We are in a capital intensive business and we do not have sufficient funds to finance the growth of our business or the construction costs of our development projects or to support our projected capital expenditures. As a result, we will require additional funds from further equity or debt financings, including tax equity financing transactions or sales of preferred shares or convertible debt to complete the development of new projects and pay the general and administrative costs of our business. We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of purchasers of Class A common stock offered hereby. We are currently authorized to issue 325,000,000 shares of common stock and 5,000,000 shares of preferred stock with preferences and rights as determined by our board of directors. The potential issuance of such additional shares of common stock or preferred stock or convertible debt may create downward pressure on the trading price of our Class A common stock. We may also issue additional shares of Class A common stock or other securities that are convertible into or exercisable for Class A common stock in future public offerings or private placements for capital raising purposes or for other business purposes, potentially at an offering price or conversion price that is below the offering price for Class A common stock in this offering.

You will suffer immediate and substantial dilution in the book value per share of your Class A common stock as a result of this offering.

The initial public offering price of our Class A common stock is considerably more than the pro forma net tangible book value per share of our outstanding Class A common stock, as adjusted to reflect completion of this offering. This reduction in the book value of your equity is known as dilution. This dilution occurs in large part because our earlier investors paid substantially less than the initial public offering price when they purchased their shares. Investors purchasing Class A common stock in this offering will incur immediate dilution of $2.75 in pro forma net tangible book value per share of Class A common stock, as adjusted to reflect completion of this offering and giving effect to the pro forma as adjusted assumptions set forth under "Capitalization."

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements in this prospectus, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects, revenues, income and capital spending. We generally identify forward-looking statements with the words "believe," "intend," "expect," "seek," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project" or their negatives, and other similar expressions. All statements we make relating to our estimated and projected earnings, margins, costs, expenditures, cash flows, growth rates and financial results or to our expectations regarding future industry trends are forward-looking statements.

These forward-looking statements are subject to risks and uncertainties that may change at any time, and, therefore, our actual results may differ materially from those that we expected. The forward-looking statements contained in this prospectus are largely based on our expectations, which reflect many estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and 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. In addition, management's assumptions about future events may prove to be inaccurate. We caution all readers that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will prove correct or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the numerous risks and uncertainties as described under "Risk Factors" and elsewhere in this prospectus. All forward-looking statements are based upon information available to us on the date of this prospectus. We undertake no obligation to update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties associated with our forward-looking statements relate to, among other matters, the following:

- our ability to complete our wind energy projects or acquire wind energy assets;
- fluctuations in supply, demand, prices and other conditions for electricity, other commodities and RECs;
- changes in law;
- public response to and changes in the local, state and federal regulatory framework affecting renewable energy projects, including the potential expiration or extension of the 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;
- the availability of financing, including tax equity financing, for our wind energy projects;
- our ability to continue as a going concern;
- risks associated with our hedging strategies;
- our substantial short-term and long-term indebtedness;
- competition from other energy developers;

development constraints, including limited geographic availability for suitable sites, obtaining permits on a timely basis and availability of interconnection;

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- the limited operating history of and technical issues experienced by one of our key turbine suppliers, Clipper;
- potential environmental liabilities and the cost of compliance with applicable environmental laws and regulations;
- our electrical production projections (including assumptions of curtailment and facility availability) for our wind energy projects;
- our ability to operate our business efficiently, manage capital expenditures and costs (including general and administrative expenses) effectively and generate cash flow;
- our ability to retain and attract senior management and key employees;
- our ability to keep pace with and take advantage of new technologies;
- availability of suitable wind resources and other weather conditions that affect our electricity production;
- the effects of litigation, including administrative and other proceedings or investigations relating to our wind energy projects under development and those in operation;
- conditions in energy markets as well as financial markets generally, which will be affected by interest rates, foreign currency fluctuations and general economic conditions;
- strains on our resources due to the expansion of our business;
- non-payment by customers and enforcement of certain contractual provisions;
- the effective life and cost of maintenance of our wind turbines and other equipment; and
- other factors discussed under "Risk Factors."

MARKET AND INDUSTRY DATA

This prospectus includes market and industry data that we have developed from independent consultant reports, publicly available information, various industry publications, other published industry sources and our internal data and estimates. Our internal data, estimates and forecasts are based upon information obtained from trade and business organizations and other contacts in the markets in which we operate and our management's understanding of industry conditions.

USE OF PROCEEDS

We estimate that the net proceeds to us from the sale of Class A common stock in this offering will be approximately $275.2 million, based on an offering price of $25.00 per share, the midpoint of the range set forth on the cover of this prospectus, after deducting estimated underwriting discounts and commissions and estimated offering expenses.

We are required under the terms of our Wind Acquisition Loan (which had a variable interest rate of 5.01% at September 30, 2010 and matures in June 2011) to make a principal payment estimated to be approximately $15 to $20 million as a result of this offering. Additionally, we intend to use approximately $78 million of net proceeds from this offering to retire the First Wind Term Loan (which has a fixed interest rate of 17%) in March 2011 in advance of its March 2013 maturity. We intend to use the remainder of the offering proceeds to fund a portion of our project development and construction costs for 2010-2013 and for general corporate purposes.

A $1.00 increase or decrease in the assumed initial public offering price of $25.00 would increase or decrease net proceeds to us from this offering by approximately $11.2 million after deducting estimated underwriting discounts and commissions and estimated offering expenses.

DIVIDEND POLICY

We do not expect to declare or pay any cash or other dividends on our Class A common stock, as we intend to reinvest cash flow generated by operations in our business. Our debt agreements effectively limit our ability to pay dividends on our Class A common stock, and we may also enter into credit agreements or other arrangements in the future that prohibit or restrict our ability to declare or pay dividends on our Class A common stock. Class B common stock will not be entitled to any dividend payments.

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CAPITALIZATION

The following table sets forth the consolidated capitalization of:

First Wind Holdings, LLC on an actual basis as of September 30, 2010;

First Wind Holdings Inc. on a pro forma basis as of September 30, 2010 to give effect to all of the reorganization transactions described in "The Reorganization and Our Holding Company Structure;" and

First Wind Holdings Inc. on a pro forma as adjusted basis as of September 30, 2010 to give further effect to our sale of shares of common stock in this offering at an assumed initial public offering price of $25.00 per share, the midpoint of the range set forth on the cover of this prospectus, after deducting estimated underwriting discounts and commissions and estimated offering expenses.

You should read this table together with the information under "Unaudited Pro Forma Financial Information," "Selected Historical Financial and Operating Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "The Reorganization and Our Holding Company Structure," "Description of Capital Stock" and in the consolidated financial statements included elsewhere in this prospectus.

	As of September 30, 2010		
	First Wind Holdings, LLC Actual	**First Wind Holdings Inc. Pro Forma (unaudited)**	**First Wind Holdings Inc. Pro Forma As Adjusted(2)**
	(in thousands, except share amounts)		
Long-term debt, including debt with maturities less than one year(1)	$ 561,381	$ 561,381	$ 542,631
Members' capital/stockholders' equity:			
Members' capital	848,745	N/A	N/A
Class A common stock, $0.001 par value, no shares authorized, issued and outstanding, actual; 275,000,000 shares authorized and 12,760,860 shares issued and outstanding, pro forma; 275,000,000 shares authorized and 24,760,860 shares issued and outstanding, pro forma as adjusted	N/A	13	25
Class B common stock, $0.001 par value, no shares authorized, issued and outstanding, actual; 50,000,000 shares authorized and 23,239,140 shares issued and outstanding pro forma; 50,000,000 shares authorized and 23,239,140 shares issued and outstanding, pro forma as adjusted	N/A	23	23
Additional paid-in capital	N/A	300,420	542,275
Accumulated deficit	(232,968)	(82,228)	(82,228)
Noncontrolling interests in subsidiaries	176,395	574,629	607,912
Total members' capital/stockholders' equity	792,172	792,857	1,068,007
Total capitalization	$ 1,353,553	$ 1,354,238	$ 1,610,638

(1) Approximately $112.0 million of our actual outstanding indebtedness had a maturity of less than one year as of September 30, 2010.

(2)

A $1.00 increase (decrease) in the assumed initial public offering price of $25.00 per share would increase (decrease) pro forma as adjusted stockholders' equity by $11.2 million, based on the assumptions set forth above. The pro forma as adjusted information set forth above is illustrative only and upon completion of this offering will be adjusted based on the actual offering price and other terms of this offering determined at pricing.

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DILUTION

At September 30, 2010 after giving effect to the reorganization described under "The Reorganization and Our Holding Company Structure," the net tangible book value per share of our Class A and Class B common stock was $22.02. Net tangible book value per share is determined by dividing our tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of Class A and Class B common stock. After giving effect to the sale of shares in this offering at an assumed offering price of $25.00 per share, the midpoint of the range set forth on the cover of this prospectus, after deducting estimated underwriting discounts and commissions and estimated offering expenses, and assuming all Series B Membership Interests that will be outstanding immediately after the reorganization are, together with an equal number of shares of our Class B common stock, exchanged for an equal number of shares of Class A common stock, our net tangible book value at September 30, 2010 would have been approximately $22.25 per share. This represents an immediate dilution of $2.75 per share to new investors purchasing Class A common stock in this offering, resulting from the difference between the offering price and the net tangible book value after this offering. The following table illustrates the per share dilution to new investors purchasing Class A common stock in this offering:

Assumed initial public offering price per share		$ 25.00
Net tangible book value per share at September 30, 2010 (pro forma)	$ 22.02	
Increase in net tangible book value per share attributable to new investors	0.24	
As adjusted net tangible book value per share after this offering		22.25
Dilution per share to new investors		$ 2.75

The following table sets forth at September 30, 2010 after giving effect to the reorganization, the total number of shares of Class A common stock purchased from us, and the total consideration and average price per share paid by existing equity holders and by new investors purchasing Class A common stock in this offering, assuming all Series B Membership Interests that will be outstanding immediately after the completion of the reorganization are, together with an equal number of shares of Class B common stock, exchanged for an equal number of shares of Class A common stock, at an assumed initial public offering price of $25.00 per share, the midpoint of the range set forth on the cover of this prospectus.

	Shares Issued		Total Consideration		Average Consideration Per Share
	Number	Percent	Amount	Percent	
Existing stockholders	36,000,000	75%	871,582,835	74.4%	24.21
New investors	12,000,000	25%	300,000,000	25.6%	25.00
Total	48,000,000	100%	1,171,582,835	100.0%	24.41

If the underwriters' over-allotment option is exercised in full, the number of shares held by existing stockholders after this offering would decrease to 48.0% of the total number of shares of Class A common stock outstanding immediately following this offering, and the number of shares held by new investors would increase to 13,800,000 or approximately 52.0% of the total number of shares of Class A common stock outstanding immediately following this offering.

A $1.00 increase (decrease) in the assumed initial public offering price of $25.00 per share would increase (decrease) total consideration paid by new investors in this offering and by all investors by $11.2 million, and dilution per share for new investors by approximately $0.23.

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UNAUDITED PRO FORMA FINANCIAL INFORMATION

The following unaudited consolidated pro forma statements of operations for the year ended December 31, 2009 and the nine months ended September 30, 2010 and the unaudited pro forma consolidated balance sheet as of September 30, 2010 present our consolidated results of operations and financial position to give pro forma effect to the reorganization transactions described in "The Reorganization and Our Holding Company Structure" and the sale of shares in this offering (excluding shares issuable upon any exercise of the underwriters' over-allotment option) and the application of the net proceeds from this offering as if all such transactions had been completed as of January 1, 2009 with respect to the unaudited consolidated pro forma statement of operations data and as of September 30, 2010 with respect to the unaudited pro forma consolidated balance sheet data. The unaudited pro forma consolidated financial statements reflect pro forma adjustments that are described in the accompanying notes and are based on available information and certain assumptions we believe are reasonable, but are subject to change. We have made, in our opinion, all adjustments that are necessary to present fairly the pro forma financial data.

The unaudited pro forma financial data are presented for informational purposes only and should not be considered indicative of actual results of operations that would have been achieved had the reorganization transactions and this offering been consummated on the dates indicated, and do not purport to be indicative of statements of financial condition or results of operations as of any future date or any future period.

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FIRST WIND HOLDINGS INC.
Unaudited Pro Forma Consolidated Balance Sheet
As of September 30, 2010
(in thousands, except share amounts)

	First Wind Holdings, LLC Historical	Reorganization Adjustments		First Wind Holdings Inc.(1) Pro Forma	Offering Adjustments		First Wind Holdings, Inc.(1) Pro Forma as Adjusted
Assets							
Current assets:							
Cash and cash equivalents	$ 66,610	$		$ 66,610	$ 275,150	(4)	$ 323,010
					(18,750)	(5)	
Restricted cash	46,786			46,786			46,786
Accounts receivable	7,841			7,841			7,841
Prepaid expenses and other current assets	7,790			7,790			7,790
Derivative assets	11,355			11,355			11,355
Total current assets	140,382			140,382	256,400		396,782
Property, plant and equipment, net	838,165			838,165			838,165
Construction in progress	559,541			559,541			559,541
Turbine deposits	72,054			72,054			72,054
Long-term derivative assets	52,744			52,744			52,744
Other non-current assets	25,915			25,915			25,915
Deferred financing costs	23,468			23,468			23,468
Total assets	$ 1,712,269	$		$ 1,712,269	$ 256,400		$ 1,968,669
Liabilities and Stockholders' Equity							
Current liabilities:							
Accrued capital expenditures	$ 44,553	$		$ 44,553	$		$ 44,553
Accounts payable and accrued expenses	32,387			32,387			32,387
Derivative liabiliites	4,764			4,764			4,764
Deferred tax liability							
Other current liabilities							
Deferred revenue	11,340			11,340			11,340
Current portion of long-term debt	111,960			111,960	(18,750)	(5)	93,210
Total current liabilities	205,004			205,004	(18,750)		186,254
Long-term debt, net of current portion	449,421			449,421			449,421
Long-term derivative liabilities	12,132			12,132			12,132
Deferred income tax liability	6,523			6,523			6,523
Deferred revenue	206,951			206,951			206,951
Other liabilities	29,435	(685)	(6)	28,750			28,750
Asset retirement obligations	10,631			10,631			10,631
Total liabilities	920,097	(685)		919,412	(18,750)		900,662
Commitments and contingencies							
Members' capital/stockholders' equity First Wind Holdings, LLC members' capital	848,745	(848,745)	(2)				
First Wind Holdings Inc.							
Class A common stock, $0.001 par value		13	(2)	13	12	(4)	25
Class B common stock, $0.001 par value		23	(2)	23			23
Additional paid-in capital		300,420	(2)	300,420	241,855	(4)	542,275
Accumulated deficit	(232,968)	150,740	(2)(6)	(82,228)			(82,228)
Total First Wind Holdings members' capital/stockholders' equity	615,777	(397,549)		218,228	241,867		460,095
Noncontrolling interests in subsidiaries	176,395	398,234	(2)(6)	574,629	33,283	(4)	607,912
Total members' capital/stockholders' equity	792,172	685		792,857	275,150		1,068,007

Total liabilities and members' capital/stockholders' equity	$ 1,712,269	$	$ 1,712,269	$ 256,400	$ 1,968,669

(1) As a newly formed entity, First Wind Holdings Inc. will have no assets or results of operations until the completion of this offering.

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(2)

Represents adjustments to reflect exchange of existing members' ownership interest in First Wind Holdings LLC for approximately 48.5% of our Class A common stock and 100% of our Class B common stock along with the Series B Membership Interests in First Wind Holdings, LLC. As described in "The Reorganization and Our Holding Company Structure," after this offering, assuming the underwriters do not exercise their over-allotment option, and the reorganization transactions that we are undertaking in connection therewith, our only material asset will be our ownership of approximately 51.6% of the Membership Interests of First Wind Holdings, LLC and our only business will be to act as the sole managing member of First Wind Holdings, LLC. As such, we will operate and control all of its business and affairs and will consolidate its financial results into our financial statements. The ownership interests of the other members of First Wind Holdings, LLC will be accounted for as a noncontrolling interest in our consolidated financial statements after this offering. The exchange of shares of our Class B common stock (or Class A common stock, as the case may be) for membership units of First Wind Holdings, LLC as part of our reorganization will be accounted for as a transfer of carrying value in a recapitalization without consideration.

(3)

This offering and the reorganization transactions will not result in an immediate step-up in the value of our assets. However, future exchanges of Series B Membership Interests for shares of our Class A common stock are expected to increase the tax basis in the tangible and intangible assets of First Wind Holdings, LLC. The step-up in tax basis is initially depreciable and amortizable for tax purposes over a 15-year period. We will enter into a tax receivable agreement with certain holders of Series B Membership Interests after giving effect to the reorganization and certain future holders of Series B Membership Interests that will require us to pay such holders 85% of the amount of cash savings, if any, in U.S. federal, state and local income tax that we actually realize (or are deemed to realize in the case of an early termination payment by us, or a change in control, as discussed below) as a result of the increases in tax basis and of certain other tax benefits related to entering into the tax receivable agreement, including tax benefits attributable to payments under the tax receivable agreement.

(4)

We expect to receive net proceeds from this offering of $275.2 million based on an aggregate underwriting discount of $19.5 million and estimated offering expenses of $5.4 million. We are required to make a principal payment estimated to be approximately $15 million to $20 million as a result of this offering; additionally, we intend to use approximately $78.1 million of net proceeds from this offering to retire early our First Wind Term Loan in March 2011 and intend to use the remainder of the offering proceeds to fund a portion of our project development and construction costs for 2010-2013 and for general corporate purposes.

A $1.00 increase (decrease) in the assumed initial public offering price of $25.00 per share would increase (decrease) each of the pro forma as adjusted cash and cash equivalents and stockholders' equity by $11.2 million, after deducting estimated underwriting discounts and commissions and estimated offering expenses. The pro forma as adjusted information discussed above is illustrative only and following completion of this offering will be adjusted based on the actual offering price and other terms of this offering determined at pricing.

(5)

Reflects a payment on our Wind Acquisition Loan in accordance with the amortization schedule for this loan that contains a provision requiring an incremental payment upon completion of this offering which is estimated to be $15 million to $20 million. Also, the Company anticipates that it will make a discretionary payment of $78.1 million to retire the First Wind Term Loan in March 2011; however, this payment is not a direct result of the offering or reorganization and has been excluded from the pro forma presentation.

(6)

Reflects assumed expiration of a warrant to purchase 10.0 million Series A-1 units of First Wind Holdings, LLC at $1.00 per unit.

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FIRST WIND HOLDINGS INC.
Unaudited Pro Forma Consolidated Statement of Operations
Year Ended December 31, 2009
(in thousands, except share and per share amounts)

	First Wind Holdings, LLC Historical	Reorganization Adjustments		First Wind Holdings Inc.(1) Pro Forma	Offering Adjustments		First Wind Holdings Inc.(1) Pro Forma as Adjusted
Revenues:							
Revenues	$ 47,136	$		$ 47,136	$		$ 47,136
Cash settlements of derivatives	10,966			10,966			10,966
Fair value changes in derivatives	17,175			17,175			17,175
Total revenues	75,277			75,277			75,277
Cost of revenues:							
Project operating expenses(2)	19,709			19,709			19,709
Depreciation and amortization	34,185			34,185			34,185
Total cost of revenues	53,894			53,894			53,894
Gross income	21,383			21,383			21,383
Other operating expenses:							
Project development(2)	35,895			35,895			35,895
General and administrative(2)	39,192			39,192			39,192
Depreciation and amortization	3,381			3,381			3,381
Total other operating expenses	78,468			78,468			78,468
Loss from operations	(57,085)			(57,085)			(57,085)
Other expense(3)	(1,915)			(1,915)			(1,915)
Loss before provision for income taxes	(59,000)			(59,000)			(59,000)
Provision for income taxes	2,010			2,010			2,010
Net loss	(61,010)			(61,010)			(61,010)
Less: net loss attributable to noncontrolling int.	1,391	38,514	(4)	39,905	(9,658)	(4)	30,247
Net loss attributable to members of First Wind Holdings(5)	$ (59,619)	$ 38,514		$ (21,105)	$ (9,658)		$ (30,763)
Pro forma net loss per share (basic and diluted)(6)	$ (0.09)			$ (1.65)			$ (1.24)
Shares used in computing pro forma net loss per share (basic)(6)	649,681,382	(636,920,522)	(6)	12,760,860	(12,000,000)	(6)	24,760,860

(1) As a newly formed entity, First Wind Holdings Inc. will have no assets or results of operations until the completion of this offering.

(2) Historical amounts include stock-based compensation expense for our Series B Unit Awards. Our compensation committee has approved the grant of non-qualified stock options to employees of approximately 3.8 million. The number of options granted was determined based on an assumed public offering price equal to $25.00 per share, the mid-point of the range on the front cover of this prospectus. The number of options granted will be adjusted on the pricing date based on the actual public offering price. The exercise price for the options will be at least the public offering price. Since this award is discretionary, no pro forma adjustment has been made. We anticipate that this award will have approximately $30.0 million of grant-date fair value that will be expensed over its weighted average vesting life.

(3) Interest on anticipated cash proceeds from this offering is excluded from the pro forma presentation. We expect to receive net proceeds from this offering of $275.2 million based on an aggregate underwriting discount of $19.5 million and estimated offering expenses of $5.4 million. We are required to make a principal payment estimated to be approximately $15 million to $20 million as a result of this offering; additionally, we intend to use approximately $78.1 million of net proceeds from this offering to retire early our First Wind Term Loan in March 2011 and we intend to use the remainder of the offering proceeds to fund a portion of our project development and construction costs for 2010-2013 and for general corporate purposes.

(4) As described in "The Reorganization and Our Holding Company Structure," following this offering, and the reorganization transactions that we are undertaking in connection therewith, our only material asset will be our ownership of approximately 51.6% of the membership units of First Wind Holdings, LLC, assuming the underwriters do not exercise their over-allotment option, and our only business will be to act as the sole managing member of First Wind Holdings, LLC. As such, we will operate and control all of its business and affairs and will consolidate its financial results

into our financial statements. The ownership interests of the other members of First Wind Holdings, LLC will be accounted for as a noncontrolling interest in our consolidated financial statements after this offering. Represents adjustments to reflect noncontrolling interest resulting from the existing members' ownership interest of 100% of the Series B Units of First Wind Holdings, LLC.

(5)
First Wind Holdings, LLC is currently taxed as a partnership for federal income tax purposes. Therefore, First Wind Holdings, LLC is not subject to entity-level federal income taxation, with the exception of certain subsidiaries that have elected to be treated as corporations under the Internal Revenue Code, and taxes with respect to income of First Wind Holdings, LLC are payable by First Wind Holdings, LLC's equity holders at rates applicable to them. Following this offering, and the reorganization that we are undertaking in connection therewith, earnings recorded by us will be subject to federal income taxation. For the period presented, our loss before provision for income taxes would have resulted in a net income tax benefit. This net income tax benefit is not recognized in the pro forma presentation since it would be offset by a valuation allowance.

(6)
Pro forma basic and diluted net loss per share was computed by dividing the pro forma net income attributable to our Class A stockholders by the 12,000,000 shares of Class A common stock that we will issue and sell in this offering (assuming that the underwriters do not exercise their option to purchase an additional 1,800,000 shares of Class A common stock to cover over-allotments), plus 12,760,860 shares issued in connection with our initial capitalization, assuming that these 24,760,860 shares of Class A common stock were outstanding for the entirety of each of the historical periods presented on a pro forma basis. No pro forma effect was given to the future potential exchanges of the 23,239,140 Series B Membership Interests of our subsidiary, First Wind Holdings, LLC, together with an equal number of shares of our Class B common stock, that will be outstanding immediately after the completion of this offering and the reorganization transactions for the equal number of shares of our Class A common stock because the issuance of shares of Class A common stock upon these exchanges would not be dilutive.

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FIRST WIND HOLDINGS INC.
Unaudited Pro Forma Consolidated Statement of Operations
Nine Months Ended September 30, 2010
(in thousands, except share and per share amounts)

	First Wind Holdings, LLC Historical	Reorganization Adjustments	First Wind Holdings Inc.(1) Pro Forma	Offering Adjustments	First Wind Holdings Inc.(1) Pro Forma as Adjusted
Revenues:					
Revenues	$ 62,805	$	$ 62,805	$	$ 62,805
Cash settlements of derivatives	5,927		5,927		5,927
Fair value changes in derivatives	19,397		19,397		19,397
Total revenues	88,129		88,129		88,129
Cost of revenues:					
Project operating expenses(2)	34,162		34,162		34,162
Depreciation and amortization	35,678		35,678		35,678
Total cost of revenues	69,840		69,840		69,840
Gross income (loss)	18,289		18,289		18,289
Other operating expenses:					
Project development(2)	32,889		32,889		32,889
General and administrative(2)	24,974		24,974		24,974
Depreciation and amortization	3,443		3,443		3,443
Total other operating expenses	61,306		61,306		61,306
Loss from operations	(43,017)		(43,017)		(43,017)
Other income (expense)(3)	(4,514)	(3,665) (7)	(8,179)		(8,179)
Loss before provision for income taxes	(47,531)	(3,665)	(51,196)		(51,196)
Provision for income taxes	4,513		4,513		4,513
Net loss	(52,044)	(3,665)	(55,709)		(55,709)
Less: net loss attributable to noncontrolling int.	10,304	29,332 (4)	39,636	(7,356) (4)	32,280
Net loss attributable to members of First Wind Holdings(5)	$ (41,740)	$ 25,667	$ (16,073)	$ (7,356)	$ (23,429)
Pro forma net loss per share (basic and diluted)(6)	$ (0.06)		$ (1.26)		$ (0.95)
Shares used in computing pro forma net loss per share (basic)(6)	649,681,382	(636,920,522) (6)	12,760,860	12,000,000 (6)	24,760,860

(1) As a newly formed entity, First Wind Holdings Inc. will have no assets or results of operations until the completion of this offering.

(2) Historical amounts include stock-based compensation expense for our Series B Unit Awards. Our compensation committee has approved the grant of non-qualified stock options to employees of approximately 3.8 million. The number of options granted was determined based on an assumed public offering price equal to $25.00 per share, the mid-point of the range on the front cover of this prospectus. The number of options granted will be adjusted on the pricing date based on the actual public offering price. The exercise price for the options will be at least the public offering price. Since this award is discretionary, no pro forma adjustment has been made. We anticipate that this award will have approximately $30.0 million of grant-date fair value that will be expensed over its weighted average vesting life.

(3) Interest on anticipated cash proceeds from this offering is excluded from the pro forma presentation. We expect to receive net proceeds from this offering of $275.2 million based on an aggregate underwriting discount of $19.5 million and estimated offering expenses of $5.4 million. We are required to make a principal payment estimated to be approximately $15 to $20 million as a result of this offering; additionally, we intend to use approximately $78.1 million of net proceeds from this offering to retire early our First Wind Term Loan in March 2011 and will use the remainder of the offering proceeds to fund a portion of our project development and construction costs for 2010-2013 and for general corporate purposes.

(4) As described in "The Reorganization and Our Holding Company Structure," following this offering, and the reorganization transactions that we are undertaking in connection therewith, our only material asset will be our ownership of approximately 51.6% of the membership units of First Wind Holdings, LLC, assuming the underwriters do not exercise their over-allotment option, and our only business will be to act as the sole managing member of First Wind Holdings, LLC. As such, we will operate and control all of its business and affairs and will consolidate its financial results

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into our financial statements. The ownership interests of the other members of First Wind Holdings, LLC will be accounted for as a noncontrolling interest in our consolidated financial statements after this offering. Represents adjustments to reflect noncontrolling interest resulting from the existing members' ownership interest of 100% of the Series B Units of First Wind Holdings, LLC.

(5)

First Wind Holdings, LLC is currently taxed as a partnership for federal income tax purposes. Therefore, First Wind Holdings, LLC is not subject to entity-level federal income taxation, with the exception of certain subsidiaries that have elected to be treated as corporations under the Internal Revenue Code, and taxes with respect to income of First Wind Holdings, LLC are payable by First Wind Holdings, LLC's equity holders at rates applicable to them. Following this offering, and the reorganization that we are undertaking in connection therewith, earnings recorded by us will be subject to federal income taxation. For the period presented, our loss before provision for income taxes would have resulted in a net income tax benefit. This net income tax benefit is not recognized in the pro forma presentation since it would be offset by a valuation allowance.

(6)

Pro forma basic and diluted net loss per share was computed by dividing the pro forma net income attributable to our Class A stockholders by the 12,000,000 shares of Class A common stock that we will issue and sell in this offering (assuming that the underwriters do not exercise their option to purchase an additional 1,800,000 shares of Class A common stock to cover over-allotments), plus 12,760,860 shares issued in connection with our initial capitalization, assuming that these 24,760,860 shares of Class A common stock were outstanding for the entirety of each of the historical periods presented on a pro forma basis. No pro forma effect was given to the future potential exchanges of the 23,239,140 Series B Membership Interests of our subsidiary, First Wind Holdings, LLC, together with an equal number of shares of our Class B common stock, that will be outstanding immediately after the completion of this offering and the reorganization transactions for the equal number of shares of our Class A common stock because the issuance of shares of Class A common stock upon these exchanges would not be dilutive.

