STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: REVIEW OF PROPOSED TOWN OF	:	
NEW SHOREHAM PROJECT	:	
PURSUANT TO R.I. GEN. LAWS	:	DOCKET NO. 4111

PREFILED TESTIMONY OF EXPERT WITNESS WILLIAM P. SHORT, III

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Pre-Filed Testimony of
William P. Short III

Q. **Please state your name and business address:**

A. My name is William P. Short III. My current business address is 44 West 62nd Street, New York, New York 10023-7008 and my mailing address is P.O. Box 237173, New York, New York 10023-7173.

Q. **Please describe your qualification and experience.**

A. I am an independent consultant with a practice specializing in the field of renewable energy.

I began my professional career with Philadelphia Electric Company (now Exelon Corporation) in 1973. There I was a project engineer in its Engineering & Research Department and worked on the design, construction and operations of nuclear power plants, specializing in the emergency core cooling systems for nuclear power plants. From 1978 until 1980, I worked, as project engineer, for EBASCO (now a part of Raytheon), designing nuclear power plant security systems. From 1980 until 1996, I worked for a major investment bank, Kidder, Peabody (now part of UBS Financial Services), as an investment banker. I specialized in the financing of renewable energy companies and renewable energy projects. I financed wind farms, landfill gas power plants, geothermal power plants, geothermal companies, biomass plants and small hydro facilities. For ten years, I managed, on behalf of Kidder's investors, the operations of several wind farms in which its clients had invested.

I consulted during 1996 and 1997 on electric power de-regulation in California, advising Prudential Insurance, Deutsche Bank and CIGNA on their geothermal loan investments. During the same period of time, for Southern California Edison Company I performed analysis to support buy-out offers for above-market long-term power purchase agreements with renewable energy projects.

I worked from 1997 through 2008 for Ridgewood Power Management Corporation (hereinafter referred to as "Ridgewood"), where I was its vice president of power marketing. I managed its sales of energy, capacity and renewable energy certificates (hereinafter referred to as "REC") from its generating facilities, including two biomass plants, two landfill plants and 16 small hydro plants in New England. The two landfills and one of the hydros were located in Rhode Island. I represented Ridgewood in the legislative and regulatory process that created the various New England state Renewable Energy or Portfolio System programs (hereinafter referred to as "RPS"). I managed the regulatory effort to qualify the Ridgewood generating facilities in the various New England state RPS programs. I materially participated in the creation of the New England Power Pool Generation Information System (hereinafter referred to as "NEPOOL GIS").[1] Although Ridgewood was a small company, during the mid-2000s, with its generating assets, I, nevertheless, managed to control as much as 45% and 40% of the supply of Massachusetts and Connecticut RPS requirements, respectively, for "new" renewable facilities. For the period of 2002 through 2006, Ridgewood was the largest generator of "new" REC[2] (hereinafter referred to as "New REC") in New England. These efforts were quite successful and, by 2007, resulted in additional revenues between 66 2/3% and 100% of the combined energy and capacity revenues for Ridgewood's New England facilities.

Concerning traditional power marketing activities, I aggressively marketed the energy and capacity from Ridgewood's New England power plants. In 1999, Ridgewood's plants were the first New England independent renewable generators to sell their energy into the ISO-NE markets. In 2004, Ridgewood's plants became the first renewable generators to sell their generators' gross energy production while at the same time purchasing all of their station service needs from ISO-NE. In 2007, Ridgewood became the first New England independent renewable generator to serve load under a Standard Offer Service

[1] The NEPOOL GIS is the tracking and trading system that was established for, among other things, the verification of compliance with the various New England state RPS programs. It also provides a data base of public reports on generator production.

[2] "New" RECs may be defined collectively as Massachusetts Class I, Connecticut Class I, New Hampshire Class I, Maine Class I and Rhode Island New REC.

(hereinafter referred to as "SOS") agreement[3] exclusively with energy from renewable generation. Through 2002 until I left Ridgewood, I negotiated discounted transmission service, station service and metering service contracts with our facilities' local electric distribution companies. The SOS agreement raised Ridgewood's energy revenues by approximately $10 per megawatt-hour (hereinafter referred to as "MWh") over what they would have been otherwise while these other agreements reduced operating expenses approximately $5/MWh.

Since leaving Ridgewood in 2008, I established a consulting practice. Given my knowledge of and experience with the New England power and REC markets, all of my clients' operations are located in New England. I represent the owners or developers of wind, biomass, solar and hydro-electric projects. I qualify, manage and sell for these clients all of their REC production. I also represent load serving entities in Connecticut, Massachusetts, Maine, New Hampshire and Rhode Island. I regularly manage and purchase for these clients all of their REC requirements. I maintain a proprietary data base on the supply and demand for the various New England RPS programs. I offer extracts of this data base to both my load and generator clients. I also act as an Independent Third Party Meter Reader, qualifying behind-the-generation for the various New England RPS programs and then reading and verifying their production.

Q. **Please describe your education.**

A. I was graduated by Duke University with a Bachelor of Science in Engineering (Electrical Engineering) in 1973, the University of Pennsylvania with a Masters of Science in Engineering (Systems Engineering) in 1978 and New York University with a Masters of Business Administration (Finance and Accounting) in 1978.

Q. **Have you previously testified before State Legislatures or State Energy or Public Utility Commissions on matters pertaining to renewable energy policy or projects?**

[3] Ridgewood's affiliate Indeck Maine Energy served load under the Maine Standard Offer Service arrangement, an arrangement similar to the Basic Service of Narragansett Electric.

A. Yes, I have testified on matters pertaining to renewable energy policy at the Maine, New Hampshire, Massachusetts, California and Connecticut state legislatures. I have testified on matters pertaining to renewable energy policy or projects at the California Energy Commission, California Public Utilities Commission, New York Public Service Commission, New Hampshire Public Utilities Commission, Maine Public Utilities Commission, Massachusetts Department of Energy Resources, Rhode Island Public Utilities Commission and Connecticut Department of Public Utility Control.

Q. **Do you belong to any professional organizations or committees?**

A. Yes, I am a member of the American Nuclear Society, the Geothermal Resources Council and the Institute of Electrical and Electronic Engineers.

Q. **What is your role in this proceeding?**

A. I have been retained by Michael and Maggie Delia as an expert witness in this proceeding.

Q. **Can you summarize your conclusions of the Project?**

A. The power purchase agreement between Narragansett Electric Company and Deepwater Wind Block Island, LLC for the project, a 6-8 wind turbines, up to 30 MW wind farm (hereinafter the "Project") does not represent a commercially *reasonable* long-term contract between a Rhode Island electric distribution company (Narragansett Electric Company) and a developer or sponsor (Deepwater Wind Block Island, LLC) for a to-be-developed renewable energy resource (the Project); and

The Project will not stabilize long-term energy prices at the lowest prices but at prices between two and three times to three to four times estimates of future energy prices; and

The Project will only minimally enhance environmental quality as opposed to other renewable energy technologies; and

The Project will create minimal jobs in Rhode Island in the renewable energy sector; and

The Project will not facilitate the financing of other renewable energy generation within the jurisdictional boundaries of Rhode Island or adjacent state or federal waters but actually crowd out more economical renewable projects in Rhode Island; and

The Project will not provide any net direct economic benefit to Rhode Island.

Q. **Why is the Project's contract not a commercially *reasonable* long-term contract between Narragansett Electric Company and Deepwater Wind, LLC?**

A. The Project is too small to be commercially reasonable; thus, its long-term contract is not reasonable. The furthest along off-shore wind farms off the coast of the Mid-Atlantic and New England states (Cape Wind and Delaware Bluewater Wind) are each approximately 450 MW. The Project's proposed size is 1/15th of those projects. The Project is too small to have economics of scale,[4] economics of numbers or economic benefits that would exceed on a per MWh basis those of larger off-shore wind farms or other on-shore renewable energy projects. The project is nothing more than a demonstration project[5] and, as a demonstration project it is far too large, it could be built vastly smaller (i.e., one turbine) and closer to the Rhode Island mainland in order to prove the point, if proof were needed, that off-shore wind can be built and operate successfully in Rhode Island waters.

If the Project was built to a commercial or utility scale (300 MW or more), it could be built at an alternate sight -- for example, far to the east of Block Island, just to the east side of the shipping channel to Newport. If sited there, the Project would be largely over the horizon and out-of-sight from Block Island and the Rhode Island mainland. Unlike now with the Project and the Cape Wind project in Nantucket Sound, that site would have considerably less intervenor opposition and less negative impact on the non-marketable values of the proposed SAMP area[6] . Finally, its revenue requirements on a per MWh basis would be less, more in line with those of the proposed Bluewater Wind wind farm

[4] See page 9, line 19 of the direct testimony of Madison Milhous.
[5] See page 9, line 2 of the direct testimony of Madison Milhous.
[6] See page 50 of the November 23, 2009 draft of the Ocean Special Area Management Plan.

off of the Delaware beaches.[7] This referenced off-shore wind project has an initial projected cost per MWh between 17% and 25% less than the Project's initial cost of $235.75/MWh. With a smaller escalation rate than the Project, after twenty years Bluewater Wind will cost between 32% and 38% less than the Project.

The cost of the Bluewater Wind project is not a complete "apples-to-apples" comparison to the Project. Bluewater Wind's cost includes the cost of the undersea cable from the wind farm to the mainland substation, near Millsboro, Delaware, where it interconnects with Delmarva Power's 230 KV/138 KV transmission system. The Project only includes the undersea cable to Block Island, not the undersea cable from Block Island to the Rhode Island mainland. This cost has been estimated in the direct testimony of Daniel Glenning ranging between $35 and $50 million.[8] Like the Project's costs, Narragansett Electric proposes to recover these costs from its distribution ratepayers.

I believe that, in order to perform an "apples-to-apples" comparison, one should include the annual carrying costs of this cable investment in the cost of the Project. Using the annual revenue requirements of Narragansett Electric from the direct testimony of David Tufts[9] and adding those numbers to the Project cost, the true initial Project cost increased by nearly $80.00/MWh to $324.87/MWh. Over the twenty-year life of the PPA, these costs would raise the above-market, non-discounted and discounted cost of the Project by $104 million and $64 million, respectively.

Using these numbers with the cable cost included, the Bluewater Wind project has an initial projected cost per MWh between 38% and 44% less than the Project's initial cost of $285.25/MWh. After twenty years, with the cable nearly completely paid for, Bluewater Wind will still cost between 33% and 39% less per MWh than the Project.

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[7] The Delmarva Bluewater Wind contact specifies 2007 price for capacity price of $70.23/KW-year, an energy price of $98.93/MWh and a REC price of $15.32/REC with 350% multiplier. These prices are subject to a 2.5% annual escalation rate. Assuming a 2012 in-service date, full capacity credit and a 40% capacity factor, the all-in price would be $195.27/MWh. If the capacity credit is only 28%, the 2012 all-in price would be $178.35/MWh.
[8] See page 8, line 3 of the direct testimony of Daniel Glenning.
[9] See David Tufts' Exhibit DET-1, page 1of 5 of his direct testimony for details.

In summary, the Project's costs are significantly above that of the furthest along off-shore wind project on the East Coast, Bluewater Wind. No person would build the Project unless he could obtain the significant subsidies proposed here. It is my opinion that Narragansett Electric would not even entertain the Project if it could purchase the output from a utility-scale project, such as one that could be built directly to the east of Block Island on the east side of the shipping channel to Newport. Given these significant subsidies, I cannot find the Project's power purchase agreement a commercially reasonable long-term contract.

Q. **Can you explain why the Project will not stabilize long-term energy prices at the lowest prices but at prices between two and three times estimates of future energy prices?**

A. While the Project tends to stabilize long-term energy prices, it would do so at an excessive price to the ratepayers of Narragansett Electric and Block Island Power. The direct testimony of Madison Milhous of National Grid indicates that the Project's energy will cost initially twice that of other resources.[10] By the end of the contract, this energy will cost nearly three times that of other resources.[11]

Q. Do you concur with National Grid's assessment of "market" cost?

A. No, it is my opinion that the above-market cost of the Project would be materially higher than the direct testimony of Madison Milhous. These higher above-market costs will be the result of a combination of lower REC and energy prices than those mentioned in the direct testimony of Madison Milhous.

The price of New REC in New England, which peaked three years ago at over $50/REC[12] and are currently selling for less than $30/MWh,[13] could have little value within as little as 4 years and negligible value within 7 years. The direct testimony of Madison Milhous fails to take these values into account.

[10] See page 18, line 19 of the direct testimony of Madison Milhous.
[11] See page 18, line 21 of the direct testimony of Madison Milhous.
[12] In November 2006, I sold Massachusetts Class I REC for prices in excess of $54.00/REC.
[13] Recently, I sold for my generator clients Maine Class I RECs for $23/REC while I purchased for my load clients Connecticut Class I REC for $24/REC. Attached is the latest REC price sheet for New REC from Bloomberg.

The supply of existing renewable resources in New England in 2003 was about 10.8% of the total New England consumption of energy.[14] If all of this existing supply is converted to New renewable resources for one or more of the New England RPS programs, the RPS requirements for New renewable resources for nearly all of the New England states would be satisfied until the very end of this decade. With little fanfare, this has been slowly happening.

Since 2002, many existing renewable resources have qualified for one or more of the various "New" New England RPS programs as New resources; thus reducing the need for recently constructed (i.e., truly new) renewable resources in New England. For example, of the 21 biomass plants in New England that were built before 1998, 19 have been certified in one or more of the New England RPS programs for "new" renewable resources as being New. These biomass plants currently provide the plurality of the REC that qualify for the various New England state RPS programs as New renewable resources.

This trend of the qualification of existing biomass plants as New renewable resources has not abated. In the past two years, behind-the-meter production from biomass plants located at paper mills has qualified for New treatment.[15] To date, the potential annual production from just the three approved facilities totals 500,000 REC. Eventually, all biomass boilers at paper mills will be qualified and would deliver a substantial supply of New REC to the marketplace.

Since 2007, hydroelectric projects larger than 5 MW have been able to qualify for several of the New England state RPS programs.[16] Although only three hydroelectric facilities

[14] New England renewable supply as measured by the NEPOOL GIS for 2003 was 13.5 million REC or 10.8% of total New England generation. For 2008 (the latest year for which data is available), New England REC supply was 17.8 million REC or 14.2% of total New England generation.

[15] See Maine PUC website (www.maine.gov/mpuc/electricity) for details of its decisions granting "New" RPS treatment to biomass boilers at the Lincoln, Old Town and Westbrook, Maine paper mills.

[16] In Rhode Island, the hydro size limit is 30 MW. In Massachusetts, the hydro size limit is 25 MW incremental to the dam's base generation. In New Hampshire, the hydro size limit is any incremental amount to the dam's base generation. In Maine, the hydro size limit is 100 MW.

have qualified to date,[17] many are working on projects to expand their production or retrofit their facilities to qualify as New renewable resources. Since hydro currently produces about 50% of New England's supply of renewable generation, if these qualifications become as commonplace as they have been with the biomass plants, then the current surplus of supply of REC from existing renewable resources could more than double.

Since Rhode Island and all of the other New England RPS programs accepts REC from renewable resources located outside of New England, one has to consider those supplies affecting the price of New REC in New England. In New York, where in its RPS uses long-term contacts to procure REC, the contract terms are for ten-year terms.[18] Nearly all of these contracts are with wind farms. The first of these contracts will expire in 2017 and the last should expire in 2024. While the first wave of contracts was small, only 300 MW, the total number of contracts should total around 3,000 MW. Once their contracts in New York expire, the owners of these wind farms will obviously seek the highest prices, as many of their New York competitors already do,[19] and export their energy and RECs to New England.

A similar development should occur with eastern Canada wind farms, starting as early as 2013. To date, Hydro Quebec has executed 1,400 MW of 10-year contracts with wind farm developers.[20] Hydro Quebec's goal is to develop a total of 3,500 MW of wind farms. The earliest expiration date of these contracts is 2013. With no RPS requirement in Quebec or, for that matter, all of Canada, the closest market for these facilities' REC is the New England states RPS programs. Consequently, when these wind projects come off

[17] TransCanada recently qualified its 15-Mile Falls Hydroelectric Project on the Connecticut River in Grafton County, New Hampshire and Caledonia County, Vermont, as a Massachusetts Class I renewable resource. More details can be found at www.lowimpacthydro.org.

[18] In addition, currently about 1/3 of all New York wind projects export their production to New England in order to satisfy the New RPS requirements of the various New England states, including that of Rhode Island.

[19] Currently, nine wind projects, with a generating capacity of 463.5 MW, from New York are already qualified as New England New renewable resources.

[20] To date, Hydro Quebec only exports RECs from two wind projects under contract (total capacity of 108 MW) with it into New England. Both of these have been qualified as New England New renewable resources.

contract, their REC production will naturally seek buyers in the New England if no market for REC exists in Quebec.

Outside of New England, the price of REC used to satisfy other state RPS programs is currently less than those showed on page 1of 2 to National Grid's responses to the Division's first set of data requests.[21] Except for the New England RPS programs, nearly all state RPS programs are presently satisfied with REC costing less than $10/REC. In many jurisdictions, such as in Texas, the cost is already less than $2/REC. Over the long-term, I foresee the price for New REC approaching that of the balance of America and not the other way around. It is my opinion that, when Narragansett goes to sell the RECs from the Project in the spot REC market, it will find that the REC price is nowhere near the prices shown on page 1of 2 to National Grid's responses to the Division's first set of data requests. For the reasons cited above, the above-market cost of the Project will be substantially greater than the projections made in the direct testimony of Madison Milhous.

I believe that there are two other major flaws in the direct testimony of Madison Milhous with respect to the prices for energy. There was a complete absence of the mention of new nuclear plants being constructed in New England during the term of the Project's contract.[22] While I can understand such a conclusion for this decade, I believe that it is gross mistake to exclude nuclear power totally in the second half of this analysis.

Presently, there are approximately 30 new nuclear plants in the development pipeline in the United States.[23] While none are currently proposed for New England, one each is proposed for New York, Pennsylvania and Maryland.[24] Each will be built at an existing site of or close by an operating nuclear power plant and each will be a merchant facility.[25]

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[21] See page 36 of 64 page, National Grid's response to Division's first set of Data Request.
[22] See pages 2-35 and 2-36 of Synapse's Avoided Energy Supply Costs in New England – 2009 Report.
[23] More information of the United States' nuclear renaissance, including a complete listing of all proposed new nuclear facilities, may be found in the August 2009 issue of Nuclear News. www.ans.org.
[24] A joint venture of Constellation Energy and EDF are proposing to build one reactor each for Maryland (Calvert Cliffs 3) and New York (Nine Mile Point 3) while PPL Corporation is proposing one for Pennsylvania (Bell Bend).
[25] A merchant facility is a power plant that is not built in rate-base; any high financing costs, construction overruns or poor operating performance are the responsibility of the owner and not the ratepayer.

Although not cheap to construct, these facilities should have revenue requirements[26] in line with those shown in Exhibit 7 of the direct testimony of Madison Milhous for the period after 2020.

Given that new nuclear power plants are being proposed at the sites of existing nuclear plants, it appears that an additional three plants could be constructed in New England. Assuming that the minimal additional transmission is built and public opposition can be overcome, one nuclear facility each could be constructed at Seabrook[27], Millstone[28] and Pilgrim.[29] One large nuclear plant in New England could meaningfully shift the spot market price of energy downward by driving off-line the highest price fossil-fired resources. Three large nuclear plants in New England will do more, by dramatically lowering the price of spot energy, particularly for prices during the off-peak hours, when facilities with low fuel costs predominate.

The other development not mentioned in the direct testimony of Madison Milhous is a discussion of how the spot market for energy functions versus the longer term energy market works. While the longer term energy market operates off a future natural gas forwards[30] price with appropriate adders[31] times a system-wide heat rate,[32] the spot market operates off a spot market price for natural gas[33] plus all of the aforementioned adjustments. As a result, in New England we have high forward power prices (for example, those prices determined in Narragansett's Basic Service auctions) and at the same time low spot prices for power (for example, the ISO-NE spot energy market).

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[26] See pages 266-271 of California Energy Commission's Renewable Energy – Cost of Generation Update
[27] The Seabrook site was permitted for two 1,250 MW nuclear plants. Only Unit 1 was completed.
[28] The Millstone site was once the site of three operating nuclear plants. Unit 1, a 675 MW unit, has been retired. Its site can be made available for additional nuclear generation.
[29] The Pilgrim site was permitted for only 1 unit.
[30] A natural gas forward price is a futures contract price for natural gas sold or bought on the New York Mercantile Exchange.
[31] An appropriate adder would be the cost of RGGI, SO_2 and NOx allowances.
[32] Heat rate is measure of the efficiency to convert chemical energy into electrical energy. In New England the marginal heat rate is approximately 8,125 BTU/KWh.
[33] A spot price for natural gas price is the price for natural gas bought for consumption in the near-term, such as daily, weekly, balance-of-month or near-month gas. The near-month contract is the most current futures contract sold or bought on the New York Mercantile Exchange.

The problem with the direct testimony of Madison Milhous is that, when Narragansett goes to sell the Project's energy, the energy will be sold into this ISO-NE spot energy market while the basis for the above market costs is based upon these long-term natural gas forward prices. Since spot energy prices over time are consistently less than less than longer term energy prices, the above-market cost calculations of Narragansett are understated.

A commercial banking analogy may help here to explain what Narragansett is proposing to do here. Assume that Narragansett is proposing to borrow long-term from the Project money at a fixed 12% interest rate when the going fixed long-term rate is 6%. Then Narragansett proposes to lend this money out at short-term interest rates, which float over time. Narragansett's analysis says that this money will earn an interest of 6%. However, at any one-time, floating short-term interest rates are generally less than fixed long-term rates and over a time period, such as twenty years, floating, short-term rates have always been less than fixed, long-term rates. Thus, Narragansett will not receive 6% interest on its loans but a figure more like 2%. Narragansett's projected loss is, therefore, not 6% on each dollar borrowed from the Project but 10%, or 67% more than its forecast. What Narragansett is proposing in this example would be to be made whole for all of its losses (10%), not the difference between 12% and 6% interest rates.

As I mentioned earlier, I have marketed and bought power in the wholesale market. Regarding power purchases, beginning in 2004 Ridgewood bought 6 MW of around-the-clock power. Periodically, we compared the prices of spot market to longer-term prices for this load. We observed over time a $15 to $20 per MWh difference in the spot price versus fixed, long-term prices for terms from six months to two years. This pricing discrepancy still persists between the short-term and longer-term power markets. Consequently, it is my opinion that this feature of the spot electricity markets in New England could reduce the energy market revenues earned by Narragansett between $15 and $20 per MWh for the life of the Project's contract.

In summary, I believe that the Project's contract will stabilize rates for Rhode Island ratepayers at prices at a minimum of two to three times greater than they would otherwise be if the Project was not constructed or its contract was not executed. If my predictions of REC prices and energy markets are correct, the above-market cost of the Project would be 25% more than the estimate cited in the direct testimony of Madison Milhous.

Q. How much money in non-discounted and discounted dollars would that above-market cost be?

A. Using Narragansett's assumptions, the above-market cost of the Project for the period 2013-2032 was estimated to be approximately $389 million, the cost of the Project's power was estimated to $696 million, and the market value of the Project's power was estimated to be $308 million. Discounting these cash flows streams with a 7% discount rate, the above-market cost of the Project, the cost of the Project's power and the market value of the Project's power were $184 million, $342 million and $158 million, respectively.

Applying my assumptions on lower REC and energy prices, the above-market cost of the Project, the cost of the Project's power and the market value of the Project's power were $471 million, $696 million and $225 million, respectively. Discounting these cash flows streams with a 7% discount rate, the above-market cost of the Project, the cost of the Project's power and the market value of the Project's power were $229 million, $342 million and $112 million, respectively. Obviously, any material drop in the market value of the REC and energy will greatly increase the cost of the Project to the ratepayers of Rhode Island.

Q. **Why do you believe that the Project will only minimally enhance environmental quality as opposed to other renewable energy technologies?**

A. Wind is an unreliable, intermittent energy source. A power pool such ISO-NE cannot rely on wind generation to be there at critical times. This is particularly true during the afternoon summer hours when peak loads are the highest. Since the production from a wind resource of this size cannot be reliably forecasted, ISO-NE does not require wind

resources to schedule any of their production in the ISO-NE Day-Ahead energy market.[34] Instead, wind resources are permitted to operate exclusively in Real-Time energy market.[35]

The ISO-NE divides its energy markets into Day-Ahead energy market and Real-Time energy market. The Day-Ahead energy market is roughly nine times the size of Real-Time energy market. Since wind resources of this size only operate in the Real-Time energy market, they influence essentially only the dispatch of approximately 10% of the generation in New England. Even then, when wind operates, it will not necessarily be backing down fossil-fired resources but rather generation used to provide regulation for the regional grid such as pumped storage or hydro units with automatic generation control. Both of these types of generation have no air emissions and minimal environmental impact.

Looking at the dispatch of generation resources over a five-minute time period, although the electric grid does respond quickly to changes in the generation of all intermittent units, it does not respond immediately but with a small time delay. Within five minutes or less ISO-NE will re-dispatch the system based upon the current level of load and generation resources in operation. Thus, the grid immediately absorbs the unexpected wind production when excesses are produced but does not change the order of generation dispatch until the next dispatch period. The same thing happens when wind resources quickly reduce their output. For these reasons and the fact that the Project being just 30 MW of peak generation in a power pool of over 30,000 MW of generation, I believe that the Project will have a lower impact on reducing the air emissions from 30 MW of fossil-fired generation.

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[34] Day-Ahead energy market is the market for which all reliable generators are required to participate by ISO-NE. This market requires generators to offer firm levels of production for each hour of the next power day. If the generator cannot perform in the Day-Ahead energy market, the generator is penalized. If the generator can perform in the Day-Ahead energy market, these generators generally earn superior prices to prices of the Real-Time energy market. Given the unreliable nature of wind resources, wind generators do not have to participate in the Day-Ahead energy market.

[35] The Real-Time energy market is a pure spot market. There are no penalties of non-performance and, generally, prices are less than the prices paid for Day-Ahead energy market. Whatever these generators produce is purchased by ISO-NE at the clearing price of the Real-Time energy market.

This conclusion has been observed by others. Jay Apt of Carnegie Mellon University has estimated CO_2 and NOx emissions reductions gas generators operating in conjunction with wind.[36] The salient points of his conclusions are as follows:

> "Carbon dioxide emissions reductions from a wind (or solar PV) plus natural gas system are likely to be 75-80% of those assumed by policy makers. … For the best system we examined, NOx reductions with 20% wind or solar PV penetration are 30-50% of those expected. For the worst, emissions are increased by 2-4 times the expected reductions with a 20% RPS with using wind or solar PV."

A similar conclusion has been reached Peter Lang, a retired engineer formerly with the Canadian Nuclear Fuel Waste Management Program.[37] His conclusions were:

> "Wind power does not avoid significant amounts of greenhouse gas emissions;
> Wind power is a very high cost way to avoid greenhouse gas emissions; and
> Wind power, even with high capacity penetration, can not make a significant contribution to reducing greenhouse gas emissions."

Looking out over a longer operating period, if wind resources were reliable generating resources that could consistently follow a dispatch schedule like a biomass plant or landfill facility, the marginal air emissions analysis of Dave Nickerson would be accurate.[38] Then, wind resources would provide another feature that reliable renewable resources

[36] See "Air Emissions Due To Wind And Solar Power," Warren Katzenstein and Jay Apt. http://pubs.acs.org/doi/pdfplus/10.1021/es801437t.
[37] See "Cost and Quantity of Greenhouse Gas Emissions Avoided By Wind Generation", Peter Lang. http://carbon-sense.com/wp-content/uploads/2009/02/wind-power.pdf
[38] See Dave Nickerson response to Division's Question 2.7.

provide -- permanently back out the need for fossil generation since they can consistently be relied upon to operate. For example, a 30 MW biomass power plant can force the retirement of 30 MW of fossil-fired generation while a 30 MW wind farm will be lucky if it leads to the retirement of any fossil-fired generation. For wind, the truth appears to be that it fails to produce its claimed air emissions reductions for either brief or long-term periods of time.

In summary, the Project will only at best minimally enhance environmental quality as compared against other reliable, renewable energy technologies. Under a worst case scenario, the Project may actually worsen the environmental quality of Rhode Island.

Q. **Why do you believe that the Project will create minimal jobs in Rhode Island in the renewable energy sector?**

A. The Project in and of itself is too small to build a renewable energy industry for off-shore wind for the Mid-Atlantic and New England states. In the direct testimony of Madison Milhous, the Project was called a "demonstration project."[39] These wind turbines should be assembled elsewhere. Only the site mobilization should occur on-shore. Basically, everything else should float in on barges or derricks. From those platforms, work should be performed and, once completed, then leave. During the construction period, there should only be a brief influx of a small number of construction workers and within a season they should be gone.

After the construction is over, the only full-time job that I see being created is that of a caretaker or night watchman. Other than inspecting and securing equipment after an equipment failure, this person would have little to do. The Project should be monitored and operated remotely. Maintenance would be performed by rotating crews, brought in periodically. I seriously doubt that these maintenance workers would be based in the Rhode Island area.

[39] See page 9, line 2 of the direct testimony of Madison Milhous.

My opinion would change if a large wind project was built such as the one that I mentioned that is proposed for the east side the shipping channel to Newport. With a 100 wind turbines or more, there would be sufficient on-going business to site permanently in Rhode Island maintenance crews, equipment (barges, derricks, work boats and helicopters) and maintenance, warehouses and final on-shore assembly shops. However, that project would drive everything for Rhode Island's development of a renewable energy industry while the Project would drive virtually nothing in the form of economic development. What we have here is a small project trying to pass itself off as opening the door for larger things when in fact the Project represents a dead end for economic development and a distraction from what the state should be encouraged, a commercial or utility scale wind farm (300 MW or more), built far to the east of Block Island, just to the east side of the shipping channel to Newport.

In summary, I see a few construction jobs for a brief period of time in Rhode Island and only one semi-skilled permanent job on Block Island arising after the completion of the Project.

Q. **Why do you believe that the Project will not facilitate the financing of other renewable energy generation within Rhode Island but actually crowd out more economical renewable projects in Rhode Island?**

A. The statute[40] that created the ability of Narragansett Electric Company to enter into this contract for the Project has a limit of 90 MW. The Project subtracts 12 MW away from that number. Since the Project is estimated to cost at a minimum two to three times more than other generating resources, it means that other renewable projects (if the ratepayer is not to over pay for this renewable energy) have to accept less. Thus, what could have been an economical renewable project in Rhode Island may not be built so that this uneconomical project may be built. For example, if you assume that there are several renewable projects in Rhode Island, which could provide a combined generating capacity of 90 MW that could be constructed for the avoided costs cited in the direct testimony of Madison Milhous, and there is the Project, something will not be built. If the Project

[40] Long-Term Contracting Standard for Renewable Energy, Title 39, Public Utilities and Carriers, Chapter 39-26.1

moves ahead and is built, then one or more of these economical projects will be replaced by this uneconomical project and could not be constructed since the law permitting long-term contracts is capped at 90 MW. The losers are the ratepayers of Rhode Island and the potential developer of that economical renewable energy project.

In summary, if this contract is approved by the Commission, it appears that Rhode Island will only enjoys the benefits of 78 MW of economical renewable power and not the 90 MW mandated by the statute.

Q. **Will the Project provide any net direct economic benefit to Rhode Island?**

A. The simple answer is no. While the Project does provide some direct economic benefits to Rhode Island, its above-market costs to the ratepayers of Rhode Island far exceed that benefit. Even using the economic benefit cited by Dave Nickerson in his answer 2-4 to the Division's second data request, the lifetime, non-discounted benefit of the Project is only $48 million. Assuming that the National Grid above-market analysis is correct, the above-market cost of the Project is nearly $400 million on a non-discounted basis and $185 million on a discounted basis. The negative benefit on a non-discounted basis would be the $352 million ($400 million less the $48 million). The benefit of the Project is only 1/8th of its costs. Furthermore, if my viewpoint of future above-market cost is correct, the Project's benefit may well be only 1/9th to 1/10th of its costs.

In summary, the Project produces minimal economic benefits and, when compared its above-market costs, negative net benefits to the ratepayers of Rhode Island are produced. As such, along with all of my other comments, it is my opinion that the contract between Narragansett Electric Company and Deepwater Wind Block Island, LLC for the Project should not be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

In accordance with Rule 1.7D of the Rules of Practice and Procedure of the Public Utilities Commission, I hereby certify that on the 19th day of January, 2010, a copy of the within was mailed electronically to the attached service list.

Marianne Deeley

National Grid – Review of Proposed Town of New Shoreham Project
Docket No. 4111 - Service List Updated 1/14/2010

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Renewable Energy Credits	Last Update	Last	Bid	Ask
Connecticut				
1) CT RECs Class 1 2009	1/11/2010	23.25	23.00	25.00
2) CT RECs Class 1 2010	1/11/2010	27.25	26.00	29.00
3) CT RECs Class 1 2011	1/11/2010	30.50	29.00	32.00
4) CT RECs Class 2 2009	1/11/2010	0.62	0.50	0.70
5) CT RECs Class 2 2010	1/11/2010	1.05	0.75	1.25
6) CT RECs Class 3 2009	1/11/2010	13.00	12.00	14.00
7) CT RECs Class 3 2010	1/11/2010	17.00	16.00	18.00
District of Columbia				
8) DC RECs Tier 1 2009	1/11/2010	1.12	1.00	2.00
9) DC RECs Tier 1 2010	1/11/2010	1.38	1.00	1.75
10) DC RECs Tier 1 2011	1/11/2010	1.75	1.25	2.25
11) DC RECs Tier 2 2009	1/11/2010	0.35	0.15	0.50
12) DC RECs Tier 2 2010	1/11/2010	0.32	0.15	0.50
13) DC RECs Tier 2 2011	1/11/2010	0.40	0.15	0.65
14) DC Solar RECs 2009	1/6/2010	250.00	250.00	250.00
Delaware				
1) DE RECs New 2008		5.00	5.00	5.00
2) DE RECs New 2009	1/11/2010	6.50	5.00	8.00
3) DE RECs New 2010	1/11/2010	10.50	9.00	12.00
4) DE RECs Existing 2008	1/11/2010	0.53	0.20	0.85
5) DE RECs Existing 2009	1/11/2010	0.85	0.75	1.25
6) DE RECs Existing 2010	1/11/2010	1.12	1.00	1.25
7) DE Solar RECs 2009	1/11/2010	225.00	210.00	240.00
8) DE Solar RECs 2010		275.00	275.00	320.00
Illinois				
9) IL Wind 2009	1/11/2010	6.50	6.00	7.00
Massachusetts				
10) MA RECs Class I 2009	1/11/2010	26.00	26.00	29.00
11) MA RECs Class I 2010	1/11/2010	31.50	30.00	33.00
12) MA RECs Class II 2009	1/11/2010	10.00	5.00	15.00
13) MA RECs Class II 2010	1/11/2010	15.50	6.00	25.00
14) MA RECs Class II 2011	1/11/2010	16.00	7.00	25.00
Maryland				
15) MD RECs Tier 1 2009	1/11/2010	1.00	0.75	1.25
1) MD RECs Tier 1 2010	1/11/2010	1.50	1.00	1.50
2) MD RECs Tier 1 2011	1/11/2010	1.25	1.00	1.50
3) MD RECs Tier 2 2009	1/11/2010	0.45	0.25	0.65
4) MD RECs Tier 2 2010	1/11/2010	0.25	0.15	0.35
5) MD RECs Tier 2 2011	1/11/2010	0.32	0.15	0.50
6) MD Solar RECs 2009	12/29/2009	362.50	350.00	375.00
Maine				
7) ME RECs New 2009	1/11/2010	27.00	23.00	27.00

8) ME RECs New 2010	1/11/2010	28.50	26.00	31.00
9) ME RECs Existing 2009	1/11/2010	0.17	0.15	0.20
10) ME RECs Existing 2010	1/11/2010	0.25	0.15	0.35
New Hampshire				
11) NH RECs Class 1 2009	1/11/2010	32.50	30.00	35.00
12) NH RECs Class 1 2010	1/11/2010	34.00	32.00	36.00
13) NH RECs Class 2 2009	1/11/2010	100.00	75.00	125.00
14) NH RECs Class 3 2009	1/11/2010	25.50	23.00	28.00
15) NH RECs Class 3 2010	1/11/2010	25.50	23.00	28.00
16) NH RECs Class 4 2009	1/11/2010	26.00	25.00	27.00
1) NH RECs Class 4 2010	1/11/2010	26.00	25.00	27.00
New Jersey				
2) NJ RECs Class 1 2010	1/11/2010	5.00	4.75	5.50
3) NJ RECs Class 1 2011	1/11/2010	11.00	11.25	12.25
4) NJ RECs Class 1 2012	1/11/2010	13.75	13.00	14.50
5) NJ RECs Class 2 2010	1/11/2010	0.82	0.50	1.00
6) NJ RECs Class 2	1/11/2010	1.00	0.75	1.25
7) NJ Solar RECS 2010		662.00	662.00	663.00
8) NJ Solar RECs 2011	1/11/2010	625.00	600.00	650.00
Ohio				
9) OH Solar RECs 2009	1/7/2010			
10) OH Solar RECs 2010		300.00	300.00	400.00
Pennsylvania				
11) PA RECs Tier 1 2009	1/7/2010	2.25	1.00	3.50
12) PA RECs Tier 1 2010	1/11/2010	3.00	2.00	3.00
13) PA RECs Tier 1 2011	1/11/2010	4.75	4.00	5.50
14) PA RECs Tier 2 2009		0.25	0.25	
15) PA RECs Tier 2 2010	1/11/2010	0.23	0.05	0.45
1) PA RECs Tier 2 2011	1/11/2010	0.30	0.10	0.50
2) PA Solar RECs 2009	1/11/2010	310.00	295.00	325.00
3) PA Solar RECs 2010		275.00	275.00	320.00
Rhode Island				
4) RI RECs New 2009	1/11/2010	31.50	30.00	33.00
5) RI RECs New 2010	1/11/2010	34.00	32.00	36.00
6) RI RECs Existing 2010	1/11/2010	1.12	1.00	1.25
Texas				
7) ERCOT RECs 2008	12/29/2009	1.02	0.90	1.15
8) ERCOT RECs 2009	1/11/2010	1.10	1.00	1.20
Western Electricity Coordinating Council				
9) WECC Wind Green-E Cert. Back Half 2008	1/11/2010	5.00	4.50	5.50
10) WECC Wind Green-E Cert. Front Half 2009	1/11/2010	5.50	5.00	6.00
11) WECC Wind Green-E Cert. Back Half 2009	1/11/2010	6.50	5.50	7.50
National				
12) National Wind Green-E Cert. Back Half 2008	1/11/2010	0.88	0.80	0.95
13) National Wind Green-E Cert. Front Half 2009	1/11/2010	0.88	0.80	0.95
14) National Wind Green-E Cert. Back Half 2009	1/11/2010	1.12	1.00	1.25
1) National Wind Green-E Cert. Front Half 2010	1/11/2010	1.30	1.10	1.50

2) National Green-E Any Tech. Back Half 2008	1/11/2010	0.88	0.80	0.95
3) National Green-E Any Tech. Front Half 2009	1/11/2010	0.88	0.80	0.95
4) National Green-E Any Tech. Back Half 2009	1/11/2010	1.12	1.00	1.25
5) National Green-E Any Tech. Front Half 2010	1/11/2010	1.30	1.10	1.50

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Air Emissions Due To Wind And Solar Power

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Renewables portfolio standards (RPS) encourage large-scale deployment of wind and solar electric power. Their power output varies rapidly, even when several sites are added together. In many locations, natural gas generators are the lowest cost resource available to compensate for this variability, and must ramp up and down quickly to keep the grid stable, affecting their emissions of NO_x and CO_2. We model a wind or solar photovoltaic plus gas system using measured 1-min time-resolved emissions and heat rate data from two types of natural gas generators, and power data from four wind plants and one solar plant. Over a wide range of renewable penetration, we find CO_2 emissions achieve ~80% of the emissions reductions expected if the power fluctuations caused no additional emissions. Using steam injection, gas generators achieve only 30−50% of expected NO_x emissions reductions, and with dry control NO_x emissions increase substantially. We quantify the interaction between state RPSs and NO_x constraints, finding that states with substantial RPSs could see significant upward pressure on NO_x permit prices, if the gas turbines we modeled are representative of the plants used to mitigate wind and solar power variability.

Introduction

Renewable electricity generated by sources whose output varies rapidly—wind and solar photovoltaic—provided 0.79% of the United States' 2007 net electricity generation (*1*), but these sources are growing. Renewables portfolio standards (RPSs) enacted by 25 states, along with federal subsidies, have encouraged renewable energy sources (*2*−*4*). California requires that 20% of its electric power be generated from renewables by 2010, New Jersey requires 12% by 2012, and Texas requires ~3% by 2015 (*5*−*7*).

When these sources provide a significant fraction of electricity, other generators or rapid demand response must compensate when their output drops (*8, 9*). Renewable energy emissions studies (*10*−*12*) have not accounted for the change in emissions from power sources that must be paired with variable renewable generators such as wind and solar. In many locations, natural gas turbines will be used to compensate for variable renewables. When turbines are quickly ramped up and down, their fuel use (and thus CO_2 emissions) may be larger than when they are operated at a steady power level. Systems that mitigate other emissions such as NO_x may not operate optimally when the turbines' power level is rapidly changed.

Renewables that substitute for fossil generators avoid emissions (emissions displacement). Life cycle assessments (LCAs) estimate the emissions attributed to producing, constructing, operating, maintaining, and decommissioning a given technology (*13*). Although integration studies have discussed increased reserve requirements for variable renewable sources, Weisser notes the resulting ancillary emissions are not typically included in LCAs (*13*).

Two methods used to identify the displaced generators are economic dispatch analysis and generation portfolio analysis (*11*). Economic dispatch analysis assumes the displaced generators are those with the highest marginal costs of operation (transmission constraints are considered in a few studies). Typically these generators are natural gas and oil fired turbines, although coal plants are on the margin at times (*14*). In portfolio analysis the emissions displaced are the differences in a system's generation portfolio before and after variable renewable power is added. That approach assumes a renewable plant displaces generation equally from all assets, not solely from the generators operating on the margin (*10*).

LCAs and emissions displacement studies use emissions factors (kg of pollutant per MWh) to calculate produced or displaced emissions. When fossil-fuel generators are used to compensate for renewables' variability, their emissions are likely to be underestimated by emissions factors calculated for full-power steady-state operations.

Denny and O'Malley (*15*) modeled emissions reductions from wind power penetration using an economic dispatch model for Ireland and an emissions factor that varies with turbine power for a natural gas combined-cycle turbine (NGCC) and a simple-cycle natural gas combustion turbine (CT), concluding that CO_2 would be reduced 9% for a wind penetration factor of 11% (82% of the expected reduction for that penetration of wind) and NO_x emission reductions would be 90% of the expected reductions. Their model uses hourly data sets that are not able to capture a portion of the rapid fluctuations of wind (*8*) and does not depend on ramp rate; they did not examine the effects of different NO_x mitigation methods.

Model

To estimate emissions from fossil fuel generators used to compensate for variable wind and solar power, we model the combination of variable renewable power with a fast-ramping natural gas turbine to provide baseload power. We use a regression analysis of measured emissions and heat rate data taken at 1-min resolution from two types of gas turbines to model emissions and heat rate as a function of power and ramp rate (Supporting Information). The required gas turbine power and ramp rate to fill in the variations in 1-min data from four wind farms and one large solar photovoltaic (PV) plant are determined, then the emissions are computed from the regression model. The system emissions are compared to the emissions of a natural gas plant of the same size, and to the emissions reductions expected from displacement analysis.

Data

We obtained 1-min resolution emissions data for seven General Electric LM6000 natural gas combustion turbines and two Siemens-Westinghouse 501FD natural gas combined-cycle turbines. The LM6000 CTs have a nameplate power limit of 45 MW and utilize steam injection to mitigate NO_x emissions. A total of 145 days of LM6000 emissions data was

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used in the regression analysis. The Siemens-Westinghouse 501FD NGCC turbines have a nameplate power limit of 200 MW with GE's Dry Low NO_x system (lean premixed burn) and an ammonia selective catalytic reduction system for NO_x control. Emissions data for 11 days were obtained for the 501FD NGCC.

The renewables data includes 1-s, 10-s, and 1-min resolution and are from four wind farms and one large solar photovoltaic facility located in the following regions in the United States: Eastern Mid-Atlantic, Southern Great Plains, Central Great Plains, Northern Great Plains, and Southwest (Supporting Information Table S6).

Approach

The objective of the model plants is to maintain a constant power output by minimizing the error ε between the expected output and the realized output of the model plant at time i (eq 1). The gas turbine model is subject to physical operating constraints: the upper and lower power limits (eq 6) and how quickly the turbine can change its power output (eq 7). As discussed in the Supporting Information, the emission and heat rate data we obtained for the gas turbines did not cover all combinations of power and ramp rate. We therefore further constrain the model to operate only in regions of the power-ramp rate space for which we have data. Here we focus on estimating the additional emissions caused by variability, and caution that we have made no attempt to ensure the stability of an electrical grid. Grid dynamic response may somewhat change our results.

$$Min\ \varepsilon_{P,i} = Min|P_{A,i} - P_{I,i} - \varepsilon_{P,i-1}| \tag{1}$$

where $\varepsilon_{P,i} \equiv$ error in power plant output, $P_{I,i} \equiv$ ideal power plant output

$$\begin{aligned} P_{A,i} &\equiv P_{W,i} + n \cdot P_{GT,i} \\ &\equiv \text{wind power} + \text{natural gas power} \\ &\equiv \text{actual power generated} \\ i &\equiv \text{time index} \\ n &\equiv \text{number of gas turbines} \end{aligned} \tag{2}$$

$$\dot{P}_{GT} \equiv \frac{dP_{GT}}{dt} \equiv \text{ramp rate of gas turbine} \tag{3}$$

Subject to:

$$P_A = \text{constant} \tag{4}$$

$$\text{Max}(P_W) = \text{Max}(n \cdot P_{GT}) \tag{5}$$

$$P_{\text{Min}} < P_{GT} \leq P_{\text{Max}} \tag{6}$$

$$\dot{P}_{\text{Min}} \leq \dot{P}_{GT} \leq \dot{P}_{\text{Max}} \tag{7}$$

We average the wind data to 1-min resolution to match the time resolution of the natural gas generator emissions data and scale each wind or PV data set's maximum observed power generated during the data set to the nameplate capacity of the paired natural gas turbine. From each renewable data set we calculate the required power levels and ramp rates of the natural gas turbine needed to keep the output of the baseload power plant constant. The operating and data constraints of the natural gas turbine are applied, causing the model gas generator's output power to differ slightly from this ideal power profile, as it would in practice.

The power level and ramp rate of the turbine are used as inputs for an emissions model based on a multiple regression analysis of the measured emissions of two types of natural gas turbines. We model only NO_x and CO_2 emissions from the turbine. Power plant CO emissions account for less than 1% of CO emissions in the United States and are not considered in our analysis (*16*).

We calculate CO_2 emissions from the measured heat rate of the generator and the type of fuel used. Assuming complete combustion, the CO_2 emission rate can be derived from the heat rate by multiplying by EIA's natural gas conversion factor of 0.053 t of CO_2 per MMBTU (*17*). Although operating a turbine at low or medium power loads generally results in incomplete combustion, assuming complete combustion is a reasonable approximation for calculating CO_2 emissions, since most CO and hydrocarbon radicals are oxidized to CO_2 in the atmosphere (*18*). Using 1-min resolution emissions data obtained from an electric generation company for two types of gas turbines, we modeled CO_2 emission rates as a function of power level and ramp rate. We use the emissions models to calculate the mass emitted during a given time interval and sum over all time intervals to obtain the mass emitted during a simulation:

$$M = \sum_{t=1}^{T} \frac{dM_t}{dt} \Delta t \tag{8}$$

where:

$$\begin{aligned} M &= \text{total mass of pollutant emitted} \\ \frac{dMt}{dt} &= f(P_{GT,t}, P_{GT,t}) = \text{mass emission rate of gas turbine} \\ &\quad \text{for time period } t \\ \Delta t &= \text{time interval of data set} \\ T &= \text{time length of data set} \end{aligned} \tag{9}$$

Results

If a given level of penetration α of wind or solar energy causes no additional emissions from gas generators, we can define the mass of expected emissions (φ) in terms of the mass of emissions from the gas units (M_{GT}) as

$$\varphi = M_{GT} * (1 - \alpha) \tag{10}$$

The expected emissions reductions are $M_{GT} * \alpha$. That is, emissions are expected to be displaced linearly according to the penetration factor of the renewables, an assumption we refer to as equivalent displacement. Dividing eq 10 by the energy produced, we define the emissions expected predicted by an equivalent displacement model:

$$\varphi_F = \varphi / \sum_{\text{time}} P \tag{11}$$

If the actual system mass emissions are M_A then the fraction of expected emissions reductions (η) that are achieved is

$$\eta = (M_{GT} - M_A)/(M_{GT} - \varphi) \tag{12}$$

We define the difference between the expected emissions and the actual emissions of a system as

$$M_V = M_A - \varphi \tag{13}$$

Consider a system with generators that emit 2 tons of CO_2 per MWh without renewables in the system. Suppose with 10% variable renewables in the system, system emissions are 1.8 tons per MWh. Then η would be $(2 - 1.8)/0.2 = 100\%$ and M_V would be 0. On the other hand, if the emissions were 1.9 tons per MWh with 10% renewables, η would be 50% and M_V would be 0.1 tons per MWh. This framing allows an assessment of the degree to which the introduction of variable renewables displaces emissions from fossil generators, and of the equivalent displacement assumption.

Table 1 summarizes results for the five variable power data sets when used in their entirety (without nights for the solar data). A system with renewables that uses LM6000 turbines for fill-in power achieves 76−79% of the expected

TABLE 1. Baseload Power Plant Model Results for 5 Variable Renewable Power Plant Data Sets (Note That with Night Periods Removed, the Day-Only Capacity Factor for the Solar PV Plant Was 45%; the 95% Prediction Intervals Are Shown for a Least Squares Multiple Regression Analysis) (*19*)

	energy produced			NO_x		CO_2	
	renewable (MWh)	natural gas (MWh)	baseload total (MWh)	percent of expected emissions reduction (η)	variability emissions (M_V, in kg)	percent of expected emissions reduction (η)	varibility emissions (M_V, in tonnes)
LM6000							
Eastern Wind	1,300	9,600	11,000	45% ± 4	270	79% ± 1	160
Northern Great Plains Wind	660	450	1,100	20% ± 3	350	76% ± 1	88
Central Great Plains Wind	3,400	2,800	6,200	33% ± 4	820	76% ± 1	440
Southern Great Plains Wind	7,700	9,000	17,000	22% ± 3	2,300	77% ± 1	1,000
Southwest PV (days)	170,000	210,000	380,000	23% ± 3	36,000	78% ± 1	15,000
501FD							
Eastern Wind	6,000	42,000	48,000	−220 (+300, −120)	1,000	76% ± 1	770
Northern Great Plains Wind	2,900	2,000	4,900	−620% ± 100	1,100	76% ± 1	400
Central Great Plains Wind	15,000	13,000	28,000	−500% (+150, − 10)	4,500	76% ± 1	1,900
Southern Great Plains Wind	34,000	38,000	72,000	−600% ± 100	13,000	76% ± 1	4,800
Southwest PV (days)	730,000	930,000	1,700,000	−640% ± 100	230,000	77% ± 1	70,000

CO_2 emissions reductions and 20−45% of the expected NO_x emissions reductions. An emissions displacement analysis would have overestimated emissions reductions by ∼23% for CO_2 emissions and by 55−80% for NO_x emissions. Similar penalties of 24% are incurred for 501FD CO_2 emissions reductions, but NO_x emissions increase by factors of 2−6 times the amount emissions were expected to be reduced, because of the unoptimized NO_x performance of the 501FD system below 50% power.

To investigate the dependence of system emissions on the penetration of renewable energy, we select time periods in our long data sets that have different capacity factors. For wind power data, a sliding window of 1,000 min was used. We note the high correlation between the nth data subset and the n+1 data subset, which differ by only 2 data points, but this method allows us to explore a wide range of penetration of renewable power. For solar data, each day was treated as a data subset (night periods are removed from the data). The solar data was 732 days in length, yielding 732 different capacity factor results. We combined the results from each analysis and in penetration factor intervals of 1% plot the mean and area encompassed by two standard deviations in Figure 1a−d.

Our model predicts that CO_2 emission factors decrease linearly with renewable penetration at a slope of −0.5 (compared to the expected −0.65, the negative of the

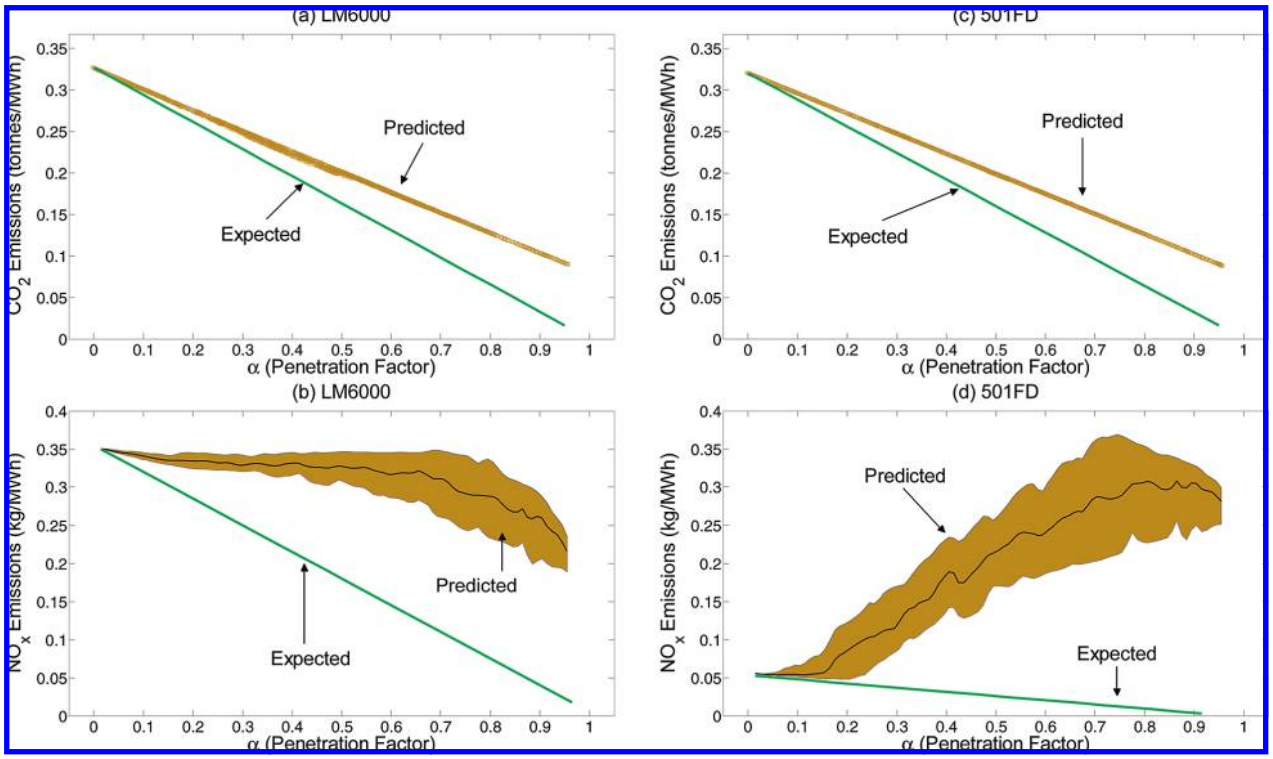

FIGURE 1. Mean renewable plus natural gas emission factors vs renewable energy penetration levels (α) (solid black line); area shown represents 2 standard deviations of all five data sets (shaded brown area); see Figure 2 for representative single data set variability. The expected emissions factor (green, lower line in each figure) is shown for comparison. (a) LM6000 CO_2. (b) LM6000 NO_x. (c) 501FD CO_2. (d) 501FD NO_x.

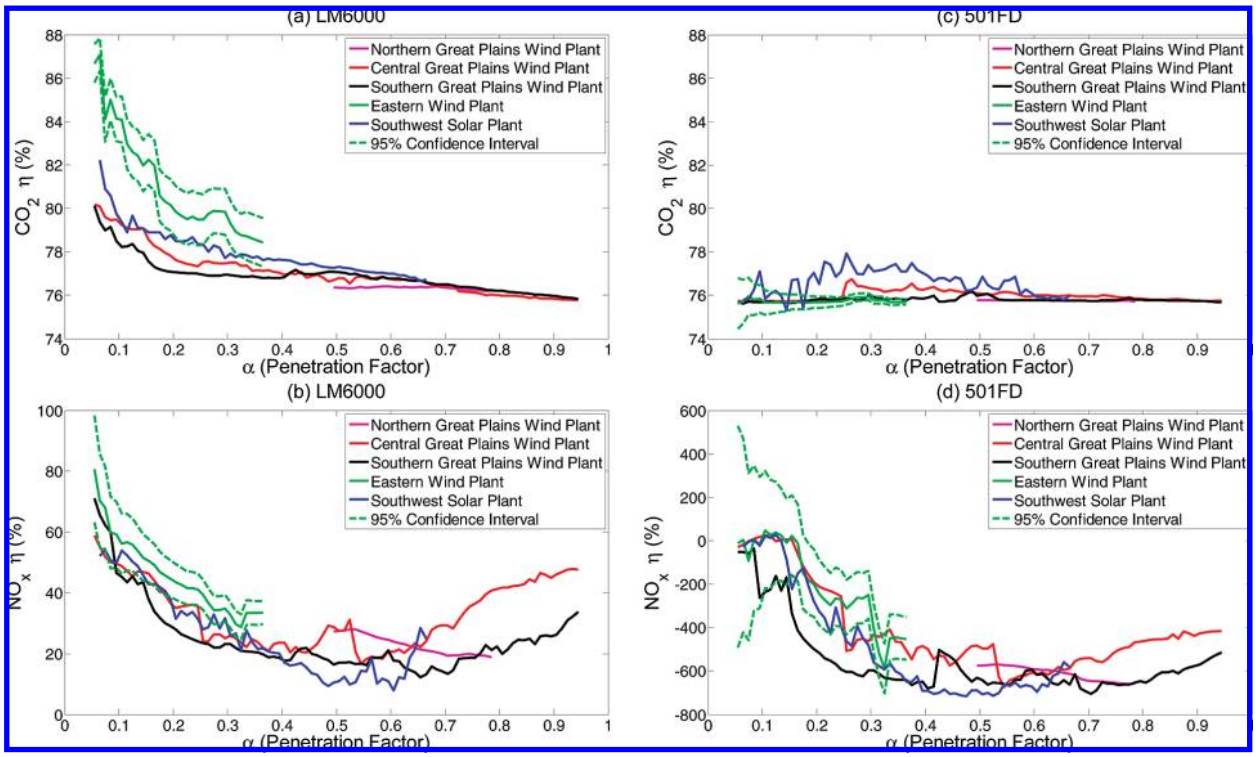

FIGURE 2. Renewable plus gas generator system mean expected emission reductions (η) vs variable energy penetration factors (α). 95% prediction intervals (dashed lines) are shown only for the Eastern Wind plant. (a) LM6000 CO_2. (b) LM6000 NO_x. (c) 501FD CO_2. (d) 501FD NO_x.

emissions factor, eq 11) for LM6000s and −0.48 compared to −0.64 (expected) for 501FDs (Figure 1a and c). At penetration levels of 1, predicted emissions are not eliminated because the natural-gas turbine is modeled as a spinning reserve.

Below 65% renewable penetration, the LM6000 NO_x emission factor is roughly constant. Thus, adding renewables is not effective in reducing NO_x for such a system (Figure 1b).

A threshold effect is observed for the 501FD turbine: for penetration values below ~15%, the predicted NO_x emission factor nearly matches the expected emission factor (Figure 1d). Since the dry low NO_x control system is optimized for constant high power operations, it is not surprising that this turbine design exhibits high NO_x emissions as the penetration of wind or solar energy increases to the point that the turbine must cycle to low power. Limiting the 501FD's P_{min} limit to >50% nameplate capacity avoids the poor NO_x regions of the DLN system (discussed in the Supporting Information), and results in NO_x emissions reductions. This approach is applicable only if the ratio of energy provided by natural gas generators with DLN to variable power plants is greater than 2:1.

Viewed in terms of η, as the penetration of variable power increases the fraction of expected emissions reductions achieved from a system with LM6000 turbines decreases from ~87% to 78% for the Eastern wind data and from 80% to 76% for the Southern and Central Great Plains wind data sets (Figure 2a). Increasing the penetration factor of variable power effectively reduces the natural gas turbine from steady-state full power conditions to transient-state cycled power conditions and results in higher NO_x emissions. NO_x reductions from a system using LM6000 turbines are roughly half the expected value at 10% penetration, reaching a minimum of 10−30% at a penetration of ~50% (Figure 2b).

Emissions of CO_2 from a system with 501FD turbines are ~76% of that expected with no significant dependence on penetration (Figure 2c). The large inertia of the 501FD combined-cycle plant results in a heat rate that depends only on power (Supporting Information Figure S6), and the deviations from a constant fraction of achieved expected emissions are caused by the constraints we impose on operating the turbine to stay within the limits of the data. As more variable renewable power is added, the NO_x emission factor (Figure 2d) increases because the 501FD is forced to spend a higher percentage of its time operating in high NO_x emissions regions (as discussed previously).

Interactions between RPSs and CAIR

We examine the implications of our results by analyzing the potential interaction between state RPSs and the Clean Air Interstate Rule (CAIR). The District of Columbia Circuit Court of Appeals vacated CAIR in July 2008 (*20*), but here we examine the interactions between an RPS and CAIR, under the assumption that a similar NO_x emission rule will come into force in the future. CAIR was designed to reduce annual NO_x emissions 60% by 2015 (*21*). States with large RPSs may experience NO_x emissions from gas turbines used to fill in the variable renewable power that can make it more difficult to meet CAIR requirements. We estimate what percentage these ancillary emissions could consume of a state's CAIR annual NO_x emissions allocation in 2020 (*22*) (most RPSs are fully phased in by 2020; here we assume that the 2020 NO_x limits are the same as those in 2015).

We assume all RPSs in CAIR states are fulfilled and that all RPS targets that can be met by wind are. We convert RPSs that are specified by a percentage to MWh of wind generation in 2020 by using the EIA assumption that load will grow linearly to 3% above 2008 load (*23*). We also assume all displaced and fill-in generators are similar to either LM6000s or 501FDs. We estimate the expected emission reductions ($M_{GT} - \varphi$) by using NO_x emission factors of 0.2 kg/MWh for LM6000s and 0.15 kg/MWh for 501FDs obtained from EPA's AP-42 database (*24*). For each state, we average the estimated η for the four wind farm data subsets and use eq 12 to estimate

TABLE 2. Summary Results of CAIR Analysis for the 12 CAIR States with a Renewables Portfolio Standard (The Wind Penetration Fraction Is the Larger of the Fraction of the State's 2020 RPS Requirement That Could Be Fulfilled by Wind, or Currently Installed Wind. The CAIR Allowance is the 2015 Allowance. Note: Fractions May Not Match Exactly Due to Rounding)

			LM6000 with steam injection		501FD with DLN	
state	wind penetration fraction (α)	state's annual CAIR NO_x allowance (thousand tonnes)	M_V annual (tonnes)	% M_V of state's CAIR allowance	M_V annual (tonnes)	% M_V of state's CAIR allowance
Delaware	0.18	8.6	48	0.56	140	1.6
Illinois	0.18	60	1200	2.0	3400	5.8
Iowa	0.07	43	29	0.07	59	0.13
Maryland	0.075	11	40	0.37	260	2.4
Minnesota	0.25	34	730	2.2	2000	6.0
Missouri	0.11	60	250	0.42	220	0.37
New Jersey	0.16	12	350	3.0	910	7.7
New York	0.077	19	120	0.64	820	4.2
North Carolina	0.11	44	320	0.72	290	0.65
Pennsylvania	0.07	65	180	0.27	1000	1.6
Texas	0.033	150	590	0.04	120	0.08
Wisconsin	0.1	31	140	0.45	120	0.40

M_A. Finally, we use eq 13 to derive the mass of NO_x emissions attributed to variability that are not currently included in most emissions displacement studies.

Table 2 summarizes the CAIR analysis. When LM6000 turbines are used, the potential emissions associated with variability are significant for Illinois, Minnesota, and New Jersey: countering wind's variability could consume 2−3% of each state's annual CAIR allocations. If 501FDs are used, 7 of the 12 states could have 2−8% of their annual CAIR allocations used to provide fill-in power for wind or PV power plants.

In states like New Jersey, careful selection of the NO_x controls used for wind compensation may be warranted to avoid upward pressure on NO_x permit prices, similar to when the NO_x budget was first implemented (*25*). Using the emissions from Table 2 and assuming an annual NO_x emission permit price of $2,800 per ton, the costs associated with degraded emissions performance can be as high as 0.24 cents per kWh of renewable energy for NO_x emissions. With a carbon price of $50 per ton carbon dioxide, the added costs can be as high as 0.50 cents/kWh for CO_2 emissions. These costs do not include the additional maintenance costs that may arise from cycling the gas turbines to compensate for the renewables' variability.

As part of their NO_x control strategy, states may choose to award NO_x allowances to eligible renewable energy and energy efficiency projects. These awards range from a few percent of the NO_x allowances to as much as 15%. New Jersey's set-aside is 5%, and Minnesota has proposed a 15% renewable set-aside (*26*). Our results caution that annual average emissions factors may not be appropriate for the summer ozone control months, since the character of the variability of both wind and solar PV is dependent on the season.We note that the awards are based on the equivalent displacement assumption, and states that use gas generators to compensate for wind or solar PV variability may find that assumption is not warranted.

The calculations above assume that variability in renewable generation results in similar variability in the natural gas generators used to compensate. There are several reasons this may not be correct, including use of coal and oil generators for compensation and interaction between renewable variability and load variability (*8*), so the estimates in Table 2 are likely to provide an upper bound on estimates of the emissions increase associated with wind and solar generation's variability. Storage systems other than pumped hydroelectric are presently not cost-effective (*27*), but may reduce the need for ramping generators should their costs fall.

Discussion

Carbon dioxide emissions reductions from a wind (or solar PV) plus natural gas system are likely to be 75−80% of those presently assumed by policy makers. Nitrous oxide reduction from such a system depends strongly on the type of NO_x control and how it is dispatched. For the best system we examined, NO_x reductions with 20% wind or solar PV penetration are 30−50% of those expected. For the worst, emissions are increased by 2−4 times the expected reductions with a 20% RPS using wind or solar PV.

The fraction of expected emissions reduction, η, is calculated assuming that the emissions predicted to be displaced originate from the same generator type that provides fill-in power: Figure 2a and b assume a LM6000 is displaced and a LM6000 is providing compensating power; Figure 2c and d assume 501FDs. Realistically, displaced generators will differ from the generators providing fill-in power and would produce different results. We have shown that the conventional method used to calculate displaced emissions is inaccurate, particularly for NO_x emissions. A region-specific analysis can be performed with knowledge of displaced generators, dispatched compensating generators, and the transient emissions performance of the dispatched compensating generators. The results shown here indicate that at large scale variable renewable generators may require that careful attention be paid to the emissions of compensating generators to minimize additional pollution.

If system operators recognize the potential for ancillary emissions from gas generators used to fill in variable renewable power, they can take steps to produce a greater displacement of emissions. By limiting generators with GE's DLN system to power levels of 50% or greater, ancillary emissions can be minimized. Operation of DLN controls with existing (but rarely used) firing modes that reduce emissions when ramping may be practical. On a time scale compatible with RPS implementation, design and market introduction of generators that are more appropriate from an emissions viewpoint to pair with variable renewable power plants may be feasible.

Acknowledgments

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son, Elisabeth Gilmore, Mitchell Small, Scott Matthews, and Adam Newcomer for helpful discussions, Tom Hansen of Tucson Electric Power for supplying the solar PV data, and the companies that supplied the wind and gas generator data, who wish to remain anonymous. Three anonymous referees made very helpful suggestions that have improved the paper.

Supporting Information Available

Additional data and information. This material is available free of charge via the Internet at http://pubs.acs.org.

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ES801437T

POWER PURCHASE AGREEMENT

between

DELMARVA POWER & LIGHT COMPANY

("Buyer")

and

BLUEWATER WIND DELAWARE LLC

("Seller")

June 23, 2008

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APPENDICES

SCHEDULES

POWER PURCHASE AGREEMENT

This Power Purchase Agreement ("Agreement") is made between Delmarva Power & Light Company, a Delaware corporation ("Buyer") and Bluewater Wind Delaware LLC, a Delaware limited liability company ("Seller") as of June 23, 2008. Seller and Buyer are referred to individually as a "Party" or collectively as "Parties".

W I T N E S S E T H

WHEREAS, pursuant to the State of Delaware's Electric Utility Retail Customer Supply Act of 2006, and at the direction of the Delaware Public Service Commission (the "Commission"), the Director of the Office of Management and Budget, the Controller General and the Energy Office of the State of Delaware (collectively with the Commission, the "Agencies"), Buyer has solicited proposals for the construction of new electric generating resources within the State of Delaware to result in Buyer entering into a power purchase agreement to buy electric power (capacity, energy and ancillary services) to supply a portion of Buyer's customer requirements.

WHEREAS, Seller submitted a proposal to Buyer for the sale of capacity, Energy and Environmental Attributes from the Project, a wind-powered electric generating facility to be located on the outer continental shelf in the Atlantic Ocean off the coast of the State of Delaware east of Rehoboth Beach, Delaware, as further described and defined in Section 1.1.

WHEREAS, at the direction of the Agencies, Buyer and Seller have negotiated the terms and conditions pursuant to which, subject to regulatory approvals and the satisfaction of other conditions precedent, Seller will sell to Buyer and Buyer will buy from Seller a portion of the Contract Capacity, Energy, and Environmental Attributes from the Project on the terms and conditions set forth herein.

WHEREAS, the Products to be supplied by Seller under this Agreement will be purchased by Buyer for consumption by all of Buyer's Delaware customers and the costs incurred as result of the Agreement will be recovered through a non-bypassable surcharge charged to all of Buyer's Delaware customers.

NOW, THEREFORE, in consideration of the mutual promises and covenants contained herein and in the Ancillary Agreements, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, intending to be legally bound and to bind their respective successors and assigns, the Parties do hereby mutually agree as follows;

ARTICLE I
GOVERNING TERMS

1.1 Definitions. As used in this Agreement, the following terms have the meanings set forth below:

"Affiliate" means, with respect to any Person, (i) each Person that, directly or indirectly, controls or is controlled by or is under common control with such designated Person, (ii) any Person that beneficially owns or holds 10% or more of any class or voting securities of such designated Person or 10% or more of the equity interest in such designated Person, and (iii) any Person of which such designated Person beneficially owns or holds 10% or more of any class of voting securities or in which such designated Person beneficially owns or holds 10% or more of the equity interest. For the purposes of this definition, "control" (including, with correlative meanings, the terms "controlled by" and "under common control with"), as used with respect to any Person, shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities or by contract or otherwise.

"After-Tax Basis" means, with respect to any payment received or deemed to have been received by any Party, the amount of such payment (the "Base Payment") supplemented by a further payment (the "Additional Payment") to such Party so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Taxes (including any federal, state or local income taxes) required to be paid by such Party in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account any current or previous credits or deductions arising from the underlying event giving rise to the Base Payment and the Additional Payment), be equal to the amount required to be received. Such calculations shall be made on the assumption that the recipient is subject to federal income taxation at thirty five percent (35%) for the relevant period or periods, and state and local Taxes at the highest rates applicable to corporations with respect to such Base Payment and Additional Payment, and shall take into account the deductibility (for federal income tax purposes) of state and local income taxes.

"Agencies" has the meaning set forth in the first recital hereto.

"Agreement" has the meaning set forth in the introductory paragraph hereto.

"Ancillary Agreements" means, individually or collectively, the Project Security Agreements, any account control agreement entered into pursuant to Section 5.4, and each of the other agreements entered into by the Parties in connection herewith or therewith.

"Ancillary Services" means all products deemed to be "Ancillary Services" by PJM and FERC (as of the Execution Date or a future date during the Contract Term) associated with the Project or the Contract Capacity being supplied hereunder.

"Annual Inflation Adjustment" or "AIA" has the meaning set forth in Section 4.2(a)(iv).

"Authorized Representative" has the meaning set forth in Section 14.16.

"Available" shall mean (i) with respect to a Unit, that the Unit is able to operate and produce sufficient electricity to deliver Energy to the Delivery Point as required

under the Agreement, and (ii) with respect to the Project, that each of the Units forming a part of the Project is able to operate and produce sufficient electricity to deliver Energy to the Delivery Point as required under the Agreement.

"Availability" shall mean the percentage of time during a given period of time that a Unit or the Project is Available.

"Balancing Amounts" shall have the meaning set forth in Section 3.5(e)(ii).

"Base Capacity Payment Rate" or "BCPR" has the meaning set forth in Section 4.2(a)(i).

"Base Energy Rate" or "BER" has the meaning set forth in Section 4.2(a)(ii).

"Base Renewable Energy Credits Rate" or "BRR" has the meaning set forth in Section 4.2(a)(iii).

"Business Day" means any day except a Saturday, Sunday or a day that PJM declares to be a holiday, as posted on the PJM website. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. EPT.

"Buyer" means Delmarva Power & Light Company, a Delaware corporation.

"Buyer Group" has the meaning set forth in Section 11.1(a).

"Buyer Scheduling Obligation" has the meaning set forth in Section 3.5(d).

"Buyer Unexcused Failure" has the meaning set forth in Section 3.16.

"Buyer's Event of Default" has the meaning set forth in Section 12.1.

"Buyer's Lien" has the meaning set forth in Section 8.3.

"Buyer's Percentage" means, in all cases subject to the Project sizing limitations of Section 2.4, the percentage equal to 200 divided by the then-current Project Capacity (for example, if the Project Capacity is 450 MWs, Buyer's Percentage is equal to 44.44%); *provided, however*, if Project Capacity is reduced pursuant to Section 5.4(c) to a level below 200 MW, Buyer's Percentage shall remain the Buyer's Percentage that existed immediately prior to such reduction.

"C&D Canal" means the canal that connects from the lower Delaware River to the upper Chesapeake Bay and that transects lower New Castle County, DE.

"Capacity" means, as of any time, the aggregate nameplate capacity rating of the Units for which the Commercial Operation Date shall have occurred.

"Capacity Charges" has the meaning set forth in Section 3.5(h).

"Capacity Resource" means a generating unit or resource eligible to sell the capacity product from such generating unit or resource in the PJM RPM Market, as determined in accordance with the PJM Agreements and the PJM Capacity Rules.

"Capacity Value" means, with respect to a Unit, Unit Group, or the Project and any full Capacity Year, the amount of generating capacity, expressed in MWs, that PJM determines the Unit, Unit Group, or Project can reliably contribute during summer peak hours and which can be traded as unforced capacity credits in the PJM RPM Market for the Locational Delivery Area in which the Delivery Point is located, as such Capacity Value shall be determined for each full Capacity Year in accordance with the PJM Agreements and the PJM Capacity Rules, and as such capacity valuation may be revised for wind generators by PJM from time to time.

"Capacity Year" means each "Delivery Year" as defined in the PJM Agreements and PJM Capacity Rules, for a Capacity Resource, which Capacity Year is currently contemplated to run from June 1 in a given year to the following May 31.

"Change of Control" means any transfer, sale, assignment, pledge or other disposition of shares of or interests in Seller having the result (directly or indirectly and either immediately or subject to the happening of any contingency) of changing the entity or entities which possess the power (directly or indirectly and either immediately or subject to the happening of any contingency) to direct or cause the direction of the management or policies of Seller (from the entity or entities possessing such power as to Seller as of the Execution Date), whether such change is voluntary or involuntary on the part of Seller.

"Cleared Capacity Value" means, for any Capacity Year, the aggregate amount, if any, (expressed in MWs) of Capacity Value for the Project for such Capacity Year that (i) Seller shall have offered into the PJM RPM Market in accordance with the PJM Agreements and the PJM Capacity Rules and in accordance with Seller's Capacity Offer Discretion, and (ii) shall have cleared in any of the Base Residual Auction or First, Second or Third Incremental Auctions (as each of such terms are defined in the PJM Capacity Rules) for such Capacity Year.

"Collateral" shall mean the Pre-Services Term Period Security, Development Period Security, the Services Term Security, the Delay Damages Account and any funds held therein, the collateral provided at any time under the Project Security Agreements and any other collateral (including Letters of Credit) to be provided by Seller to Buyer pursuant to the terms hereof (individually or collectively as the context requires).

"Commercial Operation" shall mean, as of a certain date, with respect to a Unit, Unit Group or the Project (as applicable), and in compliance with applicable Permits and the terms and conditions of this Agreement, respectively, that:

(a) such Unit, each Unit in the Unit Group, or each Unit forming a part of the Project (as applicable), as the case may be, (i) is fully commissioned in accordance with the terms of the Turbine Supply Agreement, and Seller and

Turbine Supplier shall have executed and delivered a commissioning certificate (which has been provided to Buyer) evidencing such completion of commissioning, (ii) has passed the Initial Performance Test, (iii) is operating and able to produce and deliver Products pursuant to the terms of this Agreement and in accordance with Good Utility Practice, (iv) the Seller shall be a PJM Member, (v) the Unit, Unit Group, or Project as applicable has been accepted as a Capacity Resource of PJM as of that certain date, (vi) the Capacity Value and Cleared Capacity Value for the Project for the Capacity Year during which such Commercial Operation will have occurred and the next following Capacity Year (subject to such adjustments for such next following Capacity Year as are contemplated by the PJM Capacity Rules) have been notified in writing to Buyer, and Seller shall be able to transfer a Contract Capacity Amount for the next following Capacity Year to Buyer based on the Contract Capacity for such following Capacity Year, provided that this requirement shall not limit in any way Seller's Capacity Offer Discretion, and (vi) all Energy to be delivered to the Buyer at the Delivery Point pursuant this Agreement from such Unit, Unit Group or the Project, as applicable, qualifies as generation from an Eligible Energy Resource under the RPS Act and the Commission RPS Rules;

(b) the Electrical Interconnection Facilities necessary to (i) qualify the Unit, Unit Group, or Project as a Capacity Resource of PJM with the ability to deliver the Capacity Value of such Unit, Unit Group, or the Project as of such certain date, and (ii) permit the delivery of Delivered Energy to the Delivery Point up to the Capacity of such Unit, Unit Group or Project, as the case may be, shall have been fully commissioned in accordance with the EPC Contract and other applicable Project Contracts and all performance testing relating to such Electrical Interconnection Facilities under the EPC Contract and other applicable Project Contracts shall have been successfully completed; and

(c) the applicable computer monitoring system (CMS) for the Project shall have been installed and tested and shall be fully operational in order to permit continuous reporting and monitoring of the performance of such Unit, Unit Group or Project, as the case may be, in accordance with the terms of the Turbine Supply Agreement or other applicable Project Contract.

"Commercial Operation Date" shall mean, in the case of a Unit, a Unit Commercial Operation Date, a Unit Group, the Unit Group Commercial Operation Date, and, in the case of the Project as a whole, the Project Commercial Operation Date.

"Commission" has the meaning set forth in the first recital hereto.

"Commission RPS Rules" means the Commission's Rules and Procedures to Implement the Renewable Energy Portfolio Standard in effect on the date hereof and as amended and supplemented from time to time (or any successor publication in effect from time to time implementing the Delaware Renewable Energy Portfolio Standards Act, 26 Del. C., § 351-363).

"Construction Period" shall mean the period of time commencing on the issuance of the EPC Notice to Proceed and ending forty two (42) months thereafter, as such period may be extended, on a day for day basis, by (i) Force Majeure Events or (ii) litigation by third parties (resulting in an injunction materially adversely affecting the construction or operation of the Project other than for reasons of Seller fault), occurring after or continuing beyond the EPC Notice to Proceed.

"Contract Capacity" means, for each Capacity Year, the aggregate amount of MWs equal to the Cleared Capacity Value for such Capacity Year; provided that (a) during the sixth and seventh Capacity Years to commence after the beginning of the Services Term, the Contract Capacity shall mean the greater of (1) the Cleared Capacity Value for such Capacity Year and (2) 80% of the Capacity Value for such Capacity Year; and (b) commencing with the eighth Capacity Year to commence after the beginning of the Services Term, the Contract Capacity shall mean the greater of (1) the Cleared Capacity Value for such Capacity Year and (2) 85% of the Capacity Value for such Capacity Year.

"Contract Capacity Amount" means, for each Capacity Year, the amount in U.S. Dollars to be credited to Buyer in the PJM eRPM system equal to (i) the Buyer's Percentage of Contract Capacity for such Capacity Year, multiplied by (ii) the Project Capacity Resource Clearing Price for such Capacity Year.

"Contract Term" has the meaning set forth in Section 2.1.

"Contract Year" means a period of twelve (12) consecutive months; the first Contract Year shall commence on the Initial Delivery Date; and each subsequent Contract Year shall commence on the anniversary of the Initial Delivery Date.

"Costs" means, with respect to a Non-Defaulting Party, brokerage fees, commissions and other similar documented third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace this Agreement; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of this Agreement.

"Credit Rating" means, with respect to any entity, on any date of determination, the respective ratings then assigned to such entity's unsecured, senior long-term debt or deposit obligations (not supported by third party credit enhancement) by a Rating Agency, or if such entity does not have a unsecured, senior long-term debt rating, then the rating assigned to such entity as its "issuer rating" by a Rating Agency.

"Critical Milestones" means each of the Milestones set forth on Schedule 1 hereto that are identified as Critical Milestones in Schedule 1.

"Cure" has the meaning set forth in Section 8.2(a).

"Date Certain" has the meaning set forth in Section 5.4.

"Day-Ahead Schedule" has the meaning set forth in Section 3.5(a).

"Deemed Generated Energy" means, during an applicable period of time, the quantity of Energy, expressed in MWh, that would have been produced by the Project, delivered to the Delivery Point as Delivered Energy and sold to Buyer in accordance with the terms of the Agreement during such period but for Buyer's Unexcused Failure. Deemed Generated Energy shall be determined by taking into account the following:

(1) in the case of Deemed Generated Energy actually delivered to the Delivery Point, the Delivered Energy during such period measured by the Project Meter (and not otherwise subject to a Dispatch Down Period); and

(2) in the case of Deemed Generated Energy not actually delivered to the Delivery Point (and not otherwise subject to a Dispatch Down Period), (a) during such period, the actual fifteen (15) minutes (or more frequent, as reasonably available) wind speeds (interpolated over time intervals, if necessary) measured by the wind monitoring equipment located on each Unit as adjusted as a result of any Site calibration testing available for operation immediately prior to the commencement of the period in question and maintained using Good Utility Practices, or, if such monitoring equipment is unavailable during a relevant interval, then using other available data or interpolated data determined using Good Utility Practices, (b) the guaranteed Power Curve provided by the Turbine Supplier (adjusted by historical data for the Project compiled by Seller, including the results of any Power Curve testing), as applied to the wind speeds referred to in clause (a), and (c) the actual Availability of each Unit and the availability of the Electrical Interconnection Facilities necessary to deliver Energy to the Delivery Point, as such Deemed Generated Energy shall be adjusted for station power adjustments or electrical uses, auxiliary loads and Electrical Losses to the Delivery Point using historical data for the Project.

"Deemed Generated Energy Compensation Amount" has the meaning set forth in Section 3.16.

"Default Interest Rate" means the Interest Rate plus four percent (4%); *provided, however*, the Default Interest Rate shall never exceed the maximum rate permitted by applicable Law.

"Defaulting Party" has the meaning set forth in Section 12.1(a) or (b).

"Delay Damages" has the meaning set forth in Section 5.4.

"Delay Damages Account" has the meaning set forth in Section 5.4(a).

"Delay Damages Account Control Agreement" has the meaning set forth in Section 5.4(a).

"Delivered Energy" means the Buyer's Percentage of the Energy produced from the Project, as measured in MWh by the Project Meter at the Delivery Point in

accordance with PJM rules. In no event shall Delivered Energy exceed 200 MWs in any given hour.

"Delivery Point"

(a) for all Delivered Energy delivered pursuant to this Agreement shall be the Point of Receipt;

(b) for the Contract Capacity Amount for any Capacity Year shall be as set forth in the PJM Agreements and the PJM Capacity Rules;

(c) for Environmental Attributes shall be as set forth in the GATS Operating Rules or other applicable Laws; and

(d) for Ancillary Services (if any), shall be as set forth in the PJM Agreements.

"Delmarva Zone" means the geographic area defined as the Delmarva Zone, as may be modified from time to time, within the PJM Control Area, as set forth in Attachment J to the PJM Tariff.

"DEMEC" means Delaware Municipal Electric Corporation, or any successor organization thereto.

"Development Period Security" has the meaning set forth in Section 8.1(a).

"Direct Claim" means any claim by an Indemnitee on account of an Indemnifiable Loss which does not result from a Third Party Claim.

"Disclosing Party" has the meaning set forth in Section 14.8.

"Disclosure Order" has the meaning set forth in Section 14.8.

"Dispatch Down Period" means the period of time during which (a) there is any curtailment ordered from PJM or any Governmental Authority, including the temporary shutdown of the Project for reasons including but not limited to any Emergency, (b) there is any curtailment ordered by Buyer based on any warning of an anticipated Emergency, or warning of an imminent condition or situation, which jeopardizes Buyer's electric system integrity or the integrity of other systems to which Buyer is connected, as determined by Buyer in Buyer's discretion consistent with Good Utility Practice and not inconsistent with the PJM Agreements or applicable Interconnection Agreements; (c) there is any curtailment ordered by Buyer due to over generation as established in accordance with the PJM Agreements or applicable Interconnection Agreements; (d) there is any curtailment ordered by Buyer in accordance with the PJM Agreements or applicable Interconnection Agreements based upon Buyer's forecast of over generation, including, but not limited to, a request by PJM to manage over generation conditions; (e) there is any curtailment ordered by a Participating Transmission Owner in accordance with the PJM Agreements or applicable Interconnection Agreements; (f) there is

scheduled or unscheduled maintenance on a Participating Transmission Owner's transmission facilities or the Interconnection Facilities that prevents (i) Buyer from receiving or (ii) Seller from delivering Delivered Energy at the Delivery Point or transmission of Energy from the Delivery Point; or (g) Buyer or Seller otherwise curtails, interrupts, or reduces deliveries of Energy pursuant to the terms of the Interconnection Agreements; *provided, however*, none of (a) through (g) shall be caused by any act or failure to act by Buyer that is inconsistent with Buyer's rights and obligations under this Agreement or the Interconnection Agreements.

"Early Termination Date" has the meaning set forth in Section 12.2(a).

"Eastern Prevailing Time" or "EPT" means Eastern Standard Time or Eastern Daylight Savings Time, whichever is in effect on any particular date.

"Economically Unfeasible" means that, as demonstrated by Seller and confirmed by the Independent Evaluator in a written report to Buyer and Seller explaining the rationale for its conclusion, Seller, as a reasonably prudent wind power developer, acting consistent with Good Utility Practice and applying a risk/return calculation typical of the wind electricity generation industry, would not choose to develop an offshore wind power generation facility at the Site under the rules and procedures set forth in the MMS Regulations, taken in combination with the terms of the Agreement.

"Effective Date" is the first date on which the conditions precedent to the full effectiveness of this Agreement have occurred as set forth in Section 5.1.

"Electrical Interconnection Facilities" means the apparatus required to safely and reliably interconnect with and deliver Energy from the Units to the Delivery Point and for the Seller to satisfy its obligations pursuant to Section 3.1(a), including the collection system between each Unit and the offshore transmission or switching equipment, transmission from the offshore location of the Project to the onshore Project substation facilities, connection, transformation, switching, metering, communications, control, and safety equipment related thereto, including both those Electrical Interconnection Facilities required pursuant to the terms of the Interconnection Agreements and the facilities described on Appendix 1 hereto under the heading "Electrical Interconnection Facilities"; provided that, by including any offshore electrical facilities in the Electrical Interconnection Facilities for purposes of this Agreement, Seller does not consent to the exercise of jurisdiction over such facilities by PJM or FERC to the extent PJM or FERC does not otherwise have such jurisdiction.

"Electrical Losses" means all applicable losses, including, but not limited to, any transmission or transformation losses between the Units and the Point of Receipt, and any method to account for losses established by PJM and assigned to the Point of Receipt for the Project.

"Emergency" means (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an

electric system or the safety of persons or property; or (ii) a condition that requires implementation of Emergency procedures as defined in the PJM Manuals.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in units of kilowatt-hours or megawatt-hours, net of auxiliary loads and station electrical uses (unless otherwise specified).

"Environmental Attributes" means "Renewable Energy Credits" and "Generation Attributes" of the Project that the Renewable Energy Credits represent (as both terms are defined by the Commission RPS Rules and the RPS Act), and any and all other federal, state or other credits, Regional Greenhouse Gas Initiative credits or certificates, benefits, emissions reductions, offsets, or allowances, howsoever entitled, that are attributable to the Project, the Products or the Project's displacement of fossil-fuel derived or other conventional Energy generation (other than PTCs or other monetary grants or tax credits), including, without limitation, (i) any environmental certificates issued by PJM under the GATS in connection with Energy generated by the Project; (ii) any such Environmental Attributes attributable to the Cleared Capacity Value of the Project; or (iii) any voluntary emission reduction credits obtained from the Project.

"EPC Contract" means the Seller's engineering, procurement and construction contract with the EPC Contractor for the construction of all aspects of the Project other than that portion that is subject to the Turbine Supply Agreement.

"EPC Contractor" means the engineering, procurement and construction contractor responsible for constructing the Project pursuant to the EPC Contract.

"EPC Notice to Proceed" means the notice to proceed issued to the EPC Contractor under the EPC Contract to commence the construction activities relating to the Project.

"Equitable Defenses" means any bankruptcy, insolvency, reorganization and other Laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

"Event of Default" shall mean a Seller's Event of Default and/or a Buyer's Event of Default.

"Excess Products" has the meaning set forth in Section 3.1(c).

"Execution Date" shall mean the date first above written.

"Expected Generation Schedule" has the meaning set forth in Section 3.5(a)(i).

"Federal Funds Interest Rate" means, for any day, the weighted average (rounded upwards, if necessary, to the next 1/100 of 1%) of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers, as published on the next succeeding Business Day by the Federal Reserve Bank of New York, or, if such rate is not so published for such next succeeding Business Day,

the average (rounded upwards, if necessary, to the next 1/100 of 1%) of the quotations for such day.

"FERC" means the Federal Energy Regulatory Commission, or any successor organization.

"FIN 46" has the meaning set forth in Section 5.1(a).

"FIN 46 Determination" has the meaning set forth in Section 12.4.

"Financial Closing" means the binding closing of the debt or other third party financing necessary to construct the entire Project.

"Financing Closing Deadline" has the meaning set forth in Section 5.2(e).

"First Party" has the meaning set forth in Section 14.15.

"Fitch" means Fitch Investors Service, Inc. or its successor.

"Force Majeure Event" shall mean any event or circumstance which wholly or partly prevents or delays performance of any obligations arising under this Agreement, but only if and to the extent such event or circumstance is beyond the reasonable control of, and not the result of the fault or negligence of, or caused by, the Party seeking to have its performance obligation excused thereby, which by the exercise of due diligence such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it has been unable to overcome, including but not limited to: (1) acts of God, including but not limited to landslide, lightning, earthquake, storm, hurricane, flood, drought, tornado, or other natural disasters and weather related events; (2) fire or explosions; (3) transportation accidents affecting delivery of equipment only if such accident occurs prior to the Commercial Operation Date of the Project or the Units in question; (4) sabotage, riot, acts of terrorism, war and acts of public enemy; or (5) restraint by court order or other Governmental Authority; provided that such restraint is of a general nature and not specific to the Project, the Agreement or the Buyer Group or Seller Group and does not arise from any action or inaction of the Party claiming the Force Majeure Event that is in contravention of or not consistent with its rights and obligations under this Agreement or is otherwise in violation of Law.

Force Majeure Events shall not include: (i) a failure of performance of any third party, including any party providing electric transmission service, except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure Event as defined above; (ii) economic hardship; (iii) lack of need for, or the availability of more favorable terms for the purchase or sale of, any Product during the Services Term or the Pre-Services Term Period; (iv) failure to timely apply for, obtain or maintain Permits; (v) breakage or malfunction of equipment (except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure Event as defined above); and (vi) a Forced Outage (except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure Event as defined above).

"Forced Outage" means any unplanned reduction or suspension of the electrical output from the Unit, Unit Group, or Project (as applicable) or unavailability of a Product in whole or in part from the Unit, Unit Group, or Project (as applicable) in response to an Emergency or unanticipated mechanical or electrical trip in response to an alarm or equipment malfunction (such events as specified in the PJM Agreements) and any other unavailability of the Project for operation, in whole or in part, for maintenance or repair that is not a Planned Outage or Maintenance Outage and not the result of a Force Majeure Event.

"Forecast Consultant" means an experienced commercial wind energy forecast provider reasonably acceptable to Buyer; provided that, following a designation of a Forecast Consultant, if the forecasts for Energy delivered to the Delivery Point provided by such Forecast Consultant to Buyer pursuant to Section 3.5 shall deviate (for a period to be established by the Operating Committee) by more than twenty five percent (25%), in the case of next-day forecasts, or by more than ten percent (10%), in the case of next-hour forecasts, in each case from the actual Delivered Energy delivered to the Delivery Point, upon the request of Buyer, Seller and Buyer shall agree on a mutually acceptable replacement Forecast Consultant. The Parties agree to periodically consider in good faith the incorporation of alternative performance benchmarks based upon the generally accepted state of the art in forecast performance as it may evolve over time.

"Forecast Period" has the meaning set forth in Section 3.5(a)(i).

"Forecasted Energy Notices" has the meaning set forth in Section 3.5(a).

"GAAP" means generally accepted accounting principles in the United States of America in effect from time to time.

"Gains" means, with respect to a Non-Defaulting Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of this Agreement and commencing from the Early Termination Date for the remaining Pre-Services Period Term and Services Term, determined in a commercially reasonable manner and based on the Projected Delivered Energy for such period of time, subject to Section 12.2 and Section 12.6. Factors used in determining economic benefit may include, without limitation, reference to information either available to it internally or supplied by one or more third parties, including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets, market price references, market prices for a comparable transaction, forward price curves based on economic analysis of the relevant markets, settlement prices for a comparable transaction at liquid trading hubs (e.g., NYMEX), all of which should be calculated for the remaining Pre-Services Term Period and Services Term to determine the value of the Products. The discount rate to be applied for purposes of determining any Gains shall be the same discount rate applied for purposes of determining any Losses.

"GATS" means the Generation Attribute Tracking System developed by PJM-Environmental Information Services, Inc. and operated in accordance with GATS Operating Rules, or any successor system and/or rules.

"GATS Operating Rules" means the operating rules for the GATS that are published by the PJM Environmental Information Services, Inc., from time to time and that are currently posted on the PJM Internet site at *www.pjm-eis.com/documents/downloads/gats-operating-rules.pdf* as of the Execution Date.

"Good Utility Practices" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry (in the case of Buyer) and the wind power industry (in the case of Seller) during the relevant time period, and any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

"Governmental Authority" means any international, federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

"Governmental Charges" means, other than Taxes, any charges or costs that are assessed or levied by any Governmental Authority (other than charges imposed by PJM or any other interconnection or transmission provider) or other Person, including local, state or federal authorities that would affect the sale and purchase of Products contemplated by this Agreement, either directly or indirectly.

"Guaranteed Initial Delivery Date" means December 1, 2014.

"Hazardous Substance" means, collectively, (a) any chemical, material or substance that is listed or regulated under applicable Laws as a "hazardous" or "toxic" substance or waste, or as a "contaminant" or "pollutant" or words of similar import, (b) any petroleum or petroleum products, flammable materials, explosives, radioactive materials, asbestos, urea formaldehyde foam insulation, and transformers or other equipment that contain polychlorinated biphenyls ("PCBs"), and (c) any other chemical or other material or substance, exposure to which is prohibited, limited or regulated by any Laws.

"Hourly Schedule Updates" has the meaning set forth in Section 3.5(a)(iv).

"Indemnifiable Loss" means any and all damages, claims, losses, liabilities, obligations, costs and expenses, including reasonable legal, accounting and other expenses, and the costs and expenses of any and all actions, suits, proceedings, demands (by any Person, including any Governmental Authority), assessments, judgments, settlements and compromises.

"Indemnitee" has the meaning set forth in Section 11.1(c).

"Indemnitor" has the meaning set forth in Section 11.1(c).

"Independent Evaluator" means an independent and neutral Person with a nationally recognized reputation in the analysis of the development and financing of wind energy projects to be nominated by Seller and approved by Buyer in its reasonable discretion within thirty (30) days of Seller's nomination thereof; provided however that the Independent Evaluator shall not be then, currently as of the nomination, engaged by, or on behalf of, or have previously been engaged by or on behalf of, Seller or any Affiliate of Seller unless expressly disclosed to and approved by Buyer, such approval not be unreasonably withheld.

"Indian River Line Assets" means those interconnection facilities that the applicable Participating Transmission Owner (which may be Buyer) will assume ownership of and maintain for a fee paid by Seller. These are generally described as the interconnection facilities between Seller's on-shore substation, as identified in Appendix 1, and the Point of Receipt at the Indian River Substation. These assets shall include an approximately twelve (12) mile 230 or 138 kV transmission line, breakers, switches, metering, and an appropriate transformer, if required consistent with Good Utility Practice, as further illustrated in Appendix 1.

"Indian River Substation" means the substation located next to Indian River Power Plant on the Delmarva Peninsula in Sussex County, Delaware, as recognized by PJM, to be specified in the Interconnection Construction Service Agreement and further specified in Appendix 1.

"Initial Delivery Date" means the date on or after the Effective Date on which all of the conditions precedent set forth in Section 5.3(a) have been satisfied or waived by written agreement of the Parties.

"Initial Performance Test" has the meaning used in Section 3.12.

"Instructed Operation" means (i) an Operational Order, (ii) a mandatory direction of PJM, or (iii) an action required pursuant to the PJM RAA to meet Emergencies and reliability needs including voltage support.

"Interconnection Agreements" means, collectively, as appropriate, (i) the interconnection agreement to be entered into among PJM, Seller and Buyer for the interconnection of the Project to the PJM Grid at the Delivery Point, (ii) the Interconnection Services Agreement, (iii) the Interconnection Construction Services Agreement, and (iv) the Interconnection Studies.

"Interconnection Construction Services Agreement" means an agreement entered into by Seller, the Participating Transmission Owner, and PJM pursuant to Subpart B of Part VI of the PJM Tariff and in the form set forth in Attachment P of the PJM Tariff, relating to construction of Attachment Facilities, Network Upgrades, and Local Upgrades (as each such term is defined in the PJM Tariff) and coordination of the construction and

interconnection of an associated Customer Facility (as defined in the PJM Tariff). The Interconnection Construction Service Agreement between Buyer, Seller, and PJM with respect to the Indian River Line Assets shall include: (1) descriptions and drawings detailing the interconnection facilities and construction responsibilities; (2) the use of Buyer's Indian River to Bethany rights of way (approximately twelve (12) miles) for construction of facilities serving Seller; (3) a schedule of key dates for completion of the Indian River Line Assets; and (4) a payment schedule for construction of the Indian River Line Assets commensurate with expected construction costs.

"Interconnection Services Agreement" means an agreement among PJM, Seller, and the applicable Participating Transmission Owner (which may be Buyer) regarding interconnection under Part IV and Part VI of the PJM Tariff with respect to the Project.

"Interconnection Studies" means, collectively, the Interconnection Feasibility Study, System Impact Study, Facilities Study, and Optional Interconnection Study (as such terms are defined in the PJM Tariff) or other studies regarding interconnection of new generation facilities undertaken by PJM pursuant to the PJM Tariff with respect to the Project for interconnection of new generation facilities.