(7)

Reflects assumed expiration of a warrant to purchase 10.0 million Series A-1 units of First Wind Holdings, LLC at $1.00 per unit.

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SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

You should read the following selected consolidated financial data together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and notes thereto appearing elsewhere in this prospectus. The selected consolidated statement of operations data for the years ended December 31, 2007, 2008 and 2009 and the selected consolidated balance sheet data as of December 31, 2008 and 2009 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected consolidated statement of operations data for the nine months ended September 30, 2009 and 2010 and the selected consolidated balance sheet data as of September 30, 2010 are derived from our unaudited interim consolidated financial statements included elsewhere in this prospectus. The unaudited interim period financial information, in the opinion of management, includes all adjustments, which are normal and recurring in nature, necessary for the fair presentation of the periods shown. The selected consolidated statement of operations data for the years ended December 31, 2005 and 2006 and the selected consolidated balance sheet data as of December 31, 2005, 2006 and 2007 are derived from our audited consolidated financial statements not included in this prospectus. Our historical results may not be indicative of the operating results to be expected in any future periods.

	Year Ended December 31,					Nine Months Ended September 30,	
	2005	2006	2007	2008	2009	2009	2010
	(Dollars in thousands)						
Statement of Operations Data:							
Revenues:							
Revenues	$ 72	$ 7,063	$ 23,817	$ 28,790	$ 47,136	$ 30,468	$ 62,805
Cash settlements of derivatives		(922)	(1,670)	(4,072)	10,966	8,388	5,927
Fair value changes in derivatives		9,770	(9,801)	14,760	17,175	19,192	19,397
Total revenues	72	15,911	12,346	39,478	75,277	58,048	88,129
Cost of revenues:							
Project operating expenses		1,339	9,175	10,613	19,709	13,269	34,162
Depreciation and amortization of operating assets		1,945	8,800	10,611	34,185	23,445	35,678
Total cost of revenues		3,284	17,975	21,224	53,894	36,714	69,840
Gross income (loss)	72	12,627	(5,629)	18,254	21,383	21,334	18,289
Other operating expenses							
Project development	6,706	16,028	25,861	35,855	35,895	32,694	32,889
General and administrative	1,557	6,598	13,308	44,358	39,192	28,599	24,974
Depreciation and amortization	158	294	1,215	2,325	3,381	2,443	3,443
Total other operating expenses	8,421	22,920	40,384	82,538	78,468	63,736	61,306
Income (loss) from operations	(8,349)	(10,293)	(46,013)	(64,284)	(57,085)	(42,402)	(43,017)
Risk management activities related to non-operating projects	(6,784)	(13,131)	(21,141)	42,138			
Other income (expense)	19	458	1,078	827	(1,915)	(4,860)	(4,514)
Interest expense, net of capitalized interest	(2,803)	(3,049)	(9,820)	(4,846)		(3)	
Loss before provision for income taxes	(17,917)	(26,015)	(75,896)	(26,165)	(59,000)	(47,265)	(47,531)
Provision for income taxes					2,010		4,513
Net loss	(17,917)	(26,015)	(75,896)	(26,165)	(61,010)	(47,265)	(52,044)
Less: net loss attributable to noncontrolling interests			7,825	11,107	1,391	6,771	10,304
Net loss attributable to members of First Wind Holdings, LLC before cumulative effect of adoption of FIN 46R	(17,917)	(26,015)	(68,071)	(15,058)	(59,619)	(40,494)	(41,740)
Cumulative effect of adoption of FIN 46R(1)	(703)						

Net loss attributable to members of First Wind Holdings, LLC	$ (18,620)	$ (26,015)	$ (68,071)	$ (15,058)	$ (59,619)	$ (40,494)	$ (41,740)
Net loss attributable per common unit(2) (basic and diluted)	$ (0.38)	$ (0.24)	$ (0.36)	$ (0.05)	$ (0.09)	$ (0.06)	$ (0.06)
Weighted average number of common units (basic and diluted)	49,095,347	107,712,405	189,161,855	278,288,518	649,681,382	649,681,382	649,681,382
Other Financial Data:							
Net cash provided by (used in):							
Operating activities(3)	$ (3,195)	$ (31,799)	$ (26,370)	$ (41,589)	$ (54,478)	$ (40,288)	$ 203,464
Investing activities	(25,286)	(311,281)	(334,007)	(477,268)	(253,533)	(325,894)	(39,278)
Financing activities	30,244	346,500	358,107	556,059	298,749	374,012	(129,043)
Selected Operating Data:							
Rated capacity (end of period)(4)		30 MW	92 MW	92 MW	478 MW	274 MW	504 MW
Electricity generated		56,629 MWh	239,940 MWh	275,024 MWh	656,365 MWh	437,143 MWh	849,614 MWh
Average realized energy price(5)		$ 108/MWh	$ 103/MWh	$ 97/MWh	$ 85/MWh	$ 82/MWh	$ 78/MWh
Project EBITDA(6)		$ 4,802	$ 14,945	$ 15,589	$ 35,867	$ 22,350	$ 33,723

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	As of December 31,					As of September 30,
	2005	2006	2007	2008	2009	2010
	(in thousands)					
Balance Sheet Data:						
Property, plant and equipment, net	$ 484	$ 81,452	$ 192,076	$ 187,316	$ 950,610	$ 838,165
Construction in progress	29,075	85,153	346,320	571,586	472,526	559,541
Total assets	37,998	372,500	770,666	1,311,591	1,698,154	1,712,269
Long-term debt, including debt with maturities less than one year	35,195	257,884	465,449	532,441	632,046	561,381
Members' capital (deficit)	(24,671)	88,519	147,876	653,092	849,373	792,172

(1) We adopted FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, an interpretation of FIN 46(R) effective December 31, 2006, and as a result of being the primary beneficiary of certain VIEs, were required to consolidate them in accordance with GAAP. FIN 46(R) defined a VIE as an entity in which the equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. A VIE must be consolidated only by its primary beneficiary, which is defined as the party who, along with its affiliates and agents, absorbs a majority of the VIE's expected losses or receives a majority of the expected residual returns as a result of holding variable interests.

(2) The basic net loss attributable per common unit for each of the five year periods ended December 31, 2009 and for the nine month periods ended September 30, 2009 and 2010 has been presented for informational and historical purposes only. After completion of this offering, as a result of the reorganization events that have taken place or that will take place immediately prior to completion of the offering as described in "The Reorganization and Our Holding Company Structure," the shares used in computing net earnings or loss per share will bear no relationship to these historical common units.

(3) Operating cash flows for the nine months ended September 30, 2010 include a prepayment for energy for our Milford I project of approximately $232 million.

(4) As of December 31, 2005, 2006, 2007, 2008 and 2009, we had 30 MW, 30 MW, 92 MW, 274 MW and 504 MW, respectively, of combined operating and under construction rated capacity.

(5) Average realized energy price per MWh of energy generated is a metric that allows us to compare revenues from period to period, or on a project by project basis, regardless of whether the revenues are generated under a PPA, from sales at market prices with a financial swap, from sales at market prices or a combination of the three. Although average realized energy price is based, in part, on revenues recognized under accounting principles generally accepted in the United States (GAAP), this metric does not represent revenue per unit of production on a GAAP basis. We adjust GAAP revenues used to compute this metric in several respects:

- Under GAAP, recognition of revenues from the sale of New England RECs is delayed due to regulations that limit their transfer to the buyer to quarterly trading windows that open two quarters subsequent to generation. To match New England REC revenue to the period in which the related power was generated, in calculating this metric, we add New England REC revenues attributable to generation during a period but not yet recognized under GAAP, and subtract New England REC revenue recognized under GAAP in the period but generated in a prior period.

- In addition, in order to focus this metric on realized energy prices, we exclude the effects of mark-to-market adjustments on financial swaps.

Average realized energy price changes over time due to several factors. Historically, the most significant factor has been the growth of our business and the corresponding change in pricing mix. Each project has a different pricing profile, including varying levels of hedging in relation to electricity generation, and in certain cases, short periods of unhedged exposure to market price fluctuations as hedging agreements are put in place.

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The table below shows the calculation of our average realized energy price for the periods presented:

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
	(dollars in thousands)				
Numerator					
Total revenue	$ 12,346	$ 39,478	$ 75,277	$ 58,048	$ 88,129
Add (subtract):					
New England REC timing(a)	2,461	1,947	2,060	1,239	(2,237)
Mark-to-market adjustments(b)	9,801	(14,760)	(21,322)	(23,339)	(19,397)
	$ 24,608	$ 26,665	$ 56,015	$ 35,948	$ 66,495
Denominator					
Total energy production (MWh)	239,940	275,024	656,365	437,143	849,614
Average realized energy price					
(numerator/denominator)	$ 103/MWh	$ 97/MWh	$ 85/MWh	$ 82/MWh	$ 78/MWh

(a) New England REC timing represents the difference between: (i) New England RECs generated in earlier periods that qualified for GAAP revenue recognition in the applicable period and (ii) New England RECs generated in the applicable period and sold to a creditworthy counterparty under a firm sales contract where revenue is deferred under GAAP until the applicable quarterly trading window occurs. The gross amounts of such New England RECs are as follows:

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
	(dollars in thousands)				
New England RECs					
Included in revenues	$ (2,076)	$ (4,488)	$ (8,803)	$ (7,328)	$ (11,477)
Generated during the period	4,537	6,435	10,863	8,567	9,240
	$ 2,461	$ 1,947	$ 2,060	$ 1,239	$ (2,237)

(b) The mark-to-market adjustments for the 2009 periods include the effect of a financial hedge modification fee of $4,147 in addition to market adjustments of $17,175 and $19,192 for the year and the nine months, respectively.

(6) We evaluate the performance of our operating projects on the basis of their Project EBITDA, which is a non-GAAP financial measure. We use Project EBITDA to assess the performance of our operating projects because we believe it is a measure that allows us to: (i) more accurately evaluate the operating performance of our projects based on the energy generated during each period (through the exclusion of mark-to-market adjustments and the effects of New England REC timing, for which the GAAP accounting treatment does not correspond to the energy generated during the period) and (ii) assess the ability of our projects to support debt and/or tax equity financing (through the exclusion of depreciation and amortization that is not indicative of capital costs that would be expected over the term of the financing and general and administrative expenses that are not incurred at the project level). Our ability to raise debt and/or tax equity financing for our projects is a key requirement of our development plan as described in " Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Financing Requirements." We believe it is important for investors to understand the factors that we focus on in managing the business, and therefore we believe Project EBITDA is useful for investors to understand. In addition, as long as investors consider Project EBITDA in combination with the most directly comparable GAAP measure, gross income (loss), we believe it is useful for investors to have information about our operating performance on a period-by-period basis, without giving effect to GAAP requirements that require the recognition of income or expense that does not correspond to actual energy production in a given period, and we believe it is useful for investors to consider a measure that does not include project-related depreciation and amortization. Because lenders and providers of tax equity financing frequently disregard the non-cash charges and GAAP timing differences noted above when determining the financeability of a project, we believe that presenting information in this manner can help give investors an understanding of our ability to secure financing for our projects. Project EBITDA can be reconciled to gross income (loss),

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which we believe to be the most directly comparable financial measure calculated and presented in accordance with GAAP, as follows (in thousands):

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
Gross income (loss)	$ (5,629)	$ 18,254	$ 21,383	$ 21,334	$ 18,289
Add (subtract):					
Depreciation and amortization of operating assets	8,800	10,611	34,185	23,445	35,678
New England REC timing	2,461	1,947	2,060	1,239	(2,237)
Mark-to-market adjustments(a)	9,801	(14,760)	(21,322)	(23,339)	(19,397)
KWP I property tax assessment(b)	(488)	(463)	(439)	(329)	1,390
Project EBITDA	$ 14,945	$ 15,589	$ 35,867	$ 22,350	$ 33,723

(a) The mark-to-market adjustments for the 2009 periods include the effect of a financial hedge modification fee of $4,147 in addition to market adjustments of $17,175 and $19,192 for the year and the nine months, respectively.

(b) In June 2010, the County of Maui, Hawaii retroactively assessed property taxes for our KWP I project totaling approximately $1.4 million plus penalties and interest for 2007, 2008 and 2009. We have appealed these retroactive assessments as well as the amount then billed by the county for 2010. The KWP I property tax assessment adjustment reflects these retroactive assessments in the periods to which they relate.

Project EBITDA does not represent funds available for our discretionary use and is not intended to represent or to be used as a substitute for gross income (loss), net income or cash flow from operations data as measured under GAAP. We use Project EBITDA to assess the performance of our operating projects and not as a measure of our liquidity. Investors should consider cash flow from operations, and not Project EBITDA, when evaluating our liquidity and capital resources. The items excluded from Project EBITDA are significant components of our statement of operations and must be considered in performing a comprehensive assessment of our overall financial performance. Project EBITDA and the associated period-to-period trends should not be considered in isolation.

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

The historical financial data discussed below reflect the historical results of operations and financial condition of First Wind Holdings, LLC and do not give effect to our reorganization. See "The Reorganization and Our Holding Company Structure" and "Unaudited Pro Forma Financial Information" for a description of our reorganization and its effect on our historical results of operations. Our consolidated financial statements and the accompanying notes beginning on page F-1 contain additional information that you should refer to when considering investing in our Class A common stock. Statements in this discussion may be forward-looking, and these forward-looking statements involve risks and uncertainties. See "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent wind energy company focused solely on the development, financing, construction, ownership and operation of utility-scale wind energy projects in the United States. Our projects are located in the Northeastern and Western regions of the continental United States and in Hawaii. We have focused on these markets because we believe they provide the potential for future growth and investment returns at the higher end of the range available for wind projects. These markets have relatively high electricity prices, a shortage of renewable energy and sites with good wind resources that can be built in a cost-effective manner. Moreover, we have focused our efforts on projects and regions with significant expansion opportunities, often enabled by transmission solutions that we have developed and built.

Wind energy project returns depend mainly on the following factors:

- *Energy price.* The realized price of energy, including power, capacity and REC sales and the effect of cash settlements from related hedging activities.

- *Wind.* The quality of the wind resources, operational performance and the resulting energy production, otherwise known as NCF. NCF is the measure of a wind energy project's actual production expressed as a percentage of the amount of power the wind energy project could have produced running at full capacity for a particular period of time.

- *Construction costs.* The installed costs of the project, including transmission, balance-of-plant, turbines, interest during construction, financing costs and fees and development expenses.

- *Financing.* The financeability and cost of capital to construct the project.

- *Government incentives.* PTC, ITC, government grants and other government incentives.

Our strategy considers all of these factors in combination and focuses on margins, returns on invested capital and value creation as opposed solely to project size. Some of our projects, while having high construction costs, still offer attractive returns because of favorable wind resources or energy prices. Additionally, in many cases, smaller, more profitable projects can create as much value as do larger, lower-returning projects. We assess the profitability of each project by evaluating its net present value. We also evaluate a project on the basis of its Project EBITDA, as described under " How We Measure Our Performance," including the ratio of Project EBITDA to project development and construction costs.

Factors Affecting Our Results of Operations, Financial Condition and Cash Flows

Significant Recent Growth

Since January 1, 2006, we have significantly expanded our installed base of projects and our project development pipeline, and with them, our development capabilities and our headcount. Our rapid growth makes it difficult to compare consolidated financial results from period to period. As of December 31, 2009, we operated six projects with combined rated capacity of 478 MW, and we owned two generator leads with transmission capacity of approximately 1,200 MW. As of September 30, 2010, we operated seven projects with combined rated capacity of 504 MW and had four projects totaling 232 MW under construction. In contrast, as of December 31, 2008 and 2007 we operated three projects with combined rated capacity of 92 MW. As of December 31, 2009, we had approximately 200 employees in 10 offices in our markets, compared with 170 employees at December 31, 2008 and 85 employees at December 31, 2007.

As our business has grown, we have increased our expenditures on general and administrative functions necessary to support this growth. We believe that, apart from additional costs expected to be incurred as a public company, we have achieved sufficient general and administrative capabilities to support our future growth without requiring significant increases in general and administrative expenses.

Our results of operations have varied significantly due to variations in our project development activities, the timing of our projects, volatility in commodity prices that affect the fair value of our financial hedges and the overall increased cost of expanding our business. Additionally, we have experienced variability in 2008, 2009 and the nine months ended September 30, 2010 from expensing previously-capitalized development costs for projects that were discontinued or recategorized as Tier 2 after reaching the Tier 1 development stage. These write-offs amounted to $9.1 million in the aggregate, or approximately 8.7% of our development expenses incurred from January 1, 2008 through September 30, 2010. Although we believe our current process for determining whether to promote projects to Tier 1 mitigates this risk, we could experience similar write-offs in the future. See "Business How We Classify Our Projects."

Financing Requirements

Wind energy project development and construction are capital intensive. In addition to the cost of turbines, discussed below, we also incur material costs and expenses for land acquisition, feasibility studies, construction and other development costs. As a result, our ability to access capital markets efficiently and effectively is crucial to our growth strategy. The recent worldwide financial and credit crisis has reduced liquidity and the availability of credit. However, since the beginning of 2009, we have refinanced, raised or received approximately $2.5 billion for our company and projects in 20 refinancing and new capital-raising activities and customer prepayments. These activities included project debt financings, tax equity financings, intermediate holding company financings, government grants, Sponsor equity contributions and customer prepayments. We expect to fund the development of our projects with a combination of cash flows from operations, debt financings, tax equity financings, government grants and capital markets transactions such as this offering. See "Business Project Financing."

State-Level Support

Among the more significant factors driving growth in our business are state-mandated RPS and in some cases, municipal level RPS. An RPS is a program mandating that a specified percentage of electricity sales in a state or municipality come from renewable energy, including wind energy. Currently, 29 states and the District of Columbia have implemented RPS requirements, more than double the number of states with RPS requirements in 2003. For example, in the Northeast and

California, two of our target markets, there are RPS targets of between 15% and 40% by 2013 to 2020 and 33% by 2020, respectively. In June 2009, Hawaii, the third region where we operate and where we have the largest utility-scale wind energy project in the state, increased its RPS target to 40% by 2030. See "Industry." To the extent states continue to strengthen their RPS requirements, our opportunities for growth will continue to increase.

Power Purchase Agreements and Financial Hedging

The market prices of electricity and RECs materially affect the economic feasibility of our development projects and our results of operations. In the past 12 months, the price of electricity in the Northeast and West has fluctuated significantly, based in part on the costs of fossil fuels. There is no clear trend in prices for electricity or RECs in our markets. To limit the impact of market price variability on our revenues, we enter into PPAs and financial hedges covering the estimated revenue stream from a significant portion of the electricity we produce. We also seek to maximize the value of the RECs we generate by selling forward under long-term contracts the amount of RECs we expect to produce. We believe that stabilizing our revenues in this manner benefits us, our lenders and tax equity investors and enhances our ability to obtain long-term, non-recourse financing. We have PPAs or hedges on all seven of our operating projects and we expect to have PPAs or hedges on all of our 2010 projects. Approximately 90% of estimated revenues from our current operating projects are hedged through 2011. We plan to hedge approximately 90% of the estimated revenues for 2011 for the four projects currently under construction and the two projects we plan to have under construction in 2010. Most of the estimated aggregate revenues from our operating projects and 2010 projects is hedged through 2020.

We believe the widespread support for renewable energy demonstrated by state RPS programs has improved our ability to negotiate and enter into long-term PPAs with utilities. We expect an increasing percentage of our electricity sales to be made pursuant to long-term PPAs. For example, Milford I, which commenced commercial operations in November 2009, has a PPA with Southern California Public Power Authority (SCPPA) to supply 20 years of power to the cities of Los Angeles, Burbank and Pasadena. We entered into another PPA with SCPPA in October 2010 to sell all of the output of our Milford II project. In connection with our Sheffield project, which is in our 2010 project construction portfolio, we have fully negotiated and received approval on long-term PPAs with three Vermont utilities: Vermont Electric Cooperative, Inc. (VEC), City of Burlington Electric Department (BED) and Washington Electric Cooperative (WEC). For our Stetson II project that recently began operations, we have a long-term PPA with Harvard University to sell half of the electricity and RECs generated by the project. In addition, we expect to sell 100% of our energy and capacity from our Rollins project, which is also part of our 2010 project construction portfolio, to two utilities in Maine under 20-year PPAs. See "Business Our Portfolio of Wind Energy Projects." In some instances we commit to sell minimum levels of generation. If the project generates less than the committed volumes, we may be required to either buy the shortfall of electricity on the open market or make payments of liquidated damages.

When we enter into financial hedges and contracts for forward sales of RECs, we base the contracted amount on estimates we believe with a high degree of certainty that we can produce; however, actual amounts may be materially different from our estimates for a variety of reasons, including variable wind conditions and turbine performance. In the event a project does not generate the amount of electricity covered by a related financial hedge, we could incur significant losses under the hedge if electricity prices were to rise substantially above the fixed prices provided for in the hedge. A shortfall in the production of RECs could require us to purchase RECs at current market prices for delivery under a forward sales contract, and the market price may be higher than the contracted price. Additionally, our hedges may result in significant volatility in our quarterly and annual financial results as we are required to mark them to market through earnings on a periodic basis.

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Turbine Supply and Pricing

The majority of the total cost of a wind energy project is attributable to turbine purchases, so turbine purchases have been and will continue to be our principal capital expenditure. As a result, the price trend of turbines has a direct impact on our results of operations and the method of financing our turbines has a direct impact on our cash flows and liquidity.

Historically we have needed to secure turbine orders early in the project-development lifecycle. Turbine suppliers generally required up-front payments upon execution of a turbine supply agreement with significant progress payments well in advance of turbine delivery. We used turbine supply loans to finance approximately 70% to 80% of these progress payments. This financing method was prevalent in part because in recent years demand for turbines often exceeded supply, a factor that also resulted in the price of turbines generally increasing between 2006 and 2008.

However, an expanding turbine supply chain, coupled with the global economic downturn, has mitigated this trend, resulting in an oversupply of turbines globally. This oversupply led to a significant downward trend in prices for turbines beginning in 2009. We expect that lower turbine prices will mitigate the impact on electric energy prices of low natural gas prices. We believe that as long as these market conditions persist, we will not need to dedicate long-term capital commitments to turbine purchases or make milestone payments far in advance of anticipated delivery. For a project in construction, we seek project financing, which typically allows us to repay and terminate the turbine supply loans relating to that project.

We have no firm turbine commitments for delivery after 2010 and as a result we believe we have the opportunity to benefit from the improved pricing and terms currently available for turbine purchases for our 2011 projects and beyond. We have taken steps to benefit from the weakness in the turbine industry. For example, in 2009 we amended our agreements with Clipper to give us the right, but not the obligation, to buy turbines from Clipper for up to 633 MW of deliveries between 2011 and 2015, subject to the forfeiture of up to $89.5 million in deposits and progress payments that we have made and are scheduled to make to Clipper, if we decide not to buy any additional turbines from them.

Federal Programs

We utilize federal government programs supporting renewable energy, which enhance the economic feasibility of developing our projects. The key federal programs include the ITC, grants and loan guarantees under the ARRA, the PTC and accelerated depreciation of renewable energy property. Under the ARRA, project owners can receive a cash grant in lieu of the ITC paid by the U.S. Treasury representing 30% of the ITC-eligible costs of building wind energy producing assets. In September 2009, our Cohocton and Stetson I projects were among the first recipients of such cash grants, receiving approximately $115 million. Our Milford I project received approximately $120 million of such grants in March 2010 and our Stetson II project received approximately $19 million of such grants in June 2010. In addition to cash grants, Sections 1703 and 1705 of the ARRA establish loan guarantee programs administered by the U.S. Department of Energy (DOE). These programs call for over $40 billion of federal loan guarantees to be allocated for innovative technology authorized under the Energy Policy Act of 2005 and approximately $15 billion to be made available for commercially proven technology. In July 2010, we entered into a $117 million construction and term loan facility guaranteed by the Department of Energy to help finance construction of our Kahuku project. We plan to apply for cash grants for the other projects we begin to construct in 2010. We may also apply for additional loan guarantees for some of our projects.

Historically, the PTC has been subject to extension on an annual basis, resulting in uncertainty that made it difficult to successfully execute qualifying development activities. However, the ARRA extended the PTC through 2012 for wind projects, reducing uncertainty about whether a wind project would qualify for the PTC since this determination cannot be made until the project is placed in service. The tax equity financing market has allowed us to monetize certain of these tax benefits that would otherwise be deferred until such time as we have taxable income. Changes in or elimination of these policies could render certain of the projects in our development portfolio uneconomic, increase our financing costs or otherwise adversely affect our financing efforts, increase our equity requirements and adversely affect our growth.

Wind Variability and Seasonality

The profitability of a wind energy project is directly correlated with wind conditions at the project site. In addition to annual variations, each of our projects experiences unique daily and seasonal variations in its wind resources, which will in turn affect the revenue profile of that project. For example, our projects in the Northeast tend to be sited in winter-peaking, storm-driven wind resources where a majority of the electricity production (and therefore REC production) occurs from October through March. In Utah, the wind resource is more often summer peaking and driven by thermal conditions that result from heat generated by sunlight. In Hawaii, we experience trade winds throughout the year.

These daily and seasonal variations are carefully studied by our meteorological team to develop an annual output profile that reflects seasonal variations in cash flow that can be expected from individual projects. Our finance and commodities teams use these projections to plan and structure our hedges and financings to account for seasonal variation. Our meteorological teams are able to draw on data for nearly 95% of our project pipeline, and use this data to prepare computer models to estimate potential wind levels. For the seven projects we expect to have under construction or place in operation in 2010, we had, at September 30, 2010, an average of nearly seven years of wind data collected from 22 meteorological towers. For our Tier 1 and Tier 2 development projects as of September 30, 2010, approximately 82% of our meteorological data is for one or more years, and approximately 72% of this data is for three or more years.

In regions with liquid power markets, the price of electricity may vary by season, depending on weather conditions that often affect system load conditions, as in the case of extreme heat or cold leading to increased use of heating, ventilation and air conditioning systems. We are able to mitigate some of the seasonal variation in pricing by hedging a portion of our output. See " Power Purchase Agreements and Financial Hedging."

Public Company Expenses

We believe that our general and administrative expenses will increase in connection with the completion of this offering. This increase will consist of legal and accounting fees and additional expenses associated with complying with the Sarbanes-Oxley Act of 2002 and other regulations affecting publicly traded companies. We anticipate that our ongoing general and administrative expenses will also increase as a result of being a publicly traded company, in part due to the cost of filing annual and quarterly reports with the SEC, investor relations, directors' fees, directors' and officers' insurance and registrar and transfer agent fees. Our consolidated financial statements after completion of this offering will reflect the impact of these increased expenses, which will affect the comparability of our financial statements with periods prior to completion of this offering.

Effects of the Reorganization

First Wind Holdings Inc. was formed for the purpose of this offering and has only engaged in activities in contemplation of this offering. Upon completion of the offering, all of our business will continue to be conducted through First Wind Holdings, LLC, which is the holding company that has conducted all of our business to date. First Wind Holding Inc. will be a holding company, whose principal asset will be its managing member interest in First Wind Holdings, LLC. All of the equity of First Wind Holdings, LLC outstanding prior to the reorganization that will not be owned by First Wind Holdings Inc. will be either exchanged for our Class A common stock or Series B Membership Interests of First Wind Holdings, LLC and an equal number of shares of our Class B common stock. Unvested Series B Units and vested Series B Units that do not then have current value will expire. For more information regarding our reorganization and holding company structure, see "The Reorganization and Our Holding Company Structure."

We expect that future exchanges of Series B Membership Interests, together with an equal number of shares of Class B common stock, for shares of our Class A common stock will result in increases in the tax basis in the tangible assets of First Wind Holdings, LLC. We expect that these increases in tax basis, which would not have been available but for our new holding company structure, will reduce the amount of tax that we would otherwise be required to pay in the future. We will be required to pay a portion of the cash savings we actually realize from such increase (or are deemed to realize in the case of an early termination payment by us, or a change in law, as discussed below) to certain holders of the Series B Membership Interests, which include our Sponsors and certain of our employees and current investors, pursuant to a tax receivable agreement. See "The Reorganization and Our Holding Company Structure Tax Receivable Agreement."

First Wind Holdings, LLC is currently taxed as a partnership for federal income tax purposes. Therefore, with the exception of certain subsidiaries that have elected to be taxed as corporations, we have not been subject to entity-level federal or state income taxation, and the members of First Wind Holdings, LLC pay taxes with respect to their allocable share of our taxable income. Following the reorganization and this offering, all of the earnings of First Wind Holdings Inc. will be subject to federal income taxation.