"Interest Rate" means the Prime Rate plus two percent (2%); *provided, however*, after the occurrence and during the continuation of an Event of Default by a Party, the Interest Rate applicable with respect to payments made by such Party shall be the Default Interest Rate, and provided further, that the Interest Rate shall never exceed the maximum rate permitted by applicable Law.

"kW" means kilowatt(s).

"kWh" means one kilowatt of electric power over a period of one hour.

"Law" means any statute, law, treaty, convention, rule, regulation, ordinance, code, Permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction issued, adopted, administered or implemented by a court or Governmental Authority, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which become effective during the Contract Term; or any binding interpretation of the foregoing.

"Letter(s) of Credit" shall mean a letter of credit in the form of an irrevocable, transferable standby letter of credit from a Qualified Issuer, in form and substance reasonably satisfactory to Buyer.

"Licensed Professional Engineer" means a person mutually acceptable to Buyer and Seller, each in its reasonable discretion, who (i) has training and experience in the power industry specific to the technology of the Project, (ii) has no economic relationship, association, or nexus with Seller or Buyer, other than to meet the obligations of Seller pursuant to this Agreement, (iii) is not a representative of a consultant, engineer, contractor, designer or other individual involved in the development, construction or operation of the Project or of a manufacturer or supplier of any equipment installed at the

Project, and (iv) is licensed in an appropriate engineering discipline for the required certification being made.

"Lien" means any mortgage, pledge, hypothecation, assignment, mandatory deposit arrangement, encumbrance, lien (statutory or other), or preference, priority or other security agreement of any kind or nature whatsoever, including, without limitation, any sale-leaseback arrangement, any conditional sale or other title retention agreement, and any financing lease having substantially the same effect as any of the foregoing.

"Load Serving Entity" or "LSE" means any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving an end-user within the PJM Control Area, and (ii) that has been granted the authority or has an obligation pursuant to state or local Law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

"Locational Marginal Price" means the locational price for Energy at the Delivery Point as determined by PJM in accordance with the PJM Agreements; or equivalent concept by PJM with the same economic effect as Locational Marginal Price as set forth herein.

"Losses" means, with respect to a Non-Defaulting Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of this Agreement and commencing from the Early Termination Date for the remainder of the Pre-Services Term Period and the Services Term, determined in a commercially reasonable manner and based on the Projected Delivered Energy for such period of time, subject to Section 12.2 and Section 12.6. Factors used in determining the loss of economic benefit may include, without limitation, reference to information either available to it internally or supplied by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets, market price references, market prices for a comparable transaction, forward price curves based on economic analysis of the relevant markets, settlement prices for a comparable transaction at liquid trading hubs (e.g. NYMEX), all of which should be calculated for the remaining term of the Agreement to determine the value of the Products. The discount rate to be applied for purposes of determining any Losses shall be the same discount rate applied for purposes of determining any Gains. If the Non-Defaulting Party is the Seller, then "Losses" shall exclude any loss of Production Tax Credits or other federal or state tax credits related to the Project or generation therefrom.

"Maintenance Outage" means a "Generator Maintenance Outage" as defined in the PJM Agreements.

"Maximum Delay Damages" shall have the meaning set forth in Section 5.4.

"Mechanical Availability Percentage" shall mean, for a given period and for all Units and Electrical Interconnection Facilities that are a part of the Project during such

period or any part thereof (the "Relevant Units"), a percentage calculated in accordance with the following formula:

$$\text{Mechanical Availability Percentage} = 100 \times \frac{\text{(the sum of the aggregate Operational Hours during the applicable period for all Relevant Units)}}{\text{(the sum of the aggregate Base Hours during the applicable period for all Relevant Units)}}$$

Where:

"Base Hours" for each Relevant Unit shall mean the number of hours in the applicable period, less the sum of (without duplication):

(1) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy as a result of an Instructed Operation or Dispatch Down Period (but excluding hours (or portions of hours) in which such Dispatch Down Period or Instructed Operation is in effect due to the act or omission of Seller (to the extent inconsistent with Seller's rights and obligations hereunder));

(2) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy solely as a result of Operational Limitations and not because the Relevant Unit is unavailable to deliver Delivered Energy due to a Planned Outage, a Maintenance Outage or a Forced Outage; and

(3) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy solely as a result of a Force Majeure Event and not because the Relevant Unit is unavailable to deliver Delivered Energy due to a Planned Outage, a Maintenance Outage or a Forced Outage;

provided that, for purposes of the calculation of the Mechanical Availability Percentage under Section 12.1(a)(viii), the amount of hours set forth in Item (3) above shall not be subtracted from the definition of Base Hours.

"Operational Hours" for each Relevant Unit shall mean the number of hours (or portions of an hour) in the applicable period, less the sum of (without duplication):

(1) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy as a result of a Dispatch Down Period or an Instructed Operation (including, for the

avoidance of doubt, hours (or portions of hours) in which such Dispatch Down Period or Instructed Operation is in effect due to the act or omission of Seller (to the extent inconsistent with Seller's rights and obligations hereunder));

(2) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy solely as a result of Operational Limitations and not because the Relevant Unit is unavailable to deliver Delivered Energy due to a Planned Outage, a Maintenance Outage or a Forced Outage;

(3) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy as a result of a Planned Outage or Maintenance Outage or a Forced Outage; and

(4) any hours (or portions of an hour) during such period that such Relevant Unit is not operational or is unable to deliver Delivered Energy solely as a result of a Force Majeure Event and not because the Relevant Unit is unavailable to deliver Delivered Energy due to a Planned Outage, a Maintenance Outage or a Forced Outage.

"Milestone" shall mean any or each of the milestones forth in Schedule 1 relating to the construction, development, testing and operation of the Project.

"Minimum Performance Requirement" has the meaning set forth in Section 3.15.

"MMS" means the Minerals Management Service, a bureau of the United States Department of the Interior, or its successor agency.

"MMS Regulations" has the meaning set forth in Section 5.6.

"Monthly Fixed Payment" or "MFP" has the meaning set forth in Section 4.2(b).

"Monthly Payment Date" has the meaning set forth in Section 6.2.

"Monthly Schedule" has the meaning set forth in Section 3.5(a)(ii).

"Moody's" means Moody's Investor Services, Inc., or its successor.

"MPR Base Amount" shall mean the product of the following equation, expressed in MWh: ((Buyer's Percentage of Project Capacity x 8760) x .32).

"MW" means megawatts.

"MWh" means megawatt hour.

"NERC" means the North American Electric Reliability Corporation or a successor organization that is responsible for establishing reliability criteria and protocols.

"Network Upgrades" means the transmission facilities that meet the definitions of Network Upgrades which are identified by PJM as necessary to allow the Project's Capacity to be recognized as a Capacity Resource by PJM as determined and identified in the Interconnection Studies approved in connection with the construction of the Project. Network Upgrades do not include the Indian River Line Assets or the modifications necessary to the Indian River Substation to connect the Indian River Line Assets that are directly assigned to Seller.

"Non-Defaulting Party" has the meaning set forth in Section 12.2.

"Notice" means a written communication which is delivered in the manner required by Section 14.1, as applicable to that communication.

"Notice of Claim" has the meaning set forth in Section 11.1(c).

"Operating Procedures" has the meaning set forth in Section 3.13.

"Operational Limitations" of the Project are the parameters set forth in Appendix 1, describing the operational limitations of the Project.

"Operational Order" means a mandate issued by a Governmental Authority or PJM that the Seller has no discretion to ignore or avoid to offer or provide a Product or to Start-Up, Shut-Down, curtail or operate all or any part of the Project. An Operational Order would include, for example, a mandate issued by the U.S. Secretary of Energy to offer capacity or energy or to operate the Project during an Emergency. In contrast, by way of further example, a legal obligation to test all or any part of the Project for the purpose of maintaining its Permits is not considered an Operational Order.

"Outage" means the partial or full unavailability or inability of each Unit of the Project or any portion of the Project associated with the ability to deliver Products or to operate at 100% of its Capacity due to a Forced Outage, Scheduled Maintenance Outage, or Force Majeure Event, including any derating or inability to produce a Product (other than as disclosed in Appendix 1 as an Operational Limitation).

"Outage/Availability Notification Form" has the meaning set forth in Section 3.10(a).

"Outage/Availability Notification Procedures" has the meaning set forth in Section 3.5(c).

"Outage Due to Wind Conditions" has the meaning set forth in Section 3.10(g).

"Outage Extension" means an extension of a Planned Outage or Maintenance Outage beyond its previously estimated completion date established at the start of the Planned Outage or Maintenance Outage that satisfies the requirement for a Planned Outage extension or Maintenance Outage extension as specified in the PJM Agreements.

"Participating Transmission Owner" means an entity that (i) owns, operates and maintains transmission lines and associated facilities and/or has entitlements to use certain transmission lines and associated facilities, and (ii) has transferred to PJM operational control of such facilities and/or entitlements to be made part of the PJM Grid.

"Party" or "Parties" has the meaning set forth in the first paragraph of the Agreement.

"Permit" means any permit, authorization, license, order, consent, waiver, exception, exemption, variance, or other approval by or from, and any filing, report, certification, declaration, notice or submission to or with any Governmental Authority, including any of the foregoing relating to the ownership, siting, construction, operation, use or maintenance of the Project under any applicable environmental or other Law.

"Permitting Deadline" has the meaning set forth in Section 5.2(c).

"Permitting Milestone" has the meaning set forth in Section 5.2(c).

"Person" means an individual, partnership, joint venture, corporation, limited liability company, trust, association or unincorporated organization, or any Governmental Authority.

"PDE Multiplier" means, as of the date of calculation of Projected Delivered Energy, the ratio of (1) Projected Project Nameplate Capacity; divided by (2) Capacity (expressed in MWs) of the Project as of such date of calculation.

"PJM" means PJM Interconnection, LLC, or any successor organization thereto.

"PJM Agreements" means the PJM Tariff, PJM Operating Agreement, PJM RAA, PJM Manuals and any other applicable PJM bylaws, procedures, rules, manuals or documents, or any successor, superseding or amended versions thereof that may take effect from time to time.

"PJM Capacity Rules" means the rules and procedures for the PJM capacity markets set forth in the PJM Agreements, currently Attachment DD of the PJM Tariff, and as further explained in PJM Manual 18: PJM Capacity Market, as such rules and procedures may be amended from time to time.

"PJM Control Area" means the control area recognized by NERC as the PJM Control Area.

"PJM Grid" means the system of transmission lines and associated facilities of the Participating Transmission Owners that have been placed under PJM's operational control.

"PJM Manual" or "PJM Manuals" means the instructions, rules, procedures and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM Control Area and PJM Interchange Energy Market.

"PJM Member" means any entity satisfying the requirements of PJM to conduct business with PJM, including transmission owners, generating entities, Load Serving Entities and marketers.

"PJM Operating Agreement" means the Operating Agreement of PJM or its successor, including superseding or amended versions of such operating agreement that may take effect from time to time.

"PJM RAA" means the Reliability Assurance Agreement, dated as June 2, 1997, as revised or amended, by and among Buyer and the other parties signatory thereto.

"PJM RPM Market" means the market administered by PJM for the centralized procurement of unforced capacity for the purposes of LSEs meeting their capacity obligations under the PJM Agreements as governed by the PJM Capacity Rules.

"PJM Tariff" means the PJM Open Access Transmission Tariff providing transmission service within the PJM Control Area, as in effect from time to time, including any schedules, appendices or exhibits attached thereto.

"Planned Outage" means a "Generator Planned Outage" as defined in the PJM Agreements.

"Point of Receipt" means the point of interconnection on the PJM Grid where Capacity and Energy from the Project will be made available to PJM under Part II of the PJM Tariff, this point being on the high side of the 230/138 kV transformer at the Indian River Substation, or if the transformer is not located at the Indian River Substation, the bus or equivalent connection at the Indian River Substation to which the Indian River Lines Assets are connected, as further detailed in Appendix 1.

"Post Date Certain Units" has the meaning set forth in Section 5.4(e).

"Power Curve" means the measure of the kWh output of a Unit or the Project as a function of wind speed, measured consistent with Good Utility Practices (as applicable for the terms of this Agreement) and provided in the Turbine Supply Agreement.

"Pre-Construction Services Agreement" has the meaning set forth in Section 5.2(g).

"Pre-Initial Delivery Date Products" has the meaning set forth in Section 3.1(a)(ii).

"Pre-Services Term Period" has the meaning set forth in Section 3.1(a)(ii).

"Pre-Services Term Period Security" has the meaning set forth in Section 8.1(b).

"Prime Rate" means the per annum rate of interest published by the Wall Street Journal as the prime lending rate or "prime rate", with adjustments in that varying rate to be made on the same day as any change in that rate is so published.

"Product" shall mean, collectively, Energy, Contract Capacity, Ancillary Services (if applicable), and Environmental Attributes.

"Project" means the electric generation facility described in Appendix 1, consisting of the Units and the Site, the Electrical Interconnection Facilities, and any other ancillary facilities, goods, equipment, rights to the Site and other rights, Permits and real property associated therewith.

"Project Capacity" shall mean the total intended aggregate nameplate capacity rating of the Project to be determined by Seller and declared by Seller to Buyer via written Notice on or before the second anniversary of the Execution Date pursuant to Section 2.4.

"Project Capacity Resource Clearing Price" means, for each Capacity Year, the price point for the Base Residual Auction (BRA) Resource Clearing Price for such Capacity Year in the Locational Delivery Area in which the Delivery Point is located, as such price point shall be determined in accordance with the PJM Capacity Rules expressed in dollars per kW-year or dollars per MW-year if appropriate.

"Project Commercial Operation" means Commercial Operation with respect to the Project.

"Project Commercial Operation Date" means the date on which Seller (a) notifies Buyer in writing that Project Commercial Operation has occurred (in accordance with the Project size requirements of Section 5.4), and (b) provides a certification of a Licensed Professional Engineer, substantially in the form attached hereto as Appendix 2, certifying satisfactory completion of Project Commercial Operation.

"Project Contracts" shall mean the Turbine Contracts, the EPC Contract, the Interconnection Agreements, any contract with the Forecast Consultant, any Project operations agreement, and any other material contracts entered into in connection with the development, construction, installation, maintenance, servicing or operation of the Project or the provision of CMS and SCADA.

"Project Financing Liens" shall mean Liens granted to the Senior Secured Lenders, which Liens secure construction loans, term-debt or working capital facilities of the Project and which collectively comply with the provisions of Section 8.3 of the Agreement.

"Project Meter" shall mean the revenue quality electricity generation meter included within the Project facilities, the proposed location of which is identified in Appendix 1 hereto, which meter shall register all Delivered Energy delivered to the Delivery Point pursuant to the terms of this Agreement.

"Project Permitted Liens" means (i) the Liens created by the Senior Security Documents so long as the same comply with the provisions of Section 8.3 of this Agreement and (ii) other Liens permitted to exist under the terms of the Senior Security Documents.

"Project Security Agreements" has the meaning set forth in Section 8.3.

"Projected Delivered Energy" means:

(a) if such date of calculation shall occur prior to the Initial Delivery Date, the sum of the PDE Monthly Averages for each calendar month calculated over a deemed term equal to twenty-five (25) years, where the "PDE Monthly Average" for each calendar month of the year shall be the average of (i) the actual Delivered Energy plus any Deemed Generated Energy for each full calendar month that has occurred since the first Unit Group Commercial Operation Date, and (ii) the Delivered Energy for each such full calendar month as set forth in the Expected Generation Schedule for each of such calendar months for which the clause (i) data is unavailable, with each PDE Monthly Average for the twelve (12) calendar months being multiplied by the PDE Multiplier (to take into effect a presumed full Project nameplate capacity rating equal to the Projected Project Nameplate Capacity); provided that the amount of Delivered Energy used in such calculations (whether based on actual Delivered Energy, Deemed Generated Energy or that set forth in the Expected Generation Schedule), shall not exceed the maximum amounts of MWs for any hour or year which corresponds to the pro rata amounts associated with the Projected Project Nameplate Capacity. The intent of this provision is to recognize and take into account the seasonal nature of the Delivered Energy during the course of a calendar year. For example, if the Pre-Services Term Period prior to the date of calculation is 15 months commencing on January 1, the PDE Monthly Average would be separately calculated for January, taking into account the historical data for the two Januarys that shall have occurred in the Pre-Services Term Period, and the corresponding data for those two Januarys in the Expected Generation Schedule. Similarly, the PDE Monthly Average would be separately calculated for May, taking into account the historical data for the one May that shall have occurred in the Pre-Services Term Period, and the corresponding data for that May in the Expected Generation Schedule. The size adjustment for the PDE Multiplier shall then be made for each calendar month, and each such average monthly amount shall be presumed to apply for a deemed twenty-five (25) year term. By way of further example, if the Pre-Services Term Period does not include a particular calendar month in an applicable year, the PDE Monthly Average for such month will be deemed to be Delivered Energy for such month as set forth in the Expected Generation Schedule.

(b) if such date of calculation shall occur after the Initial Delivery Date, the sum of the Historical Monthly Averages for each calendar month calculated over a deemed term equal to the number of months in the remaining Services Term that would have been in effect in the absence of an Early Termination Date. The "Historical Monthly Average" for each calendar month of the year shall be the average of the actual Delivered Energy plus any Deemed Generated Energy for each such calendar month that has occurred since the Initial Delivery Date; provided that in the event that there shall not be at least three (3) years of historical performance data for any calendar month, then the Historical Monthly Average for such calendar month shall be the average of (i) the actual Delivered Energy plus any Deemed Generated Energy for each such full calendar month that has occurred since the Initial Delivery Date, and (ii) the Delivered Energy for each such full calendar month as set forth in the Expected Generation Schedule for each

of such calendar months for which the clause (i) data is unavailable. If a particular calendar month in an applicable year has not occurred since the Initial Delivery Date, the Historical Monthly Average for such month will be deemed to be the Delivered Energy for such month as set forth in the Expected Generation Schedule.

"Projected Project Nameplate Capacity" means at any time prior to the Initial Delivery Date, the Project Capacity, provided, however, if the total Project Capacity has not achieved Commercial Operation at such time, such lesser amount of MWs as the Independent Evaluator shall confirm is reasonably likely to achieve Commercial Operation by the Date Certain (which amount shall be zero if the Independent Evaluator determines at least sixty percent (60%) of the Project Capacity would not have achieved Commercial Operation by the Guaranteed Initial Delivery Date).

"PTC" has the meaning set forth in Section 5.7.

"PTC Termination Date" has the meaning set forth in Section 5.7.

"Qualified Issuer" means a U.S. commercial bank (or a foreign bank with a U.S. branch reasonably acceptable to Buyer) having total assets of at least $10 billion and a senior unsecured long-term Credit Rating (unenhanced by third-party support) equivalent to A- or better as determined by S&P and the equivalent by Moody's or Fitch.

"Rating Agency" or "Rating Agencies" shall mean, individually or collectively, S&P, Moody's and Fitch.

"Recording" has the meaning set forth in Section 14.17.

"Regulatory Approval" shall consist of:

(a) a final non-appealable order of the Commission and the Agencies that

(i) approves the terms of the Agreement without modification and

(ii) orders Buyer to enter into the Agreement and

(iii) includes a provision from the Commission that authorizes Buyer to recover its costs incurred as a result of the Agreement through its rates, unless, after Commission review, any such costs are determined by the Commission to have been incurred in bad faith, are the product of waste or out of an abuse of discretion, or in violation of law.

(b) approval of the Agreement by FERC to the extent FERC approval is required.

"Regulatory Charges" has the meaning set forth in Section 9.2.

"Regulatory Charges Payment" has the meaning set forth in Section 9.2.

"Reliability*First* Corporation" means Reliability*First* Corporation, a Delaware non-profit corporation, or a successor organization that is responsible for establishing reliability criteria and protocols under or on behalf of the NERC for the portion of the PJM Control Area containing the Delmarva South Zone.

"Regulatory Disclosures" has the meaning set forth in Section 14.8.

"Renewable Energy Credits" or "RECs," shall have the meaning set forth in the Commission RPS Rules and the RPS Act.

"Replacement PPA" has the meaning set forth in Section 3.1(e).

"Resource Adequacy Requirement" or "RAR" means a standard or requirement established and administered by the Commission, PJM, FERC, or other Governmental Authority, whereby unit-specific Capacity is identified and the physical unit is made available for meeting such requirement; the eligibility to count Capacity toward the Resource Adequacy Requirement may be determined by identifying the full resource adequacy capability of specific Units or an amount of resource adequacy capability from a combination of all or any part of the Units (not including the PJM RPM Market as in place as of the Execution Date and related PJM Agreements).

"RPS Act" shall mean Delaware's Renewable Energy Portfolio Standards Act, 26 Del. C., § 351-363.

"S&P" means Standard and Poor's Ratings Group., a division of McGraw Hill, Inc., or its successor.

"Scheduled Maintenance" means removing the equipment included in the Project, or any portion thereof, from service availability, in whole or in part, for inspection and/or general overhaul of one or more major equipment groups of the type that (i) is necessary to reliably maintain the Project consistent with Good Utility Practices, (ii) cannot be reasonably conducted during the Project's operations, (iii) causes the available Capacity to be reduced to less than 100% of the total Capacity (as applicable for a specific month) and (iv) has been scheduled and Noticed in accordance with the requirements of Section 3.10 and the PJM Manuals.

"Scheduled Maintenance Outage" is a Planned Outage or Maintenance Outage during which Scheduled Maintenance is performed, provided that only a Planned Outage or Maintenance Outage that has been Noticed and is otherwise in accordance with Section 3.10 shall be considered a Scheduled Maintenance Outage.

"Second Party" has the meaning set forth in Section 14.15.

"Seller" shall mean Bluewater Wind Delaware LLC, a Delaware limited liability company.

"Seller Group" has the meaning set forth in Section 11.1(b).

"Seller's Capacity Offer Discretion" shall mean the reasonable discretion of the Seller to determine whether to submit an offer into the PJM RPM Market, and the quantity, price, and other terms of such offers, all in accordance with the PJM Capacity Rules, consistent with the objective of the Parties to maximize the Cleared Capacity Value while allowing the Seller to reasonably manage the risk associated with participating in the PJM RPM Market. The Parties acknowledge that, because of the Seller's Capacity Offer Discretion, the existence or amount of Cleared Capacity Value in any Capacity Year is not guaranteed.

"Seller's Event of Default" has the meaning set forth in Section 12.1(a).

"Senior Loan Documents" means the documents under which the Senior Secured Lenders provide construction, working capital or term debt financing to Seller, secured by the Senior Security Documents.

"Senior Secured Lenders" means Persons not affiliated with Seller who provide construction, working capital or term debt financing for the Project (and the agents thereof) and hold first-priority security interests in the collateral granted under the Senior Security Documents.

"Senior Security Documents" means, collectively, all documents granting the Senior Secured Lenders a security interest in any property or assets of the Seller to secure the obligations of the Seller to the Senior Secured Lenders under the Senior Loan Documents, including a mortgage and security agreement.

"Services Term" has the meaning set forth in Section 2.1.

"Services Term Security" has the meaning set forth in Section 8.1(c).

"Settlement Amount" has the meaning set forth in Section 12.2(d).

"Shared Facilities" shall mean one or more off-shore substations which are included in the Project, all undersea cables connecting such substations to land, access rights to the Indian River Line Assets and all other rights and property associated with the transmission of Energy from the off-shore substations to the Point of Receipt.

"Shut-Down" means the action of causing all or part of the Project to cease producing Energy and/or Ancillary Services (if applicable).

"Site" means certain federal waters of the Atlantic Ocean off of the coast of Delaware, certain Delaware State waters, and certain associated real property and rights therein located onshore in the State of Delaware, where the Project (including the Electrical Interconnection Facilities) is located, as identified and described in Appendix 1.

"Start-Up" means the action of causing all or part of the Project to begin producing Energy and/or Ancillary Services (if applicable) from a state of no or zero production.

"Subsequent Performance Tests" has the meaning used in Section 3.12.

"Tax Investor" has the meaning set forth in Section 14.5(a).

"Taxes" means all foreign and domestic taxes, rates, levies, assessments, surcharges, duties and other fees and charges of any nature, whether currently in effect or adopted during the Term, including but not limited to, ad valorem, consumption, excise, franchise, gross receipts, import, export, license, property, sales, stamp, storage, transfer, turnover, use or value-added Taxes, payroll, unemployment, and any and all items of withholding, deficiency, penalty, addition to tax, interest or assessment related thereto.

"Termination Fee" has the meaning set forth in Section 5.4.

"Termination Payment" has the meaning used in Section 12.2.

"Test Energy" means that Delivered Energy which is produced by a Unit, a Unit Group or the Project (as applicable) and delivered to the Delivery Point for Buyer's purchase pursuant to Section 3.1(a)(iii), in order to perform testing of a Unit, a Unit Group or the Project (as applicable), prior to Commercial Operation.

"Third Party" means a Person that is not a member of the Buyer Group or the Seller Group.

"Third Party Claim" means a claim, suit or similar demand by a Third Party.

"Turbine Contracts" shall mean the Turbine Supply Agreement and any related wind turbine generator service and maintenance agreement entered into by Seller, and any guarantees or credit support provided in connection therewith.

"Turbine Notice to Proceed" means the notice to proceed issued to the Turbine Supplier under the Turbine Supply Agreement.

"Turbine Supplier" means the vendor to be selected by Seller to enter into the Turbine Supply Agreement, currently anticipated to be Vestas Wind Systems A/S.

"Turbine Supply Agreement" means the agreement to be entered into by Seller and the Turbine Supplier for the supply to the Project of the Units set forth on Appendix 1 hereto, and the related turbine warranty agreement providing certain warranties and/or guaranties in connection with the performance of the Units.

"Turbine Supply Availability" shall mean the mechanical "availability" of a Unit as determined in accordance with the Turbine Supply Agreement.

"Unit" means each of the wind generation units described in Appendix 1 forming a part of the Project from which Seller has agreed to provide Products to Buyer pursuant to this Agreement.

"Unit Commercial Operation" means the achievement of Commercial Operation with respect to a Unit.

"Unit Commercial Operation Date" means the date on which Seller (a) notifies Buyer in writing that Unit Commercial Operation for a Unit has occurred, and (b) provides a certification of a Licensed Professional Engineer, substantially in the form attached hereto as Appendix 2, certifying satisfactory completion of Commercial Operation for the Unit in question.

"Unit Group" shall mean each forty-five (45) MW (or lesser amount with respect to the final group of Units to be constructed during a construction season pursuant to Section 3.1(a)(ii)) nameplate capacity group of Units which Seller sequentially installs at the Site.

"Unit Group Commercial Operation" means the achievement of Commercial Operation with respect to a Unit Group.

"Unit Group Commercial Operation Date" means the date on which Seller (a) notifies Buyer in writing that Unit Group Commercial Operation for a Unit Group has occurred, and (b) provides a certification of a Licensed Professional Engineer, substantially in the form attached hereto as Appendix 2, certifying satisfactory completion of Commercial Operation for the Unit Group in question.

"United States Bankruptcy Code" means title 11 of the United States Code.

1.2 Interpretation. Unless otherwise required by the context in which any term appears: (a) capitalized terms used in this Agreement shall have the meanings specified in Section 1.1; (b) the singular shall include the plural and vice versa; (c) references to "Articles," "Sections," "Schedules," "Annexes," "Appendices" or "Exhibits" (if any) shall be to articles, sections, schedules, annexes, appendices or exhibits hereof, unless otherwise specified; (d) all references to a particular Person in any capacity shall be deemed to refer also to such Person's successors and permitted assigns in such capacity; (e) the words "herein," "hereof" and "hereunder" shall refer to this Agreement as a whole and not to any particular section or subsection hereof; (f) the words "include," "includes" and "including" shall be deemed to be followed by the phrase "without limitation" and shall not be construed to mean that the examples given are an exclusive list of the topics covered; (g) all accounting terms not specifically defined herein shall be construed in accordance with GAAP; (h) references to this Agreement shall include a reference to all appendices, annexes, schedules and exhibits hereto, as the same may be amended, modified, supplemented or replaced from time to time; (i) references to any agreement, document or instrument, including the PJM Agreements, shall be construed at a particular time to refer to such agreement, document or instrument as the same may be amended, modified, supplemented or replaced as of

such time; (j) the masculine shall include the feminine and neuter and vice versa; (k) references to a Law shall mean a reference to such Law as the same may be amended, modified, supplemented or restated and be in effect from time to time; (l) the term "month" shall mean a calendar month unless otherwise indicated, and a "day" shall be a 24-hour period beginning at 12:00:01 a.m. and ending at 12:00:00 midnight; provided that a "day" may be 23 or 25 hours on those days on which daylight savings time begins or ends; (m) words, phrases or expressions not otherwise defined herein that (i) have a generally accepted meaning in Good Utility Practice or the PJM Agreements, as applicable, shall have such meaning in this Agreement or (ii) do not have well known and generally accepted meaning in Good Utility Practice but that have well known technical or trade meanings shall have such recognized meanings; and (n) all references to dollars are to U.S. dollars.

ARTICLE II
TERM

2.1 Term. The "Contract Term" will commence upon the Execution Date and, unless earlier terminated pursuant to this Article II, Section 3.15, Article XII (Events of Default; Remedies), Article V (Conditions Precedent; Effective Date; Construction; and Initial Delivery Date), or any other provision hereof, and will continue until the end of the Services Term; *provided however*, that all payment and Collateral obligations between the Parties arising under this Agreement, including any compensation for the Products, Termination Payment, Termination Fee, Delay Damages, indemnification payments or other damages, shall survive until the date as of which all payments under this Agreement are indefeasibly paid in full (whether directly or indirectly such as through set-off or netting). The Initial Delivery Date will occur, on or after the Effective Date, upon satisfaction of the conditions precedent set forth in Section 5.3. The "Services Term" is the period commencing on the Initial Delivery Date and continuing until the earlier to occur of (i) the date that is twenty-five (25) years after the Initial Delivery Date, and (ii) December 1, 2039, as such date may be extended for up to eighteen (18) months for reasons of (1) a Force Majeure Event, (2) Buyer's failure to perform its obligations under the Agreement or (3) delays in obtaining the Permits set forth on Schedule 3 hereto beyond the dates set forth on Schedule 3 for reasons that are beyond Seller's control (including a delay in publication of the MMS Regulations beyond May 31, 2011), unless earlier terminated pursuant to the terms of the Agreement and in each case as reasonably documented and established by Seller.

2.2 Binding Nature. This Agreement shall be effective and binding as of the Execution Date only to the extent required to give full effect to, and enforce, the rights and obligations of the Parties under Section 5.1 (Conditions Precedent to Effective Date). Upon occurrence of the Effective Date, this Agreement shall be in full force and effect, enforceable and binding in all respects.

2.3 Failure of Timely Approvals. Buyer agrees to diligently seek Regulatory Approval on a commercially reasonable expedited basis. In the event that Buyer does not receive Regulatory Approval within one (1) year after the Execution Date either Party shall have the right to terminate this Agreement, without liability of one Party to the

other, upon the delivery of prior written Notice to that effect to the other Party, provided that such Notice is sent within sixty (60) days after such deadline. Notwithstanding the previous sentence, if the Effective Date is delayed by a timely appeal of a Regulatory Approval order or as a result of litigation or legal challenge by Buyer or its Affiliates (as described in Section 13.4), the one (1) year time period shall be extended on a day for day basis for such delay and the Effective Date shall occur on the date the applicable Regulatory Approval order is upheld and thereafter becomes final and non-appealable, if applicable. If either Party terminates this Agreement in accordance with the above provisions of this Section 2.3, Buyer shall refund to Seller the full amount of the Development Period Security posted by Seller within ten (10) Business Days of such termination.

2.4 Seller Early Termination and Declaration of Project Capacity.

(a) During the period that begins on the Execution Date and ends on the two-year anniversary of the Execution Date, on thirty (30) days prior written Notice, Seller may terminate this Agreement in its sole discretion if it is not able to find satisfactory purchaser(s) for the Excess Products, or determines that it is otherwise not prudent to continue to develop the Project. If Seller terminates this Agreement in accordance with the provisions of this Section 2.4, Buyer shall refund to Seller the full amount of the Development Period Security posted by Seller within ten (10) Business Days of such termination.

(b) On or before the second anniversary of the Execution Date, Seller shall provide Buyer with a written Notice of the final Project Capacity, which amount must at all times equal or exceed 200 MW (except with respect to reductions in Project Capacity permitted under Sections 3.1(d), 5.4, 5.7 and 12.4) and be no greater than 600 MW, and which amount can only be modified pursuant to Sections 3.1(d), 5.4, 5.7 and 12.4.

2.5 Buyer Termination Right Or Contract Modification For Change In Law. If, at any time prior to the date two (2) years after the Execution Date, any Governmental Authority amends, modifies, repeals or revokes any of the legislation described in Sections 5.1(a)(vi) or (vii), and Buyer suffers a material adverse effect as a result of such occurrence, Buyer shall have the right to terminate the Agreement in its sole discretion upon thirty (30) days prior Notice to Seller. Upon Seller's written request to Buyer, prior to any termination of the Agreement pursuant to this Section 2.5, an Independent Evaluator shall confirm within forty-five (45) days whether such material adverse effect exists. Either Party may appeal the findings of the Independent Evaluator pursuant to Article XIII. If Buyer terminates this Agreement in accordance with this Section 2.5, Buyer shall refund to Seller the full amount of the Development Period Security or Services Term Security (as applicable) posted by Seller within ten (10) Business Days after such termination. Notwithstanding the foregoing, during the 30-day Notice period described above, Seller may, as an alternative to Buyer's termination right, choose to negotiate with Buyer to amend the Agreement to account for the event(s) triggering Buyer's termination right. If Seller elects to proceed with an amendment to the Agreement, the Parties shall exercise good faith efforts to enter into an amendment to the Agreement that is reasonably acceptable to both Parties and ensures that Buyer will not

suffer any material adverse effect or other negative economic consequence from the event(s) triggering the termination. In the event the Parties are not able to enter such an amendment within sixty (60) days of Seller's election, Buyer shall have the right to terminate the Agreement at the end of the 60-day period.

ARTICLE III
OBLIGATIONS AND DELIVERIES

3.1 Transaction.

(a) Purchase and Sale Obligation.

(i) Purchase and Sale Obligation During Services Term. During the Services Term, Seller shall sell and make available to Buyer at the Delivery Point, and Buyer shall take and pay in accordance with Section 4.2 and Article VI for the following:

(A) For each Capacity Year that commences in the Services Term, Seller shall cause to be transferred to Buyer the value of Buyer's Percentage of the Contract Capacity for such Capacity Year in the following fashion. For each such Capacity Year, Seller and Buyer shall enter into a "Non-Unit Specific Capacity Transaction" under the PJM Capacity Rules pursuant to which Seller shall transfer to Buyer the Contract Capacity Amount for such Capacity Year, in consideration for the payment to Seller by Buyer of the Base Capacity Payment Rate (as adjusted) per each MW included in the calculation of the transferred Contract Capacity Amount. Each of the Parties agree to provide such notices to PJM as shall be required under the PJM Capacity Rules in order to effect such transfer of the Contract Capacity Amount to Buyer through the PJM eRPM system, including the submission and confirmation of each such transfer on a timely basis for each such Capacity Year; provided that in the event that the PJM eRPM system shall not be available for any reason for purposes of making such transfer of the Contract Capacity Amount to Buyer at any time, the Seller shall transfer such amount directly to Buyer as Buyer shall direct in a manner consistent with the timing that would have been in effect under the PJM eRPM system, or as the Parties shall otherwise agree. Seller further agrees to comply with all PJM Capacity Rules, including, without limitation, any associated bid/dispatch requirements into the PJM RPM Market or other bidding/dispatch requirement imposed through either PJM market design and tariffs, the Commission or FERC, whether or not such compliance is required to be undertaken by Seller prior to, during, or after the Services Term. The Parties acknowledge that the transfer of the value of the Buyer's Percentage of the Contract Capacity from Seller to Buyer as set forth in this subclause (A) is fixed with PJM for each Capacity Year, and as such, the last Capacity Year commencing in the Services Term may extend beyond the termination of the Services Term. Notwithstanding any such termination of the Services Term prior to the end of such last Capacity Year, unless the Parties shall otherwise agree, the Buyer's and Seller's obligations pursuant to this Section 3.1(a)(i)(A) shall survive

the termination of the Services Term until the end of such last Capacity Year. In the event that the PJM Capacity Rules or the PJM Agreements are altered in such a manner as to materially change the method through which PJM attributes value for Capacity Value and, as a consequence, the Contract Capacity Amount to be transferred to Buyer in accordance with this Agreement, the Parties agree to modify this Agreement as necessary to preserve the economic bargain between the Parties as of the Execution Date.

(B) From and after the Initial Delivery Date, all Delivered Energy produced by the Project.

(C) A quantity of RECs equal to the product of (i) the RPS Multiplier and (ii) all RECs associated with the Delivered Energy delivered pursuant to Section 3.1(a)(i)(A) and (B) and Buyer's Percentage of the Contract Capacity utilized for purposes of the calculation of the Contract Capacity Amount transferred to Buyer pursuant to such sections, together with a quantity of Environmental Attributes equal to the product of (i) the RPS Multiplier and (ii) all Environmental Attributes (other than RECs) associated with the Delivered Energy delivered pursuant to Section 3.1(a)(i)(A) and (B) and Buyer's Percentage of the Contract Capacity utilized for purposes of the calculation of the Contract Capacity Amount transferred to Buyer pursuant to such sections. The term "RPS Multiplier" shall mean the fraction that is equal to the reciprocal of the percentage of credits that Buyer receives toward meeting its Renewable Energy Portfolio Standards requirements under the RPS Act for RECs received from the Project. By way of example, if Buyer receives 350% credit toward meeting its Renewable Energy Portfolio Standards requirements for Delivered Energy from the Project, the RPS Multiplier is twenty-eight and six tenths percent (28.6%). Examples of the quantity of RECs to be purchased and sold under this Subsection are set out in Appendix 5. For the avoidance of doubt Buyer shall have no right whatsoever to any Environmental Attributes that are associated with the Delivered Energy but that are otherwise not required to be purchased by Buyer under this Section 3.1(a)(i)(C) or Section 3.1(a)(ii), or that are associated with Excess Products.

The Parties further contemplate that no Ancillary Services will be initially included in the Products to be provided to the Buyer under the Agreement. With respect to any Ancillary Services, regardless of whether currently existing or created after the Execution Date, such Ancillary Services may be sold by Seller to Buyer at each Party's option at such price and on such terms and conditions as may be mutually acceptable to Seller and Buyer in their respective sole discretion.

(ii) Purchase and Sale Obligation During the Pre-Services Term Period. Subject to the conditions precedents set forth below, on or after the initial Unit Group Commercial Operation Date and extending until the earlier of (a) the Initial Delivery Date, (b) the end of the Construction Period, and (c) the date termination of this Agreement is effective (the "Pre-Services Term Period"), Seller shall sell to Buyer the Delivered Energy, Environmental Attributes

associated with such Delivered Energy as provided in Section 3.1(a)(i) above and/or (as applicable) the value of Buyer's Percentage of the Contract Capacity utilized for purposes of the calculation of the Contract Capacity Amount in quantities consistent with the quantities to be purchased by Buyer under Section 3.1(a)(i)(C), Ancillary Services (if mutually agreed upon by Buyer and Seller as described in Section 3.1(a)(i)) produced by the Project during such period from each Unit Group that has achieved Unit Group Commercial Operation and, with respect to each Capacity Year commencing in such Pre-Services Term Period, Seller shall transfer to Buyer the Contract Capacity Amount for such Capacity Year in the manner and in accordance with the requirements of Section 3.1(a)(i)(A) (collectively, the "Pre-Initial Delivery Date Products"). Buyer shall pay for such Pre-Initial Delivery Date Products in accordance with Section 4.2 (or as agreed upon by Buyer and Seller in the case of Ancillary Services, if applicable) and Article VI and pursuant to the other terms of the Agreement set forth herein, including the conditions precedent to such obligations set forth in this Section 3.1(a)(ii) and Section 5.3(a). For the avoidance of doubt, after the end of the Pre-Services Term Period but prior to the commencement of the Services Term, Seller shall have the right to sell (at its sole discretion) to any third party any and all Energy, Environmental Attributes, Capacity Value, and Ancillary Services produced by the Project during such period.

Buyer's obligation to purchase Pre-Initial Delivery Date Products will initially commence when (i) the initial Unit Group Commercial Operation Date has occurred, (ii) Buyer has received ninety (90) days prior written Notice of the initial Unit Group Commercial Operation Date and the delivery of the Pre-Initial Delivery Date Products therefrom, and (iii) each condition to the Initial Delivery Date set forth in Section 5.3(a) shall have been met (other than Sections 5.3(a)(i), (vi), (vii) and (ix), and the condition set forth in Section 5.3(a)(xii) shall be reduced on a pro-rata basis in accordance with the nameplate capacity of the applicable Unit Group(s) not yet then having achieved a Commercial Operation Date). Each reference in such Sections to the "Initial Delivery Date" shall be changed for purposes of this Section only to "applicable Unit Group Commercial Operation Date". Buyer's obligation to purchase Pre-Initial Delivery Date Products from additional Unit Groups will commence when such additional Unit Groups have satisfied the requirements set forth in the previous sentence. The Parties agree that if on October 30 of the first calendar year during the Construction Period, a partial increment of the last Unit Group under construction in that calendar year has reached its Unit Group Commercial Operation Date, Buyer shall purchase Pre-Initial Delivery Date Products from such increment of the Unit Group from November 1 of such year as set forth in this Section 3.1(a)(ii); provided, that such obligation shall terminate on May 30 of the following year of the Construction Period if the remainder of the Unit Group has not reached the Unit Group Commercial Operation Date by such date.

In connection with the sale of Pre-Initial Delivery Date Products, Seller shall provide Buyer with a schedule (which shall be non-binding but shall be

prepared in good faith) of the projected Project Commercial Operation Date and Unit Group Commercial Operation Dates for all Units and the projected quantities of Products to be delivered from such Units on and after their Unit Group Commercial Operation Dates no later than thirty (30) days after the first of the Turbine Contracts are executed. This schedule will be promptly provided by Seller to Buyer when available and shall be updated by Seller on a monthly basis after the later of the issuance of the Turbine Notice to Proceed or the EPC Notice to Proceed, and shall be updated on a weekly basis during the ninety (90) day Notice period for the Unit Group Commercial Operation Dates of any Unit Groups delivering Pre-Initial Delivery Date Products.

The obligation of Seller to deliver the Pre-Initial Delivery Date Products from Unit Groups that have reached their respective Unit Group Commercial Operation Dates in accordance with this Section 3.1(a)(ii) shall be secured by the Development Period Security, the Buyer's Lien, and the pro-rata percentage of the Services Term Security as described in Section 8.1(b).

Notwithstanding anything to the contrary set forth in this Section 3.1(a)(ii), the Parties acknowledge and agree that the obligations of the Parties with respect to transfers of the Contract Capacity Amount to Buyer pursuant to this Section 3.1(a)(ii) shall apply only with respect to Capacity Years commencing in the Pre-Services Term Period and shall be based on the Capacity Value, Cleared Capacity Value and Contract Capacity applicable to the Project for each such Capacity Year.

(iii) Test Energy. If and to the extent the Project generates Test Energy after the commencement of the Pre-Services Term Period, Seller shall deliver to the Delivery Point and Buyer shall take all Test Energy and Environmental Attributes associated therewith (with Environmental Attribute quantities being consistent with the quantities to be purchased by Buyer under Section 3.1(a)(i)(C)) delivered to the Delivery Point and pay for such Test Energy and Environmental Attributes at the payment rates for Energy and Environmental Attributes, respectively, then applicable as set forth in Section 4.2. Prior to the commencement of the Pre-Services Term Period, Seller shall have the right to sell (at its sole discretion) Test Energy and associated Environmental Attributes into the PJM market at Seller's sole cost and expense.

(iv) Exceptions to Buyer and Seller Performance. Buyer shall not be obligated to schedule, take or pay for the Products described in Section 3.1(a) during (a) Force Majeure Events, (b) Dispatch Down Periods, (c) periods covered by an Instructed Operation that is not caused by any act or failure to act by Buyer that is inconsistent with Buyer's rights and obligations under the Agreement (to the extent of such Instructed Operation), or (d) periods covered by Seller's failure to perform its obligations hereunder. Seller shall not be obligated to sell and deliver the Products described in Section 3.1(a) during (a) Force Majeure Events, (b) Dispatch Down Periods, (c) periods covered by an Instructed Operation that is not caused by any act or failure to act by Seller that is inconsistent with Seller's

rights and obligations under the Agreement (to the extent of such Instructed Operation), (d) periods covered to the extent prevented by an Outage (subject to the provisions for declaring and remedying Outages as set forth in this Agreement), (e) periods during the continuance of an Operational Limitation effecting performance to the extent of such effect on the Project, or (f) periods covered by Buyer's failure to perform its obligations hereunder.

(b) Control. Seller shall at all times retain operational control of the Project, be responsible for all operation and maintenance of the Project and will bear all costs related to ownership, operation and maintenance of the Project.

(c) Exclusivity; Rights to Output and Payments. Except with respect to the Products not required to be purchased by or sold to Buyer as contemplated under Section 3.1(a) (the "Excess Products"), Seller will not commit less than Buyer's Percentage of the entire Project to Buyer, nor sell any Product associated with Buyer's Percentage of the Project to any Person other than Buyer (other than pursuant to an Instructed Operation). For the avoidance of doubt, the exclusivity requirements of this Section 3.1(c) shall not apply to any Excess Products and Seller shall not be prohibited in any manner whatsoever from selling such Excess Products to any third party. Except with respect to the Excess Products, Seller may not enter into any agreement or arrangement under which Products described in Section 3.1(a) may be claimed by any Person other than Buyer for purpose of satisfying such Person's obligations to PJM or any other independent system operator having jurisdiction over such Person or the Project. For the avoidance of doubt, except with respect to the Excess Products, Seller shall not cause the Project to become subject to any other obligation to deliver a Product to any other Person other than pursuant to an Instructed Operation, and Buyer shall have the exclusive right to resell any Product from the Project up to the quantities set forth in Section 3.1(a).

Subject to the reporting requirements of Section 3.5, nothing herein shall bar Seller from complying with Instructed Operations; provided that if Seller receives an Instructed Operation other than through Buyer in its capacity as a Participating Transmission Owner, Seller shall promptly report such event in accordance with Sections 3.5(b) and (c). Seller acknowledges and agrees that Buyer may take whatever measures it elects to protest or challenge any Instructed Operation, which may include communicating directly with the Governmental Authority or PJM, as applicable, responsible for such Instructed Operation. If during the Services Term or Pre-Services Term Period Seller requires the ability to operate other than as expressly contemplated herein (for example, for the purpose of conducting environmental testing or to test newly installed equipment), it shall notify Buyer, and Buyer and Seller shall work in good faith to accommodate Seller's need consistent with other provisions of this Agreement, provided Seller shall be liable for Buyer's costs in accommodating Seller's requests.

To the extent that Seller receives any payment associated with the Products to be delivered to Buyer hereunder, including non-Energy or fixed payments associated with such Products received for or in connection with Resource Adequacy Requirements or Instructed Operations from any Person other than Buyer, Seller shall remit such payment

to Buyer ("Third Party Payments"). Invoicing and payment for all amounts due from one Party to the other Party as necessary to implement this provision shall be made pursuant to Article VI. For the avoidance of doubt, Seller may execute agreements for the sale of Excess Products consistent with the terms of this Agreement prior to the completion of such performance.

(d) Project Modifications. Neither Seller nor any Affiliate of Seller (an entity shall not be deemed to be an Affiliate of Seller for the purposes of this Section 3.1(d) solely by virtue of a ten (10) percent direct or indirect shareholding), shall, without the prior written consent of Buyer, increase, modify, or decrease the Project Capacity or, after the Initial Delivery Date, the Capacity of the Project or any Unit or the number of Units, except as expressly contemplated in Section 5.4; nor take any other action with respect to the Project or in connection with any expansion of the Project or construction of any new wind facility adjacent to the Project that would, or may reasonably be expected to (i) increase the costs to Buyer under the Agreement including with regards to costs associated with negative LMPs, (ii) impair or limit the ability of the Project to supply Products to the Buyer as contemplated hereunder, (iii) impair the ability of the Buyer to purchase or receive Products from the Project as contemplated hereunder, (iv) impair the Capacity Value or the Cleared Capacity Value of the Project or the rights of the Buyer to receive the full and exclusive rights to Buyer's Percentage of the Contract Capacity, or (v) reduce the ability of Seller to deliver the Products that the Project is capable of producing as required to be delivered under the terms of the Agreement, as measured at the Delivery Point, including the full amount of Buyer's Percentage of the Contract Capacity. Buyer's consent shall not be unreasonably withheld, and the materiality of the impact of the increase, modification, or decrease on the Buyer and its customers shall be taken into account in evaluating the reasonableness of withholding consent. Buyer shall use commercially reasonable efforts to promptly respond to consent requests under this Section 3.1(d). Notwithstanding any provision herein to the contrary, in no event shall such modification result in the Project Capacity being more than 600 MW and in no event shall Buyer be required to purchase Products associated with more than 200 MW of Project Capacity.

(e) Buyer Option to Exclude Capacity. Notwithstanding anything to the contrary set forth in this Agreement, Buyer may elect in its sole discretion, at any time during the Contract Term, to discontinue its obligation to receive the Contract Capacity Amount from Seller under the Agreement and to require Seller to enter into a replacement power purchase agreement (the form of which shall be finalized promptly following the Execution Date consistent with the principles set forth in Appendix 3) pursuant to which Buyer shall purchase Energy and other Products (other than Capacity Value-related products) from Seller (the "Replacement PPA"). Buyer's notice of its election (which may be immediate) may specify a date for discontinuation for such obligation in which case Seller shall not be obligated to participate in the PJM RPM Market or to take any action to cause to be transferred to Buyer the value of Buyer's Percentage of the Contract Capacity in accordance with Section 3.1(a)(i) and (ii) with respect to any Capacity Year beginning after such date. Upon the execution, delivery and effectiveness of the Replacement PPA, this Agreement shall be deemed terminated and replaced in its entirety by such Replacement PPA; provided, however, that the obligation

of Buyer and Seller pursuant to Section 3.1(a)(i) and 3.1(a)(ii) then in effect with respect to any Contract Capacity Amount for any Capacity Year shall remain in effect until the termination of such Capacity Year. In the event Buyer exercises the option set forth in this Section 3.1(e), Seller and Buyer shall promptly take all actions necessary, including with PJM, each relevant Governmental Authority and otherwise, in order to terminate the Agreement as contemplated herein and expeditiously enter into the Replacement PPA.

3.2 Interconnection Facilities.

(a) Construction. In accordance with Article V, the Seller shall have the obligation to construct and upgrade the Electrical Interconnection Facilities (and responsibility for all costs related thereto), including metering and submetering facilities, and to cause them to become operational. Seller shall be responsible for paying the costs required by PJM or otherwise necessary for the performance of Seller's obligations set forth in the Agreement, including, without limitation, those arising under Section 3.1(a)(i)(A) and Section 3.1(a)(ii) with respect to the Capacity Value, Cleared Capacity Value and transfer of the Contract Capacity Amount to Buyer for each Capacity Year commencing in the Pre-Services Term Period or the Services Term. For the avoidance of doubt, Seller may subcontract the responsibility for construction of any Electrical Interconnection Facilities to third parties consistent with the PJM Agreements. Regardless of whether Buyer is a Participating Transmission Owner, Seller shall be responsible for all of Seller's interconnection arrangements or costs (for the avoidance of doubt, other than with respect to the cost of Network Upgrades expressly allocated to Buyer in Section 3.4(c)).

(b) Maintenance of Electrical Interconnection Facilities. To the extent required to achieve the Initial Delivery Date or the commencement of the Pre-Services Term Period, and at all times during the Pre-Services Term Period and the Services Term, Seller shall maintain and/or cause to be maintained, at its expense, the Electrical Interconnection Facilities such that the Electrical Interconnection Facilities are in compliance with the Interconnection Agreements and are capable of (i) delivering the Products that can be generated or produced using the Capacity of the Project, including the delivery of Delivered Energy to the Delivery Point during each month as applicable (in addition to such other output of the Project as the Electrical Interconnection Facilities are required to transmit), and (ii) maintaining the Capacity Value and transferring the Contract Capacity Amount to Buyer for each Capacity Year as required in accordance with the terms of this Agreement.

3.3 [Reserved].

3.4 Electric Transmission and Delivery.

(a) Title and Risk of Loss. Title to and risk of loss related to each Product required to be delivered to Buyer hereunder from or in connection with the Project shall transfer from Seller to Buyer as follows:

(i) for Delivered Energy, upon Buyer's receipt thereof at the Delivery Point;

(ii) for the Contract Capacity Amount for any Capacity Year, as set forth in the PJM Agreements and the PJM Capacity Rules;

(iii) for Environmental Attributes, as set forth in the GATS Operating Rules or other applicable Law;

(iv) for Ancillary Services (if any), as set forth in the PJM Agreements.

Until title passes to Buyer, Seller shall be deemed to be in exclusive control of the Products and shall be responsible for any damage or injury caused thereby. After title to the Products passes to Buyer, Buyer shall be deemed to be in exclusive control of such Products and shall be responsible for any damage or injury caused thereby.

(b) Seller's Responsibility. Except as otherwise expressly set forth in the Agreement, during the Services Term and the Pre-Services Term Period, Seller shall arrange, schedule and be responsible for electric transmission service up to and at the Delivery Point and any and all costs or charges imposed on or associated with the Products up to and at the Delivery Point or its delivery of the Products to the Delivery Point, including electric transmission costs, transmission losses, Electrical Losses, congestion costs and all risks and costs associated with any transmission outages or curtailment up to and at the Delivery Point, consistent with all standards and provisions set forth by FERC, PJM or any other applicable governing agency or tariff, or set forth by a Participating Transmission Owner). Seller shall maintain the power factor at the Delivery Point between 0.95 leading and 0.95 lagging consistent with PJM requirements. Regardless of whether Buyer is a Participating Transmission Owner, Seller shall be responsible for all of Seller's interconnection arrangements or costs (for the avoidance of doubt, other than with respect to the costs of Network Upgrades expressly allocated to Buyer in Section 3.4(c)).

(c) Buyer's Responsibility. (i) Buyer shall be responsible for (A) causing the Network Upgrades to be installed (unless a party other than Seller is responsible under the PJM Agreements), (B) Buyer's Percentage of the costs of such Network Upgrades constructed outside of the Delmarva Zone for which Buyer or Seller is responsible under the PJM Agreements (and Buyer's Percentage of any costs necessarily related thereto), and (C) one hundred percent (100%) of the costs of such Network Upgrades within the Delmarva Zone for which Seller or Buyer is responsible under the PJM Agreements (and any costs necessarily related thereto). Seller shall promptly reimburse Buyer for the costs of (or related to) the Network Upgrades that are incurred by Buyer and are not specifically assumed by Buyer hereunder, such amounts to be invoiced and paid by Seller promptly pursuant to the provisions of Article VI. (ii) Except as otherwise expressly set forth in the Agreement, during the Services Term and the Pre-Services Term Period, Buyer shall arrange, schedule and be responsible for electric transmission service and any and all costs or charges imposed on or associated with the Products or its receipt of the Products, in each case to the extent required to be delivered to Buyer hereunder,

including electric transmission costs and transmission losses after its receipt of the Products at the Delivery Point. Subject to Section 3.4(d), Seller shall have no liability to Buyer for transmission outages or curtailments (excepting actions by Seller inconsistent with the Agreement) after the receipt of Delivered Energy at the Delivery Point.

(d) Allocation of Certain Congestion Charges. Notwithstanding anything to the contrary set forth in this Agreement, Buyer shall be responsible for any charges and costs assessed by PJM under the PJM Agreements in connection with the delivery of the Delivered Energy to Buyer at the Delivery Point under the Agreement to the extent such charges and costs arise as a result (and solely as a result) of the Locational Marginal Price applicable to such Delivered Energy at the Delivery Point being negative (e.g., a Locational Marginal Price less than $0); provided, however, that if (i) one or more new intermittent resources with an aggregate nameplate capacity of seventy-five (75) MW or greater begin generating electricity and directly connects to the transmission system on the Delmarva Peninsula below the C&D Canal, and (ii) the new intermittent resource or resources do not construct the optional network upgrades identified in the facilities studies for such asset to allow the asset to qualify its entire maximum net output as a Capacity Resource in PJM, then from and after the time that such new intermittent resource or resources begin generating electricity, Seller shall be responsible for a percentage of any such charges and costs arising from a negative Locational Marginal Price applicable to Delivered Energy at the Delivery Point, determined in accordance with the following formula:

$$\text{Seller's Negative LMP Share} = \frac{\text{Seller's Intermittent MWs}}{\text{Total Intermittent MWs}}$$

where:

Seller's Negative LMP Share	=	The portion of the charges and costs arising from a Negative Locational Marginal Price applicable to Delivered Energy at the Delivery Point, expressed as a percentage, but from and after the commencement of generation by a new intermittent generator as described above, Seller's Negative LMP Share shall not be less than fifty percent (50%) nor more than eighty percent (80%);
Seller's Intermittent MWs	=	The Capacity of the Project, plus the maximum output of any new Peninsula Intermittent Resource owned by Seller or an Affiliate of Seller;

Total Intermittent MWs	=	Seller's Intermittent MWs plus the maximum output of all other new Peninsula Intermittent Resources; and
Peninsula Intermittent Resource	=	An intermittent resource directly connected to the transmission system on the Delmarva Peninsula below the C&D Canal.

Notwithstanding anything set forth herein to the contrary, under no circumstances shall Buyer be responsible for, and Seller shall bear the cost of (i) any congestion charges or costs (other than to the extent any such congestion charges or costs arise with respect to a negative Locational Marginal Price at the Delivery Point as set forth in the first sentence of this Section 3.4(d)), or (ii) any congestion charges or costs of any nature (including those contemplated under this Section 3.4(d)) arising in connection with any Energy delivered by Seller to or through PJM that does not constitute Delivered Energy delivered to Buyer under this Agreement. An example of a calculation of whether or not a charge attributable to a negative Location Marginal Price payable by Buyer arises pursuant to this Section 3.4(d) is set forth in Appendix 4.

3.5 Energy Forecasts, Scheduling and Balancing.

(a) Seller Energy Forecasts. No later than one hundred and twenty (120) days prior to the anticipated commencement of the Pre-Services Term Period (if applicable), or the Initial Delivery Date (to the extent there is no Pre-Services Term Period), Seller shall (1) engage the Forecast Consultant to provide the information required pursuant to this Section 3.5(a), and (2) demonstrate, to the Buyer's reasonable satisfaction, the completion and performance of the computer monitoring system (CMS) and any other reporting or monitoring facilities for the Project that shall be necessary for the provision of the information required pursuant to this Section 3.5(a). Seller shall, at its own cost and expense, comply with any PJM forecast requirements for the Project as such requirements may change from time to time, and provide to Buyer Notices containing such information as Buyer shall reasonably request for purposes of Buyer performing its obligations under this Section 3.5, including, without limitation, forecasts determined in good faith in accordance with Good Utility Practices (including the use of the services provided by the Forecast Consultant, historical performance, good faith projections and other relevant data and considerations) of the following information at the times specified herein:

(i) On or prior to the date falling fourteen (14) days before the commencement of the Pre-Services Term Period (if applicable), or the Initial Delivery Date (to the extent there is no Pre-Services Term Period) and continuing thereafter throughout the Services Term (as such period shall be reasonably determined, taking into account the expected or actual Initial Delivery Date, the

"Forecast Period"), the expected Energy to be delivered from the Project with respect to each hour during the Forecast Period (the "Expected Generation Schedule"), the expected Availability of the Project during the Forecast Period and the expected Capacity Value and Contract Capacity for each Capacity Year during the Forecast Period, as such Expected Generation Schedule, Availability and Contract Capacity shall be updated by no later than one (1) week prior to any Unit Group Commercial Operation Date occurring after the commencement of the Pre-Services Term Period;

(ii) On or prior to the date falling five (5) Business Days prior to the commencement of each calendar month (or portion thereof) falling in the Forecast Period, an update to the Expected Generation Schedule, Availability of the Project and the Capacity Value, Cleared Capacity Value, and Contract Capacity for the year commencing with such calendar month (each, a "Monthly Schedule");

(iii) On each day, between the hours of 7:00 a.m. and 10:00 a.m., commencing not later than one week prior to the commencement of the Pre-Services Term Period and continuing thereafter throughout the Forecast Period, an update to the expected Availability of the Project and the Expected Generation Schedule for each hour of the next fifteen (15) days (or for the first fifteen (15) days in the case of the initial time period) for the purpose of permitting the scheduling with PJM of the Energy to be delivered from the Project and in order for Buyer to anticipate the amount of Energy to be delivered from the Project during each day and hour of such fifteen (15)-day period (the "Day-Ahead Schedule"). The Day-Ahead Schedule shall also contain a disclosure of the existence and expected duration of any Outage or Instructed Operation known to Seller, the amount of the Capacity and Energy delivery affected by such Outage and the nature and effect of any Instructed Operation on the Project's Availability and Product delivery; provided that such information shall be provided only for days that are part of the Forecast Period;

(iv) For each hour of each day during the Forecast Period, an update to the Day-Ahead Schedule for such hour ("Hourly Schedule Updates") in accordance with the time frame of PJM's scheduling protocol (which as of the Execution Date is fifteen (15) minutes prior to the hour of such delivery); and

(v) To the extent permitted by PJM protocols for scheduling entities, real-time schedule updates to the Day-Ahead Schedule, including to the extent a variation from the forecasted Energy in such Day-Ahead Schedule is expected to result from a Force Majeure Event, a curtailment or a change in wind conditions.

The Notices required pursuant to this Section 3.5(a) shall be set forth in the forms developed by the Operating Committee. The Seller's initial good faith projection of the Project's Expected Generation Schedule based on a 450 MW Project sizing is set out on Schedule 2 in 12x24 format and has been provided to Buyer separately as of the Execution Date in a form illustrating expected generation for each hour during the Forecast Period. Seller will provide Buyer with an updated Expected Generation

Schedule (including the expected generation for each hour during the Forecast Period) within thirty (30) days of Seller determining the Project Capacity pursuant to Section 2.4. Notices required pursuant to this Section 3.5(a) shall be referred to as "Forecasted Energy Notices." Each such Forecasted Energy Notice shall be delivered to Buyer in accordance with the Operating Procedures established pursuant to Section 3.13. Notwithstanding anything to the contrary in this Agreement, the Parties agree that the Project is a unit contingent "as available" facility and any forecasts by Seller regarding the Project's performance shall be solely considered estimates of expected performance of the Project, and shall be made by Seller consistent with Good Utility Practices and based on Seller's good faith output projections (utilizing the Forecast Consultant) based on wind conditions, Power Curve performance, Availability, historical performance and other relevant data and considerations.

(b) Seller's Continuing Obligations to Provide Notice of Availability. During the Forecast Period, to the extent not reported in the most recent Forecasted Energy Notice or pursuant to Section 3.10, Seller shall (A) notify Buyer's designated representative, orally or through an automated notification system, of every Outage of the Project or imposition of an Instructed Operation as soon as possible (and in any event, using commercially reasonable efforts to do so within thirty (30) minutes after the occurrence of such Outage), (B) provide a written estimate of the expected duration of such Outage and/or nature of the Instructed Operation within three (3) hours after submittal of the initial notification pursuant to clause (A) of this sentence, and (iii) submit an Outage/Availability Notification Form, to Buyer in accordance with the instructions shown on the form. The Seller shall update Buyer periodically through the day as information becomes available as well as through Forecasted Energy Notices, with any revised estimates regarding the Project's return to full output capability and shall promptly provide Buyer Notice of any further changes in the Availability of the Project or Products from that set forth in the last notice provided, including any developments that will affect the severity or duration of each Outage, Availability and capability of the Project to deliver Products after an Outage or the scope and duration of the Instructed Operation.

(c) Other Reporting Obligations. Each Notice provided pursuant to Section 3.5(a) or 3.5(b) that includes a Notice of an Outage or Instructed Operations shall include all such information concerning such Outage, change or limitation as PJM may require to be reported by Buyer or by Seller. Each such Notice from Seller to Buyer shall be made by providing Notice in accordance with the outage/availability notification procedures to be established by the Operating Committee by the commencement of the Pre-Services Term Period (the "Outage/Availability Notification Procedures"). During the Forecast Period, Seller is responsible for providing to PJM notice of each Outage to the extent required by Law, the PJM Tariff or other PJM Agreements or contracts. During the Forecast Period, each of Seller and Buyer shall promptly communicate to the other all information received by it from PJM or any Governmental Authority regarding planned or in-progress Outages or Instructed Operations. Seller is responsible for providing regulatory bodies such as FERC and the Commission with Outage information (for example but not limited to, NERC outage reporting requirements) as required by Law, Permit, tariff or regulation.

(d) Scheduling with PJM. Subject to Section 3.4(d) and (i) the receipt by Buyer from Seller of the information required to be provided pursuant to Section 3.5(a) on a timely basis, and (ii) the allocation of credits, charges and costs set forth in Section 3.5(e), during the Services Term and the Pre-Services Term Period, the Buyer shall be responsible for scheduling with PJM's Office of Interconnection the Energy and Energy constituting Excess Products to be delivered to the Delivery Point, which scheduling shall be consistent with the timing of PJM's then-applicable scheduling protocols in accordance with Section 3.6 of this Agreement (Standards of Care) and all PJM operational protocols (the "Buyer Scheduling Obligation").

(e) Allocation of Certain PJM Scheduling Charges. Subject to Sections 3.4(b) and (c), the Parties agree that all credits, charges and costs assessed by PJM with respect to the Buyer Scheduling Obligations shall be allocated as follows:

(i) any Balancing Operating Reserve charges (as set out in the PJM Manual 28-Operating Agreement Accounting) related to deviations between the Day-Ahead Schedule submitted by Buyer to PJM pursuant to Section 3.5(d) and the real time delivery of Energy from the Project to the Delivery Point under the Agreement shall be divided evenly between the Parties with respect to Delivered Energy and Deemed Generated Energy, and one hundred percent (100%) to Seller with respect to any Energy scheduled by Buyer from the Project and not delivered to Buyer pursuant to the terms hereof; and

(ii) the Parties acknowledge that under the current PJM Agreements, the Project will be assessed or receive credits or charges from PJM based on the product of (1) the difference between the quantity of any Energy from the Project scheduled by Buyer in the Day-Ahead Market pursuant to the terms of the Agreement and the actual quantity of Energy delivered by the Project to the Delivery Point in real-time pursuant to the terms of the Agreement, and (2) the Locational Marginal Price associated with the real-time Energy delivered by the Project to the Delivery Point in excess of or less than the quantity of Energy set forth in the Day-Ahead Schedule submitted by Buyer to PJM (the "Balancing Amounts"). Balancing Amounts with respect to Delivered Energy shall be for the account of Buyer. Balancing Amounts with respect to Energy from the Project not delivered to Buyer pursuant to the terms hereof, including Excess Products, are for the account of Seller (other than Deemed Generated Energy for which Buyer is obligated to compensate Seller for pursuant to Section 3.16). The Parties agree to take all commercially reasonable actions requested by Buyer to minimize any Balancing Amounts charged to Buyer, to provide information to Buyer and, at the request of Buyer, to exercise commercially reasonable efforts to modify the arrangement set forth in this Section 3.5 in response to any changes in applicable PJM Agreements in order to minimize net charges to Buyer; provided such a change does not otherwise have a net adverse effect on Seller; and provided, further, that nothing in this sentence shall be construed to limit the obligations of Seller to provide the Forecasted Energy Notices as provided under Section 3.5(a).

(iii) any administrative charges assessed by PJM pursuant to the PJM Tariff for recovery of PJM's administrative and operating costs that are assessed on Buyer's performance of the Buyer's Scheduling Obligation shall be for the account of Seller.

(f) Seller's Operation. During the Pre-Services Term Period and the Services Term, Seller shall use commercially reasonable good faith efforts to dispatch and operate the Project in a manner consistent with Good Utility Practice so as to deliver at the Delivery Point the Energy set forth in the most recent Forecasted Energy Notice.

(g) PJM Payment Procedures. If PJM shall bill or credit Seller or Buyer directly for any Ancillary Services charges, congestion charges (including those described in Section 3.4), Balancing Operating Reserve charges, Balancing Amounts, charges for recovery of administrative and operating costs, or similar charges or credits, or other fees or penalties or credits properly payable by or to the other Party pursuant to the terms of this Agreement, the Party receiving such invoice shall deliver such invoice to the other Party and such other Party shall pay such invoice by the later of the due date or ten (10) days after receipt from the receiving Party, *provided, however*, that if there is a dispute as to which Party is responsible for payment of such invoice, the original recipient of the invoice from PJM shall remit payment of such invoice on the due date. The Party ultimately determined to be responsible for such invoice shall reimburse the other Party, together with interest at the Interest Rate if the other Party paid the invoice, within ten (10) days of such determination of responsibility.

(h) Capacity Charges. Notwithstanding anything to the contrary set forth in this Agreement, Seller shall bear all risk and responsibility with respect to any costs or credit requirements (including the posting of applicable credit support) related to its compliance with the PJM Capacity Rules in connection with the Capacity Value and the Cleared Capacity Value of the Project for any Capacity Year and the transfer to Buyer of the Contract Capacity Amount for such Capacity Year pursuant to this Agreement, including any and all charges or costs, including capacity deficiency charges, assessed by PJM or otherwise against Seller (collectively, the "Capacity Charges"). If PJM bills or credits Buyer for any charges, costs or other amounts related to any Capacity Charges, Buyer shall deliver such invoice or statement to Seller and Seller shall pay such invoice or otherwise settle such amounts by the later of the due date (if applicable) or ten (10) days after receipt from Buyer. Invoicing and payment for all amounts due from Seller to Buyer as necessary to implement this provision shall be done pursuant to Article VI.

3.6 Standards of Care.

(a) General Operations.

(i) Seller, as owner and operator of the Project, shall be responsible for complying with Good Utility Practices, all applicable requirements of Law, the Commission, PJM, NERC, Reliability*First* Corporation, and other Governmental Authorities relating to the Project (including those related to

construction, ownership and/or operation of the Project), as well as relating to the performance of its obligations under this Agreement, whether imposed pursuant to existing Law or pursuant to changes enacted or implemented during the Contract Term, including all risks of environmental matters relating to the delivery of the Products hereunder and the Project and the Site. For the avoidance of doubt, Seller will be responsible for procuring, at its expense, all Permits (other than those explicitly set forth herein as being the responsibility of the Buyer), required for operation of the Project and the performance of its obligations under this Agreement in compliance with Law. No later than sixty (60) days prior to the earlier of the first Unit Group Commercial Operation Date and the Project Commercial Operation Date, if the Seller shall not be the operator of the Project, Seller shall notify Buyer of such operator, and shall confirm that the agreement between Seller and such operator shall require the operator to operate the Project in accordance with the terms of this Agreement.

(ii) In its performance of its obligations hereunder, Buyer shall comply with Good Utility Practices, all applicable requirements of Law, the Commission, PJM, NERC, Reliability*First* Corporation, and other Governmental Authorities relating to the Project, whether imposed pursuant to existing Law or pursuant to changes enacted or implemented during the Contract Term.

(b) PJM Standards. Each Party shall perform all generation, scheduling and transmission services in compliance with all applicable (i) operating policies, criteria, rules, guidelines, tariffs and protocols of PJM, (ii) PJM scheduling and capacity resource practices and (iii) Good Utility Practices. RECs sold by Seller to Buyer hereunder shall be created and supplied by the GATS, or its successor at law (pursuant to the Commission RPS Rules). The Project shall be subject to applicable GATS Operating Rules and Seller and Buyer each shall pay for their respective costs, fees and expenses to create and maintain a GATS account for the purpose of delivering and taking delivery, as applicable, of RECs sold under this Agreement. Seller shall pay all applicable GATS fees and expenses in connection with the RECs sold under the Agreement, up to delivery of the RECs to Buyer's GATS account and Buyer shall pay all applicable GATS fees and expenses in connection with the RECs sold under the Agreement on and after the delivery of RECs sold under this Agreement to Buyer's GATS account.

(c) Reliability Standard. Seller agrees to abide by all NERC, Reliability*First* Corporation, PJM and Commission reliability requirements and all of Buyer's applicable requirements regarding interconnection and operation of the Project, updated from time to time by Buyer consistent with Good Utility Practices in consultation with Seller.

3.7 [Reserved].

3.8 Metering.

All electric metering associated with the Project including the Project Meter, whether owned by Seller or a third party, shall be installed, operated, maintained, and tested by or on behalf of Seller in accordance with NERC, Reliability*First* Corporation,

PJM Agreements, Good Utility Practices, and any applicable Buyer technical requirements and standards.

(a) Metering Cost Responsibility. The Seller shall install, maintain, operate, test and replace (as appropriate) the Project Meter, telemetry equipment, and other appropriate electric meters and back-up meters at its sole cost and expense to accurately determine Delivered Energy taken by Buyer under this Agreement or otherwise delivered by the Project.

(b) Project Meter Location. The Project Meter shall measure the delivery of Products at the Delivery Point. The actual physical location of the Project Meter is proposed to be at Seller's on-shore switching station (near Bethany, Delaware). If the physical location of the Project Meter is not at the Point of Receipt, then, in conformance with applicable PJM rules and Good Utility Practice, revenue quality loss-compensation metering shall be used to account for any transmission or transformer losses between the Project Meter and the Point of Receipt.

(c) Meter Security and Read Access. The electric meters shall be checked annually by Seller who shall provide Buyer with not less than thirty (30) days prior written Notice of such tests. Buyer shall have the right to have a representative(s) present during such tests. Seller shall be responsible for fully metering all Project generation loads, including the obligation to accurately and completely send meter telemetry into the PJM eMeter system. Seller shall exercise reasonable care in the maintenance and operation of such metering equipment so as to assure to the maximum extent practicable an accurate determination of such quantities of Energy and Products. The amount of Energy measured by the Project Meter as being delivered to the Delivery Point rounded downward to the nearest MWh shall be the basis for determining Delivered Energy and the amount of other Products delivered pursuant to this Agreement based on such Delivered Energy, subject to Buyer's testing and audit rights.

(d) Meter Retesting and Inaccuracy. Either Party may from time to time request a retest of the meters if it reasonably believes that the meters are not accurate within the tolerance limits established by PJM or the applicable service provider. The requesting Party shall pay for any such retest and shall provide the other Party with not less than fourteen (14) days prior written Notice of such retest. Such other Party will have the right to have a representative present during such retest. If any tested or retested meter is found to be not accurate within the tolerance limits established by PJM, Seller shall promptly arrange for the correction or replacement of the meter, at its expense, and the Parties shall use the measurements from the back-up meters or submeters to determine the amount of the inaccuracy. If the back-up meters or submeters are found to be not accurate within the tolerance limits and the Parties cannot otherwise agree as to the amount of the inaccuracy, the inaccuracy will be deemed to have occurred during the period from the date of discovery of the inaccuracy to the earlier of (a) one-half of the period from such discovery to the date of the last testing or retesting of the meters or (b) one hundred eighty (180) days. Any amounts due by Buyer or to be refunded by Seller as a result of any meter that is not accurate within the tolerance limits will be

invoiced by such Party within fifteen (15) days of the discovery of such inaccuracy, with payment due within thirty (30) days after the date of the invoice for such amounts.

(e) Access to Meters. To support invoice settlement purposes, Seller shall provide Buyer with reasonable access to the Project Meter and all other real-time meters, billing meters and back-up meters (i.e., all metering) in accordance with the Interconnection Service Agreement. Seller shall authorize Buyer to view the Project's on-line meter data.

(f) Telemetry. Seller shall send via a means of transmission approved by the Operating Committee and consistent with Good Utility Practice and the PJM Agreements the specific telemetry data points required for the Project, as measured by the Project Meter, including: MW, MVAR, MWH, MVARH, isolation breaker open/closed status, interconnection bus voltage, and amp flow. A data line will be required to send this data to Buyer. These telemetry data point requirements are outlined in Buyer's "Technical Considerations Covering Parallel Operations of Customer Owned Generation of One Megawatt or Greater and Interconnected with the Conectiv Power Delivery System." The MWH and MVARH values that are telemetered to Buyer must originate from the Project Meter. Seller shall have the obligation to accurately and completely send meter telemetry into the PJM eMeter system. Seller shall establish, in consultation with Buyer, a system allowing Buyer and Seller to provide real-time dynamic signals sufficient to fulfill the scheduling parameters of this Agreement and applicable PJM rules, including enabling Seller to provide real-time dynamic signals to Buyer regarding the types and amounts of Products that are to be delivered pursuant to this Agreement and enabling Seller to provide Buyer real-time dynamic signals specifying the amount of Delivered Energy that is being delivered to the Delivery Point at all times.

3.9 [Reserved].

3.10 Project Outages.

(a) Seller's Planned Outage Proposed Schedule. Seller shall notify Buyer of its proposed Planned Outages for the applicable Unit, Unit Group or the Project by submitting to Buyer and PJM a completed outage/availability notification form, such form to be developed by the Operating Committee prior to the commencement of the Pre-Services Term Period (the "Outage/Availability Notification Form") that fully accords with the requirements of this Section 3.10 as follows:

(i) within sixty (60) days of the commencement of the Pre-Services Term Period and no later than seven (7) days prior to (1) each Unit Commercial Operation Date, (2) each Unit Group Commercial Operation Date and (3) the Initial Delivery Date, in each case for the period from such date through the end of such calendar year;

(ii) for the next calendar year, by no later than September 1 of each year during the Pre-Services Term Period and the Services Term; and

(iii) for each calendar quarter (or portion thereof) falling thereafter, by no later than thirty (30) days prior to the commencement of each quarter, updating to the extent required the schedule previously Noticed pursuant to clauses (i) or (ii) above, provided that if there is no change in the schedule previously Noticed, the update shall state as such;

provided that any Seller's Planned Outage lasting longer than nine (9) consecutive days may be taken only after a minimum of thirty (30) days advance Notice prior to the month in which the Planned Outage will occur.

Any outage scheduled and subsequently taken pursuant to clause (i), (ii) or (iii) above shall be a Planned Outage. Except as provided elsewhere in this Agreement, including, without limitation, Section 3.10(c) below, Seller shall not schedule any Planned Outage for a period during which PJM prohibits a Capacity Resource from scheduling a Planned Outage.

(b) Seller's Notification of Maintenance Outages. Seller shall notify Buyer and PJM of its proposed Maintenance Outages for the Unit, Unit Group or the Project by submitting to Buyer and PJM a completed Outage/Availability Notification Form with no less than the advance notice required under the PJM Agreements (or if not specified in the PJM Agreements, no less than forty-eight (48) hours) in advance of the requested start of the Maintenance Outage. Any Maintenance Outage for which notification is provided in accordance with this Section and permission to take such outage is granted by either PJM or Buyer pursuant to Section 3.10(d), below, shall be a Maintenance Outage. Seller shall not schedule any Maintenance Outage for a period during which PJM prohibits a Capacity Resource from scheduling a Maintenance Outage, except that, with the consent of Buyer, which consent shall not be unreasonably withheld, Seller may request PJM approval of a Maintenance Outage during such a period, and, upon receipt of such PJM consent, Seller may schedule a Maintenance Outage during such a period.

(c) Buyer-Requested or Seller-Requested Changes to Planned Outage and Maintenance Outage Schedules. At any time, Buyer may request that Seller change its Planned Outage or Maintenance Outage schedule or Seller may request that Buyer consent to a change in the Planned Outage or Maintenance Outage Schedule. Upon receipt of such a request, the receiving Party shall notify the requesting Party of any economic losses and incremental costs associated with the schedule change and an alternative schedule change, if any, that would entail lower economic losses and lower incremental costs. If the requesting Party's proposed change is feasible and imposes no economic losses or incremental costs on the receiving Party (as compared to receiving Party's original Planned Outage or Maintenance Outage schedule), or if the requesting Party agrees to pay the receiving Party's economic losses and incremental costs, the receiving Party shall use commercially reasonable efforts to accommodate the requesting Party's request. Notwithstanding the foregoing, whenever PJM directs that a change be made in the Planned Outage schedule, such change shall be undertaken by Seller at its sole cost and expense, except to the extent the change affects an outage that was previously changed at the request of Buyer. Seller shall communicate the changes to PJM and seek, if required under the PJM Agreements, PJM approval for the revised

schedule. If PJM approval is required, any change shall be dependent on receipt of such approval. Any outage that is changed pursuant to this provision shall be a Planned Outage or Maintenance Outage, as appropriate.

(d) PJM Approval of Outages. Seller is responsible for securing all applicable PJM approvals and complying with all requirements under the PJM Agreements, as applicable, for all Planned Outages and Maintenance Outages, including securing changes in the proposed Planned Outage and Maintenance Outage schedules when PJM disapproves such schedules or outages or cancels previously approved Planned Outages or Maintenance Outages. Notwithstanding the foregoing, if PJM elects not to participate in this outage approval process during the Contract Term, Buyer shall be responsible for the outage approval process in accordance with the terms of PJM Agreements, provided that Buyer shall grant approvals for requested outages in accordance with the standards and criteria applicable under the PJM Agreements, and Buyer's approval shall not be unreasonably withheld and shall not adversely affect the Capacity Value.

(e) Seller Notice of Extension of Planned Outage or Maintenance Outage. At any time, Seller may notify PJM and Buyer of a need to extend a Planned Outage or Maintenance Outage by submitting to Buyer's Authorized Representative a written notification of an Outage Extension. Such Outage Extension notice shall demonstrate that the extension satisfies the applicable requirements of the PJM Agreements for an Outage Extension. Seller is responsible for submitting any required notification to PJM of the extension of the Planned Outage or Maintenance Outage. If PJM determines that the extension of the Planned Outage or Maintenance Outage qualifies as an Outage Extension, then the additional outage duration shall be considered part of the original Planned Outage or Maintenance Outage. If PJM notifies Seller that it is not accepting or processing notifications of extensions of Planned Outages or Maintenance Outages for the Unit, Unit Group or the Project as part of a policy or practice relating to wind generating resources, then Buyer shall apply the criteria set forth in the PJM Agreements to determine whether the requested extension qualifies as an Outage Extension and, if Buyer determines that the requested extension satisfies such criteria, then the Outage Extension shall be considered part of the original Planned Outage or Maintenance Outage.

(f) Exclusions. Any Outage taken pursuant to this Section that does not also meet the requirements set forth in Sections 3.10(a) through (e) above for a Planned Outage or Maintenance Outage, and any Outage taken outside of or in excess of the duration permitted for Planned Outages or Maintenance Outages or not otherwise in accordance with this Section 3.10, shall be treated as Forced Outages and the Project will be deemed to be unavailable during such periods for purposes of Section 12.1(a)(vii) and (viii).

3.11 Operations Logs and Access Rights.

(a) Operations Logs. Seller shall maintain a complete and accurate log of all material operations of the Project on a daily basis. Such log shall be maintained in accordance with Good Utility Practices and shall include, but not be limited to,

information on power production, efficiency, availability, maintenance performed, Outages, electrical characteristics of the Project and similar information relating to the availability, testing and operation of the Project and availability and production of the Products. Seller shall provide this information electronically to Buyer within fifteen (15) days of Buyer's request.

(b) Access Rights. Buyer, its authorized agents, employees and inspectors shall have the right of ingress to and egress from the Project at any time upon reasonable Notice and for any purposes reasonably connected with this Agreement, including verification of the Project's availability or unavailability and to monitor construction of the Project. Buyer shall be responsible for all costs and bear all risks associated with all such visits to the Project pursuant to this Section 3.11. While at the Project and the Site, such Persons shall comply with all applicable Law and PJM regulations and observe such safety precautions as may be reasonably required and communicated to such representatives by Seller or Seller's representatives and shall not interfere with the operation of the Project, except in the exercise of Buyer's remedies hereunder.

3.12 Performance Testing.

(a) Testing Requirement. Seller shall conduct an Initial Performance Test for purposes of establishing the Unit Group Commercial Operation Date or Project Commercial Operation Date for each Unit, and Subsequent Performance Tests during the term of, and the extent provided for in, the Turbine Supply Agreement after the achievement of such Commercial Operation Dates. Seller shall bear all costs of the Initial Performance Test and the Subsequent Performance Tests. The Parties shall provide for additional procedures and protocols related to testing, consistent with the principles set forth above, in the Operating Procedures, which shall be additional "Test Procedures", not to be included in the Initial Performance Test or the Subsequent Performance Tests.

(b) Initial Performance Test Procedure. The "Initial Performance Test" shall consist of a test of each of the Units in accordance with the terms of the Turbine Supply Agreement to confirm each such Unit is integrated with the PJM Grid and is delivering Energy to the PJM Grid consistent with PJM requirements. Buyer may have a representative present at the Project at any time during any Initial Performance Test and Section 3.11 shall apply thereto.

(c) Subsequent Performance Tests Procedures. The "Subsequent Performance Tests" shall consist of tests and warranties of the Turbine Supply Availability and Power Curve of the Units to the extent provided by, and in accordance with the terms of the Turbine Supply Agreement. Such tests and confirmation of warranted performance shall be undertaken in accordance with the terms of the Turbine Supply Agreement Buyer may have a representative present at the Project at any time during the Subsequent Performance Tests and Section 3.11 shall apply thereto. Buyer shall promptly be provided with all results of the Subsequent Performance Tests by Seller.

3.13 Operating Committee and Procedures.

(a) After the Effective Date and prior to the time period set forth in Section 3.13(b) below, the Parties shall establish an operating committee (the "Operating Committee"), consisting of three Authorized Representatives of each Party, to establish the Operating Procedures described in Section 3.13(b).

(b) At least one hundred and twenty (120) days prior to the commencement of the Pre-Services Term Period or, if there is no such Pre-Services Term Period, the Initial Delivery Date, the Operating Committee shall mutually agree upon operational procedures, not in contravention or amendment of any right or obligation set forth herein, including, but not be limited to, (1) procedures for forecasting and scheduling in accordance with Section 3.5, and, without requiring any additional obligations, cost or risk to Buyer, coordination of Buyer's scheduling obligations thereunder with the forecasting and scheduling obligations of Seller or any other third parties with PJM with respect to any Excess Products, (2) procedures for notification and verification to Buyer of the Capacity Value and Cleared Capacity Value for each Capacity Year, and procedures and management with PJM and otherwise of the transfer of the Contract Capacity Amount from Seller to Buyer for each such Capacity Year, and any other coordination required in connection with the Project's treatment as a Capacity Resource with PJM, its Capacity Value and the determination and transfer of the Contract Capacity Amount for each Capacity Year, (3) address station power usage and costs by the Project, (4) methods of day-to-day communications, (5) key personnel lists, (6) record keeping and (7) such other procedures and protocols as the Parties deem appropriate for implementation of this Agreement (the "Operating Procedures"); provided that failure to agree on such procedures (i) shall be resolved in accordance with the procedures set forth in Article XIII (Dispute Resolution) and (ii) shall not relieve either of the Parties of its obligations under this Agreement.

3.14 Resource Adequacy Requirements. The Parties acknowledge that the Commission, PJM, FERC, or another Governmental Authority may, during the Contract Term, put into place a Resource Adequacy Requirement whereby eligibility to credit Capacity toward the Resource Adequacy Requirement may be determined by identifying the Project. The Parties further acknowledge that as of the Execution Date no such Resource Adequacy Requirement exists. During the Pre-Services Term Period and the Services Term, Seller shall commit the Units to Buyer for the purpose of meeting any Resource Adequacy Requirements applicable to Buyer that may be established by the Commission, PJM (or successor control area operator) or other Governmental Authority from time to time, and shall comply with any Commission, PJM, FERC, or other Governmental Authorities requirements for meeting RAR (to the extent, in each case, that a wind-powered electric generating facility is able to comply with such Resource Adequacy Requirements). For avoidance of doubt, included within Buyer's exclusive rights to Products available from the Units and the Project described in Section 3.1(a), Buyer is entitled to all products there from that are related to RAR, including capacity tags, capacity credits, and all installed capacity and other capacity-related products pertaining to Buyer's entitlement to the Products from the Project (other than with respect to Excess Products). For the avoidance of doubt, Seller shall have the right to sell to third

parties all RAR related products that are related to the Excess Products, including capacity tags, capacity credits, and all installed capacity and other capacity-related products pertaining to such Excess Products, so long as such sale does not limit or reduce the ability of Buyer to receive the Products required to be delivered to Buyer under this Agreement.

Throughout the Pre-Services Term Period and the Services Term, Seller shall take all such actions and execute any and all documents or instruments necessary to ensure the availability and qualification of each Unit and the Project and the Capacity to meet Buyer's RAR and Buyer's or PJM's right to the use a proportionate amount of the Project and its Products (up to those maximum amounts as set forth in Section 3.1(a)) for the benefit of Buyer's RAR (to the extent, in each case, that a wind-powered electric generating facility is able to comply with applicable Resource Adequacy Requirements). The Parties acknowledge and agree that the allocation of capacity-related rights to Buyer under this Section 3.14 shall be accomplished in part through the obligations of Seller pursuant to Sections 3.1(a)(i)(A) and 3.1(a)(ii), including the transfer of the Contract Capacity Amount for each Capacity Year, but the Parties further acknowledge and agree to take such further actions as may be appropriate or desirable in order to give full effect to the intent of this Section 3.14.

Notwithstanding the foregoing, in the event that, subsequent to the Execution Date and the qualification of the Project as a Capacity Resource as required pursuant to Section 5.3(a)(x), Seller is required to incur any increase in operating or capital costs, or lost revenues due to reduced production resulting from compliance with Buyer's RAR requirements (including lost PTC revenue that would otherwise accrue to Seller due to its performance under the Agreement, as calculated in accordance with the method set forth in Section 3.16) in excess of $200,000 per year or $500,000 for the Contract Term in order to meet Buyer's RAR, Buyer shall have the option to waive or enforce compliance with the obligations related to RAR hereunder. If Buyer elects to enforce the compliance by Seller with the RAR pursuant to the previous sentence, Buyer shall compensate Seller for the incremental costs or lost revenues due to reduced production (including lost PTC revenue that would otherwise accrue to Seller due to its performance under the Agreement, as calculated in accordance with the method set forth in Section 3.16) it would not have incurred but for compliance with RAR, in excess of $200,000 per year or $500,000 for the Contract Term, as such incremental costs or lost revenues shall be reasonably demonstrated by Seller. In the event the Parties disagree on the amount needed to keep the Seller in the same financial position as it would have been in had it not been required to incur any such costs of subsequent compliance with RAR, the matter shall be resolved in accordance with the dispute resolution provisions set forth in Article 13.

Subject to the other terms of this Section 3.14, the actions required of Seller pursuant to this Section 3.14 after the Initial Delivery Date may include the following:

(i) Cooperating with Buyer, and cooperating with and encouraging the regional entity or Governmental Authority responsible for RAR administration, to certify or qualify the Project and/or Products and such portion of the Contract

Capacity as is necessary for the Buyer's Percentage of Contract Capacity to qualify for Buyer's RAR purposes; meeting any revisions to the requirements established by PJM in its resource adequacy counting protocols from those in effect as of the Initial Delivery Date, including revisions relating to the demonstration of the ongoing ability to deliver such portion of the Contract Capacity over all hours required for full RAR eligibility, and demonstrating that such portion of the Contract Capacity can continue to be delivered to the PJM Grid pursuant to any deliverability standards established by PJM or other regional entity or entities responsible for RAR administration;

(ii) Negotiating in good faith to make necessary amendments, if any, to this Agreement to conform this Agreement to subsequent clarifications, revisions or decisions rendered by the Commission or the regional entity or entities or Governmental Authority responsible for RAR administration, so as to maintain the benefits of the bargain struck by the Parties; and

(iii) Taking commercially reasonable measures necessary to comply with any changes to the requirements for meeting RAR implemented after the Initial Delivery Date.

In addition, subject to Buyer's scheduling responsibilities and ultimate responsibility therefor hereunder pursuant to Sections 3.4 and 3.5, Seller agrees to take all reasonable steps to comply (to the extent that a wind-powered electric generating facility is able to qualify), subject to the Operational Limitations, with all associated bidding/dispatch requirements imposed through either PJM market design and tariffs, the Commission, or FERC. Such bidding requirements may be imposed in the day ahead, hour ahead or real time timeframe.

3.15 Minimum Performance Requirement. During the Services Term, Seller shall be required to deliver to Buyer Delivered Energy annually in each Contract Year in an amount equal to at least fifty-two percent (52%) of the MPR Base Amount of the Project ("Minimum Performance Requirement"). In each Contract Year of the Services Term if the amount of Delivered Energy delivered to Buyer at the Delivery Point from the Project pursuant to the terms of the Agreement (and giving credit to Seller for Deemed Generated Energy attributable for such Contract Year) is less than the Minimum Performance Requirement, Seller shall pay to Buyer an amount equal to $25 total per MWh for the deficit amount of Energy and associated RECs below the Minimum Performance Requirement. Damages payable by Seller to Buyer pursuant to the terms of this Section 3.15 for failure to meet the Minimum Performance Requirement shall be capped at $1,500,000 per year and $10,000,000 in the aggregate over the Services Term. Buyer shall have the right to terminate the Agreement pursuant to Section 12.2 in the event the amount of damages payable by Seller to Buyer pursuant to this Section 3.15 reaches the cumulative limit of $10,000,000 prior to the end of the Services Term, which such occurrence shall be deemed a Seller's Event of Default.

3.16 Buyer Failure to Take Delivered Energy.

(a) During the Pre-Services Term Period and the Services Term, and subject in all respects to Section 3.1(a)(iv): (1) if Buyer fails to take Delivered Energy made available to Buyer at the Delivery Point that Buyer is required to purchase under the terms of this Agreement, or (2) if Seller is unable to generate Energy that would otherwise be delivered to and be required to be purchased by Buyer pursuant to the terms of the Agreement, in each case not resulting from a Force Majeure Event, Dispatch Down Period or an Instructed Operation, and is otherwise solely due to any act or failure to act by Buyer that is inconsistent with Buyer's rights and obligations under the Agreement, and such failure to take or inability to generate is not excused by or caused by (to the extent inconsistent with Seller's rights and obligations hereunder) Seller's action, inaction or default (a "Buyer Unexcused Failure"), then Buyer shall pay to Seller, upon Seller's written request therefor on thirty (30) days prior written Notice, an amount equal to (a) in the case of clause (2) above, the Deemed Generated Energy for such period, multiplied by the price for Delivered Energy then applicable for such period set forth in Section 4.2; and (b) in the case of clause (1) above, if positive, (x) the Deemed Generated Energy (as measured at the Project Meter) for such period, multiplied by the price for Delivered Energy then applicable for such period set forth in Section 4.2, less (y) the sales price or other amounts received by Seller with respect to such delivered Deemed Generated Energy (as measured at the Project Meter), whether from sales to third parties or into the PJM markets, from balancing amounts or otherwise (it being understood that Seller shall use all commercially reasonable efforts to seek to obtain the best price available for such Energy, and sell such delivered Deemed Generated Energy (in accordance with Section 12.6) into the PJM market) (any such payments required to be made by Buyer pursuant to this Section 3.16, the "Deemed Generated Energy Compensation Amount"). Buyer shall invoice all Deemed Generated Energy Compensation Amounts, consistent with Article VI. In the event that Buyer is compensating Seller for a Buyer Unexcused Failure as set forth in this Section 3.16, such failure to take Energy and other Products as described herein shall not constitute an Event of Default hereunder.

(b) In connection with any payment by Buyer due under Section 3.16(a) for a quantity of Deemed Generated Energy as required pursuant to this Section 3.16, Buyer shall also pay to Seller compensation for the Environmental Attributes attributable to the Deemed Generated Energy that Seller has either not been able to generate (in the case of Deemed Generated Energy covered by Section 3.16(a)(2) above) or that Seller has not been able to sell (despite its commercially reasonable efforts to do so) (in the case of Deemed Generated Energy covered by Section 3.16(a)(1)), in an amount equal to the applicable number of Environmental Attributes that would correspond to such Deemed Generated Energy multiplied by the price for Environmental Attributes then applicable for such period set forth in Section 4.2(a)(iii)(A), as adjusted pursuant to Section 4.2(a)(iv) (in the case of Deemed Generated Energy covered by Section 3.16(a)(2)), or compensation for the Environmental Attributes that were generated in connection with the Deemed Generated Energy, but which Buyer did not purchase in contravention of its obligations under this Agreement (in the case of Deemed Generated Energy covered in Section 3.16(a)(1)), in an amount equal to (if positive)

(x) the applicable number of Environmental Attributes generated with respect to such Deemed Generated Energy and which were required to be purchased by Buyer hereunder, multiplied by the price for Environmental Attributes then applicable for such period set forth in Section 4.2(a)(iii)(A), as adjusted pursuant to Section 4.2(a)(iv), less (y) the sales price or other amounts received by Seller with respect to such generated Environmental Attributes (it being understood that Seller shall use all commercially reasonable efforts to sell (pursuant to Section 12.6) such generated Environmental Attributes). In the case of Deemed Generated Energy arising under Section 3.16(a)(2) only, Seller shall receive compensation for PTCs, calculated on an After-Tax Basis, to which Seller would have been entitled and did not otherwise receive with respect to the amount of such Deemed Generated Energy on account of Buyer's Unexcused Failure at the then current PTC rate applicable to the Units in question giving effect to any inflation adjustment currently incorporated into the PTC at such time.

(c) Buyer shall additionally compensate Seller for ninety two percent (92%) of any reduction in Buyer's Percentage of Capacity Value for any Capacity Year caused by Buyer's Unexcused Failure directly resulting in a reduction of Capacity Value attributable to Deemed Generated Energy covered by Section 3.16(a)(2) above.

Calculations described above in this Section shall be initially calculated by Seller and accompanied by any supporting documentation necessary for Buyer to confirm the calculations and amounts due hereunder. Disputes regarding compensation amounts under this Section 3.16 are subject to the dispute resolution provisions of Article XIII.

ARTICLE IV
COMPENSATION

4.1 [Reserved].

4.2 Product Compensation

(a) Compensation Rates.

(i) Base Capacity Payment Rate ("BCPR") shall equal $70.23 per kW-year of Buyer's Percentage of Contract Capacity included in the calculation of the Contract Capacity Amount, as adjusted pursuant to Section 4.2(a)(iv).

(ii) Base Energy Rate ("BER") shall equal $98.93 per MWh, as adjusted pursuant to Section 4.2(a)(iv).

(iii) Base Renewable Energy Credits Rate ("BRR") shall equal the product of (A) $15.32 per REC multiplied by (B) the percentage of credits that Buyer receives toward meeting its Renewable Energy Portfolio Standards requirements under the RPS Act for RECs generated by the Project, as adjusted pursuant to Section 4.2(a)(iv). Examples of the adjustment to the BRR under this Subsection are set out in Appendix V.

(iv) The Base Capacity Payment Rate, Base Energy Rate and the Base Renewable Energy Credits Rate shall also be subject to a fixed two-and-one-half percent (2.5%) annual inflation adjustment rate for each calendar year after the year 2007 ("Annual Inflation Adjustment" or "AIA").

(b) Product Payment Obligations.

During each month of the Pre-Services Term Period and the Services Term, Buyer shall pay Seller, in arrears, a Monthly Fixed Payment ("MFP"), as full payment for the right to receive the Products and the delivery thereof (including the transfer to Buyer of the Contract Capacity Amount) pursuant to the terms of the Agreement, determined as follows:

MFP_m = [[(BCPR x 8.333%) x MCC_m] + [(BER x MED)] + [BRR x MRD]] x AIA

where,

MFP_m is the Monthly Fixed Payment for the subject month;

MCC_m is the amount of Contract Capacity (restated in kw-year) for the Capacity Year in which such month falls which has been included in the calculation of the Contract Capacity Amount for such Capacity Year to be transferred to Buyer by Seller in accordance with this Agreement; provided that MCC_m shall be zero (0) for each month that does not fall within a Capacity Year for which Seller shall have transferred the Contract Capacity Amount for such Capacity Year to Buyer in accordance with Sections 3.1(a)(i)(A) or 3.1(a)(ii);

MED is the Delivered Energy (expressed in number of MWh) delivered to Buyer in the subject month in accordance with this Agreement; and

MRD is the number of RECs delivered to Buyer in the subject month in accordance with this Agreement.