Components of Revenues and Expenses

Revenues

Our total revenues are composed of energy sales, capacity sales, sales of RECs and the effects of related hedging activities, including both the cash settlement of derivatives and fair value adjustments to mark these derivatives to market at the end of each period. When we analyze the revenues of our operating projects and the related performance of our hedging strategies, we use a metric we refer to as "average realized energy price" per MWh of energy generated.

Energy Sales

We typically sell the power generated by our projects (sometimes bundled with RECs) either pursuant to PPAs with local utilities or power companies or directly into the local power grid at market prices. Our PPAs have initial terms ranging from five to 20 years with fixed prices, market prices or a combination of fixed and market prices. We may also seek to hedge a significant portion of the market component of our power sales revenue with financial swaps. See " Risk Management Activities Related to Operating Projects."

Sales of RECs

The RECs associated with renewable electricity generation can be "unbundled" and sold as a separate attribute. In some states, we sell RECs to entities that must either purchase or generate certain quantities of RECs to comply with state RPS programs. Currently, 25 states and the District of

Columbia have adopted RPS programs that operate in tandem with a credit trading system in which generators sell RECs for renewable power they generate.

Capacity Sales

Capacity payments are made to energy generators, including those with wind energy projects, as an incentive for them to promote development and continued operational capacity sufficient to meet the customer's anticipated requirements. Capacity payments are payments made to energy generators based on their available capacity, rather than the energy generated.

Hedging Activities

We enter into derivative contracts to hedge future electricity prices to mitigate a portion of the risk of market price fluctuations we will encounter by selling power at variable or market prices. See " Quantitative and Qualitative Disclosure about Market Risk Commodity Price Risk."

Average Realized Energy Price

Average realized energy price per MWh of energy generated is a metric that allows us to compare revenues from period to period, or on a project by project basis, regardless of whether the revenues are generated under a PPA, from sales at market prices with a financial swap, from sales at market prices or a combination of the three. Although average realized energy price is based, in part, on revenues recognized under GAAP, this metric does not represent revenue per unit of production on a GAAP basis. We adjust GAAP revenues used to compute this metric in several respects:

- Under GAAP, recognition of revenues from the sale of New England RECs is delayed due to regulations that limit their transfer to the buyer to quarterly trading windows that open two quarters subsequent to generation. To match New England REC revenue to the period in which the related power was generated, in calculating this metric, we add New England REC revenues attributable to generation during a period but not yet recognized under GAAP, and subtract New England REC revenue recognized under GAAP in the period but generated in a prior period.

- In addition, in order to focus this metric on realized energy prices, we exclude the effects of mark-to-market adjustments on financial swaps.

Average realized energy price changes over time due to several factors. Historically, the most significant factor has been the growth of our business and the corresponding change in pricing mix. Each project has a different pricing profile, including varying levels of hedging in relation to electricity generation, and in certain cases, short periods of unhedged exposure to market price fluctuations as hedging agreements are put in place.

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The table below shows the calculation of our average realized energy price for the periods presented:

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
Numerator (in thousands)					
Total revenue	$ 12,346	$ 39,478	$ 75,277	$ 58,048	$ 88,129
Add (subtract):					
New England REC timing(1)	2,461	1,947	2,060	1,239	(2,237)
Mark-to-market adjustments(2)	9,801	(14,760)	(21,322)	(23,339)	(19,397)
	$ 24,608	$ 26,665	$ 56,015	$ 35,948	$ 66,495
Denominator (MWh)					
Total energy production	239,940	275,024	656,365	437,143	849,614
Average realized energy price					
(numerator/denominator)	$ 103/MWh	$ 97/MWh	$ 85/MWh	$ 82/MWh	$ 78/MWh

(1) New England REC timing represents the difference between: (i) New England RECs generated in earlier periods that qualified for GAAP revenue recognition in the applicable period and (ii) New England RECs generated in the applicable period and sold to a creditworthy counterparty under a firm sales contract where revenue is deferred under GAAP until the applicable quarterly trading window occurs. The gross amounts of such New England RECs are as follows:

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
	(in thousands)				
New England RECs					
Included in revenues	$ (2,076)	$ (4,488)	$ (8,803)	$ (7,328)	$ (11,477)
Generated during the period	4,537	6,435	10,863	8,567	9,240
	$ 2,461	$ 1,947	$ 2,060	$ 1,239	$ (2,237)

(2) The mark-to-market adjustments for the 2009 periods include the effect of a financial hedge modification fee of $4,147 in addition to market adjustments of $17,175 and $19,192 for the year and the nine months, respectively.

Cost of Revenues

Cost of revenues includes project operating expenses and depreciation and amortization of operating assets.

Project Operating Expenses

Project operating expenses consist of such costs as contracted operations and maintenance fees, turbine and related equipment warranty fees, land lease payments, insurance, professional fees, operating personnel salaries and permit compliance costs.

Depreciation and Amortization of Operating Assets

Depreciation and amortization of operating assets are included in cost of revenues once a project has begun commercial operations. Prior to that time, depreciation and amortization associated with the related property, plant and equipment is included in other operating expenses.

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Other Operating Expenses

Other operating expenses include project development expenses, general and administrative expenses and depreciation and amortization.

Project Development Expenses

We allocate development expenses by project. Project development expenses consist of initial permitting, land rights, preliminary engineering work, analysis of project wind resource, analysis of project economics and legal work. We expense all project development costs until we deem a project probable of being technically, commercially and financially viable. Once this determination has been made, we classify the project as being in the Tier 1 stage of development, at which point we begin capitalizing project development costs. After a project has been moved to Tier 1, if we subsequently determine that the project is not technically, commercially or financially viable or we move a project from Tier 1 to Tier 2, we write off the capitalized development costs. See "Business How We Classify Our Projects."

Risk Management Activities Related to Non-Operating Projects

Prior to a project's reaching commercial operations, we record fair value changes and cash settlements related to commodity derivatives as risk management activities related to non-operating projects. Once a project reaches commercial operations, we record these fair value changes and cash settlements under revenues, as risk management activities related to operating projects.

How We Measure Our Performance

Senior management's performance is evaluated based in part on annual operating and financial targets for our operating and under-construction portfolio as well as the extent to which we are prudently growing and managing our development pipeline using GAAP financial measures. We also evaluate the performance of our operating projects on the basis of Project EBITDA, which is a non-GAAP financial measure. We use Project EBITDA to assess the performance of our operating projects because we believe it is a measure that allows us to: (i) more accurately evaluate the operating performance of our projects based on the energy generated during each period (through the exclusion of mark-to-market adjustments and the effects of New England REC timing, for which the GAAP accounting treatment does not correspond to the energy generated during the period), (ii) assess the ability of our projects to support debt and/or tax equity financing (through the exclusion of depreciation and amortization that is not indicative of capital costs that would be expected over the term of the financing and general and administrative expenses that are not incurred at the project level). Our ability to raise debt and/or tax equity financing for our projects is a key requirement of our development plan as described in " Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Financing Requirements." We believe it is important for investors to understand the factors that we focus on in managing the business, and therefore we believe Project EBITDA is useful for investors to understand. In addition, as long as investors consider Project EBITDA in combination with the most directly comparable GAAP measure, gross income (loss), we believe it is useful for investors to have information about our operating performance on a period-by-period basis, without giving effect to GAAP requirements that require the recognition of income or expense that does not correspond to actual energy production in a given period, and we believe it is useful for investors to consider a measure that does not include project-related depreciation and amortization. Because lenders and providers of tax equity financing frequently disregard the non-cash charges and GAAP timing differences noted above when determining the financeability of a project, we believe that presenting information in this manner can help give investors an understanding of our ability to secure financing for our projects. Project EBITDA can be reconciled to gross income (loss), which we believe

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to be the most directly comparable financial measure calculated and presented in accordance with GAAP, as follows (in thousands):

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	2008	2009	2009	2010
Gross income (loss)	$ (5,629)	$ 18,254	$ 21,383	$ 21,334	$ 18,289
Add (subtract):					
Depreciation and amortization of operating assets	8,800	10,611	34,185	23,445	35,678
New England REC timing	2,461	1,947	2,060	1,239	(2,237)
Mark-to-market adjustments(1)	9,801	(14,760)	(21,322)	(23,339)	(19,397)
KWP I property tax assessment(2)	(488)	(463)	(439)	(329)	1,390
Project EBITDA	$ 14,945	$ 15,589	$ 35,867	$ 22,350	$ 33,723

(1) The mark-to-market adjustments for the 2009 periods include the effect of a financial hedge modification fee of $4,147 in addition to market adjustments of $17,175 and $19,192 for the year and the nine months, respectively.

(2) In June 2010, the County of Maui, Hawaii retroactively assessed property taxes for our KWP I project totaling approximately $1.4 million plus penalties and interest for 2007, 2008 and 2009. We have appealed these retroactive assessments as well as the amount then billed by the county for 2010. The KWP I property tax assessment adjustment reflects these retroactive assessments in the periods to which they relate.

Project EBITDA does not represent funds available for our discretionary use and is not intended to represent or to be used as a substitute for gross income (loss), net income or cash flow from operations data as measured under GAAP. We use Project EBITDA to assess the performance of our operating projects and not as a measure of our liquidity. Investors should consider cash flow from operations, and not Project EBITDA, when evaluating our liquidity and capital resources. The items excluded from Project EBITDA are significant components of our statement of operations and must be considered in performing a comprehensive assessment of our overall financial performance. Project EBITDA and the associated period-to-period trends should not be considered in isolation.

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Results of Operations

Nine Months Ended September 30, 2010 Compared with Nine Months Ended September 30, 2009

The following table sets forth selected information about our results of operations for the nine months ended September 30, 2010 and 2009 (dollars in thousands):

	Nine Months Ended September		2010 compared with 2009	
	2009	2010	$	%
Revenues:				
Revenues	$ 30,468	$ 62,805	$ 32,337	106%
Cash settlements of derivatives	8,388	5,927	(2,461)	-29%
Fair value changes in derivatives	19,192	19,397	205	1%
Total revenues	58,048	88,129	30,081	52%
Cost of revenues				
Wind energy project operating expenses	13,269	34,162	20,893	157%
Depreciation and amortization of operating assets	23,445	35,678	12,233	52%
Total cost of revenues	36,714	69,840	33,126	90%
Gross income	21,334	18,289	(3,045)	-14%
Other operating expenses:				
Project development	32,694	32,889	195	1%
General and administrative	28,599	24,974	(3,625)	-13%
Depreciation and amortization	2,443	3,443	1,000	41%
Total other operating expenses	63,736	61,306	(2,430)	-4%
Loss from operations	(42,402)	(43,017)	(615)	1%
Other expense	(4,860)	(4,514)	352	-7%
Interest expense, net of capitalized interest	(3)		(3)	-100%
Loss before provision for income taxes	(47,265)	(47,531)	(266)	1%
Provision for income taxes		4,513	4,513	N/M
Net loss	(47,265)	(52,044)	(4,779)	10%
Less: net loss attributable to noncontrolling interest	6,771	10,304	3,533	52%
Net income (loss) attributable to members of First Wind Holdings, LLC	$ (40,494)	$ (41,740)	$ (1,246)	3%
Key Metrics:				
Rated capacity (end of period)	274 MW	504 MW	230 MW	84%
Megawatt hours generated	437,143 MWh	849,614 MWh	412,471 MWh	94%
Average realized energy price ($/MWh)	$ 82/MWh	$ 78/MWh	$ (4) MWh	5%
Project EBITDA	$ 22,350	$ 33,723	$ 11,373	51%

N/M = not measurable/meaningful

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Project Operating Results

For the nine months ended September 30, 2010, we recorded revenues from energy sales, REC sales and capacity sales, along with cash settlements of derivatives, of $68.7 million, a 76.9% increase over the $38.9 million recorded for the comparable 2009 period. Our Project EBITDA for the nine months ended September 30, 2010 was $33.7 million, a 50.9% increase over the $22.4 million recorded in 2009. The increase in our revenues and Project EBITDA was due to the substantial increase in electricity generation in 2010, compared with 2009, which in turn was due to the substantial increase in the capacity of our projects in 2010, compared with 2009. During the nine months ended September 30, 2010, we generated 850,000 MWh of electricity, a 94.5% increase over the 437,000 MWh generated in the same period in 2009, due largely to the addition of our Milford I and Stetson II Projects, which have a combined 230 MW of rated capacity. Average realized energy price for 2010 was $78/MWh compared with $82/MWh in 2009.

Including fair value changes in derivatives, during nine months ended September 30, 2010, we recorded revenues of $88.1 million, a 51.8% increase from the $58.0 million recorded for the comparable 2009 period.

Operating base. Our 2010 operating base consists of projects that commenced operations prior to January 1, 2010. Our 2010 operating base comprises 478 MW of our total 504 MW of rated capacity and consists of the Kaheawa Wind Power I (KWP I), Mars Hill, Steel Winds I, Cohocton, Stetson I and Milford I projects.

Energy production from our 2010 operating base for the nine months ended September 30, 2010 was approximately 825,000 MWh, resulting in an NCF of 26%, which is within our expected long-term average NCF of 26% to 28%. Factors affecting generation included: windiness below the long term average we expect although within the range of our expectations; plant non-availability shortfalls due to the ramp-up of turbine availability typical in newly-commissioned projects; a transformer malfunction at Stetson II; and utility curtailment, a substantial portion of which we believe is non-recurring. Average realized energy price for the nine months ended September 30, 2010 was $78/MWh, compared with $82/MWh for the same period in 2009. Our $78/MWh average realized energy price for the nine months ended September 30, 2010 was adversely affected by the pricing at our Milford I project, for which we received a $232 million prepayment under a 20-year PPA with SCPPA. This prepayment had a favorable effect on our cost of capital for the project, but is based on a relatively low average realized energy price ($57/MWh). Excluding Milford I, our average realized energy price for the nine months ended September 30, 2010 was $91/MWh.

Additional information about the individual projects comprising our 2010 operating base is as follows:

> *Kaheawa Wind Power I (KWP I).* For the nine months ended September 30, 2010, energy production at KWP I was approximately 99,000 MWh, resulting in an NCF of 50%, compared with energy production of approximately 87,000 MWh, resulting in an NCF of 44% in the same period in 2009. Our long-term average NCF expectation is 41% to 43%. Average realized energy price for the nine months ended September 30, 2010 was approximately $81/MWh compared with approximately $83/MWh for the same period in 2009, due to the large movements in spot oil prices over the past year. While 100% of our output is sold under a 20-year PPA, 70% has a fixed price and 30% is indexed to the counterparty's avoided cost of electricity, which is heavily correlated to oil prices. At commercial operation, the project entered into an oil derivative swap agreement to stabilize the 30% indexed portion of the PPA. Project operating expenses for the 2010 period were approximately $4.3 million, compared with approximately $1.8 million in costs in the 2009 period. The increase is primarily due to a retroactive property tax assessment of approximately $1.4 million for 2007, 2008 and 2009, along with approximately $0.3 million accrued for property taxes for the nine months ended September 30, 2010, which we have

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appealed. The remaining increase is due to reclassifying certain types of costs historically included in project development expenses as project operating expenses in 2010.

Mars Hill. For the nine months ended September 30, 2010, energy production at Mars Hill was approximately 86,000 MWh, resulting in an NCF of 31%, compared with energy production of approximately 88,000 MWh, resulting in an NCF of 32% for the same period in 2009. Our long-term average NCF expectation is 35% to 37%. In 2010 we have experienced unexpected levels of utility curtailment at Mars Hill that we believe are non-recurring. Average realized energy price for the nine months ended September 30, 2010 was approximately $80/MWh, compared with approximately $91/MWh for the same period in 2009, due mostly to lower REC prices. Project operating expenses were approximately $4.5 million for the 2010 period, compared with approximately $3.5 million in costs in the 2009 period. The increase is due to reclassifying certain types of costs historically included in project development expenses as project operating expenses in 2010. Transmission costs for the nine months ended September 30, 2010 were $1.4 million, compared with $1.1 million in the 2009 period.

Steel Winds I. For the nine months ended September 30, 2010, energy production at Steel Winds I was approximately 38,000 MWh, resulting in an NCF of 29%, compared with energy production of approximately 30,000 MWh, resulting in an NCF of 23% in the same period in 2009. This increase in production was primarily due to improved operating performance of our Clipper turbines. Our long-term average NCF expectation is 29% to 31%. Average realized energy price for the nine months ended September 30, 2010 was approximately $69/MWh, compared with approximately $81/MWh for the same period in 2009. Project operating expenses for the 2010 period were approximately $1.3 million, compared with approximately $1.0 million in the 2009 period.

Cohocton. Cohocton began commercial operations on January 27, 2009. For the nine months ended September 30, 2010, energy production at Cohocton was approximately 179,000 MWh, resulting in an NCF of 22% compared with energy production of approximately 130,000 MWh, resulting in an adjusted NCF of 18% for the same period in 2009. This increase in production was primarily due to improved operating performance of our Clipper turbines. Our long-term average NCF expectation is 25% to 27%. Average realized energy price for the nine months ended September 30, 2010 was $87/MWh, compared with $102/MWh for the same period in 2009. Included in the 2009 amount is a non-recurring financial hedge settlement we received of approximately $4.1 million. If this settlement were excluded from revenues, the average realized energy price in 2009 would have been $64/MWh. In June 2009, Cohocton began participating in the New England renewable energy credit program, which affected the year over year increase in average realized energy price. Project operating expenses for the 2010 period were approximately $7.1 million, compared with approximately $4.1 million in the 2009 period. The increase reflects reclassifying certain types of costs historically included in project development expenses as project operating expenses in 2010 along with having a partial 2009 operating period.

Stetson I. Stetson I began commercial operations on January 23, 2009. For the nine months ended September 30, 2010, energy production at Stetson I was approximately 105,000 MWh, resulting in an NCF of 28%, compared with energy production of approximately 102,000 MWh, resulting in an NCF of 30% for the same period in 2009. Our long-term average NCF expectation is 30% to 32%. Average realized energy price for the nine months ended September 30, 2010 was $123/MWh, compared with approximately $89/MWh for the same period in 2009. We have a 10-year financial swap for Stetson I which did not commence until July 2009; therefore, Stetson I's 2009 results were exposed to variability of merchant power prices before commencement of the financial swap. Project operating expenses for the 2010 period were approximately $4.8 million, compared with approximately $3.8 million in the 2009 period. The increase is related to the partial 2009 operating period along with reclassifying

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certain types of costs historically included in project development expenses as project operating expenses in 2010.

Milford I. Milford I began commercial operations on November 16, 2009. Under the terms of the Milford I PPA, in February 2010 SCPPA provided an approximately $232 million prepayment for approximately 75% of the estimated annual generation delivered over 20 years. SCPPA also makes payments for the as-generated electricity for the remaining approximately 25% of our annual production at a fixed rate of approximately $59/MWh, escalating at 1.75% annually. Finally, SCPPA makes payments of approximately $11/MWh for the as-generated RECs, none of which have been prepaid, and reimburses the project for a portion of its operating costs. For the nine months ended September 30, 2010, energy production was approximately 317,000 MWh, resulting in a 24% NCF, which is within our long-term NCF expectation range of 24% to 26%, a portion of which is due to the planned ramp-up in turbine availability that is typical in newly-commissioned projects. We also experienced well below-average windiness in the first quarter of 2010, with a subsequent return to average windiness. Average realized energy price was approximately $57/MWh, and project operating expenses were $10.9 million.

Partial year projects. Our 2010 partial year operating projects will consist of projects that begin commercial operations after January 1, 2010. Our performance for the nine months ended September 30, 2010 for our 2010 partial year operating project was as follows:

Stetson II. Stetson II began commercial operations on March 12, 2010. For the nine months ended September 30, 2010, energy production at Stetson II was approximately 25,000 MWh, resulting in an NCF of 20%. This tracks below our long-term NCF expectation range of 30% to 32%. This production shortfall was due primarily to a malfunction of the main transformer which was removed, repaired and reinstalled during the period. Main transformers have a design-life of 20 to 30 years or more, so an immediate malfunction such as this is not typical. The main transformer was under warranty and we have business interruption insurance under which we have made a claim for lost revenue and related expenses. Our production at Stetson II was also impacted by the planned ramp-up in turbine availability that is typical in newly-commissioned wind projects. Our average realized energy price for the period was $94/MWh and project operating expenses were approximately $1.6 million.

Depreciation and amortization of operating assets. During the nine months ended September 30, 2010, we recorded expenses for depreciation and amortization of operating assets of $35.7 million, a 52.2% increase over the $23.4 million recorded for the same period in 2009, due largely to the substantial increase in the capacity of our operating projects in 2010 compared with 2009.

Other Operating Expenses

Project development. During the nine months ended September 30, 2010, we recorded project development expenses of $32.9 million, a 0.6% increase from the $32.7 million recorded for the same period in 2009. Stock-based compensation expense recorded in project development for the first nine months of 2010 was $1.7 million, compared with $0.6 million for the same period in 2009. The 1.7% decrease in project development costs, net of stock-based compensation, to $31.2 million for the nine months ended September 30, 2010, from $32.1 million for the nine months ended September 30, 2009, was due largely to timing of development activity in 2010 to support our development pipeline for 2011 and beyond along with the writeoff in 2010 of approximately $2.5 million of previously-capitalized costs for a project that was reclassified from Tier 1 to Tier 2. Additionally, we have classified approximately $5.2 million of certain types of costs historically included in project development expenses as project operating expenses in 2010. The impact of this change was partially offset by our classifying approximately $1.6 million of certain types of costs historically included in general and administrative expenses as project development expenses in 2010 as further described below.

General and administrative. During the nine months ended September 30, 2010, we recorded general and administrative expenses of $25.0 million, a 12.7% decrease from the $28.6 million recorded for the same period in 2009. Stock-based compensation expense recorded in general and administrative expenses in the 2010 period totaled $8.3 million, including $2.6 million related to revisions of estimated forfeitures, compared with $4.7 million in the 2009 period. The 30.4% decrease in general and administrative expenses, net of stock-based compensation, to $16.7 million for the nine months ended September 30, 2010 from $23.9 million for the nine months ended September 30, 2009 was due largely to reductions in non-recurring third party legal and consulting expense incurred during 2009 along with our classifying approximately $1.6 million of certain types of costs (primarily related to securing real estate, PPAs and other project related contracts) historically included in general and administrative expenses as project development costs in 2010. Comparing the nine months ended September 30, 2010 with the same period in 2009 we have increased our rated capacity by 84% while reducing our general and administrative expenses. Apart from certain additional costs we will incur as a public company, we believe that we have achieved scale in general and administrative capabilities to support our future growth without significant additions to headcount and overhead costs related to non-operating activities.

Depreciation and amortization expenses. During the nine months ended September 30, 2010, we recorded depreciation and amortization expenses of $3.4 million, a 40.9% increase over the $2.4 million recorded for the same period in 2009, due largely to capital expenditures related to corporate assets such as leasehold improvements, vehicles, office equipment and furniture.

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Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

The following table sets forth selected information about our results of operations for the years ended December 31, 2009 and 2008 (dollars in thousands):

	Year Ended December 31,		2009 compared with 2008	
	2008	2009	$	%
Revenues:				
Revenues	$ 28,790	$ 47,136	$ 18,346	64%
Cash settlements of derivatives	(4,072)	10,966	15,038	N/M
Fair value changes in derivatives	14,760	17,175	2,415	16%
Total revenues	39,478	75,277	35,799	91%
Cost of revenues:				
Project operating expenses	10,613	19,709	9,096	86%
Depreciation and amortization of operating assets	10,611	34,185	23,574	222%
Total cost of revenues	21,224	53,894	32,670	154%
Gross income	18,254	21,383	3,129	17%
Other operating expenses:				
Project development	35,855	35,895	40	0%
General and administrative	44,358	39,192	(5,166)	-12%
Depreciation and amortization	2,325	3,381	1,056	45%
Total other operating expenses	82,538	78,468	(4,070)	-5%
Loss from operations	(64,284)	(57,085)	7,199	-11%
Risk management activities related to non-operating projects	42,138		(42,138)	-100%
Other income (expense)	827	(1,915)	(2,742)	N/M
Interest expense, net of capitalized interest	(4,846)		4,846	-100%
Loss before provision for income taxes	(26,165)	(59,000)	(32,835)	125%
Provision for income taxes		2,010	2,010	N/M
Net loss	(26,165)	(61,010)	(34,845)	133%
Less: net loss attributable to noncontrolling interests	11,107	1,391	(9,716)	-87%
Net loss attributable to members of First Wind Holdings, LLC	$ (15,058)	$ (59,619)	$ (44,561)	296%
Key Metrics:				
Rated capacity (end of period)	92 MW	478 MW	386 MW	420%
Electricity generated	275,024 MWh	656,365 MWh	381,341 MWh	139%
Average realized energy price	$ 97/MWh	$ 85/MWh	$ (12)/MWh	-12%
Project EBITDA	$ 15,589	$ 35,867	$ 20,278	130%

N/M = not measurable/meaningful

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Revenues and project operating expenses

During 2009, we recorded revenues from energy sales, REC sales and capacity sales, along with cash settlements of derivatives, of $58.1 million, a 135% increase over the $24.7 million recorded during 2008. This increase was due to the substantial increase in electricity generation in 2009 compared with 2008, which in turn was due to the substantial increase in the capacity of our projects in 2009 compared with 2008. During 2009, we generated 656,365 MWh of electricity, a 139% increase over the 275,024 MWh generated in 2008, due largely to the increase in the capacity of our projects in 2009. Average realized energy price for 2009 was $85/MWh compared with $97/MWh in 2008.

Including revenues from risk management activities related to operating projects, during 2009 we recorded revenues of $75.3 million, a 90.7% increase over the $39.5 million recorded for 2008. Risk management activities related to operating projects resulted in a gain of $28.1 million for 2009 compared with a gain of $10.7 million for the same period in 2008. The $17.4 million increase for 2009 over 2008 relates to $2.4 million of mark-to-market gains on commodity swap contracts combined with net cash settlements of $15 million on the same commodity swaps.

Operating base. Our performance for 2009 and 2008 for projects that were operating prior to January 1, 2009 was as follows:

Kaheawa Wind Power I (KWP I). For 2009, energy production at KWP I was approximately 110,000 MWh, resulting in an NCF of 42%, compared with energy production of approximately 109,000 MWh, resulting in an NCF of 41% in 2008. This tracks to our long-term NCF expectation of 41% to 43%. Average realized energy price for 2009 was approximately $85/MWh compared with approximately $93/MWh for 2008, due to a decrease in oil prices. Project operating expenses for 2009 were approximately $2.4 million, or $81/kW, compared with approximately $2.7 million in costs or $91/kW in 2008.

Mars Hill. For 2009, energy production at Mars Hill was approximately 122,000 MWh, resulting in an NCF of 33%, compared with energy production of approximately 129,000 MWh, resulting in an NCF of 35% in 2008. Our 2009 performance tracks below our long-term NCF expectation of approximately 35% to 37% due to below-average wind speeds in the region. Average realized energy price for 2009 was approximately $88/MWh compared with approximately $106/MWh for 2008. Project operating expenses were approximately $5.2 million for 2009 or $124/kW compared with approximately $6.9 million in costs, or $163/kW, in 2008.

Steel Winds I. For 2009, energy production at Steel Winds was approximately 42,000 MWh, resulting in an NCF of 24%, compared with energy production of approximately 37,000 MWh, resulting in an NCF of 21% in 2008. Our 2009 performance was below our long-term NCF expectation of approximately 29% to 31% due to a combination of lower than expected turbine availability and below-average wind speeds in the region.
Lower than expected turbine availability in 2009 was primarily due to a Clipper blade wrinkle defect, which resulted in approximately 5,000 MWh of lost production in 2009, for which we have warranty protection. Adjusting for the warranty claim, the NCF would have been approximately 27%. Lower than expected turbine availability in 2008 was primarily due to two separate technical start-up problems experienced by Clipper, one related to gearboxes and the other related to blades. See "Risk Factors Risks Related to Our Business and the Wind Energy Industry One of our key turbine suppliers, Clipper Windpower Plc, has experienced certain technical issues with its wind turbine technology and may continue to experience similar issues." All of our Clipper turbines have a five-year availability warranty, which protects us from lost revenue resulting from start-up technical problems such as those described above. We believe that Clipper has remediated these technical problems.

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Our average realized energy price for 2009 was approximately $94/MWh, including warranty claims, compared with approximately $77/MWh for 2008. Project operating expenses in 2009 were approximately $1.5 million, or $74/kW compared with approximately $1.4 million or $72/kW in 2008.

On an aggregate basis for our 2009 operating base, 2009 energy production was approximately 273,000 MWh, resulting in an NCF of 34%. Adjusted for our warranty claim at Steel Winds I, our operating base NCF would have been approximately 35%, which tracks slightly below our long-term expectation of 36% to 38% due to below-average wind speeds. While below our long-term NCF expectations, our 2009 NCF was within the expected range of annual variation. Average realized energy price for the period was $88/MWh. Project operating expenses were approximately $9.1 million or $99/kW.