4.3 Most Favored Customer Pricing. Notwithstanding any other provision herein to the contrary, and considering that Buyer's costs under the Agreement will be borne by Buyer's Delaware customers, if, prior to Financial Closing, Seller or any Affiliate of Seller enters into any agreement with a third party for the sale of Excess Products in the form of Energy, Capacity or RECs from the Project (or any Units thereof) or energy, capacity or RECs from any other offshore wind energy generating facility within fifty (50) miles from the geographic center of the Project, to any Person, either directly or indirectly, on economic terms that, when all economic terms (for purposes of this Section 4.3 "economic terms" shall mean the allocation of costs associated with negative Locational Marginal Prices in Section 3.4(d) and the prices for Energy, Capacity and RECs) are considered together, are more favorable to the purchaser thereunder than those economic terms set forth in the Agreement, Seller shall offer or provide Energy, RECs and Contract Capacity (in the form of the Contract Capacity Amount consistent

with Section 3.1) hereunder on economic terms that, when considered together, are no less favorable than those offered by Seller or Seller's Affiliate to such party; *provided, however*, that (i) RECs shall only be covered by this Section 4.3 to the extent that they are sold together with associated Energy and (ii) in assessing RECs for this purpose, the RPS Multiplier and the pricing component set out in Section 4.2(a)(iii)(B) shall be excluded from consideration. For the avoidance of doubt, any (1) contract for sales of Energy (anticipated to be approximately 100,000-150,000 MWh per year) and/or capacity to DEMEC consistent with the terms of that certain sale by Seller announced in May 2007 and entered into prior to Financial Closing (for the avoidance of doubt, if contracted sales volumes are increased under such contract, while such additional sales shall be subject to this Section 4.3, the original sales under such contract shall not be subject to this Section 4.3), and (2) sales of RECs that are associated with Delivered Energy but that are otherwise not required to be purchased by Buyer under Section 3.1(a)(i)(C) or Section 3.1(a)(ii), shall not be subject to this Section 4.3. Simultaneous with Seller entering into any contract for the sale of Products or products as described in the previous sentence, Seller shall certify in writing to Buyer that it has complied with the requirements of this Section 4.3, which certification shall be accompanied by an amendment to the Agreement providing for a change in economic terms hereunder if required by this Section 4.3. At Buyer's request, Seller shall permit the Independent Evaluator to verify the accuracy of any certification required pursuant to this Section, provided that prior to such verification the Independent Evaluator shall execute a confidentiality agreement with the Seller that prohibits the Independent Evaluator from disclosing any third party contractual information (including pricing) to Buyer or third parties and either Party may appeal the finding of the Independent Evaluator pursuant to Article XIII.

ARTICLE V
CONDITIONS PRECEDENT; EFFECTIVE DATE; CONSTRUCTION; AND INITIAL DELIVERY DATE

5.1 The Effective Date.

(a) Conditions Precedent to Effective Date. The Effective Date shall be deemed to have occurred on the satisfaction or waiver of the following conditions precedent:

(i) Buyer and Seller, as applicable, shall have entered into the Project Security Agreements (other than the Delay Damages Account Control Agreement).

(ii) Seller shall have provided to Buyer the initial installment of the Development Period Security pursuant to Section 8.1(a).

(iii) Buyer's independent outside auditing firm shall have determined that Buyer will not be required to consolidate Seller on Buyer's financial statements

under the latest interpretations of the Financial Accounting Standard Board's Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities."

(iv) Regulatory Approval shall have occurred.

(v) Buyer and Seller each shall have received all third party consents necessary in order to enter into the Agreement and perform its respective obligations hereunder.

(vi) Legislation has been enacted by the State of Delaware directing the Commission to establish an adjustable non-bypassable charge that distributes all costs arising out of the Agreement to Buyer's entire Delaware customer base, unless, after Commission review, any such costs are determined by the Commission to have been incurred in bad faith, are the product of waste or out of an abuse of discretion, or in violation of law.

(vii) The RPS Act has been amended to provide that Buyer shall receive three hundred and fifty percent credit (350%) toward meeting the Renewable Energy Portfolio Standards established under the RPS Act for RECs received from the Project for at least as long as the Contract Term.

Buyer and Seller shall each use good faith efforts to achieve satisfaction of these conditions precedent.

(b) Failure of the Effective Date. Subject to the provisions of Section 2.3 regarding termination of the Agreement for failure to receive Regulatory Approval, in the event that a condition precedent to the Effective Date has not been satisfied within three hundred sixty-five (365) days of the Execution Date, provided that a Party has made commercially reasonable efforts, based on the extent of its reasonable control, to satisfy the conditions precedent to the Effective Date set forth in Section 5.1(a), such Party shall have the right to terminate this Agreement, as long as such right is exercised by Notice received within thirty (30) days after such failure and in accordance with Section 2.3. If either Party has the right to terminate this Agreement in accordance with the above provisions of this Section 5.1(b), and this Agreement is terminated pursuant to this Section 5.1(b), Buyer shall refund to Seller the full amount of Development Period Security posted by Seller within ten (10) Business Days of such termination.

5.2 Construction.

(a) Design, Development and Construction. Except as otherwise provided in an Interconnection Construction Services Agreement, as between Buyer and Seller, Seller shall have sole responsibility for the design and construction of the Project and the Project Meter and all related metering and submetering facilities, including the obligation to perform all studies, including environmental studies, pay all fees, obtain all necessary Permits and execute all necessary agreements with PJM and Participating Transmission Owners for the Electrical Interconnection Facilities necessary for the ownership, construction, operation and maintenance of the Project and delivery of Seller's Products in accordance with the terms hereof. All of such design, construction and upgrades shall

be consistent with all standards and provisions set forth by FERC, PJM or any other applicable Governmental Authority and the interconnecting Participating Transmission Owner. All Electrical Interconnection Facilities, including metering and submetering facilities, must be of sufficient capacity to permit the Project to operate at all times during each month at the Project Capacity. Metering and submetering facilities must meet such additional specifications as set forth in Section 3.8.

(b) Construction Scheduling. At least three (3) months prior to issuance of the EPC Notice to Proceed by Seller to the EPC Contractor, Seller shall provide Buyer a construction schedule detailing the schedule and construction milestones for completing the Project and each of the Units and reaching the Project Commercial Operation Date, the Initial Delivery Date and each Unit Group Commercial Operation Date. Seller shall provide Buyer with monthly progress reports, including projected time to the Project Commercial Operation Date and each Unit Group Commercial Operation Date, and Buyer shall have the right, during business hours and upon reasonable Notice, to inspect the construction site and monitor construction of the Project.

(c) Permitting. Seller shall be permitted to terminate the Agreement and Buyer will return the Development Period Security to Seller less three million dollars ($3,000,000) as liquidated damages (such liquidated damages being Buyer's sole remedy for such termination by Seller) if Seller, after making all commercially reasonable efforts to do so, is unable to secure the Permits required for the construction and commencement of Commercial Operation of the Project, excepting such Permits for operation which are routinely granted on or about the time of the commencement of Commercial Operation (the "Permitting Milestone"), on or prior to May 31, 2012 (the "Permitting Deadline"). In the event that, after making all commercially reasonable efforts to do so, Seller cannot satisfy the Permitting Milestone prior to the Permitting Deadline, then, at Seller's sole election, Seller shall be permitted to extend the Permitting Deadline by six (6) months if Seller agrees, going forward, to pay the then undrawn amount of the Development Period Security to Buyer as liquidated damages if Seller is unable to achieve the Permitting Milestone by the extended Permitting Deadline and Buyer exercises its right to terminate this Agreement for failure to meet the Permitting Milestone (which such termination and liquidated damages shall be Buyer's sole remedies for such Event of Default). Nothing in this subsection (c) shall be construed to limit the Buyer's ability to recover the full Development Period Security, Services Term Security or other damages (to the extent described elsewhere in the Agreement) for any default of Seller arising other than as a result of a failure to meet the Permitting Deadline.

(d) Critical Milestones. The Seller shall cause the development and construction of the Project to meet each of the Critical Milestones on or before the dates specified for such Critical Milestones on Schedule 1, and shall provide Notice (including evidence reasonably requested by Buyer) when each Critical Milestone is accomplished.

(e) Termination Rights for Failure to Achieve Critical Milestones.

(i) If Seller fails to complete any Critical Milestone within eighteen (18) months of the date such event is scheduled to occur on or before in

Schedule 1 and such failure is not caused by a Force Majeure Event, such failure will be deemed an Event of Default and as sole remedies for such Event of Default Buyer shall have the right to (i) terminate the Agreement upon the delivery of thirty (30) days prior Notice thereof to Seller, without liability to Seller and (ii) to retain the then undrawn amount of the Development Period Security as liquidated damages.

(ii) If Seller fails to achieve the "Financial Closing" Critical Milestone (described in Schedule 1) within eighteen (18) months of the date for such Critical Milestone set out on Schedule 1 (the "Financing Closing Deadline"), despite Seller's commercially reasonable and diligent efforts to do so, Seller shall have the right to terminate the Agreement upon (30) days prior Notice thereof to Buyer, without liability to Buyer other than that Buyer shall have the right to retain the then undrawn amount of the Development Period Security as liquidated damages (such liquidated damages being Buyer's sole remedy for such termination by Seller) for such termination by Seller. If Seller does not issue such Notice to terminate the Agreement within forty-five (45) days of the Financing Closing Deadline, such right of Seller shall be deemed to have been waived and may no longer be exercised.

(f) Reports. Within five (5) days after the close of each calendar month until the Initial Delivery Date, Seller shall provide to Buyer a Monthly Project Development and Construction Progress Report addressing each of the Milestones (see Schedule 1) including projected time to completion, in each case in a form agreed upon by the Parties. The Buyer and Seller shall also agree to regularly scheduled meetings between representatives of Buyer and Seller to review such monthly reports and discuss Seller's development and construction progress. Subject to Section 3.11, Buyer shall have the right, during business hours and upon reasonable Notice, to inspect the Site and/or on-Site Seller data and information pertaining to the Project and otherwise inspect or audit to enforce its rights pursuant to this section.

(g) Buyer and Seller shall negotiate in good faith to enter into the Interconnection Construction Service Agreement and the Interconnection Service Agreement with PJM in accordance with the PJM Agreements. After the Execution Date, Buyer and Seller shall use good faith efforts to enter into a pre-construction service agreement (the "Pre-Construction Services Agreement"), which such agreement shall require Seller to perform certain pre-construction services related to the planning, design and construction of the Indian River Line Assets, including undertaking all those activities related thereto that are not related to PJM approvals or authorizations.

5.3 Initial Delivery Date.

(a) Conditions Precedent. The Initial Delivery Date shall occur, on or after the Effective Date, upon the date on which each of the following conditions precedent have been satisfied or waived by written agreement of the Parties.

(i) Seller shall construct or cause to be constructed the Project with an aggregate nameplate capacity rating equal to ninety-four percent (94%) of the Project Capacity at no expense to Buyer, which shall include the equipment and characteristics as described in Appendix 1, and which shall reasonably be expected to enable Seller to satisfy the obligations of the Seller herein.

(ii) Seller shall construct or cause to be constructed the Electrical Interconnection Facilities at no expense to Buyer such that the Electrical Interconnection Facilities are capable of delivering the maximum quantities of Energy to the Delivery Point as contemplated in this Agreement during each month (in addition to any other output of the Project as the Electric Interconnection Facilities are required to transmit) and shall cause them to be placed into service, in each case, in accordance with the requirements of the interconnecting transmission owner and/or operator, and applicable rules, if any, of FERC, PJM, the Commission and any other organization or Governmental Authority charged with reliability responsibilities.

(iii) [RESERVED]

(iv) At Seller's expense, Seller shall have obtained (and demonstrated possession of) all Permits required for the lawful construction, operation and maintenance of the Project and the Units, inclusive of the Electrical Interconnection Facilities, including all those related to environmental matters, as necessary to permit the Seller to operate the Project at the Project Capacity and for Seller to perform its obligations under the Agreement.

(v) Seller shall have executed all interconnection and transmission services agreements, including the Interconnection Services Agreement and the Interconnection Construction Service Agreement, all agreements necessary for its use and control of the Site for purposes of the construction, operation and maintenance of the Project for a term at least equal to the Pre-Services Term Period (if a Pre-Services Term Period occurs) and the Services Term, and all other agreements that are necessary for Seller to perform its obligations hereunder, in form and substance reasonably satisfactory to both Buyer and Seller in the case of each interconnection and transmission services agreement, and which agreements shall be in full force and effect as of the Initial Delivery Date.

(vi) The Project Commercial Operation Date shall have occurred or will occur simultaneously with the Initial Delivery Date.

(vii) Seller shall provide Buyer with Notice that the Project Commercial Operation Date has occurred or will occur simultaneously with the Initial Delivery Date.

(viii) No default or Event of Default shall have occurred and remain uncured as of the Initial Delivery Date.

(ix) Seller shall have provided Buyer with Notice of the expected occurrence of the Initial Delivery Date no later than ten (10) Business Days prior and again three (3) days prior to its occurrence and again immediately prior to the date it occurs.

(x) Seller is a PJM Member and shall have entered into all required PJM Agreements required to perform under the Agreement, which shall be in full force and effect, the Project has been accepted as a Capacity Resource of PJM as of the date in question, and (i) if there shall not have been a Pre-Services Term Period, Seller shall be able to transfer the Contract Capacity Amount to Buyer as required pursuant to Section 3.1(a)(i)(A) with respect to the first Capacity Year commencing after the Initial Delivery Date, or (ii) if there shall have been a Pre-Services Term Period for which a Capacity Year remains in effect in accordance with Section 3.1(a)(ii), Seller remains able to transfer the Contract Capacity Amount for such Capacity Year to Buyer.

(xi) The Project has qualified and has been certified by the Commission as an Eligible Energy Resource (as defined by the Commission in the RPS Rules and the RPS Act) and all Energy produced by the Project qualifies as generation from an Eligible Energy Resource under the RPS Act and the Commission RPS Rules.

(xii) Seller has posted the Collateral required to be posted in favor of Buyer as of the Initial Delivery Date pursuant to Section 8.1(b) and entered into the Project Security Agreements.

(xiii) Seller shall have all necessary rights to the Project Site to construct and to operate the Project in accordance with the terms hereof.

5.4 Delay Damages; Termination Upon Delay.

(a) Subject to Section 5.5, in the event that the conditions precedent to the occurrence of the Initial Delivery Date set forth in Section 5.3 are not satisfied or waived on or prior to the Guaranteed Initial Delivery Date, for each day (or part thereof) beginning with the day after the Guaranteed Initial Delivery Date through and including the date on which the Initial Delivery Date occurs, Seller will be required to pay Buyer daily liquidated damages ("Delay Damages") in the amount of (i) $34,995 per day, to the extent the Capacity as of the Guaranteed Initial Delivery Date shall be less than 50% of the Project Capacity), or (ii) to the extent the Capacity as of the Guaranteed Initial Delivery Date shall be equal to or greater than 50% of the Project Capacity, but less than the total Project Capacity, the amount per day equal to the product of $34,995 multiplied by a fraction, the numerator of which shall be the difference between the Project Capacity and the Capacity as of the Guaranteed Initial Delivery Date, and the denominator of which shall be the Project Capacity. The maximum amount of Delay Damages payable by Seller shall be $19,177,260 ("Maximum Delay Damages") and payment thereof shall be made in accordance with Section 6.1 and 6.5.

If (x) the Initial Delivery Date is not achieved by the Guaranteed Initial Delivery Date solely due to delays in obtaining Permits as set forth on Schedule 3 or litigation initiated by third parties, in each case that has the direct effect of preventing Seller from reaching the Milestones set forth on Schedule 1 hereto, and (y) Seller has taken commercially reasonable steps to resolve any such permitting or litigation delay (in each case, as reasonably demonstrated to Buyer's satisfaction), such Delay Damages shall accrue from and after the Guaranteed Initial Delivery Date in accordance with the immediately preceding paragraph, but shall not be due and payable unless Seller fails to achieve the Initial Delivery Date by the Date Certain, in which case such accrued Delay Damages that would have otherwise been immediately payable by Seller but for such exception shall be due and payable to Buyer on the Date Certain in addition to the Termination Fee described below. Any Delay Damages accrued pursuant to the previous sentence shall be secured in favor of Buyer at the time of accrual by the posting by Seller within five (5) Business Days after the Guaranteed Initial Delivery Date of either (a) a satisfactory Letter of Credit at all times in an amount equal to such accruals or (b) cash Collateral (deposited in an account with a Qualified Issuer (such account being the "Delay Damages Account")) equal to such accruals pursuant to a customary account control agreement creating a valid and perfected first priority security interest therein in favor of Buyer in form and substance reasonably acceptable to Buyer (the "Delay Damages Account Control Agreement"). If the Initial Delivery Date does not occur by the Date Certain, Buyer may thereafter withdraw from the Delay Damages Account or draw on the Letter of Credit an amount (as liquidated damages) equal to the Delay Damages accrued in favor of Buyer pursuant to the terms of this paragraph but not yet paid to Buyer by Seller (the "Accrued Delay Damages").

(b) In addition to any Delay Damages payable by Seller pursuant to Section 5.4(a) above, in the event that Seller has not satisfied the conditions precedent to the Initial Delivery Date by May 31, 2016 (the "Date Certain"), on such date or at any time thereafter Buyer may elect to terminate the Agreement upon thirty (30) days prior Notice to Seller. Any such termination by Buyer shall be without further liability or obligation of any kind on the part of Buyer, and the Seller shall pay as liquidated damages to Buyer a termination fee (the "Termination Fee") equal to $15,000,000. (For the avoidance of doubt, upon payment of such Termination Fee, all Development Period Security shall immediately be released and cancelled.) Notwithstanding the foregoing, to the extent that (x) the actual Capacity of the Project is at least sixty percent (60%) of the Project Capacity by the effective date of the termination described above in this Section 5.4(b) and (y) all other conditions to the Initial Delivery Date set forth in Section 5.3 have been satisfied in full, then (A) Buyer's termination right described above in this Section 5.4(b) shall only be applicable to that portion of Project Capacity that has not yet reached a Unit Group Commercial Operation Date as of such effective date, and (B) the Seller shall be obligated to pay only the pro rata portion of the Termination Fee applicable to that portion of the Project Capacity that has not yet reached a Unit Group Commercial Operation Date (as of the effective date of such termination). The non-occurrence of the Initial Delivery Date by the Date Certain shall constitute an Event of Default, the sole remedy for which event is set forth in this Section 5.4(b). In the alternative, notwithstanding such Event of Default, Buyer shall have the option to extend the end date of the Services Term by a period equal to the

difference between the Guaranteed Initial Delivery Date and the actual Initial Delivery Date. For the avoidance of doubt, (i) the Maximum Delay Damages shall apply to limit aggregate Delay Damages, but shall not limit payment of the full amount of the Termination Fee as liquidated damages; and (ii) notwithstanding anything herein to the contrary, in the event of a termination pursuant to this Section 5.4(b), under no circumstances shall Buyer be entitled to collect amounts in excess of the sum of the Termination Fee, the Delay Damages, and any other amounts due under this Agreement at the time of termination, or that may become due after termination pursuant to terms hereof.

(c) If only a portion of the Project is terminated pursuant to Sections 5.4(b), 5.4(e), 5.7 or 12.4, the Project Capacity thereafter shall be equal to the aggregate nameplate capacity rating of the portion of the Project that is not terminated.

(d) On or after the Guaranteed Initial Delivery Date, to the extent Seller reasonably determines that the Project will not achieve the Initial Delivery Date with respect to one hundred percent (100%) of the Project Capacity (or such lesser amount of Project Capacity to the extent Project Capacity is reduced as permitted pursuant to the terms of this Agreement) prior to the Date Certain despite Seller's reasonable good faith efforts to achieve the Initial Delivery Date prior to such date, Seller may terminate the Agreement prior to the end of the twelve (12) month period commencing on the Guaranteed Initial Delivery Date and ending on the Date Certain by paying to Buyer the full Termination Fee and any Delay Damages accrued and unpaid prior to the date of termination (such amounts being Buyer's sole remedy for such termination by Seller).

(e) Notwithstanding the foregoing, if a Force Majeure Event of the general type set forth in items (1) through (4) of the definition of a Force Majeure Event hereunder has delayed the Project Commercial Operation Date with respect to less than 40% of the total Project Capacity beyond the Date Certain (but a minimum Capacity of 60% of the Project Capacity shall have achieved the Commercial Operation Date by the Date Certain), Seller may specify an additional number of Units in excess of the Units that have already reached a Unit Group Commercial Operation Date by the Date Certain (but in no event shall such additional Units exceed the number of MWs of the total Project Capacity affected by such Force Majeure Event) representing the additional Units of the Project Seller intends to reach a Commercial Operation Date by May 31, 2017 (such Units, the "Post Date Certain Units"). From and after the Date Certain, Seller shall exercise reasonable good faith efforts to cause the Post Date Certain Units to reach a Commercial Operation Date by May 31, 2017. Applicable performance standards and obligations of Buyer and Seller shall be adjusted on the Date Certain to reflect the number of Units that have reached a Commercial Operation Date on or prior to the Date Certain, and shall be further adjusted on the earlier of the date on which the entire Project (as contemplated in Appendix 1) has achieved a Commercial Operation Date or May 31, 2017 to further reflect the final Project size of the Units that have reached a Commercial Operation Date. Payment of a pro rata portion of the Termination Fee associated with the Post Date Certain Units shall be due and payable within five (5) days after May 31, 2017 for the portion of the Post Date Certain Units not achieving a Commercial Operation Date by May 31, 2017, and within five (5) days after May 31, 2017, Seller shall pay to Buyer

Daily Delay Damages with respect to the Post Date Certain Units for the period of time between the Date Certain and May 31, 2017 that such Units had not achieved a Commercial Operation Date. For the avoidance of doubt, the aggregate total of any such Delay Damages and all other Delay Damages incurred by Seller pursuant to Section 5.4 shall not be in excess of the Maximum Delay Damages amount. Seller shall further provide Buyer with a schedule of the projected Commercial Operation Dates of any Units being placed in service after the Date Certain pursuant to this provision and the projected quantities of Products to be delivered under the Agreement from such Units. Such schedule shall be updated on a bi-weekly basis beginning ninety (90) days prior to the Date Certain and ending on May 31, 2017.

5.5 Effect of Force Majeure. Each Critical Milestone and the Guaranteed Initial Delivery Date shall be extended on a day-for-day basis without the payment of Delay Damages, not exceeding an aggregate extension of eighteen (18) months for all such Force Majeure Events, to the extent that such Critical Milestone or Guaranteed Initial Delivery Date is delayed as a result of a Force Majeure Event invoked by the Seller in accordance with Section 14.3.

5.6 Termination of Agreement Upon Publication of MMS Regulations. Seller shall have the right to terminate the Agreement and Buyer will retain $3,000,000 in Development Period Security (or $1,500,000 in Development Period Security if such termination occurs within ninety (90) days of the Execution Date in the case of Section 5.6(b) below) if (a) definitive non appealable procedures with respect to the permitting and siting of offshore wind farms ("MMS Regulations") are not published by the MMS by May 31, 2011, or (b) at any time within ninety (90) days of the publication of the MMS Regulations, but no later than August 31, 2011, Seller determines in its reasonable discretion that the MMS Regulations, in combination with the terms of the Agreement, prevent Seller from performing its obligations under the Agreement or make such performance Economically Unfeasible and such determination is verified and confirmed in writing to Buyer and Seller by the Independent Evaluator within sixty (60) days of Notice from Seller of its intent to terminate the Agreement pursuant to this Section 5.6. In the event the MMS Regulations are not published by May 31, 2011 and Seller does not elect to exercise its termination right described in this Section 5.6 above, the extension periods and other accommodations related to the publication of the MMS Regulations set out in Section 2.1 shall no longer be effective.

5.7 Termination of Agreement Upon Termination or Modification of Production Tax Credit. Seller shall have the right to terminate the Agreement beginning six (6) months after the publication of the MMS Regulations and ending on the earlier of December 1, 2014 or the date Seller issues the EPC Notice to Proceed (the "PTC Termination Date"), if during such period the tax credit for electricity produced from wind-powered electric generation facilities described in Section 45 of the Internal Revenue Code of 1986 as in effect on the Execution Date (the "PTC") is materially adversely modified with respect to the Project or has not been extended to cover the full expected construction period of the Project (but in no event later than May 31, 2016, or June 30, 2016 for the Post Date Certain Units). In the event of such a termination Buyer will retain the Development Period Security as liquidated damages (such liquidated

damages being Buyer's sole remedy for such termination by Seller) upon such termination.

In the event that the PTC has not been so extended or has been so modified, but Seller elects not to terminate the Agreement (as provided in the previous paragraph), Seller, during the period following the PTC Termination Date and ending on the earlier of the Initial Delivery Date or May 31, 2016, or June 30, 2016 for the Post Date Certain Units, shall have the right to either (a) terminate the Agreement if, following the PTC Termination Date, the PTC is materially adversely modified with respect to the Project or has not been extended to cover the full expected construction period with respect to Units with a total nameplate capacity of greater than 40% of Project Capacity, or (b) reduce the Project Capacity down to a minimum of 60% of Project Capacity to exclude any Units with respect to which the PTC, subsequent to the PTC Termination Date, has been materially adversely modified or has not been extended to cover the full expected construction period. In consideration for any such termination or reduction in size after the PTC Termination Date, Seller shall pay Buyer a pro rata portion of the Termination Fee commensurate with the percentage of the Project Capacity not being installed (such amount being Buyer's sole remedy for such termination by Seller).

In addition, the PTC termination/exclusion right described above shall cease to be effective with respect to any Unit that has not previously been placed in service for federal income tax purposes if, prior to the PTC Termination Date, the PTC is extended to cover the full expected construction period of the Project, to the extent not later revoked or modified as described above.

ARTICLE VI
PAYMENT AND NETTING; RECORDS AND AUDIT RIGHTS

6.1 Billing and Payment.

(a) On or before the 10th calendar day of each month of the Contract Term, following the commencement of the Pre-Services Term Period, Buyer shall provide an invoice to Seller, in arrears: (a) for all amounts due from Buyer to Seller under this Agreement (unless otherwise paid pursuant to a different invoicing process as set out in this Agreement), including, as applicable, the MFP (including details of the calculation thereof pursuant to Section 4.2(b)), any amounts due to Seller pursuant to Sections 3.14 and 3.16, and the Regulatory Charges Payments, if any; and (b) for all amounts due from Seller to Buyer under this Agreement (unless otherwise paid pursuant to a different invoicing process as set out in this Agreement), including, as applicable, Delay Damages (subject to Section 6.4) and Regulatory Charges Payments. Invoices shall include amounts accrued under this Agreement in the preceding month, provided that to the extent the determination of amounts due under this Agreement are based on invoices rendered by PJM or Governmental Authorities in the preceding month, the Parties acknowledge and agree that such amounts may relate to calendar months prior to such month, as adjusted from time to time. With respect to the calculation of the MFP, Seller shall provide such additional information as Buyer shall reasonably request or as the Operating Committee shall determine.

(b) Charges and credits assessed or provided by PJM in connection with the scheduling of Energy and allocated among the Parties shall be reconciled between the Parties in accordance with PJM rules and procedures established by the Operating Committee. Buyer costs and expenses associated with Buyer's Scheduling Obligation that are allocated to Seller pursuant to Section 3.5(e) or are directly associated with Excess Products shall be invoiced by Buyer and paid by Seller pursuant to the relevant provisions of this Article VI.

6.2 Netting and Payment. If each Party is required to pay the other an amount in the same month pursuant to this Agreement or any of the Ancillary Agreements, then the Party owing the greater aggregate amount will pay to the other Party the difference between the amounts owed; *provided, however*, such netting requirement shall not apply to Regulatory Charges, indemnification payments, liquidated damages and other amounts due outside of the normal course of performance under the Agreement. Payment of all undisputed amounts owed shall be due on the same date as the monthly PJM settlement date, which is currently the first Business Day following the 19th calendar day of the month ("Monthly Payment Date"). If either the invoice due date or Monthly Payment Date is not a Business Day, then such invoice or payment shall be provided on the next following Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to an account designated by the other Party. Any undisputed amounts not paid by any Party by the applicable Monthly Payment Date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the first day after the applicable Monthly Payment Date to, but excluding, the date the delinquent amount is paid in full. Notwithstanding anything herein to the contrary, in the event Seller fails to post adequate amounts of Collateral as required hereunder, Buyer may withhold payments to be made to Seller pursuant to Section 6.1 in the amount of such deficiency or terminate the Agreement pursuant to Sections 12.1(a) and 12.2.

6.3 Disputes and Adjustments of Invoices. In the event an invoice or portion thereof or any other claim or adjustments arising hereunder is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with Notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. The Parties shall continue performance under this Agreement during the period of such dispute, but shall not be precluded from exercising any other remedy hereunder. The Parties agree to use good faith efforts to resolve the dispute or identify the adjustment as soon as possible in accordance with the provisions of Article XIII (Dispute Resolution). Upon resolution of the dispute or calculation of the adjustment, any required payment shall be made within fifteen (15) calendar days of such resolution along with interest accrued at the Interest Rate from and including the due date to, but excluding, the date on which the payment is made. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent invoices, with interest accrued at the Interest Rate from and including the date of such overpayment to, but excluding, the date repaid or deducted by the Party receiving such overpayment. Except with respect to audit corrections as provided in Section 6.6(a), any dispute with respect to an invoice is waived

unless the other Party is notified in accordance with this Section 6.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance giving rise to the payment obligation occurred, the right to payment for such performance is waived.

6.4 Termination Payment and Termination Fee. In the event that an Early Termination Date is declared pursuant to Article XII, Buyer, as calculation agent, shall determine the amount of the Termination Payment in accordance with Section 12.2, and either (a) if Seller is the owing Party, provide Seller an invoice within ten (10) Business Days of the Early Termination Date, which shall be due no later than ten (10) Business Days after receipt; or (b) if Buyer is the owing Party, pay Seller the Termination Payment no later than twenty (20) Business Days after the Early Termination Date. In the event that Seller owes Buyer the Termination Fee and any accrued but unpaid Delay Damages as of the date the Termination Fee is incurred, Buyer shall include the amount of such Delay Damages in the invoice provided under Section 6.4(b).

6.5 Records. Each Party shall keep and maintain all books and records as may be necessary or useful in performing or verifying any calculations made pursuant to this Agreement, or in verifying such party's performance hereunder, including, without limitation, operating logs, meter readings and financial records, all in accordance with Good Utility Practice. All records shall be retained by each Party for at least three (3) calendar years following the calendar year in which such records were created.

6.6 Audit.

(a) Audit Rights. Each Party, through its Authorized Representatives, shall have the right, at its sole expense, upon reasonable Notice and during normal business hours, to examine and copy the books and records of the other Party related to the Project or the Agreement to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made hereunder or to verify the other Party's performance of its obligations hereunder. Upon request, each Party shall provide to the other Party statements evidencing the Capacity Value and Cleared Capacity Value for any Capacity Year and the quantities of Delivered Energy and other Products delivered, taken or otherwise provided pursuant to this Agreement. If any statement is found to be inaccurate, a corrected statement shall be issued and any amount due thereunder will be promptly paid and shall bear interest calculated at the Federal Funds Interest Rate plus two percent (2%) from the date of the overpayment or underpayment to the date of receipt of the reconciling payment. Notwithstanding the above, no adjustment shall be made with respect to any statement or payment hereunder unless a Party questions the accuracy of such payment or statement within two (2) years after the date of such statement or payment.

(b) Reports Due to Buyer. Seller will provide to Buyer the following information with respect to the Project:

(i) Upon the request of Buyer, the manufacturers' guidelines and recommendations for maintenance of the Project equipment;

(ii) A report summarizing the results of maintenance performed during each Outage, and upon request of Buyer any of the technical data obtained in connection with such maintenance or Outage;

(iii) At all times from the earlier of the issuance of the EPC Notice to Proceed or the Turbine Notice to Proceed until the Initial Delivery Date, at the same time as and to the extent provided to the Senior Secured Lenders or other financing parties, any monthly progress reports stating the percentage completion of the Project and a summary of construction activity during the prior month;

(iv) At all times from the earlier of the issuance of the EPC Notice to Proceed or the Turbine Notice to Proceed until the Initial Delivery Date, at the same time as and to the extent provided to the Senior Secured Lenders or other financing parties, any monthly reports containing a summary of construction activity contemplated for the next month;

(v) For each month (or portion thereof) during the Pre-Services Term Period and the Services Term, a calculation of: the Mechanical Availability Percentage for such month, including the number of Base Hours and Operating Hours during such month; and a report of the electrical output and local delivery of electricity report including month and year-to-date values;

(vi) For each Capacity Year during the Pre-Services Term Period or Services Term, a calculation of the Capacity Value, following each determination thereof by PJM, and of the Cleared Capacity Value, following each auction that occurs in the PJM RPM Market that affects any such Capacity Year; and

(vii) Other safety, performance, financial information (including historical wind reports for daily and monthly averages) and reports as mutually agreed by the Parties, including notification of any material adverse events, notices of termination, and notifications of failure to meet key milestones with respect to the Project, Seller or the Project Contracts.

(c) Access Rights. Upon reasonable prior Notice (in light of the circumstances) and subject to the safety rules and regulations of Seller, Seller will provide Buyer and its authorized agents, employees and inspectors with reasonable access to the Project: (i) for the purpose of reading or testing metering equipment, (ii) as necessary to witness any performance testing associated with the Units, (iii) in connection with the operation and maintenance of the interconnection facilities, (iv) to provide tours of the Project to customers and other guests of Buyer (not more than twelve (12) times per year), (v) for purposes of implementing Section 6.6, and (vi) for other reasonable purposes at the reasonable request of Buyer. Buyer shall be responsible for all costs and bear all risks associated with all such visits to the Project pursuant to this Section 6.6(c), except in connection with any exercise of remedies under this Agreement.

While at the Project and the Site, such Persons shall comply with all applicable Law and PJM regulations and observe such reasonable safety precautions as may be required and communicated to such representatives by Seller or Seller's representatives and shall not interfere unreasonably with the operation of the Project.

6.7 Payments. All amounts due under this Agreement must be sent via wire transfer to an account and address to be specified following the date of this Agreement by each Party in a written Notice to the other Party, as updated from time to time.

ARTICLE VII
LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE FOR ANY PRODUCT, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF LIQUIDATED DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF LIQUIDATED DAMAGES IS PROVIDED (INCLUDING UNDER SECTIONS 5.2(C), 5.2(E), 5.4(A), 5.4(B), 5.4(D), 5.6, 5.7 AND 12.2) SUCH EXPRESS REMEDY OR MEASURE OF LIQUIDATED DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY THEREFOR, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY WITH RESPECT TO SUCH BREACH ARE WAIVED EXCEPT TO THE EXTENT EXPRESSLY SET FORTH HEREIN. IF NO REMEDY OR MEASURE OF LIQUIDATED DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE, PROVIDED THAT THE FOREGOING EXCLUSION SHALL NOT PRECLUDE RECOVERY BY A PARTY OF THE TERMINATION PAYMENT, THE TERMINATION FEE, DELAY DAMAGES, OR ANY LIQUIDATED DAMAGES EXPRESSLY HEREIN PROVIDED, NOR SHALL IT BE CONSTRUED TO LIMIT RECOVERY BY AN INDEMNITEE UNDER ANY INDEMNITY PROVISION IN RESPECT OF A THIRD PARTY CLAIM. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 11.1 (INDEMNITIES), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, INCLUDING FORFEITURES OF DEPOSITS, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE LIQUIDATED DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE FULL HARM OR LOSS.

ARTICLE VIII
CREDIT AND COLLATERAL REQUIREMENTS

8.1 Timing and Use of Collateral.

(a) Development Period Security. On or before August 1, 2008, Seller shall be required to establish collateral in favor of Buyer by providing Buyer with a Letter of Credit from a Qualified Issuer to secure Seller's obligations under this Agreement in the period between the Execution Date and the Initial Delivery Date (the "Development Period Security"). The Development Period Security to be provided pursuant to the first sentence of this Section 8.1(a) shall be in an amount equal to three million dollars ($3,000,000) and shall be maintained in full force and effect by Seller until its expiry pursuant to the terms hereof (subject to Section 2.3). By not later than fifteen (15) days after the Effective Date, the amount of the Development Period Security shall be increased to an amount equal to six million dollars ($6,000,000) and shall be maintained in full force and effect by Seller until its expiry pursuant to the terms hereof. In the event Buyer draws on the Development Period Security to pay Delay Damages, Seller shall promptly, and in all events within three (3) Business Days, replenish the amount of the Development Period Security by the amount drawn; provided, however, Seller shall not be required to replenish the Development Period Security in excess of the total amount of the Maximum Delay Damages. Buyer shall have the right to terminate the Agreement and retain the initial installment of the Development Period Security as liquidated damages if Seller fails to provide the increased amount of Development Period Security within fifteen (15) days after the Effective Date as set forth in this Section 8.1(a), and such failure shall be considered an Event of Default of Seller.

(b) Collateral After Commencement of Pre-Services Term Period. As a condition to the commencement of the Pre-Services Term Period and the Commercial Operation Date of each subsequent Unit Group after the commencement of the Pre-Services Term Period and during the Pre-Services Term Period, Seller shall provide Buyer with a Letter of Credit from a Qualified Issuer to be effective no later than the commencement of the Pre-Services Term Period, in an amount equal to (i) the Services Term Security, multiplied by (ii) a fraction, the numerator of which is the Capacity of the Unit Groups that have already achieved (or will achieve, upon delivery of such Letter of Credit) a Commercial Operation Date and the denominator of which is the Project Capacity (the "Pre-Services Term Period Security"). The Pre-Services Term Period Security shall be maintained (or increased to the extent additional Unit Group Commercial Operation Dates shall occur) throughout the Pre-Services Term Period in full force and effect by Seller, and shall be in addition to, and not in replacement of, the

Development Period Security. In the event Buyer draws on the Pre-Services Term Period Security to pay or satisfy any obligation of Seller hereunder, Seller shall promptly, and in all events within five (5) Business Days, replenish the amount of the Pre-Services Term Period Security by the amount drawn.

(c) Collateral After Initial Delivery Date. From and after the Initial Delivery Date, Seller shall provide Buyer with a Letter of Credit from a Qualified Issuer to be effective no later than the Initial Delivery Date in an amount equal to twelve million dollars ($12,000,000) (the "Services Term Security"). Upon delivery to Buyer of a Letter of Credit satisfying the Services Term Security, Buyer shall promptly return the Development Period Security and the Pre-Services Term Period Security to Seller (after satisfaction of any amounts then due with respect to the Development Period Security or Pre-Services Term Period Security under the Agreement). In the event Buyer draws on the Services Term Security to pay or satisfy any obligation of Seller hereunder, Seller shall promptly, and in all events within five (5) Business Days, replenish the amount of the Services Term Security by the amount drawn.

(d) Maintenance of Collateral During Services Term. Seller shall maintain in full force the Collateral set forth in Section 8.1(c) through such date as of which all payment obligations to Buyer arising under this Agreement, including any compensation for the Products, Delay Damages, a Termination Fee, a Termination Payment, indemnification payments or other damages, are paid in full (whether directly or indirectly such as through set-off or netting). Buyer shall arrange for the return of the unused portion of such Collateral promptly after each of the following have occurred: (1) the Services Term has ended, an Early Termination Date has occurred or any other termination event in compliance with this Agreement shall have occurred, as applicable; and (2) all payment obligations of the Seller arising under this Agreement, including any compensation for the Products, Delay Damages, a Termination Fee, a Termination Payment, indemnification payments or other damages, are paid in full (whether directly or indirectly such as through set-off or netting). Any such Collateral described in this Section 8.1 shall not be deemed a limitation of damages.

(e) Use of Security. Unless otherwise indicated in this Agreement, including Section 12.2, Buyer shall be entitled to draw upon the Collateral posted by Seller for any obligation of Seller arising under this Agreement that is not paid when due, whether or not an Early Termination Date or other termination of this Agreement in compliance with the terms hereof has been declared. Notwithstanding the foregoing, amounts contained in the Delay Damages Account shall only be drawn upon by Buyer pursuant to Section 5.4(a).

8.2 Letter of Credit and Other Collateral.

(a) If Seller has provided a Letter of Credit pursuant to any of the applicable provisions in this Article VIII or elsewhere in the Agreement, then not later than thirty (30) days prior to the stated expiration date of the Letter of Credit, the Seller shall renew (or cause the renewal of) each outstanding Letter of Credit, or replace (or cause the replacement of) each such Letter of Credit with one or more replacement Letters of

Credit from a Qualified Issuer in the amount required by this Agreement at the time of such renewal or replacement. In the event (A) the issuer of a Letter of Credit shall fail to meet the requirements of a Qualified Issuer; or (B) the issuer of an outstanding Letter of Credit indicates its intent not to renew such Letter of Credit; or (C) an issuer of a Letter of Credit shall fail to honor the beneficiary's properly documented request to draw on an outstanding Letter of Credit, then, within five (5) Business Days thereafter, Seller shall provide a substitute Letter of Credit from a Qualified Issuer other than the bank that has been downgraded, refused to renew or failed to honor the outstanding Letter of Credit ("Cure"). If Buyer does not receive a replacement Letter of Credit from a Qualified Issuer within the time specified in either of the two preceding sentences, it may draw on the full available amount of the Letter of Credit. Amounts drawn in such circumstances shall be held directly by the Buyer bearing interest each day at the rate per annum equal to the Monthly Federal Funds Rate as reported in Federal Reserve Bank Publication H.15-519 or its successor publication (as set on a monthly basis based on the latest month for which such rate is available) on any unapplied balance held by Buyer as described herein. Amounts drawn shall be available to be applied by Buyer for the reasons set forth in Section 8.1(e) under the conditions set forth in the Letter of Credit. If Seller fails to Cure or if such Letter of Credit expires or terminates without a full draw thereon by Buyer, or such Letter of Credit fails or ceases to be in full force and effect at any time that such Letter of Credit is required pursuant to the terms of this Agreement, such failure, expiration or termination shall be considered a Seller's Event of Default.

(b) In all cases, the costs and expenses of establishing, renewing, substituting, canceling, increasing, reducing or otherwise administering a Letter of Credit or other form of Collateral shall be borne by Seller. If Buyer has not otherwise terminated this Agreement in accordance with the terms hereof and draws on a Letter of Credit due to a failure by Seller to satisfy a payment obligation under the Agreement, Buyer shall not terminate the Agreement or declare an Event of Default hereunder solely on the basis of such payment default if (i) the proceeds from the draw satisfies in full the payment obligation, and (ii) Seller fully replenishes (to the extent such replenishment is required pursuant to the terms of this Agreement or Seller otherwise chooses to make such replenishment) such Letter of Credit to Buyer's reasonable satisfaction within five (5) Business Days subject to the limitations of Section 8.1(a) and (c).

8.3 Buyer's Lien.

(a) In addition to any other Collateral required to be provided by Seller hereunder, to secure its obligations under this Agreement, Seller shall grant to Buyer a present and continuing perfected Lien on and security interest in all of Seller's right, title and interest in and to Buyer's Percentage of the Project, the Project Contracts and all of Seller's other assets (other than Excess Products) (the "Buyer's Lien"), which Buyer's Lien shall be subordinate only to the Project Financing Lien(s) and other Project Permitted Liens that are superior to the Project Financing Lien(s) as a matter of law and which Buyer's Lien shall be *pari passu* with any and all other Liens granted to any purchaser of Energy, Contract Capacity, Environmental Attributes or Ancillary Services from the Project (and Buyer shall enter into an intercreditor agreement with such other purchasers in a form customary for transactions of this type); provided however, that

Seller shall not be deemed to be in default under this Agreement if Project Permitted Liens other than the Project Financing Lien are in existence. The amounts secured and given priority by the Project Financing Lien(s) shall not exceed seventy percent (70%) of the total cost of the Project (as reasonably documented to Buyer). Notwithstanding the foregoing, amounts secured by the Project Financing Lien(s) may be for amounts up to eighty percent (80%) of the total cost of the Project (as reasonably documented to Buyer) if the entire eighty percent (80%) is granted to the Senior Secured Lenders and eighty percent (80%) of the total cost of the Project is being financed by such Senior Secured Lenders.

(b) Prior to the Effective Date, Seller and/or Buyer, as the case may be, shall execute and record, as appropriate, separate agreements, documents, or instruments under which Seller will provide Buyer, in a form reasonably acceptable to Buyer, a fully perfected security interest(s) and a mortgage lien of the priority required hereunder for the Buyer's Lien, subordinated only to the extent expressly contemplated in Section 8.3(a) (collectively the "Project Security Agreements"). The Buyer's Lien shall secure Seller's continuing performance under this Agreement and any amounts that may be owed by Seller to Buyer pursuant to this Agreement. For the avoidance of doubt, the Buyer's Lien shall not include the pledge, assignment, or other interest in any stock or ownership interest in Seller or any Affiliate of Seller. Seller and Buyer agree to cooperate and diligently negotiate in good faith to establish the form of the Project Security Agreements, which agreements shall be in form and substance reasonably satisfactory to the Senior Secured Lenders, Seller and the Buyer, consistent with the terms set forth in Section 8.3(a) above. The Parties shall confirm, define, and perfect the Buyer's Lien by executing, filing, and recording the Project Security Agreements. In addition, Seller agrees to execute and file such Uniform Commercial Code financing statements and to take such further action and execute such further instruments as shall reasonably be required by Buyer or otherwise to confirm and continue the validity, priority, and perfection of the Project Security Agreements and the Buyer's Lien prior to the Effective Date and throughout the Contract Term. The Buyer's Lien shall be automatically discharged and released, and Buyer shall promptly take any steps reasonably required by Seller or the Senior Secured Lenders to effect and record such discharge and release, upon the expiration of the Contract Term and satisfaction by Seller of all obligations hereunder. Buyer agrees to enter into a subordination agreement with the Senior Secured Lenders in form and substance reasonably satisfactory to Buyer and the Senior Secured Lenders, evidencing the status of the Buyer's Lien vis-à-vis the Project Financing Liens and incorporating such terms and conditions as are usual and customary for a non-recourse project financing of this type but in conformity with the subordination limitations set forth in Section 8.3(a); provided, however, in no event shall Buyer be obligated to enter into any terms that are materially inconsistent with the principles regarding Buyer's Lien set forth in this Section 8.3. Notwithstanding anything to the contrary set forth herein, Buyer shall at all times have a first priority security interest in the Pre-Services Term Period Security, the Development Period Security, the Services Term Security and the Delay Damages Account. Notwithstanding the Buyer's Lien, on Seller's request Buyer agrees to negotiate in good faith the creation of a pari-passu Lien on the Shared Facilities in favor of any Person to whom the Seller or an Affiliate of Seller has provided a Lien on a wind power project adjacent to the Project to

the extent and only to the extent needed for the financing of such Project; *provided, however*, that the creation of any such Lien on Shared Facilities shall under no circumstances materially adversely affect the ability of the Project to perform its obligations under the Agreement or the Buyer Lien (other than with respect to the Shared Facilities). Buyer will negotiate on Seller's request in good faith with such Lien holder to enter into an intercreditor agreement with respect to Shared Facilities, in form and substance reasonably satisfactory to Buyer, including terms and conditions which are usual and customary in transactions of this type; provided however that such intercreditor agreement shall not impair Buyer's rights to use the Shared Facilities in exercising its rights under the Agreement.

ARTICLE IX
GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the Parties to minimize all Taxes, so long as neither Party is materially adversely affected by such efforts.

9.2 Regulatory Charges. Seller shall pay or cause to be paid all Taxes, Governmental Charges, fees and other charges imposed by any Governmental Authority ("Regulatory Charges") on or with respect to the Products arising before and at the Delivery Point, including ad valorem taxes, Taxes related to the operation or maintenance of the Project, the use or consumption of gas or other fuels, and other Taxes attributable to the Project, land, land and Site rights or interests in land and the Site for the Project. Buyer shall pay or cause to be paid all Regulatory Charges on or with respect to the Products purchased by Buyer hereunder, after receipt thereof from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Products and are, therefore, the responsibility of the Seller, but excluding any sales taxes, which shall be solely the responsibility of Buyer). In the event a Party is required by Law or regulation to remit or pay Regulatory Charges which are the other Party's responsibility hereunder, the Party that is assessed shall provided Notice to the Party that is responsible for such amounts due (together with supporting documentation), the assessed Party shall promptly pay such Regulatory Charges when due and invoice the responsible Party in accordance with Article VI, and the responsible Party shall reimburse the assessed Party in full in accordance with Article VI no later than the next Monthly Payment Date, with interest at the Interest Rate from and including the date on which the assessed Party pays the Regulatory Charges until (but excluding) the date on which the responsible Party reimburses the assessed Party (cumulatively, the "Regulatory Charges Payment"). Nothing shall obligate or cause a Party to pay or be liable to pay any Regulatory Charges from which it is exempt under the Law; provided that an exempt Party shall bear the responsibility of proving upon request its exemption as necessary to avoid the unjust imposition of a Regulatory Charge on the other Party.

ARTICLE X
REPRESENTATION AND WARRANTIES

10.1 Representations and Warranties.

(a) Representations and Warranties of Both Parties. Each Party represents and warrants to the other Party that as of the Execution Date:

(i) it is duly organized, validly existing and in good standing under the Laws of the jurisdiction of its formation and is qualified to transact business in the State of Delaware and in each other jurisdiction in which its operations or the ownership of its properties require it to be qualified, except where the failure to so qualify would not have a material adverse effect on its ability to carry out the terms of the Agreement, its financial condition, or its ability to own its properties and transact its business;

(ii) except for the Permits necessary to construct, operate and maintain the Project in the case of the Seller, and Regulatory Approval in the case of Buyer, it has all Permits necessary for it to perform its obligations under this Agreement;

(iii) the execution, delivery and performance of this Agreement is within its powers, has been duly authorized by all necessary action and does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any Law, rule, regulation, order or the like applicable to it, and it has full power and authority to carry on its business as now conducted and to enter into, and, in the case of Buyer, subject to receipt of Regulatory Approval, carry out its obligations under this Agreement;

(iv) execution and delivery of this Agreement and performance or compliance with any provision hereof will not result in the creation or imposition of any Lien upon its properties (except as expressly contemplated in favor of Buyer pursuant to this Agreement and the Project Security Agreements), or a breach of, or constitute a default under, or give to any other Persons any rights of termination, amendment, acceleration or cancellation of, such Party's articles of incorporation and bylaws (or equivalent) or any agreement to which it is a party or by which any of its respective properties is bound or affected;

(v) this Agreement has been duly and validly executed and delivered and constitutes its legally valid and binding obligation enforceable against it in accordance with its terms, subject to any Equitable Defenses;

(vi) it is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

(vii) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement; and

(viii) no Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

(b) Covenants of Seller. Seller covenants to Buyer that throughout the Pre-Services Term Period and the Services Term:

(i) Seller shall have good and marketable title to all Delivered Energy and Contract Capacity Amounts and other Products delivered to Buyer hereunder, and it will deliver the Delivered Energy, Contract Capacity Amounts, and other Products to Buyer free and clear of all Liens, security interests, claims and encumbrances on any interest therein or thereto by any Person;

(ii) Except as permitted under Sections 8.3 and 14.5(a), the Collateral shall be free and clear of all Liens, security interests, claims and encumbrances other than Project Permitted Liens;

(iii) It shall hold the rights to all Environmental Attributes from the Units and the Project that Seller is required to deliver hereunder and shall transfer such rights to Buyer free and clear of all Liens, security interests, claims and encumbrances on any interest therein or thereto by any Person;

(iv) It shall (A) take all actions to transfer to Buyer the Contract Capacity Amount for each Capacity Year as required hereunder, and (B) take no action or permit any Person (other than Buyer) to take any action that would impair in any way Buyer's ability to rely on the Units or the Products delivered hereunder (including delivery to Buyer of Buyer's Percentage of the Contract Capacity for each Capacity Year) in order to satisfy Buyer's Resource Adequacy Requirements (to the extent applicable pursuant to Section 3.14);

(v) It shall have ownership of, or a demonstrable right to control (sufficient for Seller to perform its obligations under the Agreement), the Project Site, and have all Permits necessary for it to perform its obligations under the Agreement, including all Permits necessary to install, operate and maintain the Project;

(vi) It is a PJM Member and the Project and each of the Units (i) shall be a Capacity Resource of PJM, and (ii) shall qualify and be certified by the Commission as an Eligible Energy Resource (as defined in the Commission RPS Rules and RPS Act), and all Energy produced by the Project to be delivered to Buyer hereunder shall qualify as generation from an Eligible Energy Resource under the RPS Act and the Commission RPS Rules;

(vii) All interconnection, transmission and other agreements necessary for Seller to perform its obligations hereunder (including the Interconnection Agreements) shall be in full force and effect; and

(viii) Seller shall at all times (a) install, operate, maintain and repair the Project in accordance with Good Utility Practices and to ensure Seller is capable of meeting its obligations under this Agreement over the Services Term, (b) maintain records of all operations of the Project and performance under this Agreement in accordance with Good Utility Practices and (c) follow such regulations, directions and procedures of the Buyer, any applicable Participating Transmission Owner, PJM and any other applicable Governmental Authority to protect and prevent the transmission system from experiencing any negative impacts resulting from the operation of the Project or Seller's performance hereunder.

ARTICLE XI
INDEMNIFICATION AND INSURANCE

11.1 Indemnities.

(a) Indemnity by Seller. Seller shall release, defend, indemnify and hold harmless Buyer, its directors, officers, agents, attorneys, representatives and Affiliates ("Buyer Group") against and from any and all damages, claims, losses, liabilities, obligations, costs and expenses, including reasonable legal, accounting and other expenses, and the costs and expenses of any and all actions, suits, proceedings, demands, assessments, judgments, settlements and compromises, which arise out of or relate to or are in any way connected with (i) the Product(s) delivered to Buyer prior to and at the Delivery Point; (ii) any other Energy or Product produced by the Project and not required to be delivered to Buyer hereunder; (iii) Seller's participation in the PJM RPM Market and compliance with PJM Capacity Rules; (iv) the Project and Seller's operation and/or maintenance of the Project; (v) Seller's actions or inactions, including breach and violation, with respect to this Agreement, the Ancillary Agreements or other agreements related to the development, construction, ownership, operation or maintenance of the Project; (vi) any environmental matters associated with the Project or the delivery to Buyer of the Products hereunder, including the use, disposal or transportation of Hazardous Substances by or on behalf of the Seller or at the Seller's direction or agreement, and the protection, maintenance and restoration of the Site; or (vii) resulting from Seller's negligence, misconduct, or violation of any applicable Law, or requirements of PJM, the Commission, NERC, Reliability*First* Corporation, FERC or other Governmental Authorities; in each case including any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to or destruction of property belonging to Buyer, Seller or others, excepting only such damages, claims, losses, liabilities, obligations, suits, proceedings, demands or assessments, as may be caused solely by the fault, willful misconduct or negligence of a member of the Buyer Group. Without limiting Buyer's rights to collect liquidated

damages as set forth in this Agreement, Seller shall not be liable for any loss of profit or revenues, loss of product, loss of use of products or services or any associated equipment, interruption of business, cost of capital, downtime costs, increased operating costs, claims of ratepayers for such damages, or for any special, consequential, incidental, indirect, punitive or exemplary damages of Buyer; it being understood such limitation does not apply to Third Party Claims.

(b) Indemnity by Buyer. Buyer shall release, indemnify and hold harmless Seller, its directors, officers, agents, attorneys, representatives and Affiliates ("Seller Group") against and from any and all damages, claims, losses, liabilities, obligations, costs and expenses, including reasonable legal, accounting and other expenses, and the costs and expenses of any and all actions, suits, proceedings, demands, assessments, judgments, settlements and compromises, which arise out of or relate to or are in any way connected with (i) the Products delivered in accordance with the terms hereof, after the Delivery Point, (ii) Buyer's actions or inactions, including breach and violation, with respect to this Agreement or the Ancillary Agreements, or (iii) resulting from Buyer's negligence, misconduct, or violation of any applicable Law, or requirements of PJM, the Commission, NERC, Reliability*First* Corporation, FERC or other Governmental Authorities; in each case including any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to or destruction of property belonging to Buyer, Seller, or others, excepting only such damages, claims, losses, liabilities, obligations, suits, proceedings, demands or assessments, as may be caused solely by the fault, willful misconduct or negligence of a member of the Seller Group. Without limiting Seller's rights to collect liquidated damages as set forth in this Agreement, Buyer shall not be liable for any loss of profit or revenues, loss of product, loss of use of products or services or any associated equipment, interruption of business, cost of capital, downtime costs, increased operating costs, claims of ratepayers for such damages, or for any special, consequential, incidental, indirect, punitive or exemplary damages of Seller; it being understood that such limitation does not apply to Third Party Claims.

(c) Notice of Claim.

(i) Notice of Claim. Subject to the terms of this Agreement and upon obtaining knowledge of a claim for which it is entitled to indemnity under this Section 11.1, the Party seeking indemnification hereunder (the "Indemnitee") will promptly notify the Party against whom indemnification is sought (the "Indemnitor") in writing of any damage, claim, loss, liability or expense which the Indemnitee has determined has given or could give rise to a claim under Section 11.1(a) or (b) (the written Notice is referred to as a "Notice of Claim"). A Notice of Claim will specify, in reasonable detail, the facts known to the Indemnitee regarding the claim.

(ii) Notice of Third Party Claim. If an Indemnitee receives Notice of the assertion or commencement of a Third Party Claim against it with respect to which an Indemnitor is obligated to provide indemnification under this Agreement, such Indemnitee will give such Indemnitor a Notice of Claim as

promptly as practicable, but in any event not later than seven (7) calendar days after such Indemnitee's receipt of Notice of such Third Party Claim. Such Notice of Claim will describe the Third Party Claim in reasonable detail, will include copies of all material written evidence thereof and will indicate, if reasonably practicable the estimated amount of the Indemnifiable Loss that has been or may be sustained by the Indemnitee. The Indemnitor will have the right to participate in, or, by giving written Notice to the Indemnitee, to assume the defense of any Third Party Claim at such Indemnitor's own expense and by such Indemnitor's own counsel (as is reasonably satisfactory to the Indemnitee), and the Indemnitee will cooperate in good faith in such defense.

(iii) Direct Claim. Any Direct Claim must be asserted by giving the Indemnitor written Notice thereof, stating the nature of such claim in reasonable detail and indicating the estimated amount, if practicable. The Indemnitor will have a period of sixty (60) calendar days from receipt of such Notice within which to respond to such Direct Claim. If the Indemnitor does not respond within such sixty (60) day period, the Indemnitor will be deemed to have accepted such Direct Claim. If the Indemnitor rejects such Direct Claim, the Indemnitee will be free to seek enforcement of its rights to indemnification under this Agreement.

(iv) Failure to Provide Notice. A failure to give timely Notice or to include any specified information in any Notice as provided in this Section 11.1(c) will not affect the rights or obligations of any Party hereunder except and only to the extent that, as a result of such failure, any Party which was entitled to receive such Notice was deprived of its right to recover any payment under its applicable insurance coverage or was otherwise materially damaged as a direct result of such failure and, provided further, the Indemnitor is not obligated to indemnify the Indemnitee for the increased amount of any claim which would otherwise have been payable to the extent that the increase resulted from the failure to deliver timely a Notice of Claim.

(d) Defense of Third Party Claims. If, within ten (10) calendar days after giving a Notice of Claim regarding a Third Party Claim to an Indemnitor pursuant to Section 11.1(c)(ii), an Indemnitee receives written Notice from such Indemnitor that the Indemnitor has elected to assume the defense of such Third Party Claim as provided in the last sentence of Section 11.1(c)(ii), the Indemnitor will not be liable for any legal expenses subsequently incurred by the Indemnitee in connection with the defense thereof; provided, however, that if the Indemnitor fails to take reasonable steps necessary to defend diligently such Third Party Claim within ten (10) calendar days after receiving written Notice from the Indemnitee that the Indemnitee believes the Indemnitor has failed to take such steps, or if the Indemnitor has not undertaken fully to indemnify the Indemnitee in respect of all Indemnifiable Losses relating to the matter, the Indemnitee may assume its own defense, and the Indemnitor will be liable for all reasonable costs or expenses, including attorneys' fees, paid or incurred in connection therewith. Without the prior written consent of the Indemnitee, the Indemnitor will not enter into any settlement of any Third Party Claim which would lead to liability or create any financial or other obligation on the part of the Indemnitee for which the Indemnitee is not entitled

to indemnification hereunder; provided, however, that the Indemnitor may accept any settlement without the consent of the Indemnitee if such settlement provides a full release to the Indemnitee and no requirement that the Indemnitee acknowledge fault or culpability. If a firm offer is made to settle a Third Party Claim without leading to liability or the creation of a financial or other obligation on the part of the Indemnitee for which the Indemnitee is not entitled to indemnification hereunder and the Indemnitor desires to accept and agrees to such offer, the Indemnitor will give written Notice to the Indemnitee to that effect. If the Indemnitee fails to consent to such firm offer within ten calendar days after its receipt of such Notice, the Indemnitee may continue to contest or defend such Third Party Claim and, in such event, the maximum liability of the Indemnitor to such Third Party Claim will be the amount of such settlement offer, plus reasonable costs and expenses paid or incurred by the Indemnitee up to the date of such Notice.

(e) Subrogation of Rights. Upon making any indemnity payment, the Indemnitor will, to the extent of such indemnity payment, be subrogated to all rights of the Indemnitee against any Third Party in respect of the Indemnifiable Loss to which the indemnity payment relates; provided that (i) the Indemnitor is in compliance with its obligations under this Agreement in respect of such Indemnifiable Loss, and (ii) until the Indemnitee recovers full payment of its Indemnifiable Loss, any and all claims of the Indemnitor against any such Third Party on account of said indemnity payment are hereby made expressly subordinated and subjected in right of payment to the Indemnitee's rights against such Third Party. Without limiting the generality or effect of any other provision hereof, each such Indemnitee and Indemnitor shall execute upon request all instruments reasonably necessary to evidence and perfect the above-described subrogation and subordination rights.

(f) Rights and Remedies Are Cumulative. The rights and remedies of a Party pursuant to this Section 11.1 shall be cumulative and in addition to the rights of the Parties otherwise provided in this Agreement.

11.2 Insurance. Commencing on the Effective Date Seller shall, at its sole cost and expense, procure and maintain, or cause to be procured and maintained, the following insurance coverages with an insurance company or companies rated not lower than "A-" by A.M. Best Company and be responsible for its subcontractors maintaining sufficient limits of the appropriate insurance coverage consistent with Good Utility Practices. Additionally, during the period between the Effective Date and Financial Closing (as described on Schedule 1) for construction of the Project Seller shall maintain at a minimum the insurance provisions set forth below in (a)-(f).

(a) Workers' Compensation and Employers' Liability.

(i) Workers' Compensation and basic employer's liability insurance for all employees in accordance with applicable state and federal labor codes, acts, Laws or statutes.

(ii) Employers' Liability insurance with limits of at least $1,000,000 for injury or death occurring as a result of each accident.

(b) Commercial General Liability.

(i) Comprehensive or commercial general liability insurance written on an occurrence basis with a combined single limit of at least $1,000,000 per occurrence, including premises/operations, broad form property damage liability, explosion and collapse hazard coverage, blanket contractual liability encompassing the indemnity provisions of this Agreement, independent contractors, products and completed operations, personal injury, and sudden and accidental seepage and pollution liability (and, if such insurance is obtained as part of Seller's general insurance policy for all its projects and assets, such policy, or policies, shall be written on a project-specific basis so that the limits set forth apply solely to the ownership, construction, use, operation and maintenance of Seller's interest in the Project, the Units and the Electrical Interconnection Facilities). If coverage includes an aggregate limit, that limit should be at least $10,000,000.

(c) Business Auto.

(i) Comprehensive Automobile Liability insurance with bodily injury, death and property damage combined single limits of at least $1,000,000 per occurrence covering vehicles owned, hired or non-owned.

(d) Excess Umbrella Liability Insurance.

(i) Excess Umbrella Liability Insurance with a single limit of at least $15,000,000 per occurrence and in the aggregate, in excess of the limits of insurance provided above.

(e) Marine Charterer's Liability.

(i) Marine Charterer's liability for all watercraft Seller charters or operates in performance of the Agreement, in an aggregate amount no less than $10,000,000.

(f) Additional Insurance Provisions.

(i) Such insurance shall include (1) provisions or endorsements naming Buyer, its Affiliates, directors, officers and employees as additional insureds; (2) provisions that such insurance is primary insurance with respect to the interest of Buyer and such additional insureds and that any insurance maintained by Buyer is excess and not contributory insurance with the insurance required hereunder; (3) a cross-liability or severability of insurance interest clause; (4) provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written Notice to Buyer; and (5) provisions by which the insurer waives all rights of subrogation against Buyer

and the additional insureds listed above. Seller shall provide Buyer with certificates of insurance upon written request evidencing the policies, provisions and endorsements listed above within ten (10) days after they have been obtained. In addition, upon written request, Seller shall provide Buyer with copies of the insurance policies evidenced by such certificates. The insurance coverage described above in this section shall be primary and not excess or contributing with respect to any other coverage available to Seller or to its Affiliates and shall not be deemed to limit Seller's liability under this Agreement.

(ii) Reviews of such insurance may be conducted by Buyer on an annual basis.

(iii) Upon written request, Seller shall furnish Buyer evidence of insurance for its subcontractors.

(iv) The insurance carrier or carriers and form of policy shall be subject to the reasonable approval by Buyer.

(g) To the extent that the levels or types of insurance listed above differ from the levels or types set forth in the Senior Loan Documents, the insurance requirements shall be adjusted to be consistent with the levels and types set forth in the Senior Loan Documents, provided however, that if the Senior Loan Documents are no longer in effect the coverage and types in place at that point shall continue (except if such insurance is unavailable on a commercially reasonable basis).

ARTICLE XII
EVENTS OF DEFAULT; REMEDIES

12.1 Events of Default.

(a) The Seller will be deemed a "Defaulting Party" upon the occurrence of any of the following, provided that such occurrence was not caused by the action or inaction of the Buyer in contravention of the Agreement (each a "Seller's Event of Default"):

(i) Failure to deliver to Buyer at the Delivery Point any Delivered Energy produced by the Project (other than Excess Products) as required under the Agreement and/or intentional delivery of any such Delivered Energy to any third party if not expressly permitted under the Agreement.

(ii) Failure of the Project to qualify as a Capacity Resource as required under this Agreement, or failure by Seller to transfer, or be able to transfer, the Contract Capacity Amount for any Capacity Year as required under this Agreement and/or intentional transfer of such Contract Capacity Amount to any third party if not expressly permitted under this Agreement, and any failure by Seller to take such actions under the PJM Capacity Rules, including as shall be required to transfer such Contract Capacity Amounts to Buyer as required hereunder.

(iii) Any material asset of Seller is taken upon execution or by other process of Law or if taken upon or subject to any attachment by any creditor of or claimant against Seller and the attachment is not disposed of within sixty (60) days after its levy.

(iv) Upon the occurrence of any material misrepresentation or omission in any metering (or submetering) or any report or Notice of the Project's or a Unit's availability and capability or Outage required to be made or delivered by Seller to Buyer, or undue delay or withholding of such data, report or Notice of the Project's or a Unit's availability and capability or Outage, which misrepresentation, omission or undue delay or withholding is caused by Seller's willful misconduct, gross negligence or bad faith.

(v) Seller fails to post, maintain, substitute, supplement, replenish or renew when due the Development Period Security as required under the Agreement and such failure continues for five (5) days after Notice thereof is received, except for the failure to post the remainder of the Development Period Security fifteen (15) days after the Effective Date, as to which no Notice is required.

(vi) Seller fails to comply with the Resource Adequacy Requirements or PJM Capacity Rules as and to the extent required in the Agreement which failure continues for sixty (60) days after Notice thereof is received from Buyer, and provided such failure shall not constitute a "Seller's Event of Default" if Buyer has failed to compensate Seller to the extent required in Section 3.14.

(vii) During the Services Term, the Mechanical Availability Percentage of the Project is below sixty percent (60%) for a period of eighteen (18) consecutive months.

(viii) During the Services Term, the Mechanical Availability Percentage (including for Force Majeure Events as set forth in the definition of "Mechanical Availability Percentage") of the Project is below sixty percent (60%) for a period of thirty (30) consecutive months.

(ix) Seller fails to comply with its obligations under the Project Security Agreements or the collateral security requirements in Article VIII or any other Collateral requirement or requirements with respect to Delay Damages hereunder and such failure continues for five (5) Business Days after Notice thereof is received by Seller.

(x) The Project Security Agreements (after the effective date thereof) shall cease to be effective, except in accordance with their terms, to grant the Buyer's Lien, or the Buyer's Lien shall be subordinate to any other Lien or security interest other than as permitted hereunder with respect to Project Permitted Lien(s) or Project Financing Liens, or any material default by Seller shall occur under the Project Security Agreements and such default shall continue

beyond any grace period provided therein with respect thereto, and any such failure or default noted in this Section 12.1(a)(x) continues for five (5) Business Days after Notice thereof is received by Seller.

(xi) Subject to Sections 5.4(b), (c) or (e) and any other provisions of this Agreement to the contrary or that allow for an extension, a failure to complete the conditions precedent to the Initial Delivery Date as set out in Section 5.3(a) on or before the Date Certain or a delay in completing any Critical Milestone of more than eighteen (18) months from the date set forth in Schedule 1 for reasons other than a Force Majeure Event (in each case, as extended due to a Force Majeure Event in accordance with Section 5.5, if applicable).

(b) A Party will be deemed a Defaulting Party upon the occurrence of any of the following, provided that such occurrence was not caused by the action or inaction of the Non-Defaulting Party in contravention of the Agreement (each as applicable to either Buyer or Seller, either a "Buyer's Event of Default" or "Seller's Event of Default"):

(i) A Party fails to pay an amount when due hereunder and such failure continues for thirty (30) days after Notice thereof is received.

(ii) A Party fails to perform any of its material obligations under this Agreement and such default (which is not otherwise specified to be a separate Event of Default hereunder) continues for thirty (30) days after Notice thereof is received, specifying the default; *provided, however*, that such period shall be extended for an additional reasonable period if cure cannot be effected in thirty (30) days and if corrective action, reasonably calculated to cure the default within a reasonable period of time, is instituted by the Defaulting Party within the thirty (30) day period and so long as such action is diligently pursued until such default is corrected; but not to exceed one hundred and twenty (120) days cumulatively.

(iii) Any default shall occur under any of the Ancillary Agreements or the Interconnection Agreements and such default shall continue beyond any period of grace provided therein with respect thereto, and any such default continues for five (5) Business Days after Notice thereof is received by the Defaulting Party.

(iv) A Party applies for, consents to, or acquiesces in the appointment of a trustee, receiver or custodian of its assets (including, in the case of Seller for a substantial part of the Units or the Project), or the initiation of a bankruptcy, reorganization, debt arrangement, moratorium or any other proceeding under bankruptcy Laws.

(v) Absent the consent or acquiescence of a Party, appointment of a trustee, receiver or custodian of its assets (including in the case of Seller, for a substantial part of the Units or the Project), or the initiation of a bankruptcy,

reorganization, debt arrangement, moratorium or any other proceeding under bankruptcy Laws, which in either case, is not dismissed within ninety (90) days.

(vi) Any governmental approval necessary for a Party to be able to perform all of the transactions contemplated by the Agreement expires, or is revoked or suspended and is not renewed or reinstated within a reasonable period of time following the expiration, revocation or suspension thereof, by reason of the action or inaction of such Party and such expiration, revocation or suspension creates a material adverse impact on the other Party.

(vii) Upon the occurrence of any material breach of any representation, covenant or warranty made by a Party in this Agreement, thirty (30) days after the written Notice from the other Party that any material representation, covenant or warranty made in this Agreement is false, misleading or erroneous in any material respect without the breach having been cured; *provided, however*, that such period shall be extended for an additional reasonable period if cure cannot be effected in thirty (30) days and if corrective action is instituted by the Defaulting Party within the thirty (30)-day period and for so long as such action is diligently pursued until such default is corrected, but in any event within ninety (90) days.

12.2 Remedies. For the avoidance of doubt, Buyer's remedy pursuant to this Section 12.2 for an Event of Default or termination of this Agreement under Sections 3.15, 5.2(c), 5.2(e), 5.4(b), 5.4(d), 5.6 or 5.7 shall be such remedies set forth in such specific sections, except to the extent a separate remedy or Event of Default exists under the Agreement.

(a) Upon the occurrence of an Event of Default, the non-defaulting Party ("Non-Defaulting Party") shall have the right to any combination of the following: (i) send Notice, designating a day, no earlier than the day such Notice is deemed to be received (as provided in Section 14.1) and no later than thirty (30) days after such Notice is deemed to be received (as provided in Section 14.1), as an early termination date of this Agreement ("Early Termination Date"), to terminate the Contract Term effective as of the Early Termination Date and collect liquidated damages in the amounts set forth below in this Section 12.2 ("Termination Payment"); (ii) withhold any payments due to the Defaulting Party under this Agreement; (iii) suspend performance under this Agreement; (iv) demand and require immediate payment of any amounts payable to the Non-Defaulting Party that, as of the effective date of the termination, have been incurred by the Defaulting Party but are not yet paid pursuant to the terms of this Agreement; (v) receive payments of all amounts then due and payable between the Parties under the terms of this Agreement; and (vi) subject to the terms of the Agreement and except when an exclusive remedy is provided under the terms of the Agreement, exercise any other right or remedy available at Law or in equity, other than specific performance.

(b) If Buyer is the Defaulting Party:

(i) prior to the issuance of the EPC Notice to Proceed by Seller, Buyer shall pay to Seller as liquidated damages a Termination Payment equal to the

costs reasonably incurred by Seller after the Execution Date in the development of the Units (as documented to Buyer in such detail as reasonably necessary for Buyer to verify such amounts) plus a breakage fee in an amount equal to $10 per kW multiplied by Buyer's Percentage of the Project Capacity or one million five hundred thousand dollars ($1,500,000) if such amount is required to be paid prior to Seller establishing the Project Capacity;

(ii) to the extent Seller shall have issued the EPC Notice to Proceed but prior to the Initial Delivery Date, the Termination Payment to be paid by Buyer as liquidated damages shall be calculated in the manner set forth in Section 12.2(d) below; and

(iii) on and after the Initial Delivery Date, the Termination Payment to be paid by Buyer as liquidated damages shall be calculated in the manner set forth in Section 12.2(d) below.

(c) If Seller is the Defaulting Party:

(i) prior to the Guaranteed Initial Delivery Date, Seller shall pay to Buyer as liquidated damages a Termination Payment equal to the then undrawn portion of the Development Period Security;

(ii) after the Guaranteed Initial Delivery Date but prior to the Initial Delivery Date, Seller shall pay to Buyer as liquidated damages a Termination Payment equal to the amount of the Termination Fee defined in Section 5.4, plus the amount of any unpaid Delay Damages due Buyer pursuant to Section 5.4 as of the effective date of termination; and

(ii) on and after the Initial Delivery Date, the Termination Payment to be paid by Seller as liquidated damages shall be calculated in the manner set forth in Section 12.2(d) below.

(d) On and after the Initial Delivery Date, if either Party is the Defaulting Party, the Defaulting Party shall pay to the Non-Defaulting Party a "Termination Payment" equal to, subject to subsections (e) and (f) below, the aggregate of (i) all Settlement Amounts netted into a single amount, where the "Settlement Amount" is equal to the Losses (expressed as a positive number) or Gains (express as a negative number), as applicable, expressed in U.S. dollars, which the Non-Defaulting Party incurs as a result of the liquidation of this Agreement as of the Early Termination Date; (ii) all Costs (expressed as a positive number) incurred by the Non-Defaulting Party (even if the Non-Defaulting Party experiences net Gains in excess of the Costs); (iii) amounts then due and owing (expressed as a positive number) by the Defaulting Party to the Non-Defaulting Party and not yet paid; and (iv) amounts then due and owing (expressed as a negative number) by the Non-Defaulting Party to the Defaulting Party and not yet paid. For the avoidance of doubt, if the Termination Payment is zero (0) or negative, the Defaulting Party shall owe no Termination Payment.

(e) For the avoidance of doubt, the Non-Defaulting Party shall not owe any Termination Payment to the Defaulting Party.

(f) Termination Payments shall be payable in accordance with Section 6.4. Disputes regarding the Termination Payment shall be determined in accordance with Article XIII. In no event will the Non-Defaulting Party be required to pay its Gains to the Defaulting Party.

(g) Prior to the exercise by Buyer of any right to terminate the Agreement, Buyer shall provide all required Notices to Seller, and, at the same time, to any Senior Secured Lender of which Buyer shall have Notice from Seller. Buyer shall provide each Senior Secured Lender the same opportunity to cure, on behalf of Seller, any default of Seller giving rise to such right to terminate as provided to Seller under the Agreement.

12.3 Right of Set-off and Payments by Non-Defaulting Party. The Non-Defaulting Party shall be entitled, at its option and in its discretion, to setoff against any amounts owed to the Defaulting Party by the Non-Defaulting Party under the Agreement, the Interconnection Agreements, the Ancillary Agreements or otherwise any amounts payable by the Defaulting Party to the Non-Defaulting Party under the Agreement, the Interconnection Agreements, the Ancillary Agreements or otherwise. This Section 12.3 shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any party is at any time otherwise entitled (whether by operation of Law or otherwise). Notwithstanding any provision to the contrary contained in the Agreement, the Non-Defaulting Party shall not be required to pay to the Defaulting Party any amount under this Agreement until the Non-Defaulting Party receives confirmation satisfactory to it in its reasonable discretion that all obligations of any kind whatsoever of the Defaulting Party to make any payments to the Non-Defaulting Party under the Agreement or otherwise which are due and payable as of the Early Termination Date have been fully and finally performed.

12.4 Termination Upon Consolidation of Seller.

(a) In addition to the Events of Default set forth in this Article 12 and the other termination rights of Buyer under this Agreement, Buyer has the right to terminate the Agreement with no further obligation or liability on the part of either Party if at any time during the term of the Agreement Buyer's independent outside auditing firm determines that Buyer must consolidate Seller in its financial statements under FIN 46 due to Seller's actions or other changes in circumstance not attributable to Buyer (a " FIN 46 Determination"). For the avoidance of doubt, (i) a determination by Buyer's independent outside auditing firm that Buyer must consolidate Seller (as described above) shall not in and of itself be a change in circumstance attributable to Buyer and (ii) notwithstanding the foregoing, Buyer's right to terminate the Agreement pursuant to this Section 12.4 and the consequences of such termination shall be subject to the requirements and allowances set forth in this Section 12.4 for remedying and/or mitigating the effect of such consolidation. Prior to any termination of the Agreement pursuant to this Section 12.4, Buyer and Seller shall proceed in accordance with the following process:

(i) Within five business days after learning of a FIN 46 Determination from Buyer's independent outside auditing firm, Buyer shall give Seller notice of such determination, which notice shall include a reasonable description of the basis of the determination and an estimate of the impacts of such determination upon Buyer.

(ii) Promptly following receipt of such notice, but in no event more than 15 days after Seller's receipt of such notice, Buyer and Seller will agree upon an independent evaluator to review the FIN 46 Determination. That independent evaluator shall be reasonably qualified and expert in matters of accounting with respect to power generation contracts and the financing of generation plants. If the parties are unable to agree upon an independent evaluator within such 15 day period, Seller (or both Parties jointly) shall apply to the Commission for the appointment of an independent evaluator.

(iii) Promptly upon appointment, the independent evaluator shall commence the preparation of, and within 30 days after appointment deliver to the Parties and to the Commission, a review of the FIN 46 Determination, which review shall, without limiting the inclusion of other matters the independent evaluator deems appropriate, contain a description and evaluation of:

(A) the basis for the FIN 46 Determination;

(B) the impact of the FIN 46 Determination upon each of the Parties, assuming continuation of this Agreement;

(C) the impact of a termination of this Agreement upon each of the Parties; and

(D) potential means to remedy the circumstances creating the FIN 46 Determination, including potential modifications to terms of this Agreement and/or the structure of Seller, together with a description of the costs, risks and benefits to Buyer and Seller of each such remedy.

In recommending potential means to remedy the circumstances creating the FIN 46 Determination, the independent evaluator shall give preference to remedies that avoid consolidation pursuant to FIN 46, avoid termination of the Agreement, and, to the extent practicable minimize adverse impacts (including impairment of the benefits of this Agreement on the Parties and the Buyer's customers.)

(iv) The Parties shall assist the independent evaluator throughout the process of preparing its review, including making key personnel and records available to the independent evaluator, but neither Party shall be entitled to participate in any meetings with personnel of the other Party or review of the other Party's records. The Parties shall also meet with each other during the review process to explore means of resolving the FIN 46 Determination on mutually acceptable terms.

(v) Promptly, but in no event later than five business days following receipt of the independent evaluator's review, the Parties shall meet to discuss the potential remedies proposed by the independent evaluator. Within 15 days after receipt of the independent evaluator's review, the Parties shall advise the Commission in writing whether the Parties have been able to agree on a remedy of the FIN 46 Determination, and if they have agreed, the terms of such agreement, and if they have not agreed, the concerns each Party has with potential remedies proposed by the independent evaluator. If the Parties are unable to agree, they shall request expedited consideration of the matter by the Commission.

(vi) The Parties agree that the Commission in determining the appropriate disposition of the matter brought before it under this subsection of the Agreement may consider remedies that include, without limitation, termination of this Agreement, alternative means or levels of performance of the terms of this Agreement, or payments from one Party to another as a condition to termination or continuation of this Agreement. The Parties agree, and have entered into this Agreement based on the expectation that, the Commission will endeavor to implement a disposition that avoids consolidation pursuant to FIN 46, avoids termination of the Agreement, and, to the extent practicable, minimizes adverse impacts (including impairment of the benefits of this Agreement) on the Parties and the Buyer's customers.

Although it shall be dispositive of the specific FIN 46 Determination giving rise to the process described in this subsection (a), no determination pursuant to the process described in this subsection (a) shall foreclose any subsequent right to terminate that Buyer might otherwise have under this Section 12.4 for a different and subsequent event or circumstance triggering consolidation or if FIN 46 is modified such that the same event or circumstance triggers consolidation, so long as the process described in this subsection (a) is employed.

(b) Buyer and Seller agree to use commercially reasonable efforts to minimize any consolidation effect that FIN 46 has during the term of the Agreement; provided, however, that except as provided in Section 12.4(a), neither Party shall be required to incur additional costs or other adverse effect (other than termination described above) as a result of such efforts. The Parties agree to expedite the process described in this subsection (a) as reasonably necessary to complete the process in time to avoid consolidation, if possible.

12.5 Rights And Remedies Are Cumulative. Except as provided herein, the rights and remedies of a Party pursuant to this Article XII shall be cumulative and in addition to the rights of the Parties otherwise provided in this Agreement.

12.6 Duty to Mitigate. Buyer and Seller shall each have a duty to mitigate damages pursuant to this Agreement, and each shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement, including with respect to termination of this Agreement

pursuant to Section 12.2. The Parties shall exercise commercially reasonable efforts when purchasing or selling to or from any other Person, as the case may be, Energy, Contract Capacity Amounts, Capacity Value, Environmental Attributes, and Ancillary Services (to the extent applicable) in order to mitigate damages pursuant to this Section 12.6.

ARTICLE XIII
DISPUTE RESOLUTION

13.1 Intent of the Parties. Except as provided in the next sentence, the sole procedure to resolve any claim arising out of or relating to this Agreement or any related agreement is the dispute resolution procedure set forth in this Article XIII. Notwithstanding the foregoing, either Party may seek a preliminary injunction or other provisional judicial remedy if such action is necessary to prevent irreparable harm or preserve the status quo, in which case both Parties nonetheless will continue to pursue resolution of the dispute by means of the procedure set forth in this Article XIII.

13.2 Management Negotiations. The Parties shall attempt in good faith to resolve all disputes arising out of or related to or in connection with this Agreement promptly by negotiation, as follows. Any Party may give the other Party written Notice of any dispute not resolved in the normal course of business. Senior executives of both Parties shall meet at a mutually acceptable time and place within ten (10) days after delivery of such Notice, and thereafter as often as they mutually agree, to attempt to resolve the dispute. The Parties further agree to provide each other with reasonable access during normal business hours to any and all non-privileged records, information and data pertaining to any such dispute (subject in all respects to Section 6.6). If the matter has not been resolved within thirty (30) days from the referral of the dispute to senior executives, or if no meeting of senior executives has taken place within fifteen (15) days after such referral, either Party may initiate resolution of the dispute as provided in Section 13.3. All negotiations pursuant to this clause are confidential pursuant to Section 14.8.

13.3 Dispute Resolution Before Commission. If the dispute cannot be so resolved by negotiation as set forth in Section 13.2 above, it shall be resolved at the request of any Party through the dispute resolution process administered by the Commission. Any decision by the Commission may be appealed to the extent provided by applicable Law.

13.4 Extension of Milestones. To the extent that Buyer (or any of its Affiliates) pursues any litigation seeking to terminate the Agreement after the Execution Date absent an Event of Default by Seller or other exercise of remedies, or otherwise seeks to legally challenge the process by which any rights with respect to the Project (including this Agreement, the Permits and the Site) were granted or awarded to Seller, and such litigation continues beyond March 31, 2010, the Permitting Milestone, all Critical Milestones and the Guaranteed Initial Delivery Date and the Date Certain shall each be extended, such extension not to exceed a day for day extension for each day that such litigation or legal challenge extends beyond March 31, 2010, to the extent that Seller can

reasonably demonstrate that such litigation or legal challenge has delayed the achievement of such Critical Milestone or date (including delays resulting from the exercise of that level of financial prudence that would have been exercised by a reasonably prudent wind power developer acting under the circumstances set forth in this Section 13.4).

13.5 Non-Interference. Seller acknowledges that Buyer issued a Request for Proposals for Renewable Wind Energy Generation, dated February 14, 2008 (the "Buyer Windpower RFP"), pursuant to which Buyer solicited proposals for the purchase of energy and environmental attributes from land-based and offshore wind energy providers and entered into power purchase agreements with one or more of the bidders thereunder. Seller shall not, and shall cause its Affiliates not to, intervene against or otherwise challenge the Buyer Wind-Power RFP or the wind power purchase agreements entered into (or to be entered into) in connection therewith in any way, including, but not limited to, taking any legal or other action against Buyer or any seller under the Buyer Windpower RFP or appealing to the Commission or other Governmental Authority with respect to the Buyer Windpower RFP. Buyer shall not, and shall not cause its Affiliates to, intervene against, challenge or otherwise seek to prevent or overturn the Regulatory Approval of the Agreement.

ARTICLE XIV
MISCELLANEOUS

14.1 Notices. Whenever this Agreement requires or permits delivery of a "Notice" (or requires a Party to "Notify"), all notices, requests, statements or payments shall be made to the Parties using the contact information set out below. Notices required to be in writing shall be delivered by letter, facsimile or other documentary form. Notice by facsimile or hand delivery shall be deemed to have been received by the close of the Business Day during which the Notice is received or hand delivered. Notice by overnight mail or courier shall be deemed to have been received upon delivery as evidenced by the delivery receipt. Notwithstanding the foregoing, Forecasted Energy Notices, Notices of Outages or other intra-day information regarding the operations of the Project are to be provided as required pursuant to Sections 3.5 and 3.10; and any scheduling and dispatching shall be done pursuant to the Operating Procedures.

To Buyer: Delmarva Power & Light Company
c/o Pepco Holdings, Inc
701 Ninth Street, NW
Washington, DC 20068
Attn: Peter E. Schaub, General Manager
Energy Supply
202-872-3350 (fax)

with a copy to:	Pepco Holdings, Inc. 701 Ninth St., N.W. Washington, D.C. 20068 Attn: General Counsel 202-872-2890 (phone) 202-331-6767 (fax)
to Seller:	Bluewater Wind Delaware LLC 1 Innovation Way Suite 304F Newark, DE 19711 Attn: Peter Mandelstam (917) 327-5827 (phone) (212) 663 2047 (fax)
with a copy to:	Babcock & Brown 2 Harrison Street, 6th Floor San Francisco, CA 94105 Attn: General Counsel (415) 267-1638 (phone) (415) 267-1500 (fax)

14.2 Changes to Notice and Invoicing Information. The address and contact information to which Notices or invoices shall be mailed, or amounts paid, may be changed from time to time by either Party by Notice served as hereinabove provided.

14.3 Force Majeure Event.

(a) Effect of Force Majeure Event. Except as provided in Section 12.1(a)(viii) or otherwise in the Agreement, a Party shall not be considered to be in default in the performance of its obligations to the extent that the failure or delay of its performance is due to a Force Majeure Event, and the non-affected Party shall be excused from its corresponding performance obligations to the extent due to the affected Party's failure or delay of performance. Notwithstanding the foregoing, a failure to make payments that have accrued pursuant to the terms of the Agreement when due shall not be excused due to a Force Majeure Event. The burden of proof for establishing the existence and consequences of a Force Majeure Event lies with the Party initiating the claim.

(b) Notice of Force Majeure Event. In addition to satisfying the notification provisions set forth in Sections 3.5(b) and (c), as applicable, within three (3) Business Days of the commencement of a Force Majeure Event, the Party desiring to invoke a Force Majeure Event as a cause for delay in its performance of, or failure to perform, any obligation (other than the payment of money) hereunder, shall provide the other Party Notice of the occurrence giving rise to the Force Majeure Event with details to be supplied within seven (7) Business Days thereafter describing the particulars of the Force

Majeure Event, including the expected duration and effect of such Force Majeure Event. Failure to provide timely Notice constitutes a waiver of a claim of a Force Majeure Event. Promptly, but in any event within ten (10) days, after a Notice is given pursuant to the preceding sentence, the Parties shall meet to discuss the basis and terms upon which the arrangements set out in this Agreement shall be continued taking into account the effects of such Force Majeure Event.

(c) Mitigation of Force Majeure. The suspension of performance due to a claim of a Force Majeure Event must be of no greater scope and of no longer duration than is required by the Force Majeure Event. Each Party suffering a Force Majeure Event shall take, or cause to be taken, such action as may be necessary to void, or nullify, or otherwise to mitigate, in all material respects, the effects of such Force Majeure Event. The Parties shall take all reasonable steps to ensure resumption of normal performance under this Agreement after the cessation of any Force Majeure Event.

14.4 No Dedication. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any Person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or the public, nor affect the status of Buyer as an independent public utility corporation or Seller as an independent individual or entity.

14.5 Assignment.

(a) Assignment by Seller. Without Buyer's prior written consent, Seller shall not assign this Agreement or its rights hereunder or assign or transfer control of any of the Units or the Project (without limiting the "change of control" provision included below), in each case including to Affiliates and including direct and indirect transfers and assignments (except as permitted below). Buyer's consent in each case set forth above in this Section 14.5(a) shall not be unreasonably withheld upon a showing of the proposed assignee's technical and financial capability to fulfill the requirements of Seller under this Agreement, as determined by Buyer in its reasonable discretion; provided that Seller shall not, in any event, assign this Agreement or its rights hereunder without simultaneously assigning or transferring all of the Units and the Project to the same assignee, which assignee shall retain control of the Project during the Contract Term, except in the case of a further assignment pursuant to the terms hereof (including the restrictions set forth herein). Transfer of any ownership interests in Seller to an institutional investor for purposes of allowing such institutional investor to claim PTCs (a "Tax Investor") for electrical energy produced by the Project and sold by Seller pursuant to which such Tax Investor shall not have ordinary control over the management of Seller (and further transfers of such ownership interests by such Tax Investors) shall not be treated as an assignment of the Agreement for purposes of any such consent requirement. Change in the ownership of, or the ownership interests in, Seller shall not be treated as an assignment of the Agreement; provided, however, Seller shall obtain Buyer's prior written consent (not to be unreasonably withheld) to Changes of Control, such consent to be granted upon a showing that such Change in Control does not materially adversely affect Seller's creditworthiness or qualification to perform Seller's obligations under the

Agreement; provided, however, that a Change of Control caused by a transfer of Ownership Interests (i) to an entity with gross assets of at least $10 billion (giving effect to the balance sheet value of the Project and adjusted by the Consumer Price Index from the Execution Date), or (ii) to a Babcock & Brown Wind Partners Limited (an Australian Company) controlled infrastructure related fund which controls the ability to manage the Project, or (iii) in connection with a public offering on the New York, London, NASDAQ, AIM or similar exchange shall not require approval of the Buyer if such transfer in each case does not reduce the technical or financial ability of Seller to fulfill its obligations under the Agreement. Notwithstanding the foregoing, but subject to Section 8.3, Seller may, without relieving itself from liability hereunder, transfer, sell, pledge, encumber or assign the Units, the Project, this Agreement or the accounts, revenues or proceeds under the Agreement as security for the project financing for the Project. In connection with any assignment made pursuant to the previous sentence, at the request of Seller, Buyer shall execute a consent to assignment in form and substance reasonably satisfactory to Buyer and the Senior Secured Lenders that incorporates terms and conditions customary in a project finance transaction of this type, but Buyer shall not be obligated to enter into any consent which shall adversely affect Buyer's rights hereunder (including those under Section 8.3); and provided further, Seller shall be responsible for Buyer's reasonable documented costs associated with review, negotiation, execution and delivery of such documents, including attorneys' fees. Upon any permitted assignment of Seller's rights, duties and obligations under the Agreement by an assignee under this Section 14.5(a) (other than for financing purposes, as described herein), such assignee shall agree in a writing in form and substance reasonably acceptable to Buyer to assume and be bound by the terms and conditions hereof, including all of Seller's rights, duties, obligations and liabilities hereunder, and confirm to Buyer's reasonable satisfaction that all Collateral required hereunder shall remain in full force and effect, and, upon such assumption in full, Seller shall be released and discharged from this Agreement. Seller shall provide Buyer such information as Buyer may reasonably request to determine such technical and financial ability including investment guidelines and other relevant information related to an assignee under this section.

(b) Assignment by Buyer. Buyer shall have the right to assign the Agreement subject to Seller's consent not to be unreasonably withheld; provided Seller's consent shall not be required for (1) transfers to assignees that at the time of transfer are at least as creditworthy as Buyer was on the Execution Date, or (2) transfers to any entity succeeding to all or substantially all of Buyer's assets. Notwithstanding the foregoing, Buyer may, without relieving itself from liability hereunder, transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds under the Agreement to unrelated third parties for financing purposes. In connection with any assignment made pursuant to the previous sentence, at the request of Buyer, Seller shall execute a consent to assignment in form and substance reasonably satisfactory to Seller, but which consent shall not adversely affect Seller's rights hereunder; and provided further, Buyer shall be responsible for Seller's reasonable documented costs associated with review, negotiation, execution and delivery of such documents, including attorneys' fees. Upon any permitted assignment of Buyer's rights, duties and obligations under the Agreement by an assignee under this Section 14.5(b) (other than for financing purposes, as described herein), such assignee shall agree in a writing in form and substance

reasonably acceptable to Seller to assume and be bound by the terms and conditions hereof, including all of Buyer's rights, duties, obligations and liabilities hereunder, and, upon such assumption in full, Buyer shall be released and discharged from this Agreement.

14.6 Choice of Law And Venue. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF DELAWARE, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT. ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT SHALL BE FILED ONLY WITH THE STATE OR FEDERAL COURTS LOCATED WITHIN THE STATE OF DELAWARE.

14.7 General. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. The Parties shall be able to amend this Agreement from time to time by mutual consent provided that no amendment or modification to this Agreement shall be enforceable or effected unless reduced to a writing signed by the Parties. Furthermore, no amendment of this Agreement occurring after the Execution Date, for which a Party seeks cost recovery from Buyer's ratepayers, shall be enforceable absent specific Commission approval of such amendment. This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The headings used herein are for convenience and reference purposes only. Cancellation, expiration, or earlier termination of this Agreement shall not relieve the Parties of any obligations under or pursuant to this Agreement that expressly survive by their terms (including with respect to Collateral, payments and damages as indicated in Section 2.1) or by their nature survive such cancellation, expiration, or termination. All indemnity rights shall survive the cancellation, expiration or termination of this Agreement for a period of two (2) years after the effective date of termination of this Agreement. All provisions relating to limitations of liability shall survive the cancellation, expiration or termination of this Agreement without limit. This Agreement shall be binding on each Party's successors and permitted assigns. Subject to Section 14.14, nothing in this Agreement shall in any way restrict or otherwise limit the rights of either Party under Sections 205 and 206 of the Federal Power Act.

14.8 Confidentiality. Throughout the Contract Term, neither Party shall disclose the non-public terms or conditions of this Agreement or any transaction hereunder to a third party, other than: (i) the Party's Affiliates, or it's or it's Affiliates' employees, lenders, counsel, accountants, advisors or rating agencies who have a need to know such information and have agreed to keep such terms confidential on terms commensurate with the terms set forth in this Section 14.8; (ii) in order to comply with

any applicable Law, regulation, or any exchange, control area or PJM rule, or order issued by a court or entity with competent jurisdiction over the disclosing Party ("Disclosing Party"); (iii) in order to comply with any applicable regulation, rule, or order of the Agencies or FERC; or (iv) as Buyer deems necessary in order to demonstrate the reasonableness of its actions to duly authorized Governmental Authorities or regulatory agencies including the Commission, the Delaware Department of Natural Resources and Environmental Control or any division thereof, and any other regulatory agency which claims jurisdiction over the subject matter of the Agreement. In connection with requests made pursuant to clause (ii) of this Section 14.8 ("Disclosure Order") and disclosures pursuant to clause (iii) or (iv) ("Regulatory Disclosures"), each Party shall, to the extent practicable, use reasonable efforts to: (i) notify the other Party prior to disclosing the confidential information and (ii) prevent or limit such disclosure. After using such reasonable efforts, the Disclosing Party shall not be: (i) prohibited from complying with a Disclosure Order or making the Regulatory Disclosures or (ii) liable to the other Party for monetary or other damages incurred in connection with such disclosures of the confidential information. Except as provided in the preceding sentence, the Parties shall be entitled to all remedies available at Law or in equity to enforce or seek relief in connection with the confidentiality obligation set forth in this Section. The confidentiality obligation hereunder shall not apply to any information that was or hereafter becomes available to the public other than as a result of a disclosure in violation of this Section. The Parties each recognize, acknowledge and approve that the Agreement will be made public by the Commission both in preliminary and final form in connection with the approval thereof.

14.9 Entire Agreement; Severability. This Agreement, the Interconnection Agreements and the Ancillary Agreements, including the exhibits, schedules, appendices, documents, certificates and instruments referred to herein or therein and the other contracts, agreements and instruments contemplated hereby or thereby, embody the entire agreement and understanding of the Parties in respect of the transactions contemplated by this Agreement. There are no restrictions, promises, representations, warranties, covenants or undertakings other than those expressly set forth or referred to herein or therein. This Agreement, the Interconnection Agreements and the Ancillary Agreements supersede all prior agreements and understandings between the Parties with respect to the transactions contemplated by this Agreement. If any provision in this Agreement is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties. Any determination that specific parts of this Agreement are severable shall not affect in any way the Parties' assent to this Agreement, the Interconnection Agreement and the Ancillary Agreements, including the exhibits, schedules, appendices, documents, certificates and instruments referred to herein or therein and the other contracts, agreements and instruments contemplated hereby or thereby, as one integrated, non-severable contract.

14.10 Treatment of Agreement and Related Documents. Seller acknowledges and agrees that this Agreement, the Interconnection Agreements and the Ancillary

Agreements including the exhibits, schedules, appendices, documents, certificates and instruments referred to herein or therein and the other contracts, agreements and instruments contemplated hereby or thereby to which both Buyer and Seller or their Affiliates are or become parties, while each independently setting forth the exclusive terms and conditions pertaining to the subject matter thereof, for purposes of contract interpretation, do collectively provide Buyer rights and interests in the Project related to and/or necessary for the Project, and, accordingly, Seller agrees, for itself and its successors and assigns, that all of such contracts shall be treated as an integrated economic whole, and therefore, in accordance with the standards in Section 14.14, in any bankruptcy or insolvency proceeding involving it or any of its Affiliates, all such contracts shall either all be assumed or all be rejected to the extent that assumption or rejection is permitted by Law.

14.11 Conflicts with Interconnection Agreements and Ancillary Agreements. Except as expressly provided herein or therein, in the event of any conflict or inconsistency between the terms of this Agreement and the terms of the Interconnection Agreements and any Ancillary Agreements, the terms of this Agreement shall prevail.

14.12 Counterparts. This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Agreement.

14.13 Forward Contract. The Parties acknowledge and agree that the Agreement and the transactions consummated thereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that each of Seller and Buyer is a "forward contract merchant" within the meaning of the United States Bankruptcy Code.