Partial year projects. During their first year of operation, our projects are more affected by factors like ramp-up in availability and seasonality than is typical after the project has been operating for a longer duration. This affects the comparability of a project's performance between periods that include the first year of operation. Our 2009 performance for projects that commenced operations after January 1, 2009 was as follows:

Cohocton. Cohocton began commercial operations in late January 2009. For 2009, energy production at Cohocton was approximately 204,000 MWh, resulting in an NCF of 20%. Adjusting for the factors described above for partial year projects and for warranty claims described below, the NCF would have been 23%. This NCF tracks below our long-term expectation of 25% to 27% due primarily to below-average wind speeds in the region and the planned ramp-up in turbine availability that is typical in newly commissioned projects.

Similar to Steel Winds I, the lower than expected turbine availability in 2009 was due primarily to the Clipper blade wrinkle defect, which resulted in approximately 32,000 MWh of lost production in 2009. Unlike Steel Winds I, we did not experience any other blade or gearbox problems at Cohocton because Clipper had remediated those problems in the Cohocton turbines before Cohocton was placed in service. All of our Clipper turbines have a five-year availability warranty, which protects us from lost revenue resulting from technical start-up problems such as those described above. Accordingly, we recovered the revenue from the associated lost energy production through a Clipper warranty claim. We believe that Clipper has remediated the technical problems described above. Average realized energy price for 2009 was $100/MWh. Included in this number is a non-recurring financial hedge settlement of approximately $4.1 million. If this settlement were excluded from revenues, the average realized energy price would have been $79/MWh including warranty claims. Project operating expenses were approximately $6.5 million or $52/kW.

Stetson I. Stetson I began commercial operations in late January 2009. For 2009, energy production at Stetson I was approximately 139,000 MWh, resulting in an NCF of 30%. This tracks to the low end of our long-term NCF expectation range of 30% to 32% due primarily to below-average wind speeds in the region. Average realized energy price was approximately $97/MWh. We have a 10-year financial swap for Stetson I, which did not commence until July 2009; therefore, Stetson I's results were exposed to variability of merchant power prices before then. The majority of the future annual output at Stetson I is hedged under the financial swap, which expires in 2019. Project operating expenses for 2009 were $4.7 million or $82/kW.

Milford I. Milford I began commercial operations on November 16, 2009. Under the terms of the Milford I PPA, in February 2010 SCPPA provided an approximately $232 million prepayment for approximately 75% of the estimated annual generation delivered over 20 years. SCPPA also makes payments for the as-generated electricity for the remaining approximately 25% of our annual production at a fixed rate of approximately $59/MWh, escalating at 1.75% annually.

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Finally, SCPPA makes payments of approximately $11/MWh for the as generated RECs, none of which have been prepaid, and reimburses the project for a portion of its operating costs.

For 2009, in which Milford I was operating for 46 days, energy production was approximately 40,000 MWh, resulting in an 18% NCF. This tracks below our long-term NCF expectation range of 24% to 26% due to a combination of below-average wind speeds in the region and the planned ramp-up in turbine availability that is typical in newly-commissioned projects. Average realized energy price was approximately $52/MWh, and project operating expenses were $0.9 million or $37/kW.

Depreciation and amortization of operating assets. During 2009, we recorded expenses for depreciation and amortization of operating assets of $34.2 million, a 222.2% increase over the $10.6 million recorded for 2008, due largely to the substantial increase in the capacity of our projects in 2009 compared with 2008.

Other Operating Expenses

Project development. During 2009, we recorded project development expenses of $35.9 million, which is approximately the same as the amount recorded for 2008. Project development expenses in 2009 also include a charge of $3.1 million for formerly-capitalized costs of a project that was changed from Tier 1 to Tier 2 status, and project development expenses for 2008 include a charge of approximately $3.5 million for formerly-capitalized costs of a Tier 1 project that was discontinued.

General and administrative. During 2009, we recorded general and administrative expenses of $39.2 million, an 11.6% decrease from the $44.4 million recorded for 2008, due largely to reductions in non-recurring third party legal and accounting expenses incurred during 2008 offset by an overall increase in general and administrative expenses associated with the expansion of our business. Additionally, general and administrative expense included $5.9 million of stock-based compensation expense in 2009 compared with $8.6 million in 2008. We believe that, apart from additional costs we expect to incur as a public company, we have achieved sufficient general and administrative capabilities to support our future growth without requiring significant increases in these expenses. For non-operating activities in 2010, we expect to reflect certain types of costs that were included in general and administrative expenses in 2009 and 2008 as project development expenses due to changes in our accounting systems that allow us to identify these costs.

Depreciation and amortization. During 2009, we recorded depreciation and amortization expenses of $3.4 million, a 45.4% increase over the $2.3 million recorded for 2008, due largely to an increase in capital expenditures related to anemometers used to perform wind resource analysis at our development projects; an increase in corporate assets such as vehicles, office equipment and furniture; and an increase in depreciation of construction equipment.

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Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

The following table sets forth selected information about our results of operations for the years ended December 31, 2007 and 2008 (dollars in thousands):

	Year Ended December 31,		2008 Compared to 2007	
	2007	2008	$	%
Revenues:				
Revenues	$ 23,817	$ 28,790	$ 4,973	21%
Cash settlements of derivatives	(1,670)	(4,072)	(2,402)	144%
Fair value changes in derivatives	(9,801)	14,760	24,561	N/M
Total revenues	12,346	39,478	27,132	220%
Cost of revenues:				
Project operating expenses	9,175	10,613	1,438	16%
Depreciation and amortization of operating assets	8,800	10,611	1,811	21%
Total cost of revenues	17,975	21,224	3,249	18%
Gross income (loss)	(5,629)	18,254	23,883	N/M
Other operating expenses:				
Project development	25,861	35,855	9,994	39%
General and administrative	13,308	44,358	31,050	233%
Depreciation and amortization	1,215	2,325	1,110	91%
Total other operating expenses	40,384	82,538	42,154	104%
Loss from operations	(46,013)	(64,284)	(18,271)	40%
Risk management activities related to non-operating projects	(21,141)	42,138	63,279	N/M
Other income (expense)	1,078	827	(251)	23%
Interest expense, net of capitalized interest	(9,820)	(4,846)	4,974	-51%
Net loss	(75,896)	(26,165)	49,731	-66%
Less: net loss attributable to noncontrolling interests	7,825	11,107	3,282	42%
Net loss attributable to members of First Wind Holdings, LLC	$ (68,071)	$ (15,058)	$ 53,013	-78%
Key Metrics:				
Rated capacity (end of period)	92 MW	92 MW		0%
Electricity generated	239,940 MWh	275,024 MWh	35,084 MWh	15%
Average realized energy price	$ 103/MWh	$ 97/MWh	$ (6)/MWh	-6%
Project EBITDA	$ 14,945	$ 15,589	$ 644	4%

N/M = not measurable/meaningful

Revenues and project operating expenses

During 2008 we recorded revenues from energy sales, sales of RECs and capacity sales, along with cash settlements of derivatives, of $24.7 million, a 11.6% increase over the $22.1 million recorded for 2007. This increase was due to the increase in electricity generation in 2008 compared with 2007, which in turn was due to the increase in the capacity of our projects in 2008 compared with 2007. During 2008, we generated 275,024 MWh of electricity, a 14.6% increase over the 239,940 MWh generated in 2007, due largely to our Steel Winds I project operating for only a partial year in 2007. Average realized energy price for 2008, was $97/MWh compared with $103/MWh in 2007.

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Including revenues from risk management activities related to operating projects, during 2008 we recorded revenues of $39.5 million, a 219.8% increase over the $12.3 million recorded for 2007.

Operating base. Our performance for 2008 and 2007 for projects that were operating or under construction prior to January 1, 2008, excluding Steel Winds I, was as follows:

Kaheawa Wind Power I (KWP I). For 2008, energy production at KWP I was approximately 109,000 MWh, resulting in an NCF of 41% compared with energy production of approximately 126,000 MWh, resulting in an NCF of 48% in 2007. Average realized energy price for 2008 was approximately $93/MWh compared with approximately $99/MWh for 2007. Project operating expenses for 2008 were approximately $2.7 million or $91/kW compared with approximately $3.2 million in costs or $106/kW in 2007.

Mars Hill. For 2008, energy production at Mars Hill was approximately 129,000 MWh, resulting in an NCF of 35% compared with energy production of approximately 102,000 MWh, resulting in an NCF of 36% in 2007, which was a partial year with a March 27, 2007 commercial operations date. Average realized energy price for 2008 was approximately $106/MWh compared with approximately $109/MWh for 2007. Project operating expenses for 2008 were approximately $6.9 million, or $163/kW compared with approximately $5.7 million in costs or $135/kW in 2007.

The performance of our Steel Winds I project during 2008 and 2007 was not material to our consolidated results of operations.

Depreciation and amortization of operating assets. During 2008, we recorded expenses for depreciation and amortization of operating assets of $10.6 million, a 20.6% increase over the $8.8 million recorded for 2007, due largely to the increase in the capacity of our projects in 2008 compared with 2007.

Other Operating Expenses

Project development expenses. During 2008, we recorded project development expenses of $35.9 million, a 38.6% increase over the $25.9 million recorded for 2007, due largely to an increase in development expenses from expansion of our project pipeline. Project development expenses in 2008 also include a charge of $3.5 million for formerly-capitalized costs of a Tier 1 project that was discontinued.

General and administrative expenses. During 2008, we recorded general and administrative expenses of $44.4 million, a 233.3% increase over the $13.3 million recorded for 2007, due largely to an overall increase in general and administrative expenses associated with expansion of our business and preparation for becoming a public company along with (i) expenses of approximately $4.0 million incurred for costs associated with securities registration that would have otherwise been capitalized had our initial public offering been completed; and (ii) approximately $11.5 million of non-recurring legal and administrative expenses.

Depreciation and amortization expenses. During 2008, we recorded depreciation and amortization expenses of $2.3 million, a 91.4% increase over the $1.2 million recorded for 2007, due largely to an increase in capital expenditures related to anemometers to perform wind resource analysis at our development projects; and corporate assets such as vehicles, office equipment and furniture; and depreciation of construction equipment.

Risk Management Activities Related to Non-Operating Projects

During 2008, we recorded a gain related to risk management activities related to non-operating projects of $42.1 million, compared with an expense of $21.1 million recorded for 2007, due largely to the effect of decreasing electricity prices.

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Liquidity and Capital Resources

As of December 31, 2009, we had accumulated losses since inception of $191.2 million and $752 million of long-term indebtedness (including current maturities and an advance of $120 million accounted for as a redeemable interest in our Milford I project that was repaid with ARRA grant proceeds in March 2010). These losses were largely attributable to our development and overhead activities as we grew our company to commercial scale. We expect to continue to incur significant capital expenditures and significant losses for next several years as we develop and construct new projects, purchase additional turbines, hire additional employees, expand our operations and incur additional costs of operating as a public company. As we grow, we expect to require significant additional amounts of debt, tax equity financing and equity capital.

Our requirements for liquidity and capital resources, other than for general corporate and administrative expenses and working capital needs, consist primarily of debt service requirements and capital expenditures for wind turbine purchases. Our business plan depends on our ability to repay or refinance our short-term debt. If we are successful in repaying or refinancing our short-term debt and obtaining the government grants that we intend to apply for in 2010, we believe that cash on hand, the proceeds from our financing activities and cash generated through operations, together with the net proceeds of this offering, should provide sufficient capital to support our debt service obligations, including our approximately $112.0 million of debt coming due through September 30, 2011 and early repayment of certain debt instruments such as the First Wind Term Loan, along with a portion of our current development plan through mid-2013.

Capital Expenditures

In general, our capital expenditures primarily relate to the acquisition of turbines to construct new projects and to expand existing projects. We have budgeted approximately $435 million for additional capital expenditures relating to the construction of our KWP II, Kahuku, Milford II, Rollins, Sheffield and Steel Winds II projects. See "Business Our Portfolio of Wind Energy Projects 2010 Projects." Approximately $50 million of this amount is budgeted for turbine purchases, as we have already paid for approximately 90% of the turbines required for our 2010 construction plan. We intend to finance our 2010 capital expenditures primarily through a combination of construction loans, ARRA grants and long-term project financing. We intend to use a portion of the net proceeds from this offering to fund a portion of our project development and construction costs for 2010-2013. See "Use of Proceeds."

Sources of Liquidity

We expect the principal sources of liquidity for our future operating and capital expenditures to be derived from:

- existing and new debt financings;
- existing and new tax equity financings;
- existing and new equity capital, including the proceeds from this offering;
- U.S. Treasury grants for projects placed in construction before 2010 and in service before 2013; and
- cash flow from operations, including customer prepayments.

However, there can be no assurance that any additional financing will be available or, if such financing is available, that it will be available on terms acceptable to us. Moreover, additional funds may be necessary sooner than we currently anticipate in the event of changes to development schedules, increases in development costs, unanticipated prepayments to vendors or other unanticipated expenses. If we are unable to complete the types of transactions described above, raise additional

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capital or generate sufficient operating cash flow, we could default under our lending agreements or be required to delay development and construction of our wind energy projects, reduce overhead costs, reduce the scope of our projects or abandon or sell some or all of our development projects, all of which could adversely affect our business, financial position and results of operations.

Debt

Borrowings under each of our turbine supply and construction loans are typically secured by a lien on the assets of the wind energy project to which they relate. Borrowings under our term loans are typically secured by a lien on the assets of the wind energy project to which they relate and a pledge of membership interests of our related project subsidiary. Our loan agreements generally contain covenants, including, among others, limitations on the use of proceeds and restrictions on indebtedness, liens, asset sales, dividends and distributions, investments, transactions with affiliates, transfers of ownership interests and certain changes in business. These covenants limit our subsidiaries' ability to pay us dividends or make loans or advances to us. We were in compliance with the covenants in each of our loan agreements as of September 30, 2010.

Our outstanding debt as of December 31, 2009 and September 30, 2010 was as follows (dollars in thousands):

	Interest rate at September 30, 2010	Final Maturity	Balance at December 31, 2009	Balance at September 30, 2010
Turbine Supply Loan				
Wind Acquisition Loan	5.01%	2011(1)	$ 197,868	$ 118,350
Wind Acquisition IV Loan	5.01%	2011	43,064	43,064
Construction Loans				
Milford I	N/A	2010	146,002	
Stetson II	N/A	2010	2,197	
Kahuku	3.51%	2028		53,582
Term Loans				
North Shore Note	N/A	2010	7,200	
Maine Wind Loan	3.09%	2022	14,197	12,188
New York Wind Loan	3.54%	2018	50,000	65,000
CSSW Loan	14.00%	2018	122,021	144,609
Stetson Holdings Loan	4.00%	2016	68,000	62,854
First Wind Term Loan	17.00%	2013		77,320
Other				
Construction equipment loan	7.65%	2013	4,944	4,307
Vehicle loans	0.00%-11.28%	2010-2014	840	943
Gross Indebtedness			656,333	582,217
Unamortized Discount			(24,287)	(20,836)
Carrying Value			632,046	561,381
Debt with maturities less than one year			109,238	111,960
Total long-term debt			$ 522,808	$ 449,421

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(1) $67.3 million of the September 30, 2010 balance of $118.4 million was paid on October 20, 2010 as described at Milford II below. The remainder is payable as follows: January 2011 $4.6 million, April 2011 $16.2 million, May 2011 $12.8 million and June 2011 $17.5 million.

From January 1, 2010 through October 20, 2010, we completed the following debt transactions:

Milford II. On October 20, 2010, our Milford Wind Corridor Phase II, LLC subsidiary entered into a $247.0 million, non-recourse secured credit agreement with RBS Securities Inc. as Lead

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Arranger and Bookrunner and the lenders party thereto (Milford II Loan). A portion of the proceeds of this loan were utilized to repay $67.3 million under our Wind Acquisition Loan. The Milford II Loan has a stated maturity of December 13, 2011. As of October 20, 2010, the amount outstanding under the Milford II Loan was $142.1 million.

New York Wind Loan. On September 1, 2010, we refinanced the New York Wind Loan. This refinancing increased the loan size to $79.0 million (including a $14.0 million letter of credit facility), extended the maturity date to March 1, 2018, and replaced HSH with Union Bank, N.A., Deutsche Bank Trust Company Americas and Commerzbank AG, New York Branch as lenders.

Kahuku. In July 2010, our Kahuku Wind Power, LLC subsidiary entered into a $117.3 million construction and term loan facility (Kahuku Loan) guaranteed by the DOE. The Kahuku Loan is secured by the Kahuku project and all of its assets. The DOE also has a $10 million guarantee from First Wind Holdings, LLC and an $8 million project completion letter of credit. Principal repayment will begin in March 2012 and the Kahuku Loan will mature in June 2028. As of September 30, 2010, total principal outstanding under the Kahuku Loan was approximately $53.6 million, which accrues interest at a rate of 3.51% per annum.

Wind Acquisition Loan. In June 2010, we extended the maturity of approximately $77.6 million due under our Wind Acquisition Loan to January 15, 2011. Additionally, we made a principal payment of approximately $10.4 million in August 2010.

First Wind Holdings, LLC. In March 2010, First Wind Holdings, LLC completed a $77.3 million term loan financing and also entered into a $50.0 million letter of credit facility. We used approximately $61.0 million of the proceeds from the First Wind Term Loan to partially repay the Wind Acquisition Loan turbine supply loan maturing on June 30, 2011. This partial repayment resulted in First Wind Holdings, LLC's being released from its guarantee of this indebtedness.

Wind Acquisition and Wind Acquisition IV Loans. In March 2010, we amended our $135.5 million Wind Acquisition Loan and $43.1 million Wind Acquisition IV Loan turbine supply loans. This amendment extended the maturities of approximately $96.2 million outstanding under these loans (Wind Acquisition Loan $53.1 million, Wind Acquisition IV Loan $43.1 million) from June 2010 to June 2011.

Milford Construction Loan. In February 2010, we repaid the Milford I Construction Loan as further described below.

North Shore Note. In March 2010, we repaid the North Shore Note.

During the year ended December 31, 2009, we completed the following debt financing transactions, which, along with others, are more fully described in Note 6 to our consolidated financial statements appearing elsewhere herein:

Stetson Holdings, LLC. In December 2009, Stetson Holdings, LLC entered into a $116.3 million loan facility for our Stetson I and Stetson II projects with BNP Paribas and HSH. This facility, which matures in 2016, provides a $71.0 million term loan for both the Stetson I and Stetson II projects as well as an additional $18.6 million grant bridge loan for the Stetson II project that was repaid from grant proceeds in June 2010. The facility also includes a letter of credit facility of $26.7 million. Interest is payable semi-annually at LIBOR plus 3.25% for the first three years and then increases to LIBOR plus 3.50%. We used substantially all of the proceeds of this loan to repay $59.0 million of indebtedness that was incurred in October 2009 that was secured by our Stetson I project and replaced by a $76.5 million one-year term loan that was incurred in July 2009.

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CSSW Loan. During July and September 2009, we raised $115.0 million in loans from affiliates of Alberta Investment Management Corporation (AIMCO) to CSSW, LLC, a newly-formed subsidiary that owns our Cohocton I, Stetson I and Steel Winds I operating projects, and through the issuance of Series A-2 units in First Wind Holdings, LLC to AIMCO. The CSSW indebtedness matures in January 2018, and bears interest annually at a rate of 12% if we elect to pay cash interest or 14% if we elect to pay interest in kind. The CSSW loan was amended and restated on December 22, 2009 to add Stetson II to the collateral for that loan.

Milford I Construction Loan. In April 2009, our Milford Wind Corridor Phase I, LLC subsidiary entered into a $376.4 million, non-recourse secured credit agreement with a syndicate of 11 banks led by Royal Bank of Scotland Plc. We used the proceeds of this loan to repay approximately $65.2 million then outstanding under our Wind Acquisition Loan, approximately $95.2 million then outstanding under our Wind Acquisition IV Loan and approximately $10.7 million to repay deferred amounts due to the design-builder under the balance of plant construction contract for our Milford I project. As of December 31, 2009, approximately $146.0 million was outstanding under the Milford I construction loan. This construction loan was fully repaid in the first quarter of 2010 with a combination of proceeds of our Milford I tax equity financing (as described below), SCPPA's prepayment for energy and an ARRA grant.

New York Wind Loan. In March 2009, our New York Wind subsidiary borrowed $95.5 million under a 364-day, non-recourse term loan facility with Norddeutsche Landesbank Girozentrale, New York Branch, and HSH, and obtained a letter-of-credit facility of up to $10 million. Proceeds of the loan facility were used to repay $95.5 million of turbine supply loans then outstanding. We repaid approximately $22.3 million of this loan in November 2009 and approximately $20.6 million in December 2009 with a portion of proceeds from an ARRA grant. Additionally, we repaid approximately $1.7 million in December 2009 as part of our scheduled principal payments. On December 28, 2009, we amended the New York Wind Loan to extend its maturity to June 30, 2012.

Wind Acquisition Loan. On December 12, 2008, we entered into a refinancing arrangement with HSH with respect to the Wind Acquisition Loan. In February 2009, after $108.0 million of equity capital contributions by our sponsors, an additional $45.0 million was made available under the Wind Acquisition Loan pursuant to the December 2008 agreement.

Letters of Credit

After we enter into a contract, including financial swaps, PPAs and/or REC sales contracts (collectively, revenue contracts) to hedge the cash flows we expect to receive from a project, to the extent market prices fluctuate above the contract price, we may be required to post collateral in favor of our counterparty. We typically provide letters of credit for this purpose, but if we do not have available capacity under our letter of credit facilities, we post cash (from cash on hand, subject to availability at First Wind Holdings, LLC or the applicable project). The table below summarizes letter-of-credit availability at the project level relating to the revenue contracts under which we may be

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required to post collateral, and letter-of-credit availability at the holding company level as of December 31, 2009:

	Availability at December 31, 2009 (in thousands)	
Letter of Credit Facility		
Mars Hill	$	6,448
KWP I	$	586
Steel Winds I	$	200
Stetson I	$	11,900
Cohocton	$	1,658
First Wind Holdings, LLC	$	8,242

As of December 31, 2009, a one standard deviation increase in market prices would not have required us to post collateral under our financial swaps. However, if market electricity prices rise substantially above the levels we anticipate when we enter into revenue contracts, we cannot be sure that we would have sufficient letter-of-credit availability or cash to satisfy the collateral requirements under our outstanding revenue contracts. This could lead to the unwinding of one or more revenue contracts, with the result that the corresponding cash flows would be unhedged and exposed to market fluctuations and we would owe liabilities to our counterparties. On March 23, 2010, we entered into a $50 million, two-year letter of credit facility, which provides $35.0 million of incremental letter of credit capacity to use as collateral and for other uses.

Tax Equity Financing

We have sold equity interests in certain of our operating projects under tax equity financing arrangements. These financing arrangements entitle the tax equity investors to most of the operating cash flows and substantially all of the PTCs and taxable income or loss generated by the project, including the tax benefits of accelerated five-year depreciation available under the Modified Accelerated Cost Recovery System (MACRS), until the tax equity investors achieve their targeted investment returns and return of capital, which we typically expect to occur in 10 years. As illustrated in the table below, following achievement of the targeted investment return (typically 8% 9%), the allocation of the project's operating cash flows, PTCs and taxable income or loss "flips" or reverses from our tax equity investors to us so that we receive substantially all of the project's operating cash flows, PTCs and taxable income or loss from that point forward. If the project outperforms expectations, the flip will occur sooner and if a project underperforms, it will take longer for the flip to occur. Upon the tax equity investors' achieving their targeted investment returns, we have the option to acquire their equity interests, typically representing 5% to 10% of the project's allocations of profits and losses and distributable cash, at the higher of their capital account balance and the then-current fair market value of their interest. We retain controlling interests in the subsidiaries that own the projects and, therefore, will continue to consolidate these subsidiaries. The terms of our tax equity financing arrangements also include restrictions on the transfer of assets from the relevant subsidiary without the consent of the tax equity investors.

Although the economic terms of each tax equity financing vary substantially, the following table provides an illustration of an allocation to tax equity investors of cash distributions, PTCs and taxable income or loss that may characterize a tax equity financing. The column titled "Cash Distributions" reflects the apportionment of operating cash flows; the column titled "PTCs" reflects the allocation of PTCs for U.S. federal income tax purposes; and the column titled "Taxable Income or Loss" reflects the allocation of taxable income or loss for U.S. federal income tax purposes. So long as ARRA grants are available, we would not expect to realize PTC benefits through tax equity transactions.

	Cash Distributions		PTCs(1)		Taxable Income or Loss	
	Project Owner	Tax Equity Investors	Project Owner	Tax Equity Investors	Project Owner	Tax Equity Investors
Year 1 to flip date(2)	30%	70%	1%	99%	1%	99%
Thereafter	95%	5%	95%	5%	95%	5%

(1) PTCs lapse after ten years of commercial operations and the assets are generally fully depreciated five years after commercial operations commence.

(2) Actual flip dates, as discussed above, vary and depend on the date the tax equity investors earn the agreed upon targeted investment return.

During 2007, we completed two tax equity financings and received approximately $146.3 million in aggregate up-front payments in exchange for equity interests in our subsidiaries that own our KWP I and Mars Hill projects.

On January 31, 2008, we executed an agreement for $208 million of tax equity financing related to a portfolio of our New York projects (Steel Winds I, Cohocton I and Prattsburgh I). In August 2008, $19.7 million was funded under this agreement with respect to our Steel Winds I project. Funding under the agreement was scheduled to occur in tranches upon commencement of commercial operations of each applicable project and the satisfaction of certain other conditions precedent. Our counterparty in this tax equity financing was an indirect subsidiary of Lehman Brothers Holdings, Inc., which filed for bankruptcy on September 15, 2008. On September 16, 2009, we repurchased the tax equity investor's interest in Steel Winds I for $4.5 million and terminated the agreement and such tax equity investor's remaining funding obligations.

On September 28, 2009, we entered into an agreement with Stanton Equity Trading Delaware LLC, an affiliate of Credit Suisse, for the sale of certain equity interests with respect to our Milford I project, a 204 MW wind energy project in Utah. We used proceeds from this tax equity financing, along with SCPPA's prepayment for energy, to repay our Milford I construction loan in the fourth quarter of 2009 and the first quarter of 2010.

U.S. Treasury Grants

On September 4, 2009, we received a cash grant for our Stetson I project of approximately $40.4 million under the ARRA. We used approximately $17.5 million of the proceeds of the ARRA grant to partially repay the Evergreen Wind Power V Loan, and the remaining proceeds for general corporate purposes. On September 4, 2009, we also received cash grants of approximately $74.5 million for our Cohocton project under the ARRA. We used approximately $44.6 million of the proceeds of the ARRA grant to partially repay the New York Wind Loan. On March 23, 2010, we received an ARRA grant of approximately $120 million for our Milford I project and used the proceeds to repay a portion of our tax equity financing related to our Milford I project of approximately the same amount. On June 2, 2010, we received an ARRA grant of approximately $19.3 million for our Stetson II project and used approximately $14.1 million of these proceeds to repay the then-outstanding grant bridge loan portion of the Stetson construction and term loan facility (Stetson Holdings Loan).

Customer Prepayments

In February 2010, we received an approximately $232 million prepayment for energy under the PPA for our Milford I project. This prepayment was recorded as deferred revenue and will be recognized as energy is generated based on the price specified in the PPA. We are contractually obligated to deliver a minimum amount of energy for 20 years in connection with this prepayment. In

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the event that we do not deliver the contractually specified minimum amount of energy, we may be required to purchase and deliver replacement energy. We used approximately $155 million to repay the balance of the Milford I construction loan and the rest of this prepayment was used for general corporate purposes.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Year Ended December 31,			Nine Months Ended September 30,	
	2007	**2008**	**2009**	**2009**	**2010**
Net cash provided by (used in)					
Operating activities	$ (26,370)	$ (41,589)	$ (54,478)	$ (40,288)	$ 203,464
Investing activities	(334,007)	(477,268)	(253,533)	(325,894)	(39,278)
Financing activities	358,107	556,059	298,749	374,012	(129,043)
Net increase (decrease) in cash and cash equivalents	$ (2,270)	$ 37,202	$ (9,262)	$ 7,830	$ 35,143

Operating activities. Net cash provided by operating activities during the nine months ended September 30, 2010, was $203.5 million, compared with a net use of cash of $40.3 million during the same period in 2009. This increase was due primarily to receipt of a prepayment for energy for our Milford I project of $232 million, offset by the factors discussed for the results of operations for the nine months ended September 30, 2010.

Net cash used in operating activities during 2009 was $54.5 million, compared with $41.6 million during 2008. This decrease was due primarily to the factors discussed for the results of operations for 2009, coupled with increases due to timing of payments of invoices.

Net cash used in operating activities during 2008 was $41.6 million, compared with $26.4 million during 2007. This increase was due primarily to the increases in development and general and administrative expenses previously discussed offset by timing of payments of invoices.