14.14 Future Treatment. The Parties agree and acknowledge that the standard of review for any avoidance, breach, rejection, termination, or other cessation of performance of or changes to any portion of this integrated, non-severable Agreement (as described in Section 14.10) over which FERC has jurisdiction, whether proposed by the Seller, the Buyer, a non-party, or FERC acting sua sponte, shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Serv. Co., 350 U.S. 332 (1956) and Federal Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348 (1956), as such standard may be subsequently clarified by the Supreme Court of the United States or inferior courts. The Parties further agree and acknowledge that the standard of review for any proposed avoidance, breach, rejection, termination, or other cessation of performance or changes to any portion of this integrated, non-severable Agreement (as described in Section 14.10) over which the United States District Court or the United States Bankruptcy Court for the district in which a proceeding is pending, whether proposed by the Seller, the Buyer, or a non-party, shall be the standard of review set forth in In re Mirant Corp., 318 B.R. 100 (N.D. Tex. 2004). In connection with the application of such standards, the Parties agree that any failure to perform the Agreement on behalf of Seller would cause a disruption in the supply of electricity and may lead to an increase in rates paid by Buyer's customers. Nothing in this paragraph shall adversely affect, in any way, the protections afforded to a non-debtor counterparty under the United States Bankruptcy Code.

14.15 Certain Fees and Expenses. Each Party (the "First Party") agrees to pay to the other Party (the "Second Party"), upon written demand from the Second Party from time to time, the amount of all expenses and costs, including reasonable attorneys' fees and expenses, paid or incurred by the Second Party (i) after any of the obligations due to the Second Party by the First Party under this Agreement are not paid or performed when due (whether by demand, acceleration or otherwise), which arise as a result of such failure to pay or perform, and (ii) after a default or an Event of Default of the First Party shall occur, which arise as a result of such Event of Default. The First Party also agrees to pay to the Second Party, upon written demand by the Second Party from time to time, interest on the outstanding amount of such expenses and costs paid by the Second Party, from the date of the Second Party's demand for payment of such expenses until the same are paid in full, at the Interest Rate. The fees and expenses of the independent evaluator with respect to Section 12.4 will be shared equally between the Parties. The fees and expenses of an Independent Evaluator with respect to any other provision hereof will be paid for by Seller.

14.16 Authorized Representatives. Each Party shall provide Notice to the other Party of the persons authorized to make or receive Notices and perform other functions related to the administration of the Agreement on behalf of such Party, including with respect to scheduling under Section 3.5 ("Authorized Representative"). Such Notice shall include the scope of the Authorized Representative(s) individual authority and responsibilities. Either Party may change its designation of such persons and the scope of their individual authorities and responsibilities from time to time by providing Notice.

14.17 Recordings. Unless a Party expressly objects to a Recording (defined below) at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording ("Recording") of all telephone conversations between the Parties to this Agreement, and that any such Recordings will be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to this Agreement. Each Party waives any further notice of such monitoring or recording and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. Failure of a Party either to provide such notification or obtain such consent shall not in any way limit the use of the Recordings pursuant to this Agreement.

14.18 Amendments to PJM Agreements. Subject to the restriction on amendments in Section 14.7, in the event that the PJM Agreements are altered after the Execution Date in such a manner so as to provide a material economic benefit to one Party at the economic cost of the other Party, the Parties agree to negotiate in good faith to amend this Agreement as necessary to conform this Agreement to such altered PJM Agreements so as to maintain the relative benefits of the economic bargain evidenced by this Agreement on the Execution Date.

14.19 Obligation to Act in Good Faith, Etc. The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this Agreement. Unless expressly provided otherwise in this Agreement, where the Agreement requires the consent, approval or similar action by a Party, such consent,

approval, or action shall be made or given in such Party's sole discretion acting consistent with Good Utility Practice and its other obligations under this Agreement, including Section 3.6 and this Section 14.19.

[Remainder of page intentionally left blank.]

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be duly executed by its authorized representative as of the date first written above.

Seller: BLUEWATER WIND DELAWARE LLC

By: Peter D. Mandelstam
Name: PETER D. MANDELSTAM
Title: PRESIDENT

Buyer: DELMARVA POWER & LIGHT COMPANY

By: _____
Name:
Title:

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be duly executed by its authorized representative as of the date first written above.

Seller: BLUEWATER WIND DELAWARE LLC

By:_____
Name:
Title:

Buyer: DELMARVA POWER & LIGHT COMPANY

By: _____
Name: DENNIS WRAGE
Title: CHIEF EXECUTIVE OFFICER

APPENDIX 1

THE UNITS AND THE PROJECT

Buyer and Seller acknowledge that as of the Execution Date the Project is in an early stage of development. Buyer and Seller in turn acknowledge that this Appendix 1 represents an approximate description of the Project, the Site, the Units, the Electrical Interconnection Facilities and the Operational Limitations, and that changes and further detail regarding each of these items will developed over time by Seller. Buyer and Seller thus agree that this Appendix 1 may be revised and supplemented by Seller on a commercially reasonable basis consistent with Good Utility Practice from time to time to reflect further details regarding the Project which Project shall be in accordance with the terms of the Agreement. Notwithstanding the foregoing, unless otherwise agreed by the Parties, the Project's total Project Capacity shall be no less than 200 MW (except with respect to reductions in Project Capacity permitted under Sections 3.1(d), 5.4, 5.7 and 12.4) and shall not exceed 600 MW in accordance with Section 2.4, and the general location, the Indian River Line Assets, and the Point of Receipt shall not be modified without Buyer's consent. Seller shall revise on an interim basis Appendix 1 by the Effective Date, and shall use commercially reasonable efforts to make such revision as complete as possible. Seller shall provide Buyer regular updates on the process of finalizing this Appendix 1 which appendix shall be finalized no later than the Project Commercial Operation Date.

Site

The Site includes that portion of the Atlantic Ocean whose nearest point is approximately 11.5 nautical miles East of Rehoboth Beach, DE and north of the Delaware Bay southern shipping channel consisting of the general area between Latitude 38° 30' N and 38° 46' N and Longitude 74° 40' W and 74° 53' W, in which the Units are located. The Site further includes the seafloor, underground, or above ground corridor through which electrical interconnection cables transit from this ocean area to the Indian River Substation, as further described below. The Site also includes any land or ocean area on which is located interconnection, maintenance, control, or other facilities necessary to enable or support operation of the Project. For further detail please see Attachment A to this Appendix 1, which is conceptual.

Units

The Units shall be three-bladed, up-wind wind turbine generators, including associated towers, supporting structures, and foundations. Unit specific information to be provided when reasonably available.

Electrical Interconnection Facilities

It is anticipated that the Electrical Interconnection Facilities shall consist of 34.5 kV cables which interconnect the Units to appropriate (consistent with Good Utility

Practices) substation(s) located on (an) offshore platform(s). Each of these offshore substation(s) will be connected to Seller's on-shore substation by certain underwater/underground and above ground circuit(s) consistent with Good Utility Practices. It is proposed that Seller may interconnect to the Buyer's transmission system near the Bethany substation. It is further planned that Seller's Energy will then be transmitted approximately 12 miles along Buyer's Bethany to Indian River rights-of-way and transmission facilities to the Buyer's Indian River Substation. The Indian River substation is located at 30387 Gate "A" Road, Millsboro, DE 19966. A conceptual non-binding schematic of this interconnection structure is shown in example format in Attachment B to this Appendix 1. The description of the Indian River Line Assets is provided by Buyer and is subject to change prior to finalization of Appendix 1.

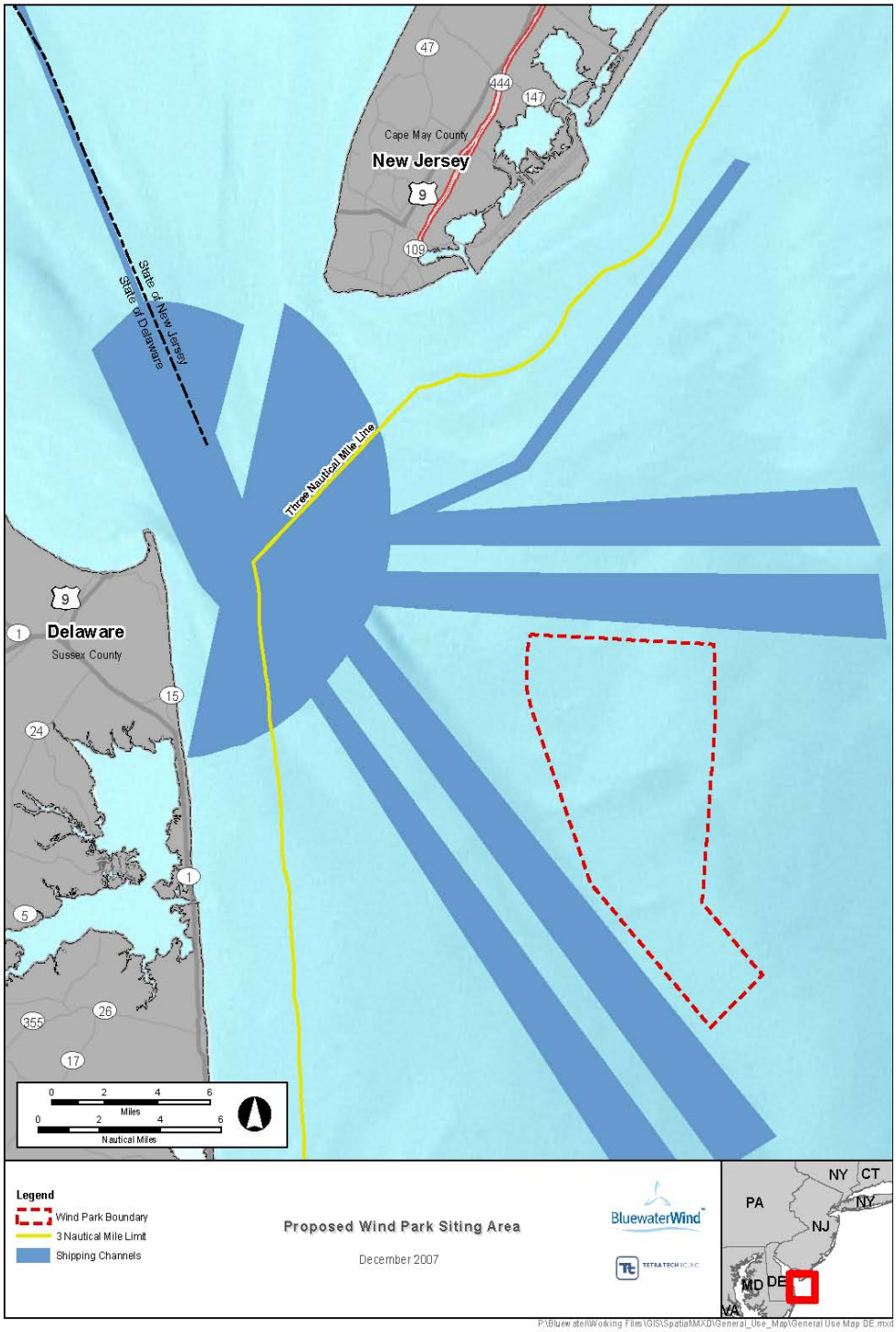
Operational Limitations

To be provided upon execution of the Turbine Supply Agreement.

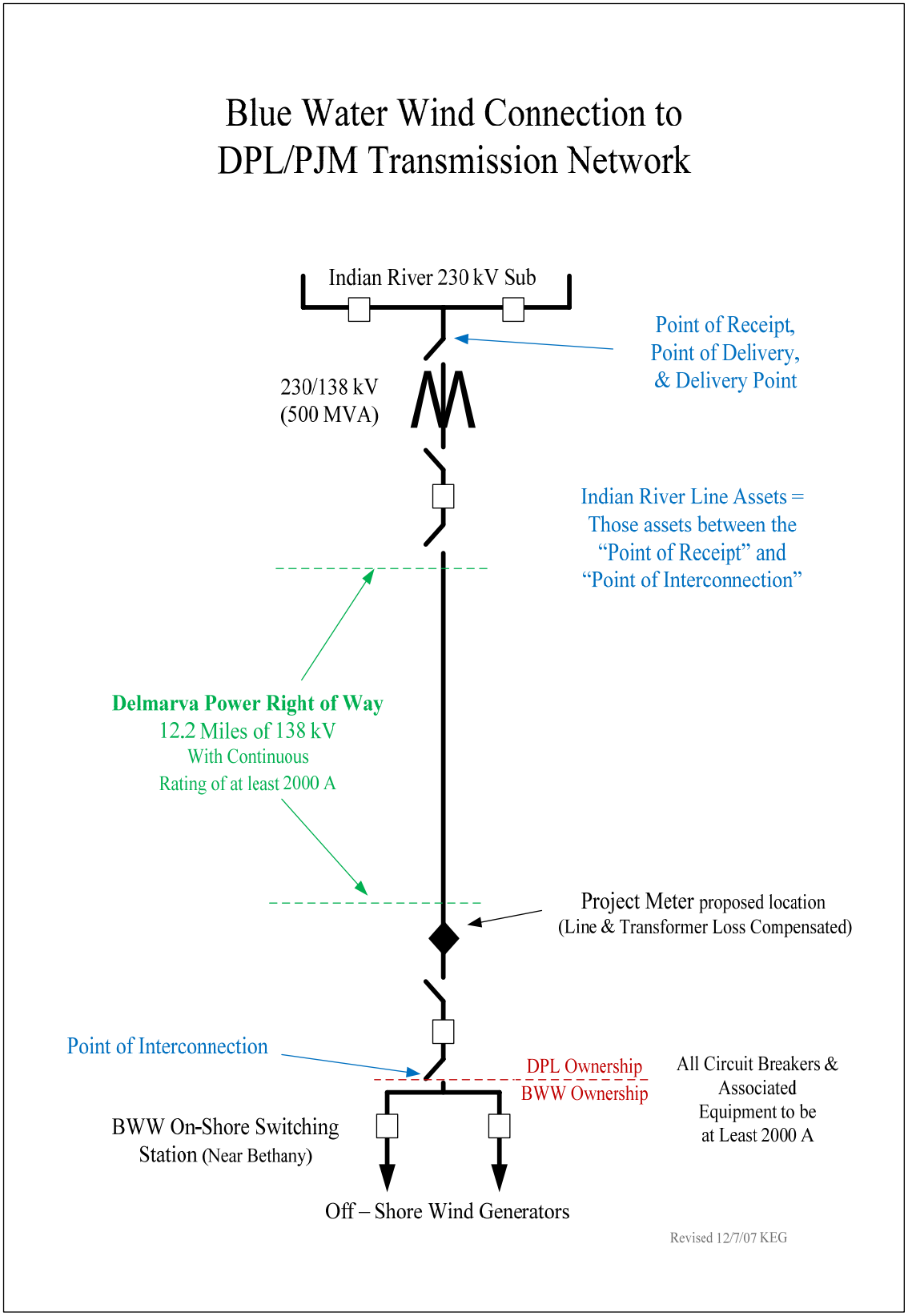
Other Project Assets

Descriptions of other Project Assets to be provided when available to Seller.

ATTACHMENT A



ATTACHMENT B



APPENDIX 2

FORM OF COMMERCIAL OPERATION CERTIFICATION

Date: [_____]

With respect to: [NOTE: insert Unit number, Unit Group number, or notation that this certificate is submitted with respect to the Project as a whole]

1. [Insert name of Licensed Professional Engineer] (the "Expert") has delivered this Commercial Operation Certificate on the above date to the duly authorized representatives of Delmarva Power & Light Company, a Delaware corporation ("Buyer"), pursuant to the terms of that certain Power Purchase Agreement by and between Bluewater Wind Delaware LLC ("Seller") and Buyer dated June 23, 2008 (the "Agreement").

2. Capitalized terms used, but not otherwise defined herein, have the meanings set forth in the Agreement.

3. With respect to [the above noted][NOTE: insert Unit number, Unit Group number, or notation that this certificate is submitted with respect to the Project as a whole][, as further described in Attachment A hereto][NOTE: attach identification of Unit or Unit Group; if Project certification, do not include], the Expert certifies and represents to Buyer that the following statements are true as of the date set forth above:

1. [Such Unit][Each Unit in such Unit Group][Each Unit forming a part of the Project]:

    a. is fully commissioned in accordance with the terms of the Turbine Supply Agreement, and Seller and Turbine Supplier have executed and delivered a commissioning certificate (which has been provided to Buyer) evidencing such completion of commissioning;

    b. has passed the Initial Performance Test;

    c. is operating and able to produce and deliver Products pursuant to the terms of this Agreement and in accordance with Good Utility Practice;

2. The Seller is a PJM Member, and [the Unit] [the Unit Group] [the Project] has been accepted as a Capacity Resource of PJM;

3. The Capacity Value and Cleared Capacity Value for the Project for the current Capacity Year and the next Capacity Year (subject to such adjustments for such next following Capacity Year as are contemplated by the PJM Capacity Rules) have been notified in writing to Buyer, and

Seller is able to transfer a Contract Capacity Amount for the next Capacity Year to Buyer based on the Contract Capacity for the next Capacity Year;

4. All Energy to be delivered to the Delivery Point pursuant to the Agreement from [such][Unit][Unit Group][the Project] as applicable, qualifies as generation from an Eligible Energy Resource under the RPS Act and the Commission RPS Rules; and

5. The Electrical Interconnection Facilities necessary to (i) qualify the Project as a Capacity Resource of PJM with the ability to deliver the Capacity Value of [such][Unit][Unit Group][the Project], and (ii) permit the delivery of Delivered Energy to the Delivery Point up to the Capacity of [such][Unit][Unit Group][the Project] has been fully commissioned in accordance with the EPC Contract and other applicable Project Contracts and all performance testing relating to such Electrical Interconnection Facilities under the EPC Contract and other applicable Project Contracts has been successfully completed; and

6. The applicable computer monitoring system (CMS) for the Project has been installed and tested and is fully operational in order to permit continuous reporting and monitoring of the performance of [such][Unit][Unit Group][the Project] in accordance with the terms of the Turbine Supply Agreement or other applicable Project Contract; and

7. Therefore, [the above noted Unit has achieved Unit Commercial Operation.][the above noted Unit Group has achieved Unit Group Commercial Operation.][the Project has achieved Project Commercial Operation.]

Expert: [_____]

By:_____

Name:

Title:

APPENDIX 3

ENERGY-ONLY PPA PRINCIPLES

1. All provisions of the Agreement remain, other than as noted in this Appendix 3.
2. In selling to Buyer the Delivered Energy, RECs and Environmental Attributes as set forth in Section 3.1(a)(i)(C) and 3.1(a)(ii) of the Agreement, Seller shall transfer to Buyer all rights and obligations related to Buyer's Percentage of the Capacity Value.
3. All other references to capacity sales, related provisions and unneeded definitions are deleted.
4. All capacity related covenants (including those related to Resource Adequacy Requirements and Outage scheduling), including conditions precedent and commercial operation requirements, are deleted.
5. Buyer shall continue to schedule all Energy pursuant to the Buyer Scheduling Obligation (other than day-ahead scheduling obligations, which shall be at Buyer's sole option, depending upon its election whether to treat the Agreement as a Capacity Resource) and related provisions, as further specified in the Agreement.
6. Balancing Operating Reserve charges shall continue to be split between the Parties to the extent set forth in the Agreement.
7. Balancing Amounts shall continue to be for the account of Buyer to the extent set forth in the Agreement.
8. Seller shall take such actions with respect to the Project as are required under the PJM Agreements to enable Buyer's Percentage of the Capacity Value under the Agreement to qualify as a Capacity Resource for the benefit of Buyer.
9. The Base Energy Rate shall be equal to $104.23 per MW/hour in 2007 dollars with the Annual Inflation Adjustment as set forth in the Agreement.
10. The Base Renewable Energy Credits Rate shall be equivalent to the amount set forth in the Agreement as adjusted pursuant to Section 4.2 and further adjusted with the Annual Inflation Adjustment as set forth in the Agreement.

APPENDIX 4

CONGESTION/LMP CALCULATION (ILLUSTRATIVE)

Buyer Assuming All LMP

Scenario 1

- LMP at Indian River Substation is -$10.00 per MW-h during a given hour. No other intermittent resource.
- Project delivers 200 MW-h to node during such hour and Buyer's Percentage is 50%.
- Buyer responsible for $1,000 negative LMP charge for that hour.

Scenario 2

- LMP at Indian River Substation is $10.00 per MW-h. No other intermittent resource.
- Project delivers 200 MW-h to node during such hour and Buyer's Percentage is 50%.
- No negative LMP so Buyer receives $1,000 if power re-sold in spot market.
- No payment owed by Seller.

Buyer-Seller Allocation of LMP

Scenario 3

- LMP at Indian River Substation is -$10.00 per MW-h during a given hour. Intermittent resource exists resulting in 80/20 LMP sharing pursuant to Section 3.4 of the Agreement.
- Project delivers 200 MW-h to node during such hour and Buyer's Percentage is 50%.
- Seller responsible for $1,800 negative LMP charge for that hour
- Buyer responsible for $200 negative LMP charge for that hour

Scenario 4

- LMP at Indian River Substation is -$10.00 per MW-h during a given hour. Intermittent resource exists resulting in 80/20 LMP sharing pursuant to Section 3.4 of the Agreement.
- Project delivers 400 MW-h to node during such hour and Buyer's Percentage is 50%
- Seller responsible for $3,600 negative LMP charge for that hour
- Buyer responsible for $400 negative LMP charge for that hour

APPENDIX 5

EXAMPLES OF ADJUSTMENTS TO REC PURCHASE OBLIGATION AND PRICING (ILLUSTRATIVE)

Scenario 1

- Project Capacity = 200 MW
- Buyer's Percentage = 100%
- Project generates 200 MWh of Energy and 200 RECs in an hour
- RPS Act allows for Buyer to receive 350% credit toward meeting Renewable Energy Portfolio Standards under RPS Act for RECs from Project: RPS Multiplier = 1/350% = 28.57% rounded to 28.6%
- RECs purchased and sold under Section 3.1(a) = 57 (RPS Multiplier of 28.6% of Buyer's 100% entitlement): 200 RECs*28.6% = 57.2 rounded to 57
- Base Renewable Energy Credits Rate (BRR) = $53.62 per REC (as adjusted by the Annual Inflation Adjustment): $15.32/REC*350% = $53.62/REC
- Total Purchase Price for applicable period = $3,056.34: 57 RECs*$53.62/REC = $3,056.34

Scenario 2

- Project Capacity = 450 MW
- Buyer's Percentage = 44.44%: 200/450 = .4444 or 44.44%
- Project generates 200 MWh of Energy and 200 RECs in an hour
- RPS Act allows for Buyer to receive 350% credit toward meeting Renewable Energy Portfolio Standards under RPS Act for RECs from Project: RPS Multiplier = 1/350% = 28.57% rounded to 28.6%
- RECs purchased and sold under Section 3.1(a) = 25 (RPS Multiplier of 28.6% of Buyer's 44.44% entitlement): 200 RECs*44.44%*28.6% = 25.42 rounded to 25
- Base Renewable Energy Credits Rate (BRR) = $53.62 per REC (as adjusted by the Annual Inflation Adjustment): $15.32/REC*350% = $53.62/REC
- Total Purchase Price for applicable period = $1,340.50: 25 RECs*$53.62 = $1,340.50

SCHEDULE 1

CRITICAL MILESTONES

Commencement of Avian Studies for Permits: December 31, 2009

Install Met Tower: June 30, 2011

Application to MMS for Outer Continental Shelf (OCS) Lease: Within eighteen (18) months after publication of non-appealable MMS Guidelines

Financial Closing: August 31, 2012

The binding closing of the debt or other unaffiliated third party financing necessary to construct the entire Project.

Notice to Proceed: September 30, 2012

Issuance of both the EPC Notice to Proceed and the Turbine Notice to Proceed.

Site: August 31, 2012

Seller has all necessary rights to the Project Site to construct and operate the Project in accordance with the Agreement.

Permitting: August 31, 2012

Receipt of Permits necessary for the construction and operation of the Project, other than those routinely granted upon due application that are not normally obtained before commencement of construction or operation, for a period at least equal to the Pre-Services Term Period and the Services Term, as applicable.

Turbine Supply Agreement and EPC Contract: August 31, 2012

Execution and delivery of the Turbine Supply Agreement and EPC Contract for the Project.

SCHEDULE 2
INITIAL EXPECTED ENERGY PRODUCTION SCHEDULE

Buyer and Seller agree that this Schedule 2 is representative of the calendar year, full hour by hour schedule that Seller has provided to Buyer as of the Execution Date.

BLUEWATER WIND DELAWARE OFFSHORE WIND PARK
AVERAGE OUTPUT BY MONTH AND HOUR: "12 x 24" ANALYSIS *

Month	*Hour beginning*																							
	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Jan	207	187	189	201	220	214	225	207	205	204	213	226	222	224	204	198	179	185	204	191	228	208	206	203
Feb	182	163	211	186	198	191	197	204	193	174	183	190	170	169	168	176	172	158	159	173	183	185	184	192
Mar	185	169	184	172	196	203	207	195	186	199	186	167	173	160	159	160	167	152	156	160	169	161	154	177
Apr	125	131	134	138	140	174	145	157	173	178	176	165	155	161	160	151	139	132	132	94	96	122	114	109
May	113	115	112	120	115	117	110	115	104	116	112	105	88	98	97	102	112	120	138	119	122	114	109	100
Jun	63	62	52	69	69	79	72	87	82	88	84	98	92	100	95	109	108	106	95	98	79	79	69	64
Jul	86	85	67	69	55	70	73	64	67	61	59	65	81	92	109	100	106	90	95	96	75	77	64	77
Aug	81	76	65	54	55	58	66	61	73	72	79	78	92	93	101	99	104	105	101	91	86	89	89	60
Sep	132	147	140	139	148	148	142	144	148	120	117	109	114	114	107	107	102	108	121	113	115	130	139	139
Oct	162	143	140	149	140	132	132	136	171	144	160	140	134	129	126	121	150	160	128	143	160	153	161	152
Nov	186	191	181	189	180	185	183	184	197	197	195	195	176	183	184	204	178	192	188	192	187	195	193	184
Dec	235	226	246	241	238	255	246	222	215	199	180	176	179	154	172	176	193	192	201	216	195	209	197	213

* Each cell denotes MWs and is equal to monthly one-hour averages
The sum of all data does not reflect full output of Bluewater Wind's Offshore Wind Park.

SCHEDULE 3

PERMITTING SCHEDULE

Buyer and Seller acknowledge that as of the Execution Date the Project is in an early stage of development. Buyer and Seller in turn acknowledge that this Schedule 3 represents an approximation of the Permits and scheduled receipt dates necessary for the performance of Seller's obligations pursuant to this Agreement, and that other Permits and scheduled receipt dates necessary for the performance of Seller's obligations pursuant to this Agreement may not be known as of the Execution Date. Buyer and Seller thus agree that this schedule may be revised and supplemented by Seller on a commercially reasonable basis consistent with Good Utility Practice from time to time to reflect additional Permits and time periods, and consistent with, and changes in scheduled dates that are reasonably necessary for and consistent with the performance of Seller's obligations pursuant to the Agreement. Seller shall use commercially reasonable good faith efforts to finalize Schedule 3 by the Effective Date, and to the extent the list of Permits is not finalized by the Effective Date Seller shall complete such list as soon as possible thereafter.

Federal Approvals

MMS Meteorological Tower Permit	February 2009
Federal Aviation Administration (FAA) Approval of tower lighting	July 2010
National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS) Incidental Harassment Authorization (IHA) or Notice of Non-Applicability	December 2010
U.S. Environmental Protection Agency (EPA) Air Quality Permit	December 2010
U.S. EPA National Pollutant Discharge Elimination System (NPDES) Permit	December 2010
Army Corps of Engineers (ACOE) Rivers and Harbors Act (RHA) Section 10 and Clean Water Act (CWA) Section 404 permits	January 2011
U.S. Coast Guard (USCG) Approval of Private Aids to Navigation	March 2011

Minerals Management Service (MMS) Outer Continental Shelf (OCS) Lease and Construction Permit	March 2011

<u>State Approvals</u>

State of Delaware, Department of Natural Resources & Environmental Control (DNREC), Office of the Secretary, Coastal Zone Act Exemption	September 2010
State of Delaware, DNREC, Coastal Management Program, Coastal Zone Management Consistency Determination	January 2011
Delaware DNREC, Division of Water Resources Subaqueous Lease, Wetland and CWA Section 401 Permit	February 2011
Delaware DNREC, Division of Soil and Water Conservation Coastal Construction Permit and Letter of Authorization	February 2011
Delaware DNREC, Division of Soil and Water Conservation NPDES Permit	February 2011
Delaware Department of Transportation Utilities Franchise & Utilities Construction Permits	February 2011

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2008-173

January 27, 2009

LINCOLN PAPER AND TISSUE, LLC
Request for Certification for RPS Eligibility

ORDER GRANTING NEW RENEWABLE RESOURCE CERTIFICATION

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

I. SUMMARY

In this Order, we certify the Lincoln Paper and Tissue (Lincoln) biomass facility as a Class I new renewable resource eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B) of the Commission rules.

II. BACKGROUND

A. New Renewable Resource Portfolio Requirement

During its 2007 session, the Legislature enacted an Act To Stimulate Demand for Renewable Energy (Act). P.L. 2007, ch. 403 (codified at 35-A M.R.S.A. § 3210(3-A)). The Act added a mandate that specified percentages of electricity that supply Maine's consumers come from "new" renewable resources.[1] Generally, new renewable resources are renewable facilities that have an in-service date, resumed operation or were refurbished after September 1, 2005. The percentage requirement starts at one percent in 2008 and increases in annual one percent increments to ten percent in 2017, unless the Commission suspends the requirement pursuant to the provisions of the Act.

As required by the Act, the Commission modified its portfolio requirement rule (Chapter 311) to implement the "new" renewable resource requirement (referred to as the renewable portfolio standard or RPS). *Order Adopting Rule and Statement of Factual and Policy Basis,* Docket No. 2007-391 (Oct. 22, 2007). The implementing

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[1] Maine's electric restructuring law, which became effective in March 2000, contained a portfolio requirement that mandated that at least 30% of the electricity to supply retail customers in the State come from eligible resources, which are either renewable or efficient resources. 35-A M.R.S.A. § 3210(3). The Act did not modify this 30% requirement.

rules designated the "new" renewable resource requirement as "Class I"[2] and incorporated the resource type, capacity limit and the vintage requirements as specified in the Act. The rules thus state that a new renewable resource used to satisfy the Class I portfolio requirement must be of the following types:

- fuel cells;
- tidal power;
- solar arrays and installations;
- wind power installations;
- geothermal installations;
- hydroelectric generators that meet all state and federal fish
- passage requirement; or
- biomass generators, including generators fueled by landfill gas.

In addition, except for wind power installations, the generating resource must not have a nameplate capacity that exceeds 100 MW. Finally, the resource must satisfy one of four vintage requirements. These are:

1) renewable capacity with an in-service date after September 1, 2005;

2) renewable capacity that has been added to an existing facility after September 1, 2005;

3) renewable capacity that has not operated for two years or was not recognized as a capacity resource by the ISO-NE or the NMISA and has resumed operation or has been recognized by the ISO-NE or NMISA after September 1, 2005; or

4) renewable capacity that has been refurbished after September 1, 2005 and is operating beyond its useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

The implementing rules (Chapter 311, § 3(B)(4)) establish a certification process that requires generators to pre-certify facilities as a new renewable resource under the requirements of the rule and provides for a Commission determination of resource eligibility on a case-by-case basis.[3] The rule contains the information that

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[2] The "new" renewable resource requirement was designated as Class I because the requirement is similar to portfolio requirements in other New England states that are referred to as "Class I." Maine's pre-existing "eligible" resource portfolio requirement is designated as Class II.

[3] In the *Order Adopting Rule* at 6, the Commission noted that a request for certification can be made at any time so that a ruling can be obtained before a capital investment is made in a generation facility.

must be included in a petition for certification and specifies that the Commission shall provide an opportunity for public comment if a petitioner seeks certification under vintage categories 2, 3 and 4. Finally, the rule specifies that the Commission may revoke a certification if there is a material change in circumstance that renders the generation facility ineligible as a new renewable resource.

B. Petition for Certification and Supplemental Comments

On April 8, 2008, Lincoln submitted a petition for certification of its generation facility as a Class I new renewable resource pursuant to Chapter 311 of the Commission's rules. The petition stated that the generation facility is a 13.5 MW biomass facility fueled by wood waste, process sludge and black liquor and that it is a new installation with a commercial start date of January 15, 2008. The petition also stated that the generation unit is "connected to the grid, behind the meter." In a letter dated April 16, 2008, Staff requested that Lincoln provide the following supplemental information: 1) a detailed description of what constitutes wood waste, process sludge and black liquor, including how each is derived; and 2) an explanation of what is meant by "connected to the grid, behind the meter," including whether any of the generation is currently or expected in the future to be sold into the wholesale market. In addition, the Commission, on April 16, 2008, provided an opportunity for interested persons to comment on the Lincoln petition.

On April 29, 2008, Lincoln provided the supplemental information requested by Staff. With respect to the fuel used at the generation facility, Lincoln stated that: 1) the wood waste it uses for fuel is comprised of 63% biomass chips (whole tree chips and toppings cut from the woods), 17% mill residue (ground up or hogged wood by-products and sawdust), and 20% chip mill bark (residue of debarking during the pulpwood making process); process sludge is the process waste from the paper, tissue and pulp making process that passes through a water treatment plant; and 3) black liquor is a by-product of the pulping process that contains organic material derived from the digestion of wood in a digester. In addition, Lincoln explained that the generation is not currently or expected in the future to be sold into the wholesale market. Lincoln also stated that the facility is a replacement of a 50-year-old turbine with a new more efficient and higher capacity turbine that reduces the amount of power that would need to be delivered to Lincoln by the New England market.

In a May 15, 2008 letter to Lincoln, the Staff stated that under the NEPOOL Generation Information System (GIS) rules, Lincoln's generation would not be eligible for GIS certificates because it is used behind-the-meter.[4] The Staff requested a rationale justifying certification noting that, in the absence of GIS eligibility, certification

[4] Under the then exiting GIS rules, only facilities below 5 MW were allowed to self report their generation to receive GIS certificates. Larger facilities were required to be part of the ISO-NE settlement system with their output to the system metered according to ISO-NE rules. GIS Rule 2.1.

under the Commission rules would appear to have no purpose and provide no value to Lincoln.[5] In a letter dated August 8, 2008, Lincoln responded that its facility is eligible for Class I certification even in the absence of GIS certificates for several reasons. First, the facility falls within the statutory and regulatory definition of a new renewable resource in that it is fueled by biomass and has an in-service date after September 2005. Second, Maine law does not expressly prohibit behind-the-meter generation and does not require generation to be delivered to the grid. Maine's RPS statute requires only that the facility generate power that "can physically be delivered" to the ISO-NE market, 35-A M.R.S.A. § 3210(2)(B), and Commission rules define physical deliverability to include energy that "is otherwise used to serve electricity load within the ISO-NE or NMISA control areas," Ch. 311, § 6(D). Finally, Lincoln notes other New England states (including Connecticut, Massachusetts and Rhode Island) allow behind-the-meter generation to satisfy their RPSs.

C. Interested Persons Comments

As mentioned above, the Commission provided interested persons the opportunity to comment on Lincoln's petition. The Commission received comments from the Natural Resources Council of Maine (NRCM) and Sustainable Energy Advantage (SEA). The Commission also received responsive comments from Lincoln.

1. Natural Resources Council of Maine

NRCM commented that the RPS relates solely to retail competitive electricity providers and, because Lincoln does not intend to sell the electricity to retail providers, there is no purpose in certifying Lincoln's facility. NRCM also commented that the Commission should only certify biomass resources which are reasonably likely to come from "sustainable resources" in order satisfy the intent of the RPS. Finally, NRCM stated that the facility does not appear to be a "new installation," but rather a replacement turbine with greater capacity and higher efficiency. Accordingly, the Commission should consider the resource as a refurbishment under Chapter 311, § 3(B)(3)(d)(viii).

2. Sustainable Energy Advantage

SEA takes no position on the petition, but stated that clarity and predictability are important in effective RPS design and critical in establishing policies that will attract investment in new renewable resources as intended by the enabling legislation. Specifically, SEA stated that the petition should be processed as a "refurbishment" (rather than a new installation) and thus involves the interpretation of an

[5] Except for northern Maine. Commission rules generally require that the compliance with the RPS be verified through GIS certificates. Ch. 311, § 6(B).

unclear part of the RPS rules. SEA urged that a specific standard for refurbishments be adopted, as exists in other New England states, such as a requirement that a specified percentage of the resulting tax basis of the facility's plant and equipment after the refurbishment be derived from capital expenditures after September 2005. SEA also urged the Commission to provide a clear definition of eligible "biomass," as has occurred in some other New England states. Finally, SEA commented that the lack of eligibility for GIS certificates should not be a barrier to certification as other states have allowed for behind-the-meter generation through independent verification and other measures.

3. Lincoln Response

Lincoln responded by stating that neither Maine law nor regulation restricts the definition of biomass and its facility is a biomass facility under the plain language of the Commission rules. Lincoln added that the consideration of a biomass definition should occur in a rulemaking proceeding, not through the review of a petition for certification. Lincoln agreed that, although it requested certification as a new facility, the refurbishment provision would be the applicable vintage category. Lincoln explained that the new turbine/generator replaced a 50-year-old turbine, delivers power at an efficiency that is over 10% higher than the replaced unit, extends the useful life of generation unit by at least 20 years, and more than doubles the electrical generation produced by the old unit. Finally, Lincoln stated that behind-the-meter generation is eligible for certification under Maine's rules in that the unit serves load within the ISO-NE control area and Commission regulations allow for alternative methods (other than GIS) to verify output and compliance. In the event the Commission determines that GIS certificates are required, Lincoln asks that it be provisionally certified subject to obtaining eligibility for GIS certificates.

D. GIS Rule Amendments

While this proceeding has been pending, there have been two amendments to the GIS rules that indicate a flexibility to accommodate behind-the-meter generation. Under the first amendment (approved by the NEPOOL Markets Committee on October 22, 2008), the 5 MW cap for behind-the-meter generation was removed for generators that participate in the ISO-NE forward capacity market and meet certain metering requirements. Lincoln indicated that it is exploring whether it can qualify under this amendment. The second amendment (approved by the NEPOOL Markets Committee on November 25, 2008) removed the 5 MW cap for behind-the-meter generation for generators located in Connecticut that have been approved by the Connecticut Department of Public Utility Control as an eligible RPS resource.

III. DECISION

The Lincoln petition raises several issues. These are: 1) whether the Lincoln facility is a biomass facility under Maine law and regulation; 2) whether the Lincoln faculty satisfies the vintage requirements; 3) whether behind-the-meter generation is eligible for RPS certification; and 4) whether GIS certificates are required under Commission rules for verification and compliance with respect to behind-the-meter generation. For the reasons discussed below, we conclude that the Lincoln facility qualifies for RPS certification. We make no ruling on the issue of whether GIS certificates associated with the Lincoln facility output are required or whether an alternative mean of measurement and verification can be employed.

A. Eligibility as Biomass

We find that the fuel used in the Lincoln facility (wood waste, process sludge and black liquor) as described in Lincoln's submissions constitutes biomass under Maine's RPS law. We understand that other states in New England have detailed definitions of biomass. However, Maine law refers only to the term biomass and the Commission declined to restrict the definition in the rulemaking process. In our order adopting the RPS rules, we stated:

> We decline to deviate from the statutory language which refers simply to "biomass generators" as previously modified by the Commission to include generators fueled by landfill gas. There was substantial debate on the definition of renewable resources (including whether facilities that use C&D waste should be excluded) prior to the Legislature's adoption of a modified list of renewable resources during the 2006 session. P.L. 2005, ch. 677 (codified at 35-A M.R.S.A. § 3210-C(1)(E)). This modified list maintained the pre-existing reference to biomass generators that we have included in the amended rule. We interpret this action as not changing the prior practice of employing a broad interpretation with respect to biomass eligibility. In a 2005 report to the Legislature, the Commission discussed a variety of issues regarding biomass eligibility (including the debate over the environmental impact of using C&D waste as a fuel) and the approaches used in other states. The Commission concluded that, without further legislative direction and in light of the unqualified statutory term "biomass," the Commission would adopt a relatively broad definition that includes all fuel derived from wood and wood byproducts (along with other organic sources).

Order Adopting Rule and Statement of Factual and Policy Basis, Docket No. 2007-391 at 4 (Oct. 22, 2007) (footnotes omitted). We agree with Lincoln that a RPS certification

proceeding is not the appropriate proceeding to consider changes to the definition of eligible biomass.

B. Vintage Requirement

Although Lincoln initially requested certification under the new installation vintage category, its facility replaces an older turbine and is therefore more appropriately reviewed under the refurbishment vintage category. The refurbishment vintage category is renewable capacity that has been refurbished after September 1, 2005 and is operating beyond its useful life or employing an alternate technology that significantly increases the efficiency of the generation process. Ch. 311 § 3(B)(3). As stated above, Lincoln's new turbine/generator replaced a 50-year-old turbine and extended the useful life of generation unit by at least 20 years. The unit generates power at a 10% higher efficiency and more than doubles the electrical generation produced by the old unit. The Lincoln refurbishment is virtually a new installation that substantially increases the useful life of the facility with a more efficient technology. As such, it is precisely the type of refurbishment that the Legislature intended to include as eligible for the new resource RPS. Accordingly, we conclude that the Lincoln facility satisfies the vintage requirement of Maine law.

C. Eligibility of Behind-The-Meter Generation

We conclude that behind-the-meter generation that meets the statutory eligibility requirements may be used to satisfy Maine's RPS. Maine's RPS statute does not exclude behind-the-meter generation. Moreover, new or substantially refurbished behind-the-meter generation promotes the underlying purpose and intent of Maine's portfolio requirement. The RPS statute contains an explicit statement of policy:

> In order to ensure an adequate and reliable supply of electricity for Maine residents and to encourage the use of renewable, efficient and indigenous resources, it is the policy of this State to encourage the generation of electricity from renewable and efficient sources and to diversify electricity production on which residents of this State rely in a manner consistent with this section.

35-A M.R.S.A. § 3210(1). As discussed above, Lincoln's facility satisfies the requirements for Class I eligibility and serves the electricity needs of a Maine consumer that would otherwise be served by the New England market. The facility uses a renewable fuel, adds to system diversity, and reduces reliance on natural gas. The impact on the system is the same as would occur if Lincoln chose to sell its generation into the market and purchased its electricity needs from the market. Thus, the Lincoln facility promotes the policies embodied in Maine's RPS. In the absence of a statutory exclusion, we find that behind-the-meter generation is eligible for Class I certification.

To be consistent with the rationale for certifying behind-the-meter generation, we conclude that Lincoln must retain GIS certificates or otherwise obtain GIS certificates necessary to satisfy Maine's RPS (both the original 30% and the "new" requirement) for that portion of its load that is served by the facility. The rationale for certifying the Lincoln facility as a Class I resource is that it is a newly refurbished renewable facility that serves Maine load. Therefore, the service of that load should comply with the RPS requirements as would occur if that load was served by a competitive electricity provider or if Lincoln chose to sell its generation into the market and purchase all of its electricity needs. We will require that Lincoln submit to the Commission an annual report by July 1st of each year that demonstrates compliance with this requirement.

E. GIS Certificates for Behind-the-Meter Generation

We make no determination on the issue of whether behind-the-meter generation should be certified if not eligible to receive GIS certificates. Such a determination would require consideration of an alternate means for measurement and verification. The GIS is a region-wide mechanism that prevents "double-counting" and greatly simplifies compliance for suppliers and verification by the Commission. We are, therefore, reluctant to consider an independent means to verify RPS compliance and believe that such a consideration is unnecessary. As stated above, NEPOOL has shown flexibility in modifying the GIS to accommodate other state's behind-the-meter RPS policies. We are thus confident that NEPOOL will accept GIS rule changes to facilitate Maine's behind-the-meter RPS policies and that would allow for the participation of the Lincoln facility.

Accordingly, we

ORDER

1. that the Lincoln Paper and Tissue biomass facility is certified as a Class I new renewable resource eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B) of the Commission rules;

2. that Lincoln Paper and Tissue shall submit a report to the Commission by July 1st of each year that demonstrates compliance with the requirement that it retain GIS certificates or otherwise obtain GIS certificates necessary to satisfy Maine's portfolio requirements for that portion of its load that is served by the certified biomass facility; and

3 that Lincoln Paper and Tissue shall provide timely notice to the Commission of any material change in the operation of the facility, including the type of fuel used in the generation process, from that described in the submissions filed by Lincoln in this proceeding.

Dated at Augusta, Maine, this 27th day of January, 2009.

BY ORDER OF THE COMMISSION

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Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Reishus
Vafiades
Cashman

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 21 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2009-208

July 9. 2009

RED SHIELD ACQUISITION, LLC
Request for Certification for RPS Eligibility

ORDER GRANTING NEW RENEWABLE RESOURCE CERTIFICATION

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

I. SUMMARY

In this Order, we certify the Red Shield Acquisition, LLC (Red Shield) biomass facility as a Class I new renewable resource eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B) of the Commission rules.

II. BACKGROUND

A. New Renewable Resource Portfolio Requirement

During its 2007 session, the Legislature enacted an Act To Stimulate Demand for Renewable Energy (Act). P.L. 2007, ch. 403 (codified at 35-A M.R.S.A. § 3210(3-A)). The Act added a mandate that specified percentages of electricity that supply Maine's consumers come from "new" renewable resources.[1] Generally, new renewable resources are renewable facilities that have an in-service date, resumed operation or were refurbished after September 1, 2005. The percentage requirement starts at one percent in 2008 and increases in annual one percent increments to ten percent in 2017, unless the Commission suspends the requirement pursuant to the provisions of the Act.

As required by the Act, the Commission modified its portfolio requirement rule (Chapter 311) to implement the "new" renewable resource requirement (referred to as the renewable portfolio standard or RPS). *Order Adopting Rule and Statement of Factual and Policy Basis,* Docket No. 2007-391 (Oct. 22, 2007). The implementing

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[1] Maine's electric restructuring law, which became effective in March 2000, contained a portfolio requirement that mandated that at least 30% of the electricity to supply retail customers in the State come from eligible resources, which are either renewable or efficient resources. 35-A M.R.S.A. § 3210(3). The Act did not modify this 30% requirement.

rules designated the "new" renewable resource requirement as "Class I"[2] and incorporated the resource type, capacity limit and the vintage requirements as specified in the Act. The rules thus state that a new renewable resource used to satisfy the Class I portfolio requirement must be of the following types:

- fuel cells;
- tidal power;
- solar arrays and installations;
- wind power installations;
- geothermal installations;
- hydroelectric generators that meet all state and federal fish
- passage requirement; or
- biomass generators, including generators fueled by landfill gas.

In addition, except for wind power installations, the generating resource must not have a nameplate capacity that exceeds 100 MW. Finally, the resource must satisfy one of four vintage requirements. These are:

1) renewable capacity with an in-service date after September 1, 2005;

2) renewable capacity that has been added to an existing facility after September 1, 2005;

3) renewable capacity that has not operated for two years or was not recognized as a capacity resource by the ISO-NE or the NMISA and has resumed operation or has been recognized by the ISO-NE or NMISA after September 1, 2005; or

4) renewable capacity that has been refurbished after September 1, 2005 and is operating beyond its useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

The implementing rules (Chapter 311, § 3(B)(4)) establish a certification process that requires generators to pre-certify facilities as a new renewable resource under the requirements of the rule and provides for a Commission determination of resource eligibility on a case-by-case basis.[3] The rule contains the information that

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[2] The "new" renewable resource requirement was designated as Class I because the requirement is similar to portfolio requirements in other New England states that are referred to as "Class I." Maine's pre-existing "eligible" resource portfolio requirement is designated as Class II.

[3] In the *Order Adopting Rule* at 6, the Commission noted that a request for certification can be made at any time so that a ruling can be obtained before a capital investment is made in a generation facility.

must be included in a petition for certification and specifies that the Commission shall provide an opportunity for public comment if a petitioner seeks certification under vintage categories 2, 3 and 4. Finally, the rule specifies that the Commission may revoke a certification if there is a material change in circumstance that renders the generation facility ineligible as a new renewable resource.

B. Petition for Certification

On June 30, 2009, Red Shield filed a petition to certify its biomass facility as a Class I renewable resource. The Red Shield facility is a 14.5 (net), 16 MW (gross) biomass facility located in Old Town, Maine. The facility currently generates electricity by burning bark and wood chips, but is permitted to burn wood pulp screening rejects and construction and demolition wood. The electricity is used by Red Shield in its business operations with the excess sold into the ISO-NE energy market.

According to the petition, the major components of the Red Shield facility are from a biomass facility located in Athens, Maine that shut down in 2001. After the expenditure of over $25 million for the components and new equipment, the facility was placed into service during 2007.

On July 8, 2009, Red Shield filed a supplement to its petition, stating that a portion of the production that is reported to the ISO-NE and the GIS administrator comes from the Great Works dam (which is not eligible for Class I certification). Red Shield indicated that it would address this issue by registering the facility as a dual fuel unit and separately reporting the biomass and hydroelectric production to the ISO-NE and the GIS. In addition, Red Shield has also created two behind-the-meter accounts in the GIS to separately report the biomass and hydroelectric behind-the-meter consumption. Finally, Red Shield indicated that it would sell the GIS certificates associated with the biomass facility to third parties, less a hold back for its compliance with Maine's RPS.

III. DECISION

The Commission has delegated to the Director of Technical Analysis the authority to certify generation facilities as Class I new renewable resources pursuant to Chapter 311, § 3(B) of the Commission rules. *Delegation Order,* Docket No. 2008-184 (April 23, 2008). Based on the information provided by Red Shield, I conclude that the biomass facility satisfies the resource type, capacity limit and vintage requirements of the rule. The facility is a biomass-fired facility that has effectively begun operations after September 1, 2005. In addition, the Commission has previously concluded that behind-the-meter generation can qualify for Maine's portfolio requirement. *Lincoln Paper and Tissue,* Docket No. 2008-173 (January 27, 2009). Accordingly, the Red Shield biomass facility is hereby certified as a Class I new renewable resource that is eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3 of the Commission rules. Red Shield shall provide timely notice to the Commission of any material change in the operation of the facility or the metering and reporting as

described in the petition and the supplement filed in this proceeding, including changes to the type of fueled used in the electricity generation process.