Investing activities. Net cash used in investing activities during the nine months ended September 30, 2010, was $39.3 million, compared with $325.9 million during the same period in 2009. This decrease was primarily the result of timing of construction and turbine procurement activities, with Stetson II, Kahuku, Milford II, Rollins and Sheffield being under construction in 2010 and Cohocton I, Stetson I and Milford I being under construction in 2009. In 2010, approximately $33.6 million of capital expenditures were paid from directly-related debt facilities, compared with $223.4 million of payments for capital expenditures from construction loans and turbines from turbine supply loans in 2009. These payments are excluded from investing cash flow amounts.

Net cash used in investing activities during 2009 was $253.5 million, compared with $477.3 million during 2008. This decrease was primarily the result of increases in turbine deposits along with construction expenditures related to Cohocton I, Stetson I and Milford I in 2008 that were financed with equity capital. In 2009, approximately $259.3 million of turbine costs for various projects and construction-related costs for Milford I were paid from directly-related debt facilities and are excluded from the 2009 investing cash flow amount. Net cash used in investing activities in 2009 also includes a $44.5 million increase in restricted cash for various operating and contingency reserves required to be held at our projects under debt agreements or other contracts.

Net cash used in investing activities during 2008 was $477.3 million, compared with $334.0 million during 2007. This increase was primarily the result of increases in turbine deposits along with construction expenditures related to Cohocton I, Stetson I and Milford I.

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Financing activities. Net cash used in financing activities during the nine months ended September 30, 2010, was $129.0 million, compared with $374.0 million of net cash provided during same period in 2009. Financing activities during the nine months ended September 30, 2010, consisted primarily of: (i) $181.5 million of net proceeds from borrowings and (ii) $139.2 million of U.S. Treasury grant proceeds, offset by repayments of borrowings of approximately $434.5 million, including a $120.0 million payment for a portion of our tax equity financing related to our Milford I project with the U.S. Treasury grant proceeds. Cash used in financing activities in 2010 also includes a $4.0 million payment made to repurchase a portion of an investor's interest in our Milford I project, along with a $4.5 million payment made to a member of First Wind Holdings, LLC under a unit redemption agreement.

Net cash provided by financing activities during 2009 was $298.7 million, compared with $556.1 million during 2008. 2009 financing activities consisted primarily of net proceeds of: (i) $140 million received from our Sponsors in connection with refinancing certain of our indebtedness, (ii) $115 million of U.S. Treasury grant proceeds, and (iii) net proceeds of approximately $96.8 million from tax equity financings offset by net repayments of indebtedness of approximately $66.0 million ($607.4 million of proceeds net of $673.4 million of repayments) and the repurchase of a tax equity investor's interest in our Steel Winds I project for $4.5 million.

Net cash provided by financing activities during 2008 was $556.1 million, compared with $358.1 million during 2007. 2008 financing activities consisted primarily of net proceeds of $496.7 million received from our sponsors in connection with refinancing certain of our indebtedness along with net proceeds of approximately $56.9 million from borrowings ($371.8 million of proceeds net of $314.9 million of repayments) and $17.9 million from tax equity financings, offset by approximately $15.4 million of distributions in respect of equity interests.

Contractual Obligations

As of December 31, 2009, we had the following contractual obligations (in thousands):

	Payments Due by Period				
	Remaining Total	2010	2011-2012	2013-2014	Thereafter
Purchase obligations(1)	$ 40,214	$ 40,214	$	$	$
Debt(2)	656,333	249,221	194,284	27,129	185,699
Estimated interest payments on long-term debt(3)	124,368	30,089	36,865	23,983	33,431
Operating leases	68,964	5,189	12,674	7,434	43,667
Total(4)	$ 889,879	$ 324,713	$ 243,823	$ 58,546	$ 262,797

(1) In November 2009, we renegotiated our turbine supply agreements with Clipper in order to convert our firm purchase commitments into rights to purchase turbines, and we extended the delivery schedule for our existing orders. These agreements provide us with the right, but not the obligation, to acquire Clipper Liberty turbines representing 633 MW of capacity for installation over the period from 2011 to 2015. We have already paid approximately $60 million in deposits and progress payments for these turbines and intend to pay approximately $30 million more in deposits and progress payments by January 15, 2011. If we decide not to purchase any additional turbines from Clipper, we will forfeit the pro rata portion of these deposits and progress payments corresponding to the schedule of future turbine purchases: $38.6 million for turbines scheduled to be purchased in 2011, $17.9 million in 2012, $10.7 million in 2013, $13.4 million in 2014 and $8.9 million in 2015. Through September 2010, we paid Clipper $11.0 million with respect to these obligations.

(2) Reflects the effects of amendments and other debt-related transactions through October 20, 2010.

(3) Estimated interest payments are based on the assumption that we will pay accrued interest on the CSSW loan compared with electing to pay interest in kind. Interest rates relating to the individual debt facilities are based on the one-month LIBOR as of December 31, 2009. Interest rate on the interest swaps are based on the three-month LIBOR as of December 31, 2009 and assume a forward rate curve.

(4) Distributions to our tax equity investors under our tax equity financing arrangements and to holders of Series B Membership Interests pursuant to our tax receivable agreement are unquantifiable future commitments and are, therefore, excluded from our contractual obligations. For additional

information, see "The Reorganization and Our Holding Company Structure Tax Receivable Agreement."

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Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on our consolidated financial statements, which have been prepared in accordance with GAAP. In applying these critical accounting policies, 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 energy industry, information provided by our customers 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 such items as the depreciable lives of property, plant and equipment, amortization periods for identifiable intangible assets, valuation of long term swap contracts, asset retirement obligations and assumptions for share-based payments, testing long-lived intangible assets for impairment and to determine their fair value if impaired. 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.

Our critical accounting policies include:

Revenue Recognition

We currently earn revenue from two primary sources: (1) the sale of electricity and (2) the sale of RECs. We recognize revenues from the sale of electricity under long-term PPAs based upon the output delivered at rates specified under the contracts. We recognize revenues from the sale of RECs based upon the rates specified under the contracts. We defer recognition of revenue in instances when not all criteria to recognize revenue have been met.

Property, Plant and Equipment

Property, plant and equipment are stated at cost (net of any U.S. Treasury grant amount received), less accumulated depreciation. Renewals and betterments that increase the useful lives of the assets are capitalized. Repairs and maintenance expenditures that increase the efficiency of the assets are expensed as incurred. Wind energy project equipment and related assets are depreciated over their estimated useful life on a straight-line basis over 20 years. Other non-wind-energy-project-related property, plant and equipment are depreciated over their estimated useful lives on a straight-line basis ranging from three to seven years.

Construction-in-progress payments, turbine deposits and turbines, insurance, interest and other costs related to construction activities are capitalized. Construction in progress is reclassified to other balances within property, plant and equipment and depreciation is begun as each project commences commercial operations.

Many of our construction and equipment procurement agreements contain damage clauses relating to construction delays and contractually specified performance targets. These clauses cover a portion of the lost margin or revenues from the wind energy project's failure to operate when targeted or to perform as guaranteed. Payments received pursuant to these clauses are recorded as a reduction of construction-in-progress.

Project Development Costs

We capitalize project development costs as construction in progress once management deems a project probable of being technically, commercially and financially viable. This determination generally occurs in tandem with management's determination that a project should be classified as a Tier 1 development project. See "Business How We Classify Our Projects."

Impairment of Long-lived Assets

Long-lived assets primarily include property, plant and equipment. We review long-lived assets for impairment whenever events or changes in business circumstances indicate that the carrying amount of the assets may not be fully recoverable or that the useful lives are no longer appropriate. Each impairment test is based on a comparison of the undiscounted cash flows to the recorded value of the asset. If there is indication of impairment, the asset is written down to its estimated fair value based on a discounted cash flow analysis. Determining the fair value of long-lived assets entails management's exercise of judgment, and different judgments could yield different results.

Derivative Financial Instruments, Risk Management Activities and Fair Value Measurements

We employ derivative financial instruments to manage our exposure to fluctuations in commodity prices and interest rates. These derivative financial instruments are recorded in the consolidated balance sheets at their respective fair values.

Accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We have not formally documented or designated our derivative financial instruments as hedges; therefore, we do not apply hedge accounting to these instruments. Accordingly, these instruments have been marked to market through earnings.

We determine fair value of commodity price and interest rate swap agreements based on quoted prices when available or through the use of alternative approaches when market quotes are not readily accessible or available. Valuation techniques for fair value are based on observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our best estimate, considering all relevant information. These valuation techniques involve management estimation and judgment. The valuation process to determine fair value also includes making appropriate adjustments to the valuation model outputs to consider risk factors. The fair value hierarchy of our inputs used to measure the fair value of our assets and liabilities consists of three levels:

Level 1 Quoted prices for identical instruments in active markets.

Level 2 Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.

Level 3 Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

If inputs used to measure an asset or liability fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the asset or liability. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and considers factors specific to the asset or liability.

Tax Equity Transactions

We account for noncontrolling interests in projects where we have entered into our tax equity financings using a balance sheet methodology. Under this methodology, the amount reported as a noncontrolling interest in our consolidated balance sheet represents the amount the tax equity investors

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would receive, at each balance sheet date, if the net assets of the projects subject to the financing were liquidated at the values reflected on our balance sheet. We recognize periodic changes in the noncontrolling interest balance as an allocation of the periodic operating results to the noncontrolling interest in the statement of operations. We evaluate each transaction that gives rise to a noncontrolling interest to determine whether this balance sheet methodology is appropriate for the facts and circumstances of the transaction. It is possible that future transactions could be accounted for differently.

Quantitative and Qualitative Disclosure about Market Risk

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

Interest Rate Risk

We are exposed to fluctuations in interest rates, as substantially all of our outstanding debt obligations carry variable interest rates, principally indexed to LIBOR. In order to mitigate this risk, we employ financial instruments to manage our exposure to fluctuations in interest rates, including using interest rate swap agreements to effectively convert our anticipated cash payments under our variable-rate financings to a fixed-rate basis. These agreements involve the receipt of variable payments in exchange for fixed payments over the term of the agreements without the exchange of the underlying principal amounts.

As of September 30, 2010, we had total debt of approximately $582.2 million, of which approximately $280.8 million represents fixed-rate debt and is, therefore, not subject to interest rate fluctuation risk. However, the balance of approximately $301.4 million is currently at floating rates, which exposes us to changes in interest rates. We have entered into several interest rate swap and cap agreements to mitigate such risk. The detrimental effect on cash interest payments through September 30, 2011 of a hypothetical 100 basis point increase in interest rates, net of the offsetting effect on the cash settlements for the interest rate hedges, would be approximately $1.3 million. In addition, a 100 basis point increase in interest rates would produce a mark-to-market gain of approximately $3.8 million for the existing interest rate hedges that we expect to remain outstanding as of September 30, 2011.

Commodity Price Risk

Our ownership and operation of projects exposes us to volatility in market prices of electricity and RECs.

In an effort to stabilize our revenue from electricity sales, we evaluate the electricity sale options for each of our development projects, including the appropriateness of entering into a PPA or a financial swap, or both. If we sell our electricity into an ISO market and no PPA is available, we may enter into a financial swap to stabilize all or a portion of our estimated revenue stream. Under the terms of our existing financial swaps, we are not obligated to physically deliver or purchase electricity. Instead, we receive payments for specified quantities of electricity based on a fixed price and are obligated to pay our counterparty the market price for the same quantities of electricity. These financial swaps cover quantities of electricity that we estimate we are highly likely to produce. As a result, gains or losses under the financial swaps are designed to be offset by decreases or increases in our revenues from spot sales of electricity in liquid ISO markets. However, the actual amount of

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electricity we generate from operations may be materially different from our estimates for a variety of reasons, including variable wind conditions and turbine availability. If a project does not generate the volume of electricity covered by the associated swap contract, we could incur significant losses if electricity prices in the market rise substantially above the fixed price provided for in the swap. If a project generates more electricity than is contracted in the swap, the excess production will not be hedged and the revenues we derive will be exposed to market price fluctuations.

We enter into PPAs when we sell our electricity into non-ISO markets or where we believe it is otherwise advisable. Under a PPA, we contract to sell all or a fixed proportion of the electricity generated by one of our projects, sometimes bundled with RECs and capacity, to a customer, often a utility. We do this to stabilize our revenues from that project. We are exposed to the risk that the customer will fail to perform under a PPA, with the result that we will have to sell our electricity at the market price, which could be disadvantageous. We also in some instances commit to sell minimum levels of generation. If the project generates less than the committed volumes, we may be required to buy the shortfall of electricity production on the open market, which could be costly, or make payments of liquidated damages.

We often seek to sell forward a portion of our RECs to fix the revenues from those attributes and hedge against future declines in prices of RECs. If our projects do not generate the amount of electricity required to earn the RECs sold forward or if for any reason the electricity we generate does not produce RECs for a particular state, we may be required to buy the shortfall of RECs on the open market or pay liquidated damages. Further, current market conditions may limit our ability to hedge sufficient volumes of our anticipated RECs, leaving us exposed to the risk of falling prices for RECs. Future prices for RECs are also subject to the risk that regulatory changes will adversely affect prices.

We would also incur financial losses as a result of adverse changes in the mark-to-market values of the financial swaps or if the counterparty fails to make payments. We could also experience a reduction in operating cash flow if we are required to post margin in the form of cash collateral. We have been required in the past and may be required in the future to post cash collateral or issue letters of credit, for our obligations under some of our hedging arrangements, if market commodity prices rise above the contract prices. These actions reduce our available borrowing capacity under the credit agreements under which these letters of credit are issued.

We measure the sensitivity of the fair value of our financial hedges to potential changes in commodity prices using a mark-to-market analysis based on the current forward commodity prices and estimates of the price volatility. We estimate that a one standard deviation move in the aggregate fair value of our commodity swap positions from September 30, 2010 to December 31, 2010 would result in approximately $17 million of gain or loss, depending on the direction of the movement in the underlying commodity prices, for the existing positions that will be outstanding as of December 31, 2010. An increase in energy forward prices will produce a mark-to-market loss, while a decrease in prices will result in a mark-to-market gain.

Counterparty Risk

Our hedges expose us to counterparty credit risk, which is the risk that our counterparties may fail to fulfill their payment and other obligations under the contractual terms of our hedges. We seek to manage counterparty credit risk by assessing and monitoring the credit standing of the existing and potential counterparties and by either entering into hedges with creditworthy entities or obtaining adequate credit support, but these efforts may not be sufficient to limit our exposure and potential for loss.

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INDUSTRY

Overview

Wind energy has been one of the most rapidly growing renewable energy sources in the United States since 2000. According to the American Wind Energy Association (AWEA), wind energy capacity in the United States grew at a compound annual growth rate (CAGR) of 34% from 2000 through 2009. The Energy Information Administration (EIA) also indicates that wind energy was the fastest growing source of new electricity supply in the U.S. electrical generation market from 2000 through 2009. This has largely been due to wind energy's increased competitiveness, advances in wind turbine technology, growing support for renewable energy sources and the advantages of wind energy over many other renewable energy sources.

According to the Global Wind Energy Council, the United States experienced the largest annual increases in cumulative installed wind capacity in the world between 2005 and 2007. There was further growth from 2007 to 2009, with U.S. cumulative installed wind capacity increasing at a CAGR of 45% from 16.8 GW to 35.2 GW, according to AWEA. Furthermore, while in the midst of the recent global economic downturn, the U.S. wind industry succeeded in installing almost 10 GW of new wind energy capacity in 2009 according to AWEA. New installed capacity additions have slowed in 2010. Capacity of 1.2 GW was added through June 30, 2010, bringing total wind capacity in the United States to over 36.3 GW, according to AWEA.

As the worldwide demand for wind energy has increased over the past several decades, economies of scale and new technology have caused the installed price of wind energy to fall more than 80% over the past 20 years, according to AWEA. As a result of wind power's increased cost competitiveness compared with other renewable technologies, wind power contributed 39% of all new U.S. electric generating capacity in 2009, according to the DOE, making it five consecutive years that wind power represented the second-largest new resource added to the U.S. electrical grid as measured by nameplate capacity. The growth in U.S. demand for renewable energy has been driven by a number of factors including concerns about energy independence, environmental and climate change concerns, a desire for lower exposure to fuel cost volatility and more recently a desire for economic development.

Many states have requirements that their energy supply consist of a specified portion of renewable energy. RPS have been enacted in 29 states and the District of Columbia and typically call for an increasing percentage of renewable energy over time. Because the state-level programs vary so much, we focus on those sub-markets within the United States that have the highest renewable energy requirements and the least access to new supply. For example, in the Northeast and California, two of our target markets there are RPS targets of between 15% and 40% by 2013 to 2020 and 33% by 2020, respectively. In June 2009, Hawaii, the third region where we operate and where we have the largest utility-scale wind energy project in the state, increased its RPS target to 40% by 2030, making it one of the highest state renewable mandates, in terms of stated percentage, in the United States, according to IHS Emerging Energy Research (IHS EER). We believe that the increasing cost competitiveness of wind energy and the growing state-level demand for renewable energy provides the potential for long-term growth of our industry.

Installed Wind Capacity

Despite its rapid growth, wind energy capacity in the United States remains a small proportion of all electrical generation. Wind energy represented only 1.8% of total U.S. electricity production in 2009 and is expected to comprise only 4.1% of total U.S. electricity production in 2035, based on data from EIA. This represents a small portion compared with the percentage of electricity produced in 2009 by wind energy in Denmark, Spain and Germany, of approximately 20%, 14% and 8%, respectively, based on data from the DOE. Based on wind energy's relatively small portion of the U.S. electricity production portfolio, we believe that substantial growth potential in wind energy development remains.

IHS EER forecasts that installed wind capacity in the United States is expected to increase at a CAGR of 19% from 2009 through 2013, reaching approximately 70.6 GW in 2013.

Installed Wind Capacity (GW)

Source: Historical figures based on AWEA 2009 report and projected figures based on IHS EER data as of May 2010.

Drivers of U.S. Wind Energy Growth

Wind energy is a key component of the renewable energy strategy of the United States. AWEA estimates new wind projects completed in 2009 accounted for approximately 39% of the entire new power-producing capacity added in the United States. We believe the following factors are the main drivers of growth of wind energy in the United States:

Improvements in Wind Technologies and Cost Reductions

Wind turbine technology has evolved significantly over the last 20 years and we expect improved efficiencies to continue in the future as turbines become larger and more advanced. According to AWEA, the average size of installed wind turbines increased from 0.7 MW in 1998 1999 to 1.7 MW in 2009. AWEA further indicates that the cost of electricity generation from utility-scale wind systems has dropped more than 80% over the last 20 years as a result of technological advances, including:

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

- advances in remote operation and monitoring systems;

- improved wind monitoring and forecasting tools, allowing more accurate prediction of wind power output and availability and better system management and reliability; and

- advances in turbine maintenance, resulting in increased turbine lives.

These technological improvements have decreased the cost of wind generation and increased the scalability of wind energy projects, increasing the amount of overall generation with fewer turbines. We expect wind turbine cost reductions and efficiency improvements to continue.

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Set forth below is a chart with comparative cost information for electric power generation.

Comparative Cost of Electric Power Generation

Source: "Levelized Cost of Energy Analysis Version 3.0," website *http://blog.cleanenergy.org/files/2009/04/lazard2009_levelizedcostofenergy.pdf*, February 2009.

Note: For each generation source, cost is calculated by taking the midpoint of the range of Lazard estimates. Reflects PTC, ITC and accelerated asset depreciation, as applicable. Assumes 2008 dollars, 20-year economic life, 40% tax rate and 5-20 year tax life. Assumes 30% debt at 8.0% interest rate, 40% tax equity at 8.5% cost and 30% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of \$2.50 per MMBtu and natural gas price of \$8.00 per MMBtu. Natural gas prices for the week ended October 6, 2010 were \$3.56 per MMBtu, according to EIA's Natural Gas Weekly Update, October 7, 2010.

Climate Change and Environmental Concerns

The concerns about global warming caused by greenhouse gas emissions have also contributed to the growth of the wind energy industry. According to the Intergovernmental Panel on Climate Change Fourth Assessment Report, the eleven years between 1995 and 2006 ranked among the warmest since 1850. Awareness in the United States of climate change and the related effects of greenhouse gas emissions has resulted in increased demand for emissions-free energy generation. On December 7, 2009, the U.S. Environmental Protection Agency (EPA) stated that there is compelling scientific evidence that global warming caused by emission of greenhouse gases endangers Americans' health, and subsequently promulgated regulations governing greenhouse gas emissions from motor vehicles and certain stationary sources. Beginning in 2011, greenhouse gas emissions from large stationary sources, including power plants and factories, will be subject to permitting requirements under the federal Clean Air Act for the first time.

On July 6, 2010 the EPA proposed a rule that would help states reduce air pollution and attain clean air standards (the Transport Rule). The Transport Rule would require 31 states and the District of Columbia to significantly reduce power plant emissions that contribute to ozone and fine particle pollution in other states and would replace the EPA's 2005 Clean Air Interstate Rule (CAIR). The Transport rule could increase the cost of traditional fossil fuel energy generation, making alternative energy sources more cost competitive.

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Set forth below is a chart showing the levels of carbon dioxide emissions of various countries.

Total Carbon Dioxide Emissions from the Consumption of Energy in 2008
(Million metric tons carbon dioxide)

Source: Energy Information Administration (EIA), "Total Carbon Dioxide Emissions from the Consumption of Energy," website *http://tonto.eia.doe.gov/ cfapps/ ipdbproject/iedindex3.cfm?tid=90&pid=44&aid=8&cid=&syid= 2008&eyid=2008&unit=MMTCD*

State and Federal Government Incentives

One of the key factors contributing to the growth of wind energy in the United States is the existence of several government incentive programs and regulatory requirements at both the state and federal levels, including:

Renewable portfolio standards. An RPS is a program mandating that a specified percentage of electricity sales in a state or municipality comes from renewable energy. As of August 2010, 29 states and the District of Columbia have RPS requirements, more than double the number of states with RPS requirements in 2004. For states with increasing RPS requirements over time, renewable energy is scheduled to reach a range of 10% to 40% when the programs are fully implemented. Additionally, federal renewable portfolio requirements have from time to time been proposed in the U.S. Congress, although the chances of enactment are highly uncertain.

Some state RPS programs (25 such programs as of September 2010) operate in tandem with a credit trading system in which participants buy and sell RECs. A REC is a stand-alone tradable instrument representing the attributes associated with one MWh of energy produced from a qualified renewable energy source. Retail energy suppliers can meet RPS requirements by purchasing RECs from renewable energy generators, in addition to producing or acquiring the electricity from renewable sources. REC prices can represent a significant additional revenue stream for wind energy generators. In RPS states where a liquid REC market does not exist, renewable energy can be bought or sold through "bundled" PPAs, where the PPA price includes the price for renewable energy attributes. In states that do not have RPS requirements, certain entities buy RECs voluntarily. These RECs, which are called voluntary RECs, have a lower price than RECs where there are RPS requirements.

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The basic proposed or enacted goals of each state's RPS program as of August 11, 2010 are identified in the map below:

Source: FERC. August 11, 2010

Note: An RPS requires a percent of an electric provider's energy sales (MWh) or installed capacity (MW) to come from renewable resources. Map percentages are final years' targets. Alaska has no RPS.

American Recovery and Reinvestment Act of 2009 (ARRA). The ARRA, which was enacted in February 2009, encourages the development of renewable energy projects in the near term by reducing financing costs and providing cash grants and tax incentives for renewable energy projects through 2012. The ARRA includes a three-year extension of wind PTCs through the end of 2012; the option to elect an ITC for up to 30% of a project's eligible capital costs in lieu of the PTC; and the additional option to receive the ITC as a cash grant from the U.S. Treasury in lieu of the ITC. According to the U.S. Treasury, approximately $5.4 billion of ARRA grants had been issued as of October 6, 2010. We received approximately $115.1 million of ARRA grants for our Cohocton and Stetson I projects in September 2009, approximately $120.1 million of ARRA grants for our Milford I project in March 2010 and approximately $19.3 million of ARRA grants for our Stetson II project in June 2010.

The DOE has loan guarantee programs under Sections 1703 and 1705 of the ARRA. These programs call for over $40 billion of DOE loan guarantees to be allocated for innovative technology authorized under the Energy Policy Act of 2005 and approximately $15 billion to be made available for commercially proven technology. In July 2010, we entered into a $117 million construction and term loan facility guaranteed by the DOE under Section 1703 of the ARRA to help finance construction of our Kahuku project in Oahu. This was the first DOE loan guarantee for a wind-energy project.

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Federal Tax Incentives

A number of federal tax incentives encourage the development of renewable energy resources, including the following:

Production tax credits. The federal PTC provides a federal tax credit of $21 per MWh for a renewable energy facility during the first ten years of its operation. This incentive currently applies to facilities that are placed in service before the end of 2012. Producers may monetize their value by entering into tax equity financing arrangements with investors. Although there can be no assurance that legislation will be enacted extending application of the PTC to projects placed in service after 2012, since 1992 the PTC has been extended and has been continuously available for wind energy projects, except for three non-consecutive periods between 1999 and 2004 when the PTC temporarily expired but was retroactively reauthorized by subsequent legislation.

Investment tax credits. The federal ITC provides a federal tax credit for 30% of total eligible capital costs for a renewable energy facility following commercial operation. A wind developer may elect an ITC in place of the PTC and has the option to collect the ITC as a cash grant from the U.S. Treasury that is payable within 60 days after an application submission. Currently, wind projects must be under construction by the end of 2010 and in commercial operation by the end of 2012, in order to qualify for the cash grant. Congress is considering several bills that would extend the grant program in some form. We cannot predict whether or in what form an extension would take place.

Accelerated depreciation. The Tax Reform Act of 1986 established MACRS, which divides assets into classes and assigns a mandated number of years over which the assets in the class depreciate for tax purposes. Under MACRS, wind energy projects have a depreciation life of five years, which is substantially shorter than the 15 to 20-year lives of non-renewable facilities. Like PTCs, the accelerated depreciation benefit may be sold to investors.

Dependence on Foreign Energy Sources

According to EIA, foreign imports provided 26% of the energy consumed in the United States in 2008. Many of the regions rich in energy supplies are politically unstable, raising public concern regarding the dependence of the United States on foreign energy imports and related threats to U.S. national security. We believe that wind energy, which supplied only 1.8% of the total electrical production in the United States in 2009, can help to decrease the dependence on foreign energy sources and satisfy a portion of the expected increased demand for electricity in the United States.

Obstacles for the Construction of Conventional Power Plants

Environmental concerns have made it difficult to build new, or expand existing, fossil fuel projects. For example, according to data gathered by Sourcewatch, a collaborative encyclopedia website, only 35 of the approximately 150 coal plants proposed in the United States between 2000 and 2006 were built or under construction by the end of 2007. Nuclear energy projects have also faced significantly increasing capital costs and steep environmental hurdles, including complications relating to the disposal of spent nuclear fuel. As a result of these hurdles and complications, no new nuclear plant has been commissioned in the United States since 1979, although two nuclear plants are under construction. Wind energy, in contrast, does not create solid waste by-products, emit greenhouse gases or deplete non-renewable resources, and thus is an attractive alternative to conventional power plants. According to the DOE's report "20% Wind Energy by 2030," wind energy industry experts estimate the nation has more than 8,000 GW of available land-based wind resources that can be captured economically. Based on IHS EER estimates, we believe there will be incremental RPS demand for approximately 120 GW of renewable capacity by 2020, assuming a 30% average net capacity factor.

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Supply Chain Improvements in the United States

The success of wind energy is heavily dependant on its cost-competitiveness vis-à-vis other renewable technologies and conventional fuels. The increasing importance of the U.S. wind market is causing a supply chain shift among global producers, several of whom have recently announced plans to build U.S. manufacturing capacity. Historically, global turbine manufacturers have assembled turbines abroad and imported them to the United States, a logistical challenge that has in the past contributed to turbine shortages and high prices. According to AWEA, as recently as 2005, 70% of the wind industry supply chain was sourced from foreign locations. By the end of 2009, imports of wind turbines and select components represented 40% of total equipment-related wind turbine costs, down from roughly 50% in 2008, and this trend of increased domestic turbine manufacturing is expected to continue, according to the DOE.

The shift to domestic wind turbine manufacturing has been due largely to the desire of wind turbine manufacturers and developers to minimize delivery time and transportation costs, which can represent up to approximately 18% of the final cost of a wind project. It also reflects the growth in U.S. demand for wind turbines and government support for wind power. According to AWEA, of manufacturers with turbines installed in the United States since 2005, over 95% (measured by capacity) either operate or plan to operate turbine assembly facilities in the United States. At least 14 major wind turbine manufacturers have or have announced that they will have turbine manufacturing facilities in the United States, according to IHS EER. Furthermore, the regulatory stability of the U.S. wind market is attracting new entrants as well. This increase in local supply has primarily occurred in the last few years and resulted in underutilization of turbine manufacturing capacity as a consequence of the recent economic downturn. With turbine supply now exceeding demand, some turbine prices have decreased up to 20% from mid-2008 levels, according to IHS EER.

Key Attributes of Our Regions: Northeast, West and Hawaii

Our projects are located in the Northeastern and Western regions of the continental United States and in Hawaii. These markets are characterized by relatively high electricity prices, a shortage of renewable energy and a favorable balance between wind resources and cost-effective sites to build. At the end of 2009, approximately 72% of installed wind capacity was outside of these markets. We believe that the combination of demand from aggressive RPS requirements, premium electricity pricing, and strong wind resources will create significant opportunities for attractive development activity.

The key attributes of our regions are set forth below:

Among the Highest Prices in the United States

Power and REC prices vary across regions and states. The price of electricity varies based on supply and demand dynamics, generation technology mix, costs of commodities and other inputs required to produce electricity, as well as the cost of relevant environmental laws and regulations. REC prices vary based on the relative strength of RPS programs and supply and demand dynamics. As illustrated below, we are actively developing wind energy projects to sell electricity in the five states with the highest electricity prices in the United States of those states with RPS programs.

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The chart below contains information concerning state power prices.

State Power Prices

($/MWh)

Source: EIA, June 2010 YTD average retail power prices by state.
Note: Indicated fuel source reflects primary electricity price driver.

Markets with Largest Amount of Wind Energy Demand Relative to Amount in Interconnection Queue

We target markets where there is significant demand for wind generation supported by RPS programs relative to the amount of wind generation that is in the interconnection queue. A majority of our target markets, such as the ISO-NE have RPS-driven demand for renewable energy that exceeds the supply of renewable energy currently proposed within the interconnection queue of each of those power markets. Based on IHS EER estimates of incremental demand through 2020, we estimate that needed capacity in New England will exceed the amount currently in the ISO-NE interconnection queue by approximately 1.9 GW. IHS EER forecasts incremental 2020 RPS demand in California to be approximately 75 TWh per year if the 33% RPS target is maintained. We believe that the capacity needed to meet 2025 RPS demand will exceed supply currently in the interconnection queue by 4.7 GW. IHS EER expects substantive attrition of renewable projects currently in the queue given the significant permitting challenges, water resource limitations, and near-term transmission constraints. This compares favorably with the Midwest Independent Transmission System Operator (MISO), the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP), where the demand supported by RPS programs is much lower than the amount of wind generation in the interconnection queue.

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The chart below presents renewable energy capacity in regional interconnection queues and the IHS EER estimated 2015, 2020 and 2025 incremental RPS demand for those regions as of May 2010.

US RTO/ISO Queues by Renewables: 2020-2025
(TWh)

Source: IHS Emerging Energy Research as of August 16, 2010.

Note: *Since no centralized queue exists for WECC, this "queue" data is sourced primarily from IHS EER pipeline data but also from Renewable Northwest Project. Other includes biomass and other. In ERCOT, solar, biomass and other included in Other.

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The chart below shows existing supply and IHS EER's estimates for 2015 RPS demand in ISO New England (ISO-NE), New York, California and Hawaii.

Based on a 30% average net capacity factor, we believe the 2015 RPS capacity shortfall would be approximately 4.3 GW in New York, 3.3 GW in ISO-NE, 5.4 GW in California and 216 MW in Hawaii.

Renewables Supply/Demand
(TWh per year)

Source: IHS Emerging Energy Research, States, NEPOOL Generation Information System, New York State Energy Research and Development Authority (NYSERDA), California Public Utility Commission, Hawaii Public Utility Commission (Hawaiian PUC) and filings. Data as of May 28, 2010.

Note: Existing supply for California and Hawaii as reported for 2009 compliance; existing supply for New York and New England represents qualified online generation as of April 2010.

Most Progressive Renewable Energy Standards

Based on IHS EER estimates, we believe that states in our markets in the Northeast, West and Hawaii will need approximately 42 GW of incremental renewable energy capacity to be built by 2020, assuming a 30% average net capacity factor.

Northeast

A number of states in the Northeast have progressive renewable energy programs, which have increased growth opportunities and demand for wind development. According to IHS EER, RPS-driven demand for renewable energy in New England exceeds the supply of renewable energy currently in the ISO-NE interconnection queue. This has strengthened the market for RECs. For example, Massachusetts's RPS program requires that renewable energy use increase at a rate of 0.5% per year, reaching 4% of total electrical generation within the state by 2009, subsequently increasing by 1% every year thereafter to 25% by 2030. The Massachusetts program establishes a series of alternative compliance payments that began at $50 per MWh in 2003 and are adjusted for inflation ($61 per MWh in 2009). New York's RPS program is intended to address increasing concerns about New York's dependence on fossil-fuel generation and its environmental impact. The New York program calls for an increase in renewable energy used in the state from approximately 19% in 2004 to 30% by 2015.

Because renewable generation capacity is currently substantially below the ultimate RPS goals, significant additional renewable generation capacity must be developed within the region, particularly in

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the New England states, if RPS program requirements are to be met. Based on IHS EER's estimates, the current RPS mandates for the New York and New England states would result in incremental renewable demand of approximately 33,900 GWh by 2020.

Ten states in the Northeast and Mid-Atlantic participate in the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions from power plants in the participating states. The participating states have implemented a regional cap-and-trade program with a market-based emissions trading system. Under the program, participating states sell carbon dioxide emission allowances in regional auctions.

West

Our West markets include states with progressive RPS programs that provide support for long-term wind and other renewable energy demand. The Western states that we focus on include California, New Mexico, Arizona, Nevada, Washington and Colorado. These states have RPS programs that mandate that 15% to 33% of total electric generation come from renewable energy by 2015 to 2025, depending on the state. While these states represent our end markets, our wind projects may be built in other states and transmit power across state lines. For example, our Milford I project is located in Utah and transmits power to Los Angeles, California. In addition to RPS programs, some states have supplemental requirements related to wind energy, such as New Mexico, which has a specific requirement that a minimum of 20% of the total renewable energy generation must come from wind resources. The RPS programs and supplemental requirements in these states require additional renewable energy development in order for the RPS program requirements to be met, and thus present significant growth opportunities for wind energy development.

While we focus on several states in the West, California has historically been and remains the key end market for the majority of our projects in this region. California may face a shortage of renewable energy supply as renewable generation capacity has not kept pace with rising demand. With one of the most progressive RPS programs in the nation, California is an attractive end market for wind energy companies. California has historically been a leader in wind development, ranking third in the United States with over 9.0 GW of installed renewable generation capacity at year-end 2008, excluding capacity from large hydro generation, according to the EIA. Early adoption of an RPS target of 20% by 2017 was a key catalyst for new wind development, while a strengthened 33% RPS finalized in 2009 will make California's RPS program one of the highest in the continental United States through 2020. Based on its unique combination of competitive electricity pricing, strong renewable energy policy and excellent wind resources, IHS EER expects California will be one of the top five windpower markets in the United States by 2020.

California's RPS program currently requires 20% of retail utility power sales from investor-owned utilities to be generated by renewable sources by 2010, a requirement that can be satisfied in part with power imported from other Western states, including Utah, Wyoming, New Mexico, Nevada and Oregon. As of December 2009, California's investor-owned utilities were forecasted to fall short of their 2010 and 2020 renewable resources requirements of 20% and 33% respectively unless they add renewable resources at a much faster pace, according to the California Energy Commission (CEC). Penalties under California's RPS program for an RPS procurement deficit are $50/MWh, up to $25 million per year. IHS EER estimates the current (33%) RPS requirement for California would result in total RPS-driven incremental demand of approximately 75,000 GWh per year by 2020. The majority of new renewable capacity is expected to be delivered by wind and solar energy, given the characteristics of this region.

California's Global Warming Solutions Act of 2006 seeks to lower California's greenhouse gas emissions to 1990 levels by 2020, caps greenhouse gas emissions from major industries and imposes significant penalties for non-compliance. California also enacted a law in 2006 prohibiting utilities from making long-term commitments for electricity generated by plants that do not comply with the greenhouse gas emission performance standards established by the CEC. The law applies to out-of-state power purchases as well as in-state power purchases and is expected to have an adverse impact on California's ability to purchase power from coal-fired power plants.

In November 2010, the California state ballot will include a proposal (known as Proposition 23) to suspend implementation of California's Global Warming Solutions Act of 2006 (also known as AB 32) until California's unemployment rate is below 5.5% for four consecutive quarters. If this Prosposition is passed, California's RPS program, which is part of AB 32, could be suspended. We cannot predict whether this Proposition will pass. If it does pass and AB 32 is suspended, our marketing into California could be adversely affected.

Hawaii

Hawaii is a strong market for wind energy. In June 2009, Hawaii expanded its RPS to 40% by 2030, making it one of the most aggressive state renewable requirements in the United States. In addition, although no legislation has been adopted, in January 2008 the Governor of Hawaii announced plans to achieve 70% of electricity sales from renewable sources by 2030.

According to EIA, Hawaii receives approximately 76% of its power from fuel oil generation and 15% of its power from coal. As a result, a significant and rapid shift to renewable energy capacity would be required to meet the state's stringent standards. Because oil is the predominant source for electricity in Hawaii, oil prices are the primary driver of local electricity prices. Hawaii imposes an oil import tax. The cost of oil in Hawaii is further compounded by the costs of transporting oil to and between its islands. The volatility and escalation of global oil prices directly correlate to volatile and increasing electricity prices in Hawaii.

The current RPS requirements for Hawaii would result in total RPS demand of 2,600 GWh per year by 2020, according to IHS EER estimates. We believe the majority of this demand will be delivered by wind energy. Assuming a 35% net capacity factor, we estimate this demand to be approximately 860 MW. By comparison, EIA data indicates that installed renewable capacity, excluding large hydro, was 239 MW as of year-end 2008. Based on the limited availability of sites and the number of wind projects in the planning stages, we believe developers with an established presence in Hawaii have a significant advantage in this market.

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BUSINESS

Overview

We are an independent wind energy company focused solely on the development, financing, construction, ownership and operation of utility-scale wind energy projects in the United States. Our projects are located in the Northeastern and Western regions of the continental United States and in Hawaii. We have focused on these markets because we believe they provide the potential for future growth and investment returns at the higher end of the range available for wind projects. These markets are characterized by relatively high electricity prices, a shortage of renewable energy and sites with good wind resources that can be built in a cost-effective manner. Moreover, we have focused our efforts on projects and regions with significant expansion opportunities, often enabled by transmission solutions that we have developed and built.

As of September 30, 2010, we operated seven projects with combined rated capacity of 504 MW, and we owned two lines that connect projects to the electricity grid (generator leads) with transmission capacity of approximately 1,200 MW. In 2009, we doubled the number of projects in our operating fleet, adding three new projects with an aggregate capacity of 386 MW. Two of these projects, Milford I, which sells power from Utah into Southern California, and Stetson I, which sells power in New England, include wholly-owned generator leads we had built in anticipation of expanding these projects. In March 2010, we commenced commercial operations of our seventh project, Stetson II, an expansion project in Maine with 26 MW of capacity.

We manage our business with a team of professionals with experience in all aspects of wind energy project development, financing, construction and operations. We have a track record of selecting projects from our development pipeline and converting them into operating projects that we believe will meet our financial return requirements. By the end of 2010, our goal is to have six additional projects with 268 MW of capacity under construction. Four of our projects (totaling 232 MW) are under construction: Kahuku (30 MW) in Hawaii, Milford II (102 MW) in the West and Rollins (60 MW) and Sheffield (40 MW) in the Northeast.

We target having approximately 1,000 MW of projects operating or under construction by the end of 2011. Thereafter, we target adding approximately 200 to 400 MW of operating/under-construction capacity each year to achieve our goal of having an operating/under-construction fleet of approximately 1,900 MW by the end of 2014. Expansions of current operating and under-construction projects make up approximately 32% (measured by capacity) of our targeted 2011-2012 projects. See " Our Development Process" and " Our Portfolio of Wind Energy Projects."

Wind energy project returns depend mainly on the following factors: energy prices, transmission costs, wind resources, turbine costs, construction costs, financing costs and availability and government incentives. In applying our strategy, we take into account the combination of all of these factors and focus on margins, return on invested capital and absolute value creation as opposed solely to project size. Some of our projects, while having high construction costs, still offer attractive returns because of favorable wind resources or energy prices. Additionally, in many cases, smaller, more profitable projects can create as much absolute value as do larger, lower-returning projects. We assess the profitability of each project by evaluating its net present value. We also evaluate a project on the basis of its Project EBITDA, as described under "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Measure Our Performance" as compared with the project's development and construction costs.

We closely manage our commodity price risk and generally construct wind energy projects only if we have put in place some form of a long-term PPA and/or financial hedge to manage commodity risk. Approximately 90% of estimated revenues through 2011 from our current operating projects are hedged. We plan to hedge approximately 90% of the estimated revenues for 2011 for the four projects currently under construction and the two projects we plan to have under construction in 2010. Most of the estimated aggregate revenues from our operating projects and 2010 projects is hedged through 2020. See "Business Revenues; Hedging Activities."

The United States is one of the largest and fastest growing wind energy markets, although capacity additions have slowed in 2010. In 2008 the United States surpassed Germany as the largest market for wind energy in the world, as cumulative installed wind energy capacity increased approximately 51% and accounted for 42% of all new energy supply in the United States, according to AWEA. Moreover, our markets are among the highest growth U.S. markets due to state mandated RPS-driven demand, premium electricity pricing, a shortage of renewable energy and strong wind resources. Based on IHS EER estimates, we believe that states in our markets in the Northeast, West, and Hawaii will need approximately 42 GW of incremental renewable energy capacity to be built by 2020, assuming a 30% average net capacity factor.

We classify each project into one of the following three categories based on the project's stage of development: operating/under-construction, Tier 1 and Tier 2. We use these categories to estimate our annual installed capacity and energy generation and for planning purposes, including allocation of capital to projects. For information regarding the criteria we use to put projects in these categories, see " How We Classify Our Projects."

A summary of our projects, as of September 30, 2010, is set forth below:

Stage of Development(1)	Northeast Actual or In Development Capacity(2)(3) (MW)	West Actual or In Development Capacity(2)(3) (MW)	Hawaii Actual or In Development Capacity(2)(3) (MW)	Total
Operating/Under-Construction				
Operating	270	204	30	504
Under-Construction	100	102	30	232
Tier 1(4)	0	0	21	21
Tier 2(4)	487	3,421	70	3,978
Total	857	3,727	151	4,735

(1) Our ability to complete our projects and achieve anticipated capacities is subject to numerous risks and uncertainties as described under "Risk Factors." We are unlikely to complete all of the projects in our current development pipeline, while some of the projects we are likely to develop in the future are not in our current pipeline.

(2) 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.

(3) For information on noncontrolling interests in our projects see Note 5 to our consolidated financial statements.

(4) Our only Tier 1 project, KWP II, is a 2010 project. One Tier 2 project (Steel Winds II, a 15 MW project) is scheduled to start construction this year and is also included in our 2010 projects. For a discussion of 2010 projects see "Business Our Portfolio of Wind Energy Projects 2010 Projects."

We believe our development pipeline of approximately 4,000 MW should enable us to meet our 2014 goal of having an operating/under-construction fleet of approximately 1,900 MW. We have land rights for approximately 80% of our development pipeline and meteorological data for approximately 95% of our development pipeline, in the majority of cases covering at least three years. We have also conducted preliminary environmental screening for all of our projects. We are unlikely to complete all of the projects in our current development pipeline, while some of the projects we are likely to develop in the future are not in our current pipeline. Our ability to complete our projects and achieve anticipated generation capacities is subject to numerous risks and uncertainties as described under "Risk Factors."

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Our Regions

Northeast

Our Northeast region includes New England and New York. We believe this region is one of the more attractive wind energy markets in the United States due to its relatively high electricity prices, tightening supply of renewable energy relative to demand and progressive renewable energy legislation. Every state in the Northeast region (other than Vermont) has an established RPS program and associated market for RECs. These programs have led to increased demand for wind energy development in these states.

In addition, the geographic proximity and interconnectivity of the various power markets within the Northeast, together with highly liquid electricity trading markets, give projects within the region the flexibility to deliver power into and qualify RECs in different markets within the region.

The Northeast has relatively limited utility-scale development opportunities due to its population density and modest wind resources. Additionally, transmission limitations constrain future increases in wind generation capacity. However, given our pipeline of projects and proven success in developing, constructing and operating wind energy projects in this region, we believe our business is well positioned for continued growth in this region. Furthermore, the transmission infrastructure we own should allow us to efficiently and economically expand in this region. We believe the relative difficulty in developing wind energy projects in this region further strengthens our position as an early entrant in this market.

For information regarding the Northeast market, see "Industry Key Attributes of Our Regions: Northeast, West and Hawaii."

West

Our West region consists of the far west and Rocky Mountain states. Of these, California is the largest electricity market in the region. California may face a shortage of renewable energy supply as renewable generation capacity has not kept up with rising demand for renewable energy. With one of the most progressive RPS programs in the nation, California is an attractive market for renewable energy generators. However, recent bottlenecks in siting and permitting renewable energy projects have led to relatively small additions of new capacity. IHS EER forecasts long term growth of renewable energy capacity in California will be driven by state transmission projects and programs such as the California Renewable Energy Transmission Initiative and the Western Renewable Energy Zones as well as developer-driven private transmission solutions. IHS EER estimates that the state will add more than 8 GW of new transmission capacity through 2020.

We have developed a private transmission platform in the West, which enables us to deliver a significant amount of wind energy generation to the California market. We have a long-term PPA with SCPPA to supply 20 years of power to the cities of Los Angeles, Burbank and Pasadena from our Milford I project in Milford, Utah and completed an 88-mile, 1,000 MW generator lead to transmit our wind energy to California. Milford I is a 204 MW project that achieved commercial operation in November 2009. Given the capacity of the Milford generator lead, we can expand our Milford platform to deliver another 750 MW of wind energy to California. The Milford II expansion project, which is described later in this section, has a capacity of 102 MW and began construction in July 2010.

While California is the largest market in the West and presents a significant opportunity for wind energy, we are actively developing projects in the West to serve states other than California. These projects are largely Tier 2 projects. We have entered into an option agreement to purchase wind energy assets that relate to a possible 2011, 20 MW California project in development. We cannot predict when or whether we would acquire these assets or complete this project.

For information regarding the West market, see "Industry Key Attributes of Our Regions: Northeast, West and Hawaii."

Hawaii

We believe the Hawaii market offers a unique opportunity for us, as the state's high electricity prices and excellent wind resources offer potential for wind projects with attractive returns. The state currently generates approximately 91% of its electricity from oil and coal-based technology. To reach the state's 2030 RPS target of having 40% of Hawaii's electricity generation come from renewable energy, a large percentage of fossil-fuel electricity generation will need to be replaced with RPS eligible technologies such as wind.

Today there is approximately 63 MW of operating wind capacity in Hawaii; 30 MW of which comes from our KWP I project, the single largest wind energy project in Hawaii. In addition, we began construction of our Kahuku project in Oahu in July 2010. We believe that conditions for developing wind energy projects in Hawaii strengthen our position as an early entrant in this market. There are relatively few buildable wind sites in the state and we believe developers with an established presence have a significant competitive advantage. We believe our development experience and knowledgeable staff in Hawaii, coupled with our platform in Hawaii, should position us for future growth in this market.

For information regarding the Hawaii market, see "Industry Key Attributes of Our Regions: Northeast, West and Hawaii."

Revenues; Hedging Activities

We generate revenues from the sale of electricity from our operating projects and from the sale of RECs generated by these operations. Approximately 90% of estimated revenues for our current operating projects are hedged through 2011. We plan to hedge approximately 90% of estimated revenues for 2011 for the six projects we plan to begin construction of or place in service by the end of 2010. For information regarding our hedging activities, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Power Purchase Agreements and Financial Hedging."

Electricity Sales

We typically sell the power generated by our projects (sometimes bundled with RECs) either pursuant to PPAs with local utilities, power companies and other entities or directly into the local power grid at market prices. Our PPAs have initial terms ranging from five to 20 years with fixed prices, market prices or a combination of fixed and market prices. We also seek to hedge a significant portion of the market component of our power sales revenue with financial swaps.

Sales of RECs

The RECs associated with renewable electricity generation can be sold. In some states, we sell RECs to entities that must purchase specific quantities of RECs to comply with state or municipal RPS programs. Currently 25 states and the District of Columbia have adopted RPS programs that operate in tandem with a credit trading system in which generators sell RECs associated with the renewable power they generate in excess of state-mandated requirements.

Commodities Hedging

In addition to PPAs, we enter into derivative contracts to hedge future electricity prices to mitigate a portion of the risk of market price fluctuations we will have by selling power at variable or market prices. We currently have entered into three financial swaps with a remaining weighted average tenor of approximately ten years, which will collectively hedge approximately 75% of our expected generation during the term of the swaps at Cohocton I, Steel Winds I and Stetson I and the portion of Stetson II's generation not sold under a PPA. We intend to enter into additional financial swaps to hedge a similar percentage of expected generation for our other Tier 1 and Tier 2 projects that will sell power in liquid ISO markets as they near commercial operations. We have also entered into an oil swap through the end of 2013 to hedge future oil prices to mitigate a portion of the risk of market price fluctuations associated with our power generation at KWP I, the pricing of 30% of which is largely tied to the costs that Maui Electric Company (MECO) avoids by substituting our electrical production for the production it otherwise would have to generate by burning fossil fuels. For additional information regarding our hedging activities, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure about Market Risk."

Strategy

Our business strategy is to build a diverse portfolio of operating projects and development opportunities. We seek opportunities where, if we are able to execute successfully, we will be able to generate attractive returns for our stockholders. These returns depend mainly on the following factors:

Energy price. We assess project returns taking into account the total realized price of energy that we earn from an operating project, or that we expect to earn from a project in our pipeline. The total realized price of energy includes power sales, REC sales and capacity payments, as well as the effect of cash settlements from related hedging activities.

Wind. The quality of the wind resources at a project, operational performance and the resulting energy production are key determinants of project performance. We measure wind resources at a given operating project by calculating the NCF, and we forecast NCF for each project in our pipeline. NCF is the measure (or estimate) of a wind energy project's actual production expressed as a percentage of the amount of power the wind energy project could have produced (or is capable of producing) running at full capacity for a particular period of time. We typically use a 25-year period in estimating a project's long-term NCF.

Construction costs. The installed costs of the project also determine whether or not the project is capable of generating appropriate returns. Construction costs include primarily the cost of turbines, and also take account the cost of transmission facilities, balance-of-plant, interest during construction, financing costs and fees and development expenses.

Financing. Because we rely on third party financing to construct our projects, we must be able to demonstrate to our lenders and tax equity investors that there is a sufficient likelihood of a project's ability to generate a given level of return, in order to secure capital at a cost that will make the project attractive for us.

Government incentives. The availability of government incentives has historically been critical to our ability to secure third party financing for our projects, and to enable us to construct projects that are expected to provide us with an attractive return on investment. We expect that for the foreseeable future this will continue to be the case.

We intend to pursue the following objectives to execute our strategy.

Develop Pipeline and Expand Operating Projects

We have identified and are developing a broad pipeline of projects in our markets, including expanding our operating projects in existing locations, and we intend to continue developing our existing pipeline of projects and increasing the number of operating projects. We focus on expansion projects because we believe they present lower execution risks than other projects. This is due to factors including our experience with the wind resources at the project site, as well as our clearer understanding of how to address particular community stakeholder concerns.

We target having approximately 1,000 MW of projects operating or under construction by the end of 2011. Thereafter, we target adding approximately 200 to 400 MW of operating/under-construction capacity each year to achieve our goal of having an operating/under-construction fleet of approximately 1,900 MW by the end of 2014. Expansions of current operating and under-construction projects make up approximately 32% (measured by capacity) of our targeted 2011-2012 projects. We are unlikely to complete all of the projects in our current development pipeline, while some of the projects we are likely to develop in the future are not in our current pipeline. Our ability to complete our projects and achieve anticipated generation capacities is subject to numerous risks and uncertainties as described under "Risk Factors."

Develop Opportunities in Financially Attractive Markets

States in our markets in the Northeast, West and Hawaii are undergoing significant growth in demand, which we expect to continue, reaching 53 GW of RPS-driven incremental demand by 2020. In order to capitalize on this expected growth, we intend to identify and add to our pipeline diverse development project opportunities in financially attractive markets, including those with relatively high electricity costs or a shortage of renewable energy and sites with good wind resources that can be built in a cost effective manner. Our team of developers focuses our prospecting and development efforts on identifying new opportunities and acquiring existing wind energy assets that we believe will meet our financial return requirements in these markets.

Implement Transmission Solutions

Our generator lead assets and capabilities enable us to develop projects in areas that would otherwise present significant transmission challenges, and we intend to continue to develop, own and operate generator leads connecting our projects to third-party electricity networks. We have built two generator leads that provide us with significant opportunities for future development. Our Stetson generator lead has approximately 115 MW of capacity available for our future expansion projects, and our Milford generator lead has approximately 750 MW of capacity available for our future expansion projects. In 2010, we began construction of expansion projects using the Stetson and Milford generator leads, leaving 700 MW of additional capacity on these lines for our future expansion projects.

Control Construction and Operations

We intend to continue to maintain control over both the construction and operational phases of our projects, because we believe exercising this control enhances our credibility, allows us to make rapid decisions and strengthens our relationships with landowners, local communities, regulators and other stakeholders. For construction projects, we manage and mitigate budget and schedule risks through arrangements with contractors that have significant experience constructing wind energy projects. We also work closely with the manufacturers of our turbines with the goal of enhancing the operating performance of our fleet.

Stabilize Revenues

We believe that stabilizing our revenues enhances our ability to obtain long-term, non-recourse financing for our projects on attractive terms. We therefore enter into long-term PPAs with utilities and electricity consumers, and, through the use of financial derivatives, we hedge our exposure to market prices for electricity. Both of these activities help to insulate our revenue stream against commodity price volatility. In addition, we seek to maximize the value of the RECs we generate by selling our electricity into markets that have higher RPS requirements and strong markets for RECs. We intend to

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continue to pursue each component of our revenue stabilization strategy, which we believe benefits us, our lenders and our tax equity investors.

Establish and Maintain Strong Local Presence

We believe that developing a substantial local presence in our markets, and encouraging substantial community stakeholder involvement, is critical to the success of each individual wind energy project because negative community sentiment can be a factor in project delays and increased costs. Through our locally deployed development teams, we work cooperatively with the communities where our projects are located to more fully understand each community's unique issues and concerns. We begin community outreach at an early stage of each project to better assess a project's feasibility, and we continue our efforts through the operating stage in order to enhance our ability to complete and operate a project successfully. This outreach often includes substantial interaction with local government officials, community groups and local media, as we explain our plans, our track record and the benefits that we believe will accrue to the community, and we endeavor to respond to concerns that community members may express such as concerns about the environmental impact of our projects.

Pursue Financing

Our business is capital intensive and requires ongoing access to debt and equity capital markets to build our projects. We believe we demonstrated our capacity to do this during the recent difficult financial market conditions. We will continue to seek third party financing in order to grow our portfolio.

Competitive Strengths

We believe there are significant opportunities for growth in the U.S. wind energy industry in general and in our markets in particular, and we intend to use the following strengths to capitalize on these opportunities.

Track Record

Over the past several years we believe we have established a track record for developing complex wind energy projects in each of our three markets. Our project development strategy sometimes includes the construction of generator leads, as in the case of Stetson I and Milford I, the use of innovative technology, as in the case with the use of a battery at our Kahuku project, or the structuring and negotiation of creative financing and risk management solutions as in our PPA with SCPPA for Milford I. In certain cases, as in KWP I, we took over projects from other developers who were unable to complete them. We believe that this particular strength will help us obtain financing for projects that present technical or operational challenges, and thereby make it possible for us to take advantage of opportunities that might not be available to other wind energy competitors.

Ability to Refinance and Raise Capital

Wind energy project development and construction are capital intensive and require access to a relatively constant stream of financing, making our ability to access capital markets efficiently and effectively crucial to our growth. We cannot be sure that financing will be available to us on attractive terms when we require it, and the recent worldwide financial and credit crisis has reduced the availability of liquidity and credit. However, since the beginning of 2009, we have refinanced, raised or received approximately $2.5 billion for our company and projects in 20 refinancing and new capital-raising activities and customer prepayments.

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Presence in Attractive Markets with Strong Demand for Renewable Energy

We believe the markets in which we are already established the Northeast, West and Hawaii present significant growth opportunities because these markets are characterized by high electricity prices, a shortage of renewable energy and sites with good wind resources that can be built on cost-effectively. Many of our projects have significant expansion opportunities, and expansions of our current operating and under-construction projects make up approximately 32% (measured by capacity) of our targeted 2011-2012 projects. Expansions of existing projects allow us to capitalize on our site-specific knowledge of wind resources as well as our familiarity and relationships with the local community. Moreover, in some cases we will be able to use our existing generator leads to connect with the regional electricity grid. Each of these factors helps to minimize a project's execution risk and helps in arranging the required financing.

Turbine Acquisition Flexibility

We have secured sufficient turbines to execute our 2010 project plan. We believe we are well positioned to take advantage of current conditions in the turbine market, which we believe is over-supplied. As a result, we have not entered into firm commitments to purchase turbines for projects in our development pipeline after 2010. We are engaged in a process of seeking requests for proposals from various turbine manufacturers for some of our 2011 and 2012 projects. As a result of excess capacity in the turbine market, we are seeing improved pricing and terms proposals from manufacturers compared with past turbine procurements. We also have agreements in place that give us the right, but not the obligation, to purchase additional turbines after 2010, allowing us to cancel our turbine orders with the forfeiture of deposits. We believe this gives us flexibility to acquire turbines at attractive prices and on favorable terms. In addition, we believe that this flexibility will allow us to take advantage of advances in turbine technology and improvements in turbine size, blade length and other technologies that will significantly improve project performance.

Experienced Management

Our management team, which holds a meaningful equity stake in our company, is experienced in all aspects of the wind energy business. Over the past two years, we have added several key personnel to our team, primarily in the areas of construction, operations and finance. We believe we can achieve our operating/under-construction fleet goal of approximately 1,900 MW by the end of 2014 without significant additions to headcount and overhead costs related to non-operating activities.

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Our Development Process

There are several key activities that occur throughout our development efforts as we move projects from development to construction to operation many of which we undertake concurrently. These activities include: prospecting; wind resource assessment; land rights procurement; revenue stabilization; turbine procurement; transmission and interconnection solutions; permitting; engineering, procurement, construction oversight and commissioning; and operations, maintenance and asset management.

As progress is made for a project we advance it through our project classification system, as described in " How We Classify Our Projects."

We evaluate projected investment returns during all stages of the development process and allocate capital among projects in a manner designed to optimize our overall investment returns. We also consider how projects will be financed. For additional information regarding our project financing activities, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Financing Requirements."

Prospecting

Prospecting is the earliest activity in our development process. It occurs before we classify a project as Tier 2. Many projects never reach the Tier 2 category. Prospecting involves a broad, high-level review of potential sites for their suitability for wind energy development. We make our initial assessments of potential sites based on a number of criteria, including wind resource suitability; constructability; access to transmission networks; site size and location; land ownership; and environmental, zoning and other local and state laws and regulations, including available state-sponsored RPS programs. We also consider the capital cost, size and expansion opportunities at a proposed site and our view of the relevant markets for electricity and RECs. Our in-house meteorology, real estate, construction and transmission teams conduct initial reviews of publicly available information, including wind reports, land records, topographical maps and power transmission maps. They also use our proprietary data to identify significant impediments that could result in a project's failure to meet our investment objectives.

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An important part of the prospecting process is an initial environmental screening, also referred to as a fatal flaw analysis. This is usually conducted using publicly available information, sometimes supplemented with a site visit, to identify documented or readily apparent environmentally sensitive areas. These areas include unique wildlife habitats, wetlands, culturally significant resources and proximity to wildlife reserves, national parks and scenic areas not generally suitable for commercial development. Prospecting may also include a preliminary assessment of a project's potential hazard to aviation safety. Once a site passes this initial review, we begin more detailed site-specific environmental assessments in connection with our permitting efforts and establish constraints for turbine siting and civil and site engineering. These typically include detailed mapping of environmental and cultural resources, studies to determine use of the site by migratory or sensitive wildlife and mapping of adjacent residential and other development, all aimed at our being able to operate a potential project safely without negatively affecting the local environment.

Wind Resource Assessment and Monitoring

We begin a wind resource assessment at the earliest stage of the development process. We base our initial assessment of the available wind resources on a review of publicly available wind maps. If the results of the initial assessment are positive, we seek to install meteorological towers to obtain long-term site-specific wind data and make wind resource estimates. Our own regional meteorological tower field teams install, maintain and decommission our meteorological towers. As of September 30, 2010, we had meteorological data for over 95% of our development pipeline. Approximately 82% of our meteorological data for our Tier 1 and Tier 2 projects is for one or more years and approximately 72% is for three or more years. Our in-house meteorological team also prepares computer models to estimate potential wind levels. In order to obtain financing, we will also seek third-party assessments at later stages of a project's development.

Land Rights Procurement

Land rights procurement begins during the prospecting process. Land rights include all necessary agreements (such as leases, options, easements and letters of intent) needed to construct and operate the project, including those associated with turbines, transmission and collection lines, access roads, facilities and any other easements that may be required. We use publicly available data or prior experience to determine if there are any known impediments to securing the land rights we need. From there, we conduct initial meetings with local landowners, government officials, community representatives and residents to gauge community support. If these meetings are favorable, we generally enter into land leases or easements with landowners to secure necessary rights to build on the site, including meteorological towers, roads, electric lines and substations, turbines, operation and maintenance facilities and associated facilities. These contracts usually have an initial term of 20 to 30 years from the commencement of commercial operations with an option for us to extend for an additional 20-year period. They generally require minimum annual lease payments during the development period, minimum payments per turbine or MW during the construction phase, and additional royalty payments based upon a percentage of the project's revenues during the operation phase. In some instances, we enter into option agreements or easements with landowners to obtain access to the project site rights to construct, operate and maintain the wind energy project and/or collection systems and generator leads or other access to transmission facilities. We have projects in development well in excess of our annual targets through 2014, with land rights for approximately 80% of our development pipeline and no known material impediments to obtaining contractual control of the balance.

Revenue Stabilization

To make it more likely that a project will meet our investment return objectives and to protect against electricity price volatility, we review the electricity sales alternatives for each project. We decide whether to enter into a long-term PPA with an electric utility or other user, or to sell the power into the market and enter into a long-term financial hedge linked to electricity prices to secure our financial returns and stabilize project revenue streams, or both. For example, in California, we entered into what we believe to be the first third-party long-term, pre-paid PPA with a public utility for a wind energy project, which allowed us to secure our revenue stream and fund construction of the project. We also have a long-term PPA with Harvard University to sell half of the electricity and RECs generated by our Stetson II project. When we can sell our electricity to power markets that are sufficiently liquid, we analyze hedging opportunities available to us later in the development process, such as long-term power swap agreements.

Turbine Procurement

We have secured sufficient turbines to execute our 2010 project plan. In the past, we entered into commitments to acquire turbines well in advance of deployment. Because we believe the turbine market is currently over-supplied, we have elected not to enter into firm commitments to purchase turbines for projects in our development pipeline after 2010. We believe this gives us flexibility to acquire turbines at attractive prices and on favorable terms. Specifically, we have maintained the right, but not the obligation, to buy turbines from Clipper for up to 633 MW of additional deliveries between 2011 and 2015, subject to the forfeiture of up to $89.5 million in deposits and progress payments that we have made and are scheduled to make to Clipper, if we decide not to buy any additional turbines from them.

We believe that the recent entry of several turbine manufacturers into the turbine-supply market, coupled with the global economic downturn, has resulted in a global oversupply of turbines. This oversupply has led to a significant downward trend in prices for turbines beginning in 2009. In May 2010, we began a process of seeking requests for proposals from various turbine manufacturers for some of our 2011 and 2012 projects. We believe the fact that we do not have commitments to purchase turbines for projects after 2010 will enable us to capitalize on the weakness in the turbine market and to procure turbines at low prices and on attractive terms.

Transmission and Interconnection

Since the availability of transmission infrastructure and access to a power grid or network are critical to a project's feasibility, we ascertain transmission capacity from public sources and our own proprietary data during the prospecting stage. If existing transmission infrastructure is available, we attempt to secure access to it when we select a potential site for development either during our prospecting activities or during the Tier 2 stage. We discuss availability with the relevant utilities and file an application with the appropriate independent system operator (ISO) or local electric utility to interconnect with the network. If transmission infrastructure does not exist or is not available for a project, we study the feasibility of developing and constructing our own generator lead. We built a 200 MW-rated 38-mile 115 kV generator lead in Washington County, Maine as part of our 57 MW Stetson I project. This provides sufficient excess capacity to accommodate up to 140 MW of expansion projects, including our 26 MW Stetson II project, which commenced commercial operations in March 2010, and our 60 MW Rollins expansion project, which is under construction. In Beaver and Millard Counties, Utah, we developed and built an approximately 88-mile 1,000 MW-rated 345 kV generator lead, with sufficient capacity to accommodate up to 750 MW of our expansion projects, including our 102 MW Milford II project, which is under construction.

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Permitting

Once we have selected a site, we begin the permitting process with relevant local, state and federal government agencies. This process includes identifying required permits; holding preliminary informational meetings with permitting agencies and stakeholder groups; determining the studies needed for permit applications and conducting the studies; preparing environmental permitting and disclosure reports; participating in public meetings; responding to information requests; and seeking project approval. We also complete preliminary design engineering, taking into account environmentally sensitive areas to avoid or minimize adverse impacts. Because the permitting process is costly and time consuming, we review all aspects of the project, including our projected investment returns, before committing significant resources to these efforts. To date, we believe we have received all material permits for our operating/under-construction projects.

Local

Permitting at the local municipal or county level often consists of obtaining a special use or conditional use permit under a land use ordinance or code, or, in some cases, rezoning in connection with the project. Obtaining a permit usually depends on our demonstrating that the project will conform to development standards specified under the ordinance so that the project is compatible with existing land uses and protects natural and human environments. To facilitate this process, we work to build a positive relationship with the community and address any concerns. We also create project-specific websites and host community outreach meetings to provide the community with pertinent information.

State

Our projects are often subject to state-level permitting requirements. These requirements may include comprehensive environmental reviews or may be limited to a specific regulatory program, or may involve both. State level comprehensive reviews typically take from six to 24 months from the date of filing to approval. Additional approvals may be required for specific aspects of a project, such as stream or wetland crossings, storm water management and highway department authorizations for oversize loads and state road closings during construction. Permitting requirements related to transmission lines may be required in certain cases.

Federal

Projects may also require federal approvals related to the potential effect of projects on aviation, the environment, endangered species and navigable waters. For additional information regarding required regulatory and environmental reviews, permits and laws, see " Regulatory Matters" and " Environmental Regulation."

Once a permit or other governmental approval has been granted, it may be appealed or challenged. The amount of time that may be needed to resolve an appeal can vary considerably.

Engineering, Procurement and Construction Oversight; Commissioning

We manage the design and construction of our projects. Construction consists of turbine installations, substation construction, interconnection work, construction of the rest of the facility, referred to as balance of plant, and, in certain cases, construction of long generator leads to connect our facility to a third-party electrical grid or network. We generally outsource turbine installation and the remaining construction to outside contractors. The contractors provide the management, supervision, labor, certain materials, tools, engineering, mobilization, testing and demobilization required to construct the project. Construction typically takes approximately seven to 15 months, with adverse weather conditions causing the largest variation in estimated completion dates. Our employees supervise and oversee all aspects of construction. Commissioning occurs immediately prior to the completion of a wind energy project. It involves testing each turbine's operation and integration within the project and to the transmission system.

Operations and Maintenance; Asset Management

Once commissioning is completed, the turbine supplier typically operates and maintains the turbine under a two to five-year operating agreement that runs concurrently with the turbine warranty. Such operating agreements usually include a guarantee of a turbine's availability to generate electricity a specified percentage of the time. The level of electricity generation covered by the availability guarantees is usually lower during the first several months of operation to allow for issues arising during the initial operation of newly-installed turbines that need to be addressed. While the turbine manufacturer is on-site operating and maintaining the turbines, we oversee the project, including management of the turbine suppliers; compliance with NERC, FERC, ISO, regional transmission organization (RTO) and state regulations; relations with landowners; and maintenance of insurance policies. Following the expiration of the supplier operating agreements, we may operate and maintain the turbines directly unless we extend existing manufacturer agreements or enter into new service agreements with other third parties. We have established two data analysis control centers in Temecula, California and Boston, Massachusetts, which control the operations of our turbines at all times.

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Project Financing

The chart below provides a generic illustration of the various project finance structures we typically employ as a wind energy project moves through its lifecycle, from development to construction and finally into operation. As illustrated below, the final financing structure differs depending on whether we elect to monetize the project's PTCs in the form of a tax equity financing or instead apply for an ARRA grant:

Lifecycle of a Typical Project Financing

Note: The sizes of the figures in this diagram are not indicative of relative amounts financed.

(1) The need for a turbine supply loan depends on the conditions of the turbine market, see "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Our Results of Operations, Financial Condition and Cash Flows Turbine Supply and Pricing."

Development and Turbine Financing

We have historically funded our project development expenses with equity. These costs primarily consist of land assembly, permitting activities, interconnection studies, meteorological studies, PPA negotiations and community outreach. In the future, we expect to fund the development of our projects with a combination of existing cash, cash flows from operations, debt financings and the proceeds of this offering.

Historically we have needed to secure turbine orders at an early stage of a project's development. We used turbine supply loans to finance approximately 70%-80% of turbine progress payments, in advance of actual construction. This practice was prevalent in our industry due largely to excess demand for turbines and long lead times. These conditions have eased. We believe that, as a result of recent changes in the turbine supply market, turbine supply loans will not be required for the foreseeable future. This may require us to make a larger initial equity investment. However, we expect that our need to make long-term capital commitments to turbine purchases far in advance of anticipated delivery will be reduced.

Construction Financing

Once a project moves to the construction phase, we typically use a combination of equity capital and construction loans to finance the construction of the project. Proceeds from the construction loan fund construction and installation costs, including retirement of related turbine supply loans, through commencement of commercial operations. Construction loans are short-term and typically appear as current debt on the balance sheet; however, as a prerequisite to funding, a construction lender usually requires that there be a committed term financing at commencement of commercial operations, which mitigates refinancing risk.

Long-term Financing

Once a project has commenced commercial operations, we currently finance the majority of a project's costs through a combination of the ARRA grants, term loans, and tax equity financing transactions, and prepayments for energy, the proceeds of which are used to retire the construction loans and, in some cases, provide for a return of a portion of equity capital. The percentage of each of these forms of financing varies by project.

The ARRA Grants

A recent development in financing our projects is the availability of U.S. Treasury grants under the ARRA. These grants are provided in lieu of the ITC and cover 30% of ITC-eligible project costs, namely the costs of constructing energy-producing assets, which are usually approximately 90% of a project's total cost. Grants are available for projects placed in service in 2009 and 2010. Projects that commence construction in 2009 or 2010 and are placed in service before 2013 are also eligible. In 2009, we received ARRA grants of approximately $115 million for our Stetson I and Cohocton projects and in March 2010, we received an ARRA grant of approximately $120 million for our Milford I project, which became operational in November 2009. Additionally, in June 2010 we received an ARRA grant of approximately $19 million for our Stetson II project, which became operational in February 2010.

Term Loans

A form of non-recourse project finance debt, term loans are sized against project-level cash flows and typically fully amortize in 10 to 12 years. We believe term loans at our operating projects are our least expensive and most attractive source of capital. We have historically used term loans to finance our projects on both a standalone basis and in combination with tax equity. We have also used multiple levels of term debt, as is the case with Cohocton, Stetson I, Stetson II and Steel Winds I, which have been financed by a combination of senior debt at the project level as well as structurally subordinated debt at CSSW, LLC, our subsidiary that owns Cohocton, Stetson I, Stetson II and Steel Winds I.

Tax Equity

Tax equity is a structured finance product that allows a wind energy project owner to monetize tax attributes that exceed the owner's federal income tax liability. The most common structure is through a "partnership flip" transaction where the project owner sells a noncontrolling ownership interest in the project subsidiary to an investor. The investor is typically allocated 99% of the tax attributes and most of the project's cash flows until it reaches a target internal rate of return, after which the investor's ownership interest in the project drops to a nominal value, usually 5%, and the owner of the controlling interest has an option to repurchase the investor's remaining interest at the then-current fair market value. Tax equity partnerships are extremely important for PTC structures, but less important

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for ARRA grant structures, where the grant effectively monetizes the tax credit through a cash payment to the project owner. However, tax equity structures may be utilized in combination with the ARRA grant to monetize accelerated depreciation benefits.

How We Classify Our Projects

We classify our projects into the following three categories based on their stage of development:

- Operating/under-construction;
- Tier 1; and
- Tier 2.

We use these categories to estimate our annual installed capacity and energy generation and for planning purposes, including allocation of capital to projects. We engage in prospecting activities, involving a broad, high level review of potential sites that may be suitable for wind energy development. We do not include these prospecting activities in our pipeline.

We assess our projects during each of these stages to determine or confirm their suitability for development. We commit resources to those projects in which we have a high level of confidence. We often decide not to proceed with projects as a result of one or more factors. These decisions primarily occur during prospecting or the Tier 2 stage, but can occur during any developmental stage. We regularly look at and actively consider, but ultimately decide to abandon, many projects representing possible capacity several times larger than the capacity in our development pipeline. The development and construction of wind energy projects involve numerous risks and uncertainties, some of which are beyond our control, and these risks and uncertainties may prevent projects in our current pipeline from reaching completion. We are unlikely to complete all of the projects in our current development pipeline, while some of the projects we are likely to develop in the future are not in our current pipeline. See "Risk Factors Risks Related to Our Business and the Wind Energy Industry."

Operating/Under-Construction Projects

Our operating projects have finished construction and commissioning and have achieved their commercial operations date. We currently have seven operating projects with 504 MW of capacity. By the end of 2010, our goal is to have six additional projects with 268 MW of capacity operating or under construction. Four of these projects (totaling 232 MW) are under construction. Our ability to achieve this goal is subject to numerous risks and uncertainties. See "Risk Factors."

Tier 1 Projects

At September 30, 2010, KWP II was our only Tier 1 project. We believe we will complete each of our Tier 1 projects. For a project to reach the Tier 1 stage, we must have completed or be in the process of completing the key development activities. For us to classify a project as Tier 1, all or substantially all of the following milestones must have been achieved:

- *Land Rights* We have secured land rights for the project site or, if the project is on federal or state land, we have applied for such rights, and the commercial terms for leases and easements have been agreed to and title commitments are being finalized;
- *Wind* We have collected wind meteorological data, and our final wind analysis and the third-party confirmation necessary to secure construction financing are underway;
- *Power Sales* We have executed, or are in the final stage of negotiating, PPAs or we are evaluating hedging alternatives if power would be sold into liquid power markets;

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Turbines Turbines have been contracted and scheduled for delivery in accordance with the project design and construction timeline;

Transmission We have received an engineering design that specifies our transmission needs, including the costs and completion date, and the transmission capacity has been confirmed;

Interconnection We have made a final determination of the facilities required to connect the project with the transmission system and of the cost and time needed to build these facilities;

Economics We have confirmed the estimated cost of building the project and conducted an economic analysis, and are finalizing a financial plan for construction; and

Permits We have received, filed or are near filing all necessary permits and we have a high degree of confidence that the permits and approvals will be received.

Tier 2 Projects

As of September 30, 2010, we had an aggregate of approximately 4,000 MW of potential capacity that we classify as Tier 2 projects. Projects included in the Tier 2 category have met all or substantially all of the following milestones:

Land Rights We have secured the critical land rights for the project site through leases or options to lease or we have determined that there are no known material impediments to securing land rights and, in many instances, we have secured a critical mass of land for the project site;

Wind We have developed preliminary wind resource estimates based on data from meteorological towers, internal screenings and proprietary data or we have completed a desktop review of wind resources;

Power Sales Either marketing and bidding for potential PPAs for those projects that do not have access to liquid power markets has occurred; or for projects newly classified as Tier 2, we have identified potential counterparties to PPAs for those projects that do not have access to liquid power markets;

Turbines For late stage Tier 2 projects we have finalized our turbine selection for the project; otherwise we will determine if there is a suitable turbine available;

Transmission Either the transmission utility is assessing the adequacy of the transmission system to deliver power, unless the project will be selling power at the point of interconnection; or for projects newly classified as Tier 2 we have completed a desktop feasibility review, have identified a potential transmission path to deliver electricity to the market, and have completed a fatal flaw analysis;

Interconnection Either the transmission utility is assessing the ability to connect the project to the transmission system, which results in a system impact study; or for projects just getting promoted to Tier 2 we have submitted a request to connect the project to the transmission system or a third-party has prepared a preliminary evaluation of the system impact and the costs of interconnection;

Economics We have completed an economic analysis with assumptions based on preliminary wind resource estimates and preliminary capital cost estimates; or for projects just getting promoted to Tier 2 we have completed initial economic analysis indicating that the project is likely to meet our financial return requirements; and

Permits Except for projects just being promoted to Tier 2, we have identified the critical permitting path, established initial contact with project stakeholders and are conducting the

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environmental and pre-construction studies as necessary for the permitting process. In the case of projects just being promoted to Tier 2, we have completed a permitting risk analysis and have not identified any significant issue in our fatal flaw analysis, and in many instances have initiated basic engineering designs and construction feasibility analysis and have begun discussions with key project stakeholders.

A summary of the land under contract, wind data and environmental assessment status for each of the Tier 1 and Tier 2 projects in our development pipeline at September 30, 2010 is set forth below.

Stage of Development	Land Under Contract	% of MW with more than One Year of Wind Data	% of MW with more than Three Years of Wind Data	Early-Stage Environmental Screening
Tier 1	Note	100%	100%	100%
Tier 2	80%	82%	72%	100%
Combined	80%	82%	72%	100%

Note:

For our only Tier 1 project, KWP II, we are negotiating with Hawaii's Department of Land and Natural Resources for a directed lease agreement.

Our Portfolio of Wind Energy Projects

Operating Projects

Cohocton

Cohocton is a 125 MW project in Steuben County, New York. Cohocton commenced commercial operations in January 2009. The project consists of 50 2.5 MW Clipper turbines. Cohocton is the second largest wind project in the state of New York. Similar to Mars Hill (described below), Cohocton qualifies a portion of its energy for New England RECs. The project provides local benefits to the community through property tax revenue and economic development, along with local renewable power sales.

We sell energy from Cohocton to NYISO Zone C for floating power prices. To stabilize Cohocton's electricity revenue, we entered into a swap with an affiliate of Citigroup for approximately 75% of expected generation through the end of 2020. 40% of the Cohocton RECs were sold to Citigroup under a long-term contract and 15% are sold to various other counterparties. These RECs are New England RECs since we wheel the related generation to New England. 40% of the Cohocton RECs are sold as New York RECs to NYSERDA under a long-term agreement.

Cohocton was among the first recipients of an ARRA grant, receiving approximately $75 million in September 2009. The remainder of our construction costs at Cohocton are financed with a combination of senior project debt from HSH Nordbank and Norddeutsche Landesbank Girozentrale and structurally subordinated debt of CSSW, LLC. Our total installed development and construction costs for Cohocton were approximately $280 million, including approximately $10 million of financing-related costs. We estimate Cohocton's long-term average NCF will be approximately 25% to 27%, as described further in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Kaheawa Wind Power I (KWP I)

KWP I is a 30 MW project in the West Maui Mountains of Maui, Hawaii, that commenced commercial operations in June 2006. The project consists of 20 General Electric (GE) 1.5 MW turbines. The development rights to KWP I were purchased by First Wind in June 2004 after several other developers had been unable to complete the project. We believe our success in developing KWP I stems from our partnering with local stakeholders and finding creative permitting solutions. For

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example, we entered into what we believe is the first habitat conservation plan that protects endangered species with respect to a wind project in the United States. Today, we operate a 1 MW prototype battery at KWP I to help stabilize wind energy output given Maui's small electricity grid. We undertook this battery program in cooperation with MECO to prepare for our expansion plans at KWP I.

KWP I has a 20-year PPA for power and RECs with MECO with a remaining term of 16 years. The PPA is 70% fixed price and 30% floating price at MECO's avoided cost, which historically is correlated to oil prices. In January 2010, MECO's avoided cost was approximately $135/MWh. To stabilize revenues on the floating portion of the contract, we entered into an oil swap with HSH Nordbank. This swap expires at the end of 2013. KWP I qualified for and receives PTCs and MACRS depreciation, along with cash payments under its PPA, and is currently financed with a tax equity investment from JP Morgan. An unrelated third party owns 49% of the common equity relating to KWP I. Our total installed development and construction costs for KWP I were approximately $65 million, including approximately $5 million of financing-related costs such as capitalized interest, fees, and other costs related to turbine supply loans, construction loans, and term financing. We estimate KWP I's long-term average NCF will be approximately 41% to 43%, as described further in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Mars Hill

Mars Hill is a 42 MW project located in Mars Hill, Maine, that commenced commercial operations in March 2007. The project consists of 28 GE 1.5 MW turbines. At the time of its commissioning, Mars Hill was the largest utility-scale wind project in New England until we commissioned our Stetson I project. We believe Mars Hill is also unique in its transmission arrangement, which allows it to provide local benefits to the community through property tax revenue and economic development while qualifying its energy for the majority of the New England REC market.

Our Energy Management Service Agreement with New Brunswick Power Corporation (NB Power), which expires at the end of 2011, provides for the wheeling arrangement as well as NB Power's purchase of our electricity. Our RECs are sold separately to various counterparties. Mars Hill qualified for and receives PTCs. It is currently financed with a tax equity investment from JP Morgan and Wells Fargo, and a term loan from HSH Nordbank. Our total installed development and construction costs for Mars Hill were approximately $95 million, including approximately $5 million of financing-related costs. We estimate Mars Hill's long-term average NCF will be approximately 35% to 37%, as described further in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Milford I

Milford I is a 204 MW project in Beaver and Millard Counties, Utah, located approximately 200 miles southwest of Salt Lake City. Milford I commenced commercial operations in November 2009. The project consists of 39 GE 1.5 MW turbines and 58 2.5 MW Clipper turbines (58.5 MW GE and 145 MW Clipper). As part of the Milford I project we also constructed an 88-mile, 1000 MW, 345 kV generator lead to interconnect to Intermountain Power Plant, a 1.9 GW coal-fired power plant in Delta, Utah. Securing right-of-way for this generator lead required gaining permission from more than 20 landowners and numerous permitting authorities. We sized the capacity of our line at 1,000 MW to accommodate future expansions, including our 102 MW Milford II project which is under construction.

Intermountain Power Plant is electrically connected to the Los Angeles Department of Water & Power control area via the STS transmission line, a 500 kV direct current line that services the Los Angeles basin. By interconnecting our Milford project at Intermountain Power Plant, we are able to use the existing STS transmission line and provide renewable power directly to the Southern California market. We executed a 20-year PPA for Milford I with SCPPA in 2007 to sell 100% of our power and

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RECs at fixed prices. The PPA includes a prepayment for a portion of the annual expected generation and ongoing payments for the remainder of the electricity, plus additional payments for RECs and reimbursements of certain operating costs. We believe the prepayment feature of the PPA is innovative and allowed us to lower our cost of capital for financing the project. We believe this benefit was passed on to consumers in the form of a reduced power price. SCPPA has an option to purchase Milford I in November 2019. In March 2010, we received an ARRA grant of approximately $120 million for Milford I. An unrelated third party has an 8% interest in the results of operations of Milford I. Our ownership of Milford I is subject to a tax equity financing. Our total installed development and construction costs for Milford I were approximately $505 million, including approximately $55 million of financing-related costs. These costs also included the 88-mile, 1,000 MW generator lead, which we expect will benefit our future expansion projects. We estimate Milford I's long-term average NCF will be approximately 24% to 26%, as described further in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Steel Winds I

Steel Winds I, which commenced commercial operations in June 2007, is a 20 MW project on the shores of Lake Erie in Lackawanna, New York, just south of Buffalo. The larger site on which the project is located was formerly a steel mill. The project consists of eight 2.5 MW Clipper turbines, the first turbines Clipper produced. We undertook this project primarily as a means of testing and gaining operating experience with the Clipper wind turbines. The project's relatively small size allowed us to initially finance the project with 100% equity, which provided more flexibility as we worked with Clipper to understand the technology and deal with start-up issues that can be common in new turbine designs. We anticipate expanding Steel Winds I in 2010 with our 15 MW Steel Winds II project, which we believe will introduce benefits of scale.

For power at Steel Winds I we receive floating power prices within NYISO Zone A. To stabilize this revenue, we entered into a swap with an affiliate of Morgan Stanley. The volume of this swap is approximately 95% of Steel Winds' expected output. This hedge expires at the end of 2016. In January 2010, we entered into a five-year PPA with an affiliate of Just Energy Income Fund for all RECs from the project. Steel Winds I qualifies for PTCs and MACRS depreciation and receives cash payments for electricity and RECs. Our total installed development and construction costs for Steel Winds I were approximately $35 million and are financed by a combination of equity and structurally subordinated debt of CSSW, LLC. We estimate Steel Winds I's long-term average NCF will be approximately 29% to 31%, as described further in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Stetson I

Stetson I is a 57 MW project in Washington County, Maine located approximately 60 miles from our Mars Hill project. Stetson I became operational in January 2009. The project consists of 38 GE 1.5 MW turbines. When commissioned, Stetson I replaced Mars Hill as the largest wind energy project in New England. As part of the Stetson I project we also constructed a 38-mile, 200 MW, 115 kV generator lead to interconnect to the ISO-NE power grid. Securing right-of-way for this generator lead required us to obtain rights through more than 95 easements, deeds, permits, licences and other agreements. We overbuilt the capacity of our transmission line by 140 MW to accommodate future expansions, 26 MW of which is now being used by our Stetson II project and 60 MW of which is available for our Rollins project, which is under construction. Operations at our Stetson I project were temporarily interrupted due to a transformer malfunction in February 2010.

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Because Stetson I connects directly into ISO-NE, all of its generation qualifies for New England RECs. We sell those RECs to numerous counterparties, similar to Mars Hill and Cohocton. Power from Stetson I is sold separately directly into ISO-NE, where we receive a floating price at the point of sale. Our point of sale has historically traded at a modest discount to Mass Hub, a liquid hub where electricity is traded. To stabilize our electricity revenue, we entered into a 10-year fixed-for-floating financial swap with an affiliate of Constellation Energy Group. This swap hedges approximately 70% of the expected output of Stetson I and a portion of the expected output from Stetson II. Stetson I was among the first projects for which an ARRA grant was given. We received approximately $40 million in September 2009. The remainder of the project is financed with a combination of senior project debt and subordinated debt of CSSW, LLC. Our total installed development and construction costs for Stetson I were approximately $175 million, including approximately $15 million of financing-related costs. These costs also include the cost of the 38-mile, 200 MW generator lead. We estimate Stetson I's long-term average NCF will be approximately 30% to 32%, as described further in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Stetson II

Stetson II is a 26 MW expansion project in Washington County, Maine. Construction on Stetson II began in October 2009, and we commenced commercial operations in March 2010. The project consists of 17 GE 1.5 MW turbines. Stetson II uses our existing infrastructure at Stetson I, including our generator lead, substation and interconnection equipment. Half of Stetson II's electricity and RECs is being sold to Harvard University under a long-term PPA. The other half is being sold directly into ISO-NE. The revenue from the majority of this portion of Stetson II's output is hedged with a financial swap. The majority of remaining REC volumes will be sold to Citigroup Energy, Inc. under a 10-year contract. Approximately 80% of Stetson II's expected electricity and REC output is covered by a PPA or otherwise hedged through 2019. Our total installed development and construction costs for Stetson II was approximately $70 million, including approximately $10 million of financing-related costs. We estimate that Stetson II's long-term average NCF will be approximately 30% to 32%. We received an ARRA grant of approximately $19 million for Stetson II in June 2010.

For more information about our operating projects see "Management's Discussion and Analysis of Financial Condition and Results of Operations."

2010 Projects

We discuss below the projects we have under construction or plan to place in construction by the end of 2010. Four of our 2010 projects are under construction. Of the remaining 2010 projects, KWP II is a Tier 1 project and Steel Winds II is a Tier 2 project.

Kaheawa Wind Power II (KWP II)

KWP II is a 21 MW expansion project adjacent to our KWP I site on Maui. The project will consist of 14 GE 1.5 MW turbines. KWP II will connect to MECO's 69 kV transmission system, which crosses the KWP I and II sites. We are negotiating with Hawaii's Department of Land and Natural Resources for a directed lease agreement. We have signed a long-term PPA for the project's electric power and RECs with MECO. The PPA is subject to approval by the Hawaiian PUC. Permitting of the project is in progress and we are currently preparing a Habitat Conservation Plan in support of the incidental-take authorization.

For this project to meet our return expectations, we need to use a battery system to help mesh the output of the project with the grid. We need the battery system to stabilize the amount of power available from the project and limit curtailment because Maui has a small electricity grid. While initial testing of the battery system has been positive, we cannot be sure the battery system will perform adequately. We believe if we are successful in coupling battery technology with our wind energy projects, it would be a competitive advantage for us. An unrelated third party owns 8% of the common equity relating to KWP II. We estimate that our total installed development and construction costs for KWP II will be approximately $115 million, including financing-related costs. This cost estimate also includes the battery energy storage system. We estimate that KWP II's long-term average NCF will be approximately 32% to 35%.

Kahuku

Kahuku is a 30 MW project on land we own on the north shore of Oahu, Hawaii. We began construction of this project in July 2010. The project will consist of 12 Clipper 2.5 MW turbines. Kahuku will connect directly into the Hawaii Electric Company's (HECO) transmission system through a transmission line that transects the project area. A 20-year fixed-price PPA has been executed with HECO and approved by the Hawaiian PUC.

We plan to incorporate a battery system for storage, similar to KWP II, as part of the Kahuku project. In July 2010, we entered into a $117 million construction and term loan facility guaranteed by the DOE under Section 1703 of ARRA to help finance construction of our Kahuku project. An unrelated third party owns 8% of the common equity relating to Kahuku. We estimate that our total installed development and construction costs for Kahuku will be approximately $145 million, including financing-related costs, the cost of the land we purchased and the battery energy storage system, but excluding reserves. We estimate that Kahuku's long-term average NCF will be approximately 30% to 32%.

Milford II

Milford II is a 102 MW expansion project in Beaver and Millard Counties, Utah, adjacent to our Milford I project. We began construction of this project in July 2010. It will consist of 68 GE 1.5 MW turbines and will use our existing infrastructure, including our substation, interconnection, equipment, 88-mile generator lead and site personnel. Milford II will transmit power over the generator lead we had built as part of our Milford I project. The project will be located on land owned by the Bureau of Land Management, the State of Utah and private landowners. We have entered into lease agreements with these landowners for terms of at least 30 years with various options to renew. We have received a right-of-way grant from the Bureau of Land Management (BLM) and are in the process of securing additional County permits.

We will sell all of the output of Milford II into the Southern California market pursuant to a PPA with SCPPA entered into in October 2010. The PPA has a prepayment feature similar to that in the Milford I PPA and a 20-year delivery term starting when Milford II commences commercial operations. SCPPA has an option to purchase the Milford II project as early as the seventh anniversary after it commences commercial operations. An unrelated third party owns 20% of Milford II, subject to our right to purchase 10% of the equity from the third party for a pre-determined price. We estimate that our total installed development and construction costs for Milford II will be approximately $275 million, including financing-related costs. We estimate that Milford II's long-term average NCF will be approximately 24% to 26%.

Rollins

Rollins is a 60 MW expansion project in Penobscot County, Maine, on which construction began in September 2010. It will consist of 40 GE 1.5 MW turbines and include an approximately 8-mile 115-kV generator lead that will tie into our existing 38-mile generator lead that serves the Stetson I and Stetson II projects. We have leased the land on which Rollins is located from private landowners under lease agreements with 25 to 27 year terms and options to extend the leases for an additional 20 years. We have a final interconnection agreement for this project with ISO-NE and Bangor Hydro Electric Company and we believe we have received all necessary approvals to deliver power through the Stetson lead to the New England grid.

All of Rollins' energy and capacity will be sold to two utilities in Maine under 20-year PPAs, whose terms begin when Rollins commences commercial operations. The project's RECs will be sold separately in New England to various counterparties. We estimate that our total installed development and construction costs for Rollins will be approximately $180 million, including financing-related costs. We estimate that Rollins' long-term average NCF will be approximately 29% to 31%.

Sheffield

Sheffield is a 40 MW project in Sheffield, Vermont, on which construction began in September 2010. It will consist of 16 2.5 MW Clipper turbines. We have entered into lease agreements with private landowners with 23 to 27-year terms and options to extend the leases for an additional 20 years. We executed a final interconnection agreement for this project with ISO-NE and Vermont Electric Power Company in April 2008 and we believe we have received all necessary approvals to connect directly into ISO-NE through a generator lead that transects the project area. For our Sheffield project, we obtained the first Certificate of Public Good granted by the Vermont Public Service Board for a utility-scale wind energy project since 1996. Our construction storm water permit issued by the Vermont Agency of Natural Resources was affirmed upon appeal. The appellants have since filed motions for reconsideration of that decision and a stay of construction. We cannot predict the outcome of these motions.

We have negotiated and received approval to enter into four PPAs with three Vermont utilities: two PPAs with VEC, one with BED and one with WEC. The PPAs with VEC include a 10-year contract for 25% of the electricity and RECs generated by the project and a 20-year contract for 25% of the electricity generated during the first 10 years and 50% of the electricity generated during the last 10 years. The PPA with WEC includes a 20-year contract for 10% of the electricity and RECs generated by the project, and the PPA with BED includes a 10-year contract for 40% of the electricity and RECs generated. During the subsequent 10 years following the BED PPA, the remaining 40% of the electricity and RECs generated is not contracted. We estimate that our total installed development and construction costs for Sheffield will be approximately $115 million, including financing-related costs. We estimate that Sheffield's long-term average NCF will be approximately 29% to 31%.

Steel Winds II

Steel Winds II is a 15 MW expansion project in Lackawanna, New York. It will consist of six 2.5 MW Clipper turbines and will use our existing infrastructure, including interconnection equipment and site personnel. We are currently in the process of securing the necessary land and other rights to conduct and operate the project. The project's System Reliability Impact Study and Facilities Study are complete and we are working towards an interconnection agreement with NYISO and National Grid. While we continue to evaluate alternatives, we anticipate selling power from Steel Winds II directly into the market through NYISO Zone A and will seek to hedge our revenue with a financial swap. In March 2010, we were awarded a 10-year contract by NYSERDA for 95% of the RECs generated by Steel Winds II. We estimate that our total installed development and construction costs for Steel Winds II will be approximately $40 million, including financing-related costs. We estimate that Steel Winds II's long-term average NCF will be approximately 28% to 30%.

2011 Projects

Our goal is to add approximately 200 MW to 250 MW of operating/under-construction capacity in 2011, which would result in our having a total of approximately 1,000 MW of operating/under-construction projects by the end of 2011. As described below, the four projects we are developing for possible construction in 2011 span our three regions: the Northeast, West and Hawaii, and represent between 275 MW and 300 MW of aggregate capacity. We discuss below the projects that we target for construction in 2011. Each of these projects is a Tier 2 project. Since the timing of construction starts is difficult to predict and is subject to numerous risks and uncertainties, some of these projects may not commence construction until after 2011 or at all. Even once a project commences operations, it may not meet our original expectations about how much energy it will generate or the returns it will achieve. In addition, we may place projects into construction in 2011 that are not in our current pipeline. See "Risk Factors Risks Related to Our Business and the Wind Energy Industry."

Bull Hill

Bull Hill is an approximately 30 MW project in Hancock County, Maine. The project site includes existing transmission capabilities. We have all of the land rights we expect to need for this project and have completed environmental screening for it. We also have over three years of meteorological data for the project. We will seek long-term revenue agreements with a utility or other customers for the energy from Bull Hill.

Kawailoa

Kawailoa is an approximately 70 MW project on Oahu, Hawaii. Upon completion, we expect it would be the largest wind-energy project in Hawaii. We have all of the land rights we expect to need for this project and have completed environmental screening for it. We also have over three years of meteorological data for the project. We are currently negotiating a PPA with a utility for the energy from Kawailoa.

Oakfield

Oakfield is an approximately 100-125 MW project in Aroostook County, Maine. Upon completion, we expect that it will be our largest wind-energy project in Maine. The project will include an approximately 60 mile generator lead to the interconnection point for our Stetson I and II projects and our Rollins project. We have approximately 90% of the land rights we expect to need for this project and have completed environmental screening for it. We also have over three years of meteorological data for the project. We will seek long-term revenue agreements with utilities or other customers for the energy from Oakfield. One of our permits for Oakfield is under appeal. We cannot predict the outcome of that appeal.

Palouse

Palouse is an approximately 70 MW project in Whitman County, Washington. We have all of the land rights we expect to need for this project and have completed the environmental screening for it. We also have over three years of meteorological data for the project. We will seek long-term revenue agreements with utilities or other customers for the energy from Palouse.

California

We have entered into an option agreement to purchase wind energy assets that relate to a possible 20 MW project being developed in California. We cannot predict when or whether we would acquire these assets or complete this project.

2012 Projects

Our goal is to add between 200 and 400 MW of operating/under construction projects in 2012. Each of these projects is a Tier 2 project and is generally less advanced than our 2011 projects. Since the timing of construction starts is difficult to predict, especially for projects planned for construction so far in advance, and is subject to numerous risks and uncertainties, some of these projects may not commence construction until after 2012, or at all. Even once a project commences operations, it may not meet our original expectations about how much energy it will generate or the returns it will achieve. In addition, we may place projects into construction in 2012 that are not in our current pipeline. See "Risk Factors Risks Related to Our Business and the Wind Energy Industry."

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Baseline

Baseline is an approximately 350 MW project in Gilliam County, Oregon. We have all of the land rights we expect to need for this project and have completed environmental screening for it. We also have over three years of meteorological data for the project. We will seek long-term revenue agreements with utilities or other customers for the energy from Baseline.

Bingham

Bingham is an approximately 115-130 MW project in Somerset County, Maine. We have substantially all of the land rights we expect to need for this project and have completed preliminary environmental screening. We also have over two years of meteorological data for the project. We will seek long-term revenue agreements with utilities or other customers for the energy from Bingham.

Bowers

Bowers is an approximately 60 MW expansion project in Penobscot and Washington Counties, Maine. We expect Bowers to connect to our 38-mile generator lead that serves our Stetson I and Stetson II projects. We have substantially all the land rights we expect to need for this project and have completed preliminary environmental screening. We also have over two years of meteorological data for the project, as well as extensive meteorological data from our nearby Stetson projects. We will seek long-term revenue agreements with utilities or other customers for the energy from Bowers.

Milford III

Milford III is an approximately 300 MW expansion project in Beaver and Millard Counties, Utah. We have all the land rights we expect to need for this project. The project is adjacent to our Milford I and II projects and will use our existing infrastructure, including our substation, interconnection, equipment and 88-mile generator lead. We will seek long-term revenue agreements with utilities or other customers for the energy from Milford III.

Competition

While we compete with owners of electrical generation assets, including owners of fossil fuel generation assets, we believe our primary competitors are developers and operators focused on renewable energy generation. Renewable energy sources, including wind, biomass, geothermal and solar, currently benefit from various governmental incentives such as PTCs, ITCs, cash grants and loan guarantees, RPS programs and associated RECs and accelerated tax depreciation. Many of these incentives are not available with respect to energy generated from fossil fuels. More specifically, we believe our primary competitors among generators of renewable energy are developers and operators of wind energy projects, given the wide range of technical and economic differences between the various forms of renewable energy.

In the wind energy sector, competition occurs primarily during the development stages of a wind energy project rather than during a project's operational phase. As discussed in "Risk Factors," wind energy projects require wind conditions that are found in limited geographic areas and at particular sites. Projects must also interconnect to electricity transmission or distribution networks to deliver electricity. We compete with other developers for desirable sites and for the ability to connect to transmission or distribution networks. Because the wind energy industry in the United States is at an early stage, we also compete with other wind energy developers for personnel with requisite industry knowledge and experience.

We can sell the electricity from our wind energy projects located near liquid power markets at wholesale market prices. In that case, we are price takers selling an undifferentiated commodity product, electricity, excluding the RECs associated with our electricity. Depending on the regulatory framework and market dynamics of a region, we may also face competition in bidding for long-term

PPAs. If our power is expected to be sold pursuant to a PPA, we may compete with other wind energy companies, as well other renewable energy generators and electricity producers in general, when we bid on or negotiate for a PPA.

The wind energy industry has a range of developers, including large integrated independent power producers and established European producers, many of whom have greater financial and other resources than we do. While our pipeline spans several regions across the country, including the Northeastern and Western regions of the continental United States and Hawaii, we have not achieved the scale of many of the larger wind energy producers.

Suppliers

Turbines are the primary equipment of a wind energy project and turbine costs represent the majority of our project investment costs. Our turbine supply strategy has changed as the market became oversupplied. Instead of entering into commitments to acquire turbines well in advance of deployment, we now intend to acquire turbines relatively close to planned installation dates to avoid financing costs and potential storage costs as well as depletion of the warranty coverage. To date, we have purchased turbines from GE and Clipper. GE and Clipper have supplied us with turbines with aggregate generating capacity of 401 MW and 375 MW, respectively. We have the right but not the obligation to acquire from Clipper additional turbines with aggregate generating capacity of 633 MW through 2015. We have paid Clipper approximately $60 million in deposits and progress payments towards turbine purchases from 2011 2015 and intend to pay approximately $30 million more in deposits and progress payments through January 15, 2011. If we elect for any reason not to acquire any additional turbines from Clipper, we will forfeit the pro rata portion of these deposits and progress payments corresponding to the schedule of future turbine purchases: $38.6 million for turbines scheduled to be purchased in 2011, $17.9 million for 2012, $10.7 million for 2013, $13.4 million for 2014 and $8.9 million for 2015. Clipper has announced a proposed transaction pursuant to which United Technologies Corporation would acquire the approximately 50% of the outstanding ordinary shares of Clipper that it does not already own. Clipper expects the transaction to be completed in December 2010. It is subject to Clipper shareholder approval and other closing conditions.

When we purchase turbines, we also enter into warranty agreements with the manufacturer. Warranties provide protections against costs associated with turbine non-performance. Warranties are typically two to five years in duration from the earlier of (i) 12 to 24 months from delivery or (ii) turbine commissioning. These warranties typically include a power curve warranty, which requires the manufacturer to pay liquidated damages if turbine output falls below a specified level at certain wind speeds and an availability warranty, which ensures the reliability of the turbines for electrical production. We also typically receive a sound level warranty. All liquidated damages payable under these warranties are subject to aggregate maximum caps. Finally, we receive a standard warranty with respect to the workmanship of the turbine equipment.

Other important suppliers include engineering and construction companies, with whom we contract prior to construction of our projects to perform civil engineering and electrical work as well as to build the required infrastructure. We believe there are a sufficient number of capable engineering and construction companies available in our markets to meet our needs.

Customers

We sell electricity and associated RECs primarily to local utilities and institutions under multi-year PPAs or in local liquid ISO markets. For the year ended December 31, 2009, the electrical production we sold to MECO, New Brunswick, Constellation NewEnergy, Inc. and SCPPA accounted for 22%, 14%, 5% and 4%, respectively, of our sales. We sell RECs to various counterparties, four of which accounted for approximately 59% of our total sales of RECs for the year ended December 31, 2009.

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Legal Proceedings

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business, including proceedings contesting our permits or the construction or operation of our projects. As is the case with other electrical power producers, our operations are subject to extensive and rapidly changing federal, state and local environmental, health and safety and other laws and regulations.

Some residents near our Mars Hill project recently commenced litigation against us based on our construction and operation of this project. While the outcome of this litigation cannot be predicted, we believe it will not have a material adverse effect on us.

Employees

As of September 30, 2010, we had approximately 220 full-time employees. None of our employees is represented by a labor union or is covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Insurance

We believe our insurance is on terms generally carried by companies engaged in similar businesses and owning similar properties in the United States and whose projects are financed in a manner similar to our projects. As is common in the wind industry, however, we do not insure fully against all the risks associated with our business either because insurance is not available or because the premiums for some coverage are prohibitive. For example, we do not maintain terrorism insurance. We maintain construction, operation and transportation insurance; casualty insurance, including windstorm, flood and earthquake coverage; business interruption insurance; primary and excess liability insurance; and worker's compensation, automobile and title insurance. We maintain "all risk" property insurance coverage in amounts based on the full replacement value of our projects (subject to certain deductibles and sub-limits for flood and earthquake coverage) and business interruption insurance that varies from project to project based on the revenue generation potential of each project. Subject to applicable deductibles, our business interruption and property insurance covers, among other things, breakdowns for twelve months and casualty losses, respectively, for our transformers. We generally do not maintain insurance for certain environmental risks, such as environmental contamination. A loss not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Regulatory Matters

We are subject to extensive regulation by various federal, state and local government agencies. The federal government regulates the wholesale sale and transmission of electric power in interstate commerce and regulates certain environmental matters. States and local governments regulate the construction of electricity generating and transmission facilities, the intrastate distribution of electricity, retail electricity sales and, in certain cases, environmental matters.

Federal Energy Regulatory Commission

The electricity industry in the United States is decentralized and comprises the following sectors: (i) a generation sector, consisting of regulated electricity utility companies, wholesale electricity suppliers and governmental entities; (ii) a high-voltage transmission sector, consisting of the regulated electricity utility companies and the governmental entities that own transmission systems, regional transmission organizations, ISOs and the companies controlling and scheduling the use of transmission networks; (iii) a distribution sector, consisting of regulated electricity utility companies and governmental entities that transport the energy from the high-voltage network to end users; and (iv) a retail supplier sector, consisting of regulated electricity utility companies and, in some limited markets, competitive suppliers, which sell electricity to retail consumers.

Our project companies that are not QFs under FERC's regulations are EWGs. EWGs are public utilities that own generating facilities that qualify for exemption from FERC's books and records regulations under the Public Utility Holding Company Act of 2005 because they are engaged exclusively in the business of owning and/or operating eligible generating facilities and selling electric energy at wholesale. Our non-QF projects sell electric capacity, energy and ancillary services at market-based rates pursuant to authority granted by FERC. In order to be eligible for market-based rate authority, our non-QF public utilities are required to establish and periodically reestablish that they do not have, or have adequately mitigated, market power, that they cannot erect barriers to market entry and that they do not engage in abusive affiliate transactions.

Our project companies that have a generating capacity of 20 MW or less are QFs that are exempt from most aspects of FERC regulation.

Other Regulation

For our operating projects with more than 75MW of capacity, we are also subject to the reliability standards of NERC. In addition, NERC has determined we are a Transmission Owner/Transmission Operator (TO/TOP) with respect to our Milford I generator lead. We are reviewing the possibility of appealing that determination. To the extent we are a TO/TOP, we will be required to comply with additional reliability standards. If we fail to comply with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

As described further under " Environmental Regulation," our activities are subject to extensive regulation by various federal environmental and natural resource agencies. These agencies include: the U.S. Army Corps of Engineers (on wetland issues); the EPA (on stormwater issues); the U.S. Fish and Wildlife Service (on wildlife and bird issues); and the Bureau of Land Management (in relation to its management of federal lands with significant wind resources).

Due to the height of wind turbines and their potential effect on aviation, we are required under certain circumstances to seek approval from the Federal Aviation Administration and/or to work with the Department of Defense.

ISO-NE and New York ISO

ISO-NE is an RTO, serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO-NE operates the region's interstate high-voltage transmission lines and wholesale electricity marketplace, through which bulk electric power is bought, sold and traded. NYISO performs the same role in New York. ISO-NE and NYISO each manage the planning and interconnection of new transmission and generation in their respective regions. ISO-NE and NYISO are independent, not-for-profit corporations.

New York Public Service Commission

The New York Public Service Commission (NYPSC) exercises limited jurisdiction over the owners of generating facilities in New York State. For example, the NYPSC exercises jurisdiction with respect to transfers of control over companies owning generating assets in New York State. In addition, the NYPSC must approve any debt issued by a generating owner that is secured by assets located in New York State. Under New York State law and EPACT 2005, NYPSC has authority to impose reliability standards that exceed those imposed by other state authorities.

Hawaii Public Utility Commission

The Hawaiian PUC regulates public utility companies operating in the state and establishes rates, tariffs, charges and fees. The Hawaiian PUC has been active in promoting energy efficiency and renewable energy projects. In 2005, Hawaii was one of six states that partnered with the EPA to explore approaches for reducing the cost of consumer electric and gas bills through policies and practices focused on energy efficiency and renewable energy sources. The Hawaiian PUC has established a Public Benefits Fund to promote the development of programs that increase energy efficiency and to decrease the state's reliance on fossil fuels. Under the program, each of the Hawaii electric companies transfers responsibility for its own energy efficiency programs to the Fund administrator with the goal of increasing the cost-effectiveness of all such programs.

Environmental Regulation

We are subject to various environmental, health and safety laws and regulations in each of the jurisdictions in which we operate. These laws and regulations require us to obtain and maintain permits and approvals, undergo environmental review processes and implement environmental, health and safety programs and procedures to control risks associated with the siting, construction, operation and decommissioning of wind energy projects, all of which involve a significant investment of time and can be expensive.

We incur costs in the ordinary course of business to comply with these laws, regulations and permit requirements. We do not anticipate material capital expenditures for environmental controls for our operating projects in the next several years. However, these laws and regulations frequently change and often become more stringent, or subject to more stringent interpretation or enforcement. Future changes could require us to incur materially higher costs.

Failure to comply with these laws, regulations and permit requirements may result in administrative, civil and criminal penalties, imposition of investigatory, cleanup and site restoration costs and liens, denial or revocation of permits or other authorizations and issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property have been brought and may in the future result from environmental and other impacts of our activities.

Environmental Permitting

We are required to obtain from federal, state and local governmental authorities a range of environmental permits and other approvals to build and operate our projects, including those described below. In addition to being subject to these regulatory requirements, we could experience significant opposition from third parties when we initially apply for permits or when there is an appeal proceeding after permits are issued. The delay or denial of a permit or the imposition of conditions that are costly or difficult to comply with can impair or even prevent the development of a project or can increase the cost so substantially that the project is no longer attractive to us.

Federal Clean Water Act

Frequently our projects are located near wetlands and we are required to obtain permits under the federal Clean Water Act from the U.S. Army Corps of Engineers for the discharge of dredged or fill material into waters of the United States, including wetlands and streams. The Army Corps may also require us to mitigate any loss of wetland functions and values that accompanies our activities. In addition, we may be required to obtain permits under the federal Clean Water Act for water discharges, such as storm water runoff associated with construction activities, and to follow a variety of best management practices to ensure that water quality is protected and impacts are minimized. Certain activities, such as stringing a power line across a navigable river, may also require permits under the Rivers and Harbors Act of 1899.

Federal Bureau of Land Management Permits

As some of our western U.S. projects are sited on BLM lands, we are required to obtain rights-of-way from the BLM. The BLM encourages the development of wind energy within acceptable areas, consistent with the federal Energy Policy Act of 2005 and the BLM energy and mineral policy. Obtaining a grant requires that the proposed project prepare a plan of development and demonstrate that it will adhere to BLM's best management practices for wind energy development, including meeting criteria for protecting environmental, archeological and cultural resources.

National Environmental Policy Act and Endangered Species Requirements

Our projects may also be subject to environmental review under the federal National Environmental Policy Act (NEPA), which requires federal agencies to evaluate the environmental impact of all "major federal actions" significantly affecting the quality of the human environment. The granting of a land lease, a federal permit or similar authorization for a major development project, or the interconnection of a significant private project into a federal project generally is considered a "major federal action" that requires review under NEPA. As part of the NEPA review, the federal agency considers a broad array of environmental impacts, including impacts on air quality, water quality, wildlife, historical and archeological resources, geology, socioeconomics and aesthetics, and alternatives to the project. The NEPA review process, especially if it involves preparing a full Environmental Impact Statement, can be time-consuming and expensive. A federal agency may decide to deny a permit based on its environmental review under NEPA, though in most cases a project would be redesigned to reduce impacts or we would agree to provide some form of mitigation to offset impacts before a denial is issued.

Federal agencies granting permits for our projects also consider the impact on endangered and threatened species and their habitat under the federal Endangered Species Act. We also must comply with and are subject to liability under the Endangered Species Act, which prohibits and imposes stringent penalties for harming endangered or threatened species and their habitats. Our projects also need to comply with the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act, which protect migratory birds and bald and golden eagles and are administered by the U.S. Fish and Wildlife Service. Most states also have similar laws. Because the operation of wind turbines may result in injury or fatalities to birds and bats, federal and state agencies often recommend or require that we conduct avian risk studies prior to issuing permits for our projects. They may also require ongoing monitoring or mitigation activities as a condition to approving a project, and may even refuse to issue a permit if the mitigation options are insufficient to address the risks. In addition, federal agencies consider a project's impacts on historic or archeological resources under the National Historic Preservation Act and may require us to conduct archeological surveys or take other measures to protect these resources.

In connection with our KWP I project, we have a 20-year Habitat Conservation Plan to benefit four species protected under state and federal endangered species programs that have habitats in the project area. The plan is designed to minimize the incidental injury or death of wildlife, and includes regular monitoring of the project area and various mitigation measures. Not all projects will require implementation of a Habitat Conservation Plan, although we expect to implement such plans for our KWP II, Kahuku and Kawailoa projects and many of the projects we develop in Hawaii due to the high occurrence of protected species in the state, and because of well-established state and federal policies that encourage these plans. In other states we expect to implement various kinds of mitigation measures, as necessary or appropriate to offset impacts to protected resources.

Other State and Local Programs

In addition to federal requirements, we are subject to a variety of state environmental review and permitting requirements. Many states where our projects are located or are being developed, including California, Hawaii, New York, Washington, Vermont and Maine, have laws that require state agencies to evaluate a broad array of environmental impacts before granting state permits. The state environmental review process often resembles the federal NEPA process described above and may be more stringent than the federal review. Our pro