BY ORDER OF THE DIRECTOR OF TECHNICAL ANALYSIS

Faith Huntington

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2009-395

January 5, 2010

S.D. WARREN COMPANY D/B/A SAPPI FINE PAPER NORTH AMERICA
Request for Certification for RPS Eligibility

ORDER GRANTING NEW RENEWABLE RESOURCE CERTIFICATION

REISHUS, Chairman; VAFIADES and CASHMAN, Commissioners

I. SUMMARY

In this Order, we certified the biomass facility owned by S.D. Warren Company d/b/a Sappi Fine Paper North America (Sappi) as a Class I new renewable resource that is eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B) of the Commission rules.

II. BACKGROUND

A. New Renewable Resource Portfolio Requirement

During its 2007 session, the Legislature enacted an Act To Stimulate Demand for Renewable Energy (Act). P.L. 2007, ch. 403 (codified at 35-A M.R.S.A. § 3210(3-A)). The Act added a mandate that specified percentages of electricity that supply Maine's consumers come from "new" renewable resources.[1] Generally, new renewable resources are renewable facilities that have an in-service date, resumed operation or were refurbished after September 1, 2005. The percentage requirement starts at one percent in 2008 and increases in annual one percent increments to ten percent in 2017, unless the Commission suspends the requirement pursuant to the provisions of the Act.

As required by the Act, the Commission modified its portfolio requirement rule (Chapter 311) to implement the "new" renewable resource requirement. *Order Adopting Rule and Statement of Factual and Policy Basis,* Docket No. 2007-391 (Oct. 22, 2007). The implementing rules designated the "new" renewable resource

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[1] Maine's electric restructuring law, which became effective in March 2000, contained a portfolio requirement that mandated that at least 30% of the electricity to supply retail customers in the State come from eligible resources, which are either renewable or efficient resources. 35-A M.R.S.A. § 3210(3). The Act did not modify this 30% requirement.

requirement as "Class I"[2] and incorporated the resource type, capacity limit and the vintage requirements as specified in the Act. The rules thus state that a new renewable resource used to satisfy the Class I portfolio requirement must be of the following types:

- fuel cells;
- tidal power;
- solar arrays and installations;
- wind power installations;
- geothermal installations;
- hydroelectric generators that meet all state and federal fish
- passage requirement; or
- biomass generators, including generators fueled by landfill gas.

In addition, except for wind power installations, the generating resource must not have a nameplate capacity that exceeds 100 MW. Finally, the resource must satisfy one of four vintage requirements. These are:

1) renewable capacity with an in-service date after September 1, 2005;

2) renewable capacity that has been added to an existing facility after September 1, 2005;

3) renewable capacity that has not operated for two years or was not recognized as a capacity resource by the ISO-NE or the NMISA and has resumed operation or has been recognized by the ISO-NE or NMISA after September 1, 2005; or

4) renewable capacity that has been refurbished after September 1, 2005 and is operating beyond its useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

The implementing rules (Chapter 311, § 3(B)(4)) establish a certification process that requires generators to pre-certify facilities as a new renewable resource under the requirements of the rule and provides for a Commission determination of resource eligibility on a case-by-case basis.[3] The rule contains the information that must be included in a petition for certification and specifies that the Commission shall

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[2] The "new" renewable resource requirement was designated as Class I because the requirement is similar to portfolio requirements in other New England states that are referred to as "Class I." Maine's pre-existing "eligible" resource portfolio requirement is designated as Class II.

[3] In the *Order Adopting Rule* at 6, the Commission noted that a request for certification can be made at any time so that a ruling can be obtained before a capital investment is made in a generation facility.

provide an opportunity for public comment if a petitioner seeks certification under vintage categories 2, 3 and 4. Finally, the rule specifies that the Commission may revoke a certification if there is a material change in circumstance that renders the generation facility ineligible as a new renewable resource.

B. Petition for Certification

On November 23, 2009, Sappi submitted a petition for certification of its Westbrook, Maine biomass plant as a Maine Class 1 new renewable resource pursuant to Chapter 311 of the Commission's rules. Sappi seeks certification of its 68 MW biomass facility[4] under the refurbishment vintage category. According to the petition, the Sappi facility is a biomass boiler and turbine installed in 1981 that would typically have a 20 year life expectancy. Since 2005, Sappi states that it has made substantial refurbishments of approximately $4.5 million to increase the useful life and the efficiency of the facility.

On December 23, 2009, Sappi supplemented its petition with a Refurbishment Project List and a Biomass Facility Maintenance Sample Project List. These lists were provided under protective order.

As required by our rules, the Commission provided interested persons with an opportunity to comment on the Sappi petition. The only comments received by the Commission were filed by William P. Short.[5] Sappi filed responsive comments and Mr. Short filed a reply to the responsive comments.[6]

C. Comments of William P. Short

Mr. Short commented that the Sappi petition should be denied for several reasons. First, Mr. Short states that the petition only lists relatively minor pieces of equipment that might have been refurbished and that no major equipment appears to have been refurbished. Second, Mr. Short states that, other than a general statement, the petition provides no evidence that the useful life of the facility when installed was 20 years. Based on his experience, Mr. Short believes that facilities, such as the Sappi facility, generally have 30–year, or more, useful lives. Third, Mr. Short states that the petition offers no evidence of the use of an alternate technology that significantly increased the efficiency of the generation process. Finally, Mr. Short states that, if the

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[4] Sappi's boiler feeds two turbines, one with a rated capacity of 50 MW and the other with a rated capacity of 18 MW. Sappi's boiler is a multi-fuel boiler but Sappi is seeking certification only for generation associated with eligible fuels.

[5] Mr. Short is a consultant that has experience with the NEPOOL GIS and the various portfolio requirements in the New England States.

[6] Mr. Short also requested intervention in this proceeding. Because this proceeding is not adjudicatory, there are no intervenors.

Sappi petition is granted, the decision would destroy Maine's Class I portfolio requirement program by flooding the market with GIS certificates from owners of nearly every pre-September 1, 2005 New England renewable generator that would be eligible due to refurbishment. This would significantly lower the price of Class I GIS certificates and deny Maine ratepayers of the benefits of new generation.

Mr. Short also states that without access to Sappi's capital refurbishment project list, no one could tell what items may be considered potentially a refurbishment. Mr. Short suggests that such information should be provided to interested persons in this proceeding under protective order.[7]

D. Sappi Response

Sappi responded to Mr. Short's comments by stating that it did refurbish the facility after September 1, 2005 through an extensive post-2005 refurbishment program to extend the useful life of the biomass facility, which exceeded $4.5 million or approximately 47% of the total fair market value of the facility. In support, Sappi points to the details of its refurbishment program over the post 2005 time period, which was filed under protective order.

Sappi also states that Mr. Short's assumption that its facility has a 30 years useful life is incorrect, noting that the original funding justification for the boiler investment in 1981 specified the economic life of the boiler to be 16 years and the operating life to be 25 years. Sappi adds that its international accounting policy maintains the standard operating life for boilers as 20 years and the original boiler manufacturer in its boiler operation and maintenance documents states that the boiler life expectancy is in the range of 20 to 30 years, with high pressure boilers, such as Sappi's boiler, exhibiting shorter life expectancy than low pressure boilers. Sappi states that its boiler was approximately 24 years old on September 2005, it had clearly exceeded it original useful life, and will continue to operate only with investments like those completed by Sappi in recent years and planned in future years.

Finally, Sappi argues that its Refurbishment Project List constitutes confidential business information in that its refurbishment of the biomass facility is a key component of Sappi's strategy to remain competitive and its competitors would be interested in the information. Sappi also states that, with its entry into the REC market, the number of its competitors broadens significantly to include other owners of biomass boilers, including Mr. Short's clients.

[7] Mr. Short argues that besides denying the petition, the Commission should set meaningful criteria for refurbishment and efficiency improvements. The issue of specific criteria is outside the scope of this proceeding.

III. DECISION

For the reasons discussed below, we certify the Sappi Westbrook generation produced from eligible fuels as a Class I new renewable resource that is eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B) of the Commission rules.

Sappi seeks certification of its facility under the refurbishment vintage category of our portfolio requirement rules, Ch 311, §3(B)(3)(d). This provision states that a generating facility is eligible if it:

> has been refurbished after September 1, 2005 and is operating beyond its useful life or employing an alternate technology that significantly increases the efficiency of the generation process.

Based on a review of Sappi's petition, its responsive comments, and its refurbishment project list, we conclude that the facility has been refurbished after September 2005 and is operating beyond it useful life. The Sappi facility has been operating for 29 years since the beginning of its service in 1981. Based on the information in Sappi's filings (the original funding justification, the accounting procedures, and the manufacturer's operation and maintenance documents), the facility is now operating beyond it original expected useful life, which would be in the range of 20 to 25 years. Moreover, we conclude that the facility's current operation is a result of substantial refurbishment after September 2005. The post-2005 refurbishment program exceeds $4.5 million or approximately 47% of the value of the facility. A review of Sappi's refurbishment project list shows that, while some of the items appear perhaps more related to routine maintenance activities, a number of expenditures were made in refurbishments necessary to extend the useful life of the facility, such as Sappi's rebuild of its traveling grate combustion components. In addition, Sappi's extensive replacement of older drives with variable speed drives should provide both life-extension as well as efficiency improvements.

We reject Mr. Short's argument that we should consider the impact of GIS certificate prices when considering Sappi's petition. Our responsibility under the portfolio requirement statute and rule is to determine only whether the facility has been refurbished after September 2005 and is operating beyond its useful life. If the result is that there is a large number of qualifying refurbishments, this means that the policy goals of the portfolio requirement are being meet. If, as a consequence, GIS certificate prices drop to levels of concern for policy makers, the proper response would be to increase the percentage requirements in the law, rather than any attempt to limit competition in the REC markets.

In addition, we agree with Sappi that its refurbishment projects are confidential business information. We also agree that Mr. Short has clients in competition with Sappi. The Commission has the institutional expertise to evaluate Sappi's refurbishment project list and there is no compelling need to release this sensitive business information to interested persons in this proceeding. We find that the potential for harm from disclosure of the information outweighs any probative value it may in this proceeding. 35-A M.R.S.A. § 1311-A (F).

Finally, the Sappi facility is a multi-fuel facility. The Commission has previously concluded that it is consistent with the purposes of Maine's portfolio requirement to allow a facility that burns both eligible and ineligible fuel to be certified for the output generated from eligible fuel. As noted in its petition, Sappi currently reports to the GIS system its output by fuel type. We therefore find that the Sappi Westbrook facility is eligible for Maine's portfolio requirement for the generation produced by eligible fuels, as reported under the GIS system.

Dated at Hallowell, Maine, this 5th of January, 2010.

BY ORDER OF THE COMMISSION

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Karen Geraghty
Administrative Director

COMMISSIONERS VOTING FOR: Reishus
Vafiades

COMMISSIONER ABSENT: Cashman

NOTICE OF RIGHTS TO REVIEW OR APPEAL

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3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

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SUMMARY OF RECENT RESEARCH ON

ADVERSE HEALTH EFFECTS OF WIND TURBINES

20 October 2009

Compiled by

Keith Stelling, MA, MNIMH, Dip Phyt, MCPP (England)

With additional files from Carmen Krogh, BScPharm

CONTENTS

1.0 INTRODUCTION

Authorities and politicians in Ontario have been repeatedly warned that industrial wind turbines are having an adverse effect on the health of those living nearby.

Health complaints are not peculiar to this province but are consistent throughout the world wherever large industrial wind turbines have been installed.

Contrary to the claims of the industry, there is a growing body of peer-reviewed research substantiating these health claims. This report attempts to catalogue the most recent.

A generally acknowledged major concern about wind turbine disturbance centres around the low frequency noise projected from this heavy industrial machinery. Until recently measurements of this type of noise have seldom been carried out near wind turbines.

There is already ample scientific evidence that low frequency noise is a cause of sleep disturbance in humans. The evidence also suggests that long term exposure normally leads to serious health problems.

Reinforcing this body of knowledge is the research that has been conducted on animals. Long term studies by European biologists indicate that habitat disturbance and abandonment takes place around wind turbine developments. Further research on animals indicates that basic survival functions such as hunting, self protection and reproduction are interrupted by low frequency noise exposure.

The only effective mitigation is to adequately separate wind turbine developments from sensitive wildlife habitats and human dwellings.

It should be no great surprise to policy makers that failure to do so exposes the rural population to a serious health threat. The only mystery is why public health authorities, Members of Provincial Parliament and the wind industry have not yet accepted their responsibility to exercise due diligence in protecting human health and already done this.

This report is intended to bring together the most recently published literature so that decision makers can now go forward and act *preventatively* before any further human suffering needlessly occurs.

1.1. Background

It is often claimed that there are health benefits in developing industrial wind energy contained in its ability to curtail excessive CO2 emissions, eliminate unacceptable pollution from coal fired electricity generating plants, provide inexpensive, renewable electricity and avert the crisis of global warming.

Indeed, such arguments have been used by the Ontario Ministries of Energy and Infrastructure, Environment, and Natural Resources as well as the commercial wind industry in an attempt to counter public health concerns. However, even a superficial investigation of the reality of commercial wind power soon challenges the acceptability of such assertions.

1.2. Public Cost

International experience to date has demonstrated that industrial wind power is unviable without heavy government subsidies and inflated feed-in tariffs. In addition it relies on massive taxpayer funding for the necessary back-up support which has to be added to existing infrastructure. $5

billion is estimated as the cost of new transmission lines needed to facilitate wind power in Ontario and $1.2 billion for each additional back-up gas plant.

1.3. Corporate Profits

The beneficiaries of this public largess are the wind developers which, in Ontario, include large multinational oil and gas producers (Suncor, Trans-Alta and Enbridge). Developments are also being proposed by foreign energy corporations including Florida Power and Light (successors to Enron). Equipment suppliers are also foreign multinationals: (Siemens, General Electric and Vesta).

1.4. Political Influence

Wind turbine developers have long exerted considerable influence over government decision making through well funded lobbying of politicians. The wind energy industry enjoys close ties with the Liberal Party.

1.5. Feasibility

In every country where wind turbines have been installed, they have failed to demonstrate economic feasibility, viability as a solution to global warming, significant CO2 reduction, efficient electricity production or protection of the environment.

In countries where industrial wind power has been added to the grid in any volume, consumer electricity costs have skyrocketed. The two countries with the highest number of installed commercial wind turbines, Germany and Denmark, now have the highest electricity rates in Europe. In Ontario, one MPP has estimated the needed additional transmission lines will add 30% to every electricity bill. Ontarians, however, are already paying more than double the market price for electricity produced by wind turbines even when it is not required and electricity rates will be even higher still once additional gas plants are built.

But most alarmingly, health issues have already arisen for many rural Ontario residents living near wind power installations.

2.0 THE SCOPE AND NATURE OF DISSENT WORLDWIDE

An increasingly well-informed public has questioned their governments' policies in promoting the rapid installation of wind turbines in the United States, Great Britain, Europe, Australia, New Zealand, and most recently Japan.

A number of professional reports, based on actual operating experience, have challenged the raison d'être of the wind turbine enterprise.

- As early as 2005, the German electricity supplier *E-ON Netz Report* warned: "Wind energy is only able to replace traditional power stations to a limited extent. Their dependence on the prevailing wind conditions means that wind power has a limited load factor even when technically available. It is not possible to guarantee its use for the continual cover of electricity consumption. *Consequently, traditional power stations with capacities equal to 90% of the installed wind power capacity must be permanently online in order to guarantee power supply at all times*".

- The *Tallinn Report* from the Tallinn Technical University of Estonia challenged the CO2 reductions that were claimed by the industry:

> "Participation of thermal power plants in the compensation of fluctuating production of windmills eliminates the major part of the expected positive effect of wind energy. . . . In some cases the environmental gain from the wind energy use was lost almost totally. . . . *It seems reasonable to ask why wind-power is the beneficiary of such extensive support if it not only fails to achieve the CO2 reductions required, but also causes cost increases in backup, maintenance and transmission, while at the same time discouraging investment in clean, firm generation capacity*."[1]

- *Der Spiegel* reported in 2008 that despite all the wind turbines in Germany (more than 20,000) "German CO2 emissions haven't been reduced by even a single gram" and even the Green Party has recognized the problem.[2] Additional coal burning facilities have been built in Germany to support wind power.

- In the United Kingdom the introduction of destabilizing wind energy to the grid has meant extensive resort to gas burning facilities and greatly increased consumption of gas so that its price in the UK has risen dramatically over the last few years.[3]

- Energy Minister Smitherman has indicated that the construction of new gas plants in Ontario will be necessary to back up renewable energy.[4] But particulate waste from new gas plants will make a new and substantial contribution to smog pollution in Ontario. Running these plants on stand-by mode will decrease their efficiency and increase CO2 emissions.[5]

2.1. Economic Feasibility

The economic feasibility of industrial wind power has been questioned on a wide scale.

In Denmark electricity costs are now the highest in Europe. The Danish experience suggests wind energy is expensive, inefficient and most importantly not even particularly green. Jytte Kaad Jensen, chief economist for ELTRA, Denmark's biggest electricity distributor laments: "In just a few years we've gone from some of the cheapest electricity in Europe to some of the most costly." And *the Danish Member of Parliament, Aase Madsen who chaired energy policy admits: "For our industry it has been a terribly expensive disaster".*

Contrary to North American wind industry spin, the Danish people have not accepted wind energy enthusiastically. Danish wind developers are now obligated under law to compensate nearby property owners for loss of real estate value. And now the Danish people have been so adamant in

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[1] A technical paper presented by the Tallinn Technical University of Estonia at the International Energy Workshop at Laxenburg, Austria in 2003. *Estimation of real emissions reduction caused by wind generators.* O. Liik, R. Oidram, M. Keel Tallinn Technical University, 5 Ehitajate tee, Tallinn 19086, Estonia.

[2] Anselm Waldermann. "Wind Turbines in Europe Do Nothing for Emissions-Reduction Goals". *Der Spiegel*. Feb 11 2009. http://www.spiegel.de/international/business/0,1518,606763,00.html.ca

[3] *The Wall Street Journal* explained in September 2008 that in order to cover the inconsistencies of the wind power now on the German grid, "Germany's gas consumption for power generation more than doubled between 1990 and 2007." Edgar Gartner. "Wind Fuels Gas". *Wall Street Journal,* 11 September 2008. In the U.K., the newly installed wind technology is also backed up by gas. Figures released in November by the OECD indicate that "in the past year alone, prices for electricity *and* natural gas in the U.K. have risen twice as fast as the European Union average".

[4] Minister Smitherman's remark was made on the Focus Ontario television show.

[5] "Thermal power stations constantly have to keep additional spinning [standby] reserve capacity equal to the maximum total power of windmills (e.g. for the case when too high wind speed stops full power operating windmills). This makes the thermal plants run inefficiently and increases fuel consumption (emissions)". (Tallinn Report. *Op. cit*.)

their objections to any further onshore wind developments that the government is going to restrict it to off-shore projects.

In Spain, a recently published economic study from Juan Carlos University has laid the blame for Spain's worsening economic crisis (reported to be in serious depression) at the doorstep of the government for its policy of subsidizing the wind industry. It points out that as a result of the unparalleled rise in electricity prices that resulted from the introduction of wind energy onto the grid, most intensive energy consuming manufacturers have left the country.

2.2. Quotes From Electricity Generation Experts

"Electricity differs from other forms of energy, and cannot be stored directly on an industrial scale. Any calculation of the CO2 emissions reduction from wind must take into account the quantity of conventional generating capacity that has to be in the grid. . . In fact, analysis of data from the UK, Denmark, Ireland, Germany and the USA shows that a substantial part of the theoretical CO2 saving does not accrue in practice. In some circumstances there may be only minimal benefit. The evidence shows that as the level of wind capacity increases, the CO2 emissions actually increase as a direct result of having to cope with the variation of wind-power output."

-- U.K. energy expert, David White: *Reduction in Carbon Dioxide Emissions: Estimating the Potential Contribution from Wind Power, published in December 2004 by the Renewable Energy Foundation in the U.K.*

"It has been estimated that the entire benefit of reduced emissions from the renewables programme has been negated by the increased emissions from part loaded plant."

-- From a paper given at the British Institution of Mechanical Engineers, by David Tolley.

"The tax breaks and subsidies for the wind industry are at the expense of ordinary taxpayers and electricity customers whose interests are not well represented in government circles. The practical effects of the tax breaks and subsidies are to:

- "Misdirect hundreds of millions of investment dollars into energy projects that produce only small amounts of low value, low quality electricity.

- "Transfer substantial wealth from ordinary taxpayers and electricity customers to "wind farm" owners by shifting tax burden from "wind farm" owners to ordinary tax payers, and passing along the high priced electricity from "wind farms" to electricity customers."

--From: *"Big Money" Discovers the Huge Tax Breaks and Subsidies for "Wind Energy" While Taxpayers and Electric Customers Pick up the Tab.* 2004, by Glenn R Schleede (a graduate of Harvard Business School's Advanced Management Program. and former Vice President of New England Electric System (NEES) former Associate Director (Energy and Science) of the White House Domestic Council).

2.3. Grass Roots Public Activism And Online Document Sources

The last two years has seen phenomenal growth in public dissent on the basis of all these objections as well as adverse health effects. Wherever industrial wind turbines have been introduced, citizens' groups have been formed to fight them.

> "I have not seen anything like this before," says Chris Forrest, vice president of communications and marketing at the Canadian Wind Energy Association (CanWEA). "Groups are coordinating fully orchestrated media campaigns with a ferocity and an intensity that has really taken us by surprise," he says.

Local groups all over the world have formed coalitions with others to create national and international organizations.

2.3.1 **The European Platform Against Windfarms (EPAW)** http://www.epaw.org/ now has 364 signatory organizations in 19 different European countries. Recently the second annual march on the Elysée Palace took place in Paris, and public protests are on the increase throughout Europe. Health issues and economic concerns are among the most important objections raised by these groups. They insist:

- that hundreds of associations, local initiatives and other groups are totally dissatisfied with wind farms;
- that intermittent, uncontrollable energy does not solve any of humanity's problems, even in part;
- that the only thing wind turbines do is cause considerable harm to people, the economy, national budgets and the environment.

2.3.2 **Country Guardian** is a UK-wide conservation group which has warned about wind turbines for nearly 20 years, since the first UK wind developments appeared in the Lake District. Initially it campaigned mainly about landscape damage, but it soon became clear that *a)* the technology of wind turbines was seriously flawed and *b)* the environmental damage extended far beyond the landscape. The group provides one of the most useful web sites for research and documentation: www.countryguardian.net

2.3.3 In the United States, there are three major coalitions, each maintaining highly respected sources of information through their web sites:

- **Industrial Wind Action Group** http://www.windaction.org/;
- **National Wind Watch** http://www.wind-watch.org/
- **Industrial Wind Energy Opposition** http://www.aweo.org/

2.3.4 In Ontario, **Wind Concerns Ontario** has grown at an impressive rate over the last year, largely out of a feeling of injustice and loss of local democratic input on planning decisions legislated by the Green Energy Act and outrage at government indifference to those suffering adverse health effects from the turbines. It is now comprised of 39 citizens' groups and extends to 26 counties and districts throughout Ontario. The web site is an invaluable source of information on the Ontario situation. http://windconcernsontario.wordpress.com/

Familiarity with these sites is essential to understanding the depth and extent of opposition to industrial wind development and the degree of concern over health issues.

It should however, be added that while North Americans seem to consider the aesthetic appearance in the landscape of wind turbine developments as a matter of individual judgment, older European societies still value the importance of beauty, architecture, and unspoiled nature as their cultural heritage—part of the value of a viable tourism resource.[6]

[6] One of the public protests currently underway in France is to save Mont Ste. Michel from an adjacent wind turbine development. There, artists are looked to for aesthetic judgments based on their training and experience. Artists from around the world opposed to defacing the rural landscape with wind turbines have contributed to a web site based in England:
http://www.artistsagainstwindfarms.blogspot.com/; http://www.artistsagainstwindfarms.com/pinboard.html.

3.0 THE HEALTH ISSUE

3.1. Available Research On Adverse Health Effects

Legislators in Ontario were warned of emerging health problem as early as April 22, 2009 by one of the province's most prominent physicians. Dr Robert McMurtry, M.D., F.R.C.S (C), F.A.C.S, is a former Dean of Medicine at the University of Western Ontario and in 1999, he became the first Cameron Visiting Chair at Health Canada - a post carrying the responsibility for providing policy advice to the Deputy Minister and Minister of Health for Canada. In December 2003, he was appointed to the Health Council of Canada and is Chair of the Wait Times and Accessibility Work Group. Dr. McMurtry is the founding Assistant Deputy Minister of the Population and Public Health Branch of Health Canada. He was appointed to Roy Romanow's Commission on the Future of Health Care in Canada in 2002 as a Special Advisor to Commissioner Romanow.

In his Deputation to the Standing Committee on General Government Regarding Bill C-150 presented at the Ontario Legislature, Dr. McMurtry stated:

> "There have been many reports of adverse health events. At the outset it must be made clear that there has not been any systematic epidemiological field study that could yield authoritative guidelines for the siting of wind turbines. Secondly no epidemiological study has been conducted that establishes either the safety or harmfulness of Industrial Wind Turbines. In short there is an absence of evidence. Accordingly until more authoritative information is available it is important to consider the growing number of reports of cases and case series of adverse health effects that are emerging."

The McMurtry report has disclosed that the number of people in Ontario reporting adverse health affects due to industrial wind turbines continues to rise. The new total as of September 13, 2009 is now 98 which is a disturbing 85% increase from 53 as reported earlier this year. Some families have been driven from their homes. See www.windconcernsontario.org

It has to be emphasized that as with all public health issues, precautionary regulation are preferable to allowing an avoidable health risk to spread. In the words of Dr. McMurtry, *"When uncertainty exists and the health and well-being of people are potentially at risk, assuredly it is appropriate to invoke the precautionary principle."*

It also has to be underlined that there is no credible research to back up industry claims that wind turbines *do not* threaten human health.

The wind industry often states that "there is no peer-reviewed scientific evidence indicating wind turbines have an adverse impact on human health". (This statement is taken directly from actual applications for approval to build industrial wind turbines).

Health Canada disagrees. In a letter dated August 6, 2009 from Health Canada Safe Environments Program (Halifax), Allison Denning, Regional Environmental Assessment Coordinator Health Canada, Atlantic Region pointed out:

*"Health Canada advises that this statement be revised to indicate that there are peer reviewed scientific articles indicating that wind turbines may have an adverse impact on human health. **In fact, there are peer reviewed scientific articles** indicating that wind turbines may have an adverse impact on human health.*

For example, Keith *et. al*. (2008), identified annoyance as an adverse impact on human health that can be related to high levels of wind turbine noise. In addition, there are several articles by Pedersen (and others) related to wind turbine annoyance (as referenced below). The relationship

between noise annoyance and adverse effects on human health is also further investigated in the manuscript by Michaud *et. al* (2008)".[7]

Like the wind industry today, the tobacco industry denied for many years that there were any adverse health effects from their products. Corporate denial of a health problem is generally a delaying tactic not in the best interest of the public.

3.2. Serious Warnings Already Issued By Credible Institutions

A number of cautions have already been provided by some of the most eminent medical authorities around the world. *These should alert decision makers at once to their responsibility:*

3.3. The National Institutes Of Health (NIH)

In 2008 the NIH (part of the US Department of Health and Human Services) warned:

> 'Wind energy will undoubtedly create noise, which increases stress, which in turn increases the risk of cardiovascular disease and cancer.' (*Environmental Health Perspectives*, volume 116, pg A237 – 238, 2008).

3.4. French National Academy Of Medicine

In 2006, the French National Academy of Medicine issued a report that concludes:

> "The harmful effects of sound related to wind turbines are insufficiently assessed. . . The sounds emitted by the blades being low frequency, which therefore travel easily and vary according to the wind, constitute a permanent risk for the people exposed to them.. The Academy recommends halting wind turbine construction closer than 1.5 km from residences".[8]

3.5. The Maine Medical Association

On September 12, 2009, the Maine Medical Association passed a Resolution to 'work with health organizations and regulatory agencies to provide scientific information of known medical consequences of wind development in order to help safeguard human health and the environment; and to 'work with other stakeholders to encourage performance of studies on health effects of wind turbine generation by independent qualified researchers at qualified research institutions'; and to 'ensure that physicians and patients alike are informed of evidence-based research results.'

3.6. Minnesota Department of Health

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[7] References listed by Health Canada include:
Keith, S. E., D. S. Michaud, and S. H. P. Bly. 2008. A proposal for evaluating the potential health effects of wind turbine noise for projects under the Canadian Environmental Assessment Act. Journal of Low Frequency Noise, Vibration and Active Control, 27 (4):253-265.
Michaud, D.; S.H.P. Bly, and S.E. Keith. 2008. Using a change in percentage highly annoyed with noise as a potential health effect measure for projects under the Canadian Environmental Assessment Act. Canadian Acoustics, 36(2): 13-28.
Pedersen E. and Halmstad, H.I. 2003. Noise annoyance from wind turbines – a review.
Swedish Environmental Protection Agency, Report 5308.
Health Canada's response to the Digby Wind Power Project Addendum,
Digby, Nova Scotia. Author: Safe Environments Program, Regions and Programs Branch, Health Canada

[8] Chouard, C-H. Le retentissement du funtionnement des eoliennes sur la sante de l'homme. (Repercussions of wind tubine operations on human health). Panorama du Medecin, 20 March 2006.

On May 22, 2009, the Minnesota Department of Health released a report evaluating the health impacts from wind turbine noise and low frequency vibrations. The conclusions noted that wind turbines generate a broad spectrum of low-intensity noise. The low frequency may affect some people in their homes, especially at night:

"The most common complaint in various studies of wind turbine effects on people is the impact on quality of life. Sleeplessness and headache are the most common health complaints and are highly correlated (but not perfectly correlated) with annoyance complaints. Complaints are more likely when turbines are visible or when shadow flicker occurs. *Most available evidence suggests that reported health effects are related to audible low frequency and with increasing outside noise levels above 35 dB(A)".*

"Low frequency noise from a wind turbine is generally not easily perceived beyond ½ mile. However, if a turbine is subject to aerodynamic modulation because of shear caused by terrain (mountains, trees, buildings) or different wind conditions through the rotor plane, turbine noise may be heard at greater distances".

"Unlike low frequency noise, shadow flicker can affect individuals outdoors as well as indoors, and may be noticeable inside any building".

3.7. Government of The State Of Victoria, Australia

In Australia, the Government of the State of Victoria has now committed to investigating the health concerns of Victorians who live near wind farms. Some landholders near the Waubra wind farm, west of Ballarat, say a low frequency hum from the turbines is making them sick. An investigation will now be conducted by WorkSafe, the Department of Human Services and the Environment Protection Authority.

4.0 A BRIEF SURVEY OF EVIDENCE BASED LITERATURE

The June 2009 report on *Sleep disturbance and wind turbine noise* by the British physician Christopher Hanning, BSc, MB, BS, MRCS, LRCP, FRCA, MD provides a useful survey of up-to-date evidence-based literature by a physician who is more qualified than most to carry out this peer review. The report can be seen in pdf form at http://www.windaction.org/documents/22602

Dr. Hanning's credentials and experience are beyond dispute. He is one of the world's foremost specialists on noise, sleep disturbance and its consequent effect on health. Dr. Hanning founded and ran the Leicester Sleep Disorders Service, one of the longest standing and largest services in the United Kingdom. The University Hospitals of Leicester NHS Trust named the Sleep Laboratory after him as a mark of its esteem.[9]

His report concludes:

> *"In weighing the evidence, I find that, on the one hand, there is a large number of reported cases of sleep disturbance and, in some cases, ill health as a result of exposure to noise from wind turbines, supported by a number of research reports that tend to confirm the*

[9] Trained at St. Bartholomew's Hospital Medical School in London England and a Fellow of the Royal College of Anaesthetists, he is honorary Consultant in Sleep Disorders Medicine to the University Hospitals of Leicester NHS Trust, (England) based at Leicester General Hospital having retired in September 2007 as Consultant in Sleep Disorders Medicine. In 1996, he was appointed Consultant Anaesthetist with a special interest in Sleep Medicine to Leicester General Hospital and Honorary Senior Lecturer to the University of Leicester.

validity of the anecdotal reports and provide a reasonable basis for the complaints. On the other, we have badly designed industry and government reports which seek to show that there is no problem. I find the latter unconvincing.

"In my expert opinion, from my knowledge of sleep physiology and a review of the available research, I have no doubt that wind turbine noise emissions cause sleep disturbance and ill health."

Dr. Hanning has also stated: *"There can be no doubt that groups of industrial wind turbines ("wind farms") generate sufficient noise to disturb the sleep and impair the health of those living nearby."*

He noted that *"families whose homes were around 900m from wind turbines found the noise, sleep disturbance and ill health eventually drove them from their homes."*

Hanning emphasizes that "inadequate sleep has been associated not just with fatigue, sleepiness and cognitive impairment but also with an increased risk of obesity, impaired glucose tolerance (risk of diabetes), high blood pressure, heart disease, cancer and depression. Sleepy people have an increased risk of road traffic accidents."

His report is examined in detail below because it represents one of the most professional reviews of the available literature. Hanning also analyzes and disputes the acceptability of several industry sponsored studies because of flawed methodologies and researchers working outside their area of competence.

CLINICAL EVIDENCE

4.1. England

Throughout the history of public health, our initial awareness of health threats has always come from *clinicians* working with patients in the field. One of the first MDs to report on wind turbine difficulties was Dr. Amanda Harry in England. Those who would dismiss the work of Dr Harry as "anecdotal" and of no significance do not understand the role played by the clinician in our understanding of pathology. (Harry, Amanda. February 2007. Wind turbines, noise, and health. 32 pp. http://www.windturbinenoisehealthhumanrights.com

Dr. Hanning points out: "Dr Amanda Harry (2007), a UK GP, conducted surveys of a number of residents living near several different turbine sites and reported a similar constellation of symptoms from all sites. A study of 42 respondents showed that 81% felt their health had been affected, in 76% it was sufficiently severe to consult a doctor and 73% felt their life quality had been adversely impacted. This study is open to criticism for its design which invited symptom reporting and was not controlled. While the proportion of those affected may be questioned *it nevertheless indicates strongly that some subjects are severely affected by wind turbine noise at distances thought by the industry to be safe*."

4.2. United States

Another physician with actual clinical experience dealing with patients affected by wind turbines is Nina Pierpont in the United States. (Nina Pierpont, MD, PhD, *Wind Turbine Syndrome: A Report on a Natural Experiment*. 2009. www.windturbinesyndrome.com)

According to Dr. Hanning, her work is "a very detailed, peer-reviewed case-control study of 10 families around the world who have been so affected by wind turbine noise that they have had to leave their homes, nine of them permanently. The turbines ranged from 1.5 to 3MW capacity at distances between 305 to 1500m. The group comprised 21 adults, 7 teenagers and 10 children of

whom 23 were interviewed. While this is a highly selected group, the ability to examine symptoms before, during and after exposure to turbine noise gives it a strength rarely found in similar case-control studies. The subjects described the symptoms of wind turbine syndrome outlined above and confirmed that they were not present before the turbines started operation and resolved once exposure ceased."

"There was a clear relationship between the symptoms, even in children, and the noise exposure. She reports also that all adult subjects reported *'feeling jittery inside'* or *'internal quivering'*; often accompanied by anxiety, fearfulness, sleep disturbance and irritability. Pierpont offers compelling evidence that these symptoms are related to low frequency sound and suggests very plausible physiological mechanisms to explain the link between turbine exposure and the symptoms."

"Of particular concern were the observed effects on children, including toddlers and school and college aged children. Changes in sleep pattern, behaviour and academic performance were noted. 7 of 10 children had a decline in their school performance while exposed to wind turbine noise which recovered after exposure ceased. In total, 20 of 34 study subjects reported problems with concentration or memory."

"Pierpont's study mostly addresses the mechanism for the health problems associated with exposure to wind turbine noise rather than the likelihood of an individual developing symptoms. Nevertheless, it convincingly shows that wind turbine noise does cause the symptoms of wind turbine syndrome, including sleep disturbance. She concludes by calling for further research, particularly in children, and a 2km setback distance."

A recently published paper on low-frequency vibration further elucidates Pierpont's work: Research from Neuroscience Letters 444 (2008) 36–41 by medical researchers McAngus Todd, Sally M. Rosengren, James G. Colebatch, demonstrates Dr. Pierpont's contention that low frequency noise and infrasound can harm the vestibular apparatus of the inner ear. The research illustrates the premise that what you cannot hear can harm you.

4.3. Dr. Michael Nissenbaum (USA)

Another group of clinicians in the USA who have studied symptoms experienced by their patients living near wind turbines have called for a moratorium on wind turbine installation until proper studies are completed. In March 2009, Dr. Michael Nissenbaum of the Northern Maine Medical Center presented his findings to the Maine Medical Association. His study, which he characterized as "alarming", suggests that his patients are experiencing serious health problems related to shadow flicker and noise emissions from the turbines near their homes. The onset of symptoms (including sleep disturbance, headaches, dizziness, weight changes, possible increases in blood pressure, as well as increased prescription medication use), all appear to coincide with the time when the turbines were first turned on in December 2006.

Dr. Nissenbaum has written: "There are many issues that need to be worked out. A moratorium is logical, unless we quickly move to adopt more stringent European and Australian standards. *Otherwise, the state's failure to act responsibly on this issue is the equivalent of abandoning its responsibility to protect public health, which would leave the people with few options other than seeking remedy and redress through the courts".*

4.4. Japan

In Japan, in February, 2009, 70 cases of adverse health effects from wind turbines were reported. The Japanese call this "Wind Turbine Disease". Their Minister of Environment fears a public health issue and is investigating low frequency sound as being of concern.

The ministry is concerned that reports of ill health could spread as more wind turbines are built near residential areas. Bouts of dizziness and inability to sleep properly were reported. When victims spent time away from the house, the symptoms quickly dissipated. But as soon as they returned, they would flare up again.[10]

So far, more than 70 people living near wind turbines have reported ill health. They include residents in Ikata, Ehime Prefecture; Higashi-Izu, Shizuoka Prefecture; Toyohashi, Aichi Prefecture; and Minami-Awaji, Hyogo Prefecture.

4.5. Ontario

Researchers and victims in Ontario have reported altered living conditions and ill health. Sleep disturbance is the most common complaint. Other symptoms include inner ear problems, cardiac concerns such as arrhythmias and palpitations, headaches and cognitive and mood disturbances. Several suffered acute hypertensive episodes which are most concerning. Some have had to leave their homes in order to protect their health[11]. These reports are consistent internationally.

There are unanswered questions about infants, children, and the unborn whose mothers are exposed, family members and workers such as farmers and technicians who live and work in close proximity to the wind turbines.

The reports of symptoms are consistent with the work of Dr. Amanda Harry, U.K., Dr. Nina Pierpont, U.S.A. and are remarkably similar to other work quoted above and to the just released study by Dr. Michael Nissenbaum in Maine who reports on 15 further cases.

Virtually always the commonest complaint is sleep disturbance. The number of sleep disturbances with the September survey results is 67 of 98 victims. Already thirty-nine individuals indicate that their health has been affected as a consequence of what they are experiencing. The number is 81 of 98 with affected health. One person has had to be admitted to hospital with an acute hypertensive episode, another experienced a cardiac arrhythmia (atrial fibrillation), 30 of 98 experienced heart palpitations. Reports of health problems are still coming in. The survey will be ongoing and results will be updated periodically.

In his literature search, *Low Frequency Noise and Infrasound (Some possible causes and effects upon land-based animals and freshwater creatures): A literary comment;* 2006, Ivan Buxton notes:

- "There are a great number of articles that include reference to the effects of infrasound and vibration upon humans. It is evident from these papers that the effect of low frequency noise on humans goes much deeper than subjective "annoyance" as has been asserted by wind proponents. On the contrary, it has already been demonstrated that cardiovascular risks and chronic endocrine effects including increased cortisol production. (As indicated by Harlow et al. (1987), chronically elevated blood cortisol may adversely impact the efficiency of animal production by reducing weight gain and otherwise affecting animals in captivity (Van Mourik and Stelmasiak 1984, Van Mourik et al. 1985) and decreasing antibody production, thereby inhibiting or suppressing the body's ability to resist disease (Roth 1984, Jensen and Rasmussen 1970, Huber and Douglas 1971, Revillard 1971, Paape et al.1973, Hartman et al. 1976, Stein et al. 1976)".

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[10] Something in the wind as mystery illnesses rise BY TSUYOSHI TAKEDA ASAHI SHIMBUN SENIOR STAFF WRITER 2009/2/6 http://www.asahi.com/english/Herald-asahi/TKY200902060054.html

[11] Canadian Hydro Developers who operated the wind turbine facility in Melancthon Township near Shelburne appear to have tacitly recognized the seriousness of these symptoms and their legal implications by purchasing six homes from those unable to remain in them. However, In order to sell and get away, the beleaguered owners had to sign agreements not to speak publicly of the transactions.

- "These impacts, particularly if chronic, can result in: increased sickness, disease, and death; a decrease in animal productivity (Knight and Cole 1991, Anderson and Keith 1980); and ultimately result in population declines [in wild animal populations] (Anderson and Keith 1980)".

These investigations offer an explanation of the reason for the symptoms that have been observed among those suffering from wind turbine effects. [12]

It should also be emphasized that there is widespread agreement on the fact that wind turbines create intrusive noise and there are many existing peer reviewed studies on the adverse health effects of noise. For example, World Health Organization, Noise and Sound, Bergland et al, 2000; Health Council of the Netherlands (HCN). 2004 The Influence of Night-time Noise on Sleep and Health. The Hague: Health Council of the Netherlands, 2004; publication no. 2004/14E; Human Rights section 9 EU June 2007 www.windturbinenoisehealthhumanrights.com

According to Buxton, "the frequency ranges are recorded in many of these studies and the overall result always appears to depend upon the exposure time when coupled with the dB and Hz levels. A few seconds is all it takes at very low Hz and high dB levels before severe problems arise".

"Very low frequency sound can travel long distances, penetrate buildings and vehicles and does not significantly diminish its properties when it changes mediums such as from air to tissue. This is because unlike ultrasound it travels 'in band' more effectively due to the propensity of low frequency sound waves to travel in a straight line".

5.0 EFFECTS OF WIND TURBINES ON WILDLIFE, LIVESTOCK AND DOMESTIC ANIMALS

Animal studies are an important tool used in modern medicine to determine harm to human health. Reports of adverse effects on animals are considered to be cautionary.

There is growing evidence that animals are affected even more severely than humans by the low frequency noise and vibrations from industrial wind turbines. This has serious implications for our treaty obligations to protect endangered and threatened species which depend on ever shrinking sensitive natural habitats. It also reinforces and provides further caution on the human health issues already listed above.

5.1. Heightened Sensitivities Of The Animal Kingdom

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[12] i) *"Selected Health risks caused by long term, whole body vibration"* by Seidel H. Federal Inst. Of Occupational Health, Berlin. (Am J. Med. 1993 Apr. 23(4) ; 589 – 604.)
ii) *"Characterising the effects of airborne vibration on human body vibration response"*
by Smith S.D. Air Force Research Lab., Wright – Patterson AFB, USA. (Aviation. Space Environment. Med. 2002 Jan; 73 (1); 36 – 45
iii) *"Low frequency noise enhances cortisol among noise sensitive subjects during work performance"* by Kerstin person-Waye. J Bengtsson, R. Rylander, F. Hucklebridge. P. Evans, A. Clow. (Dept. Environ. Medicine, Univ. of Gothenburg. (Life Science 2002 Jan 4; 70(7) 745 – 58. . [See also by same team "Effects of night time LFN on the cortisol response to awakening and subjective sleep quality)
iv) "Noise induced Endocrine Effects & Cardiovascular Risks" by H. Ising, W Babisch, B. Kruppa, Federal Environ. Agency, Inst. Of Water, Soil & Air Hygiene, Berlin.(Noise Health 1999; 1 (4); 37 – 48.
v) *"Coping with stress; Neuroendocrine Reactions & Implications for Health"* by U. Lundberg, Dept. of Psycchology, Stockholm. (Noise Health 1999; 1 (4); 67 – 74
vi) *"Possible health effects of noise induced cortisol increase"* by M. Spreng. Dept. Physiology, Univ. Erlangen, Germany (Noise Health 2000; 2(7); 59 – 64
vii) *"Acute and chronic endocrine effects of noise"*: Review of the research conducted at the Inst. For Water, Soil & Air Hygiene, Berlin. H. Ising, C. Braun (Noise Health 2000;2(7) 7 – 24.

It appears that animals are even more susceptible to low frequency noise than humans. The animal kingdom relies upon a wide range of sound frequencies inaudible to humans. It has to be remembered that within these sensitive habitats where almost no background noise is experienced, the low frequency noise and vibration projected (and transmitted through the earth) by industrial wind turbine operation is most certainly threatening or confusing to wildlife. The hearing and vibration sensitivity of most creatures in the wild is far more acute than human sound perception.

Confusion by sound emanations can lead to the failure of hunting success, self defense and ultimately survival. Snakes, for example, which rely extensively upon their perception of vibration, are particularly sensitive to habitat disturbance from industrial developments. The noise pollution at higher frequencies may explain the catastrophic effect wind turbines are having on bats, a significant keystone species within the balance of nature. Permeating a large area of natural habitat with extraneous noise pollution will have obvious repercussions for the survival of species dependent on the special characteristics of these unique refuges and, as has been observed by biologists, lead to permanent abandonment.

5.2. Shadow Flicker Concerns

Similarly the shadow flicker with its widespread emanations is another phenomenon that alerts the wild creature to danger. Confusion and avoidance are caused by both these disturbances and they may contribute to abandonment of the habitat thus affected. When such disturbance affects an already threatened species forcing it to abandon one of the last remaining suitable specialized habitats, the consequences can be catastrophic. But it has to be remembered that the ecology within any Natural Heritage System is completely inter-related and seemingly insignificant effects have major repercussions because of the interdependency of all the species within the system.

Buxton concluded: “there is a case to answer when land based animals and freshwater creatures are exposed to noise at low Hz levels. Because of the limitations of our hearing it would be easy to suppose that noises beyond our receiving range do not exist and should therefore be of no concern to us. Yet both very high and extremely low inaudible sounds may be harmful to us and other animals with similar but not identical ranges of hearing”.

“Other creatures have lower acceptance levels, as their survival is more reliant upon instinct and interpretation of unusual sounds as a source of danger.
A few seconds is all it takes at very low Hz and high dB levels before severe problems arise. There is reason to suppose that similar effects would also occur with wild animals if exposed to the sounds for long enough periods. The presumption must be that as soon as they felt uncomfortable they would move away from the zone of discomfort-- term more properly described as, disturbance and displacement, which in the case of protected species would be contrary to appropriate legislation”.

“Laboratory studies upon animals have been reviewed with quite chilling results, as it clear that deformities, damage and impairment occur to the subjects with regularity. Admittedly the animals were contained and subjected to exposure times of several hours per day at moderate to high intensity levels of LFN and infrasound. Yet fish and aquatic creatures contained in ponds and lakes would certainly be unable to escape whatever the level of sound intensity or duration of exposure”.

Buxton cites as examples of the effect of noise on animals: the reduction of egg laying by domestic poultry; injury and loss involving livestock; goats with reduced milk production; pigs with excessive hormonal secretion as well as water and sodium retention; sheep and lambs with increased heart rates, respiratory changes and reduction in feeding.

“There is clearly a cause for concern because of the likely effects upon wildlife and current protective measures seem inadequate”.

5.3. Habitat Loss: European Studies

There is a growing body of evidence from European biologists who have now completed decade-long studies of the effect of wind turbines on wildlife.

Scientists have concluded that *wind turbine developments placed near important wildlife areas have a long term, irreversible destructive effect upon these habitats. The effect is cumulative, and increases the longer the wind turbines remain in place.*

Many European studies have documented habitat degradation and avian collision mortality. The U.S. Fish and Wildlife Service guidelines were based on peer-reviewed scientific avian studies written by biologists. Important studies include Orloff and Flannery 1992, Leddy et al. 1999, Woodward et al. 2001, Braun et al. 2002, Hunt 2002 as well as studies of bats: Keeley et al. 2001, Johnson et al. 2002, Johnson et al. 2003, Manes et al. 2002, and Manville 2003.

Biologists are concerned not only with collision mortality which seems to be critical when turbines are sited on migratory flyways (and takes a greater toll on raptors, waterfowl and songbirds), but even more with long-term habitat disturbance, degradation and abandonment.

5.4. Livestock

Farmers in Ontario have observed health problems with their livestock which began shortly after the wind turbines were installed. Awareness of the research cited by Buxton (above) indicating endocrine and cardiovascular effects from noise would certainly support the symptoms observed by Ontario farmer Ross Brindley who lives near the Kingsbridge wind turbine development near Goderich. According to a report in the December 2008 *Better Farming Magazine*, his cattle exhibited aggressive and erratic behaviour, “including the kicking of newborn calves, prolapsed birthing, weight loss, decline in fertility, a high incidence of mastitis, calves being deformed at birth and a high incidence of stillbirths.” After being driven out of business as a result of problems suffered by his beef cattle herd, Brindley is suing Hydro One Networks Inc. and Edmonton Power Corporation (EPCOR).

5.5. Goats

In the same context, the BBC recently reported that 400 goats in Taiwan had died after eight wind turbines were installed close to their grazing land. "The goats looked skinny and they weren't eating. One night I went out and the goats were all standing up; they weren't sleeping”, the farmer reported. The Council of Agriculture suspects that noise may have caused the goats’ demise through lack of sleep. The power company, Taipower has offered to pay part of the cost of building a new farmhouse elsewhere.

6.0 EVALUATING WIND TURBINE NOISE

Hanning disputes the claim that continual exposure to noise results in habituation.

“It is often claimed that continual exposure to a noise results in habituation, i.e. one gets used to the noise. There is little research to confirm this assertion and a recent small study (Pirrera et al. 2009) looking at the effects of traffic noise on sleep deficiency suggests that it is not so.”[13]

He points out the flaws of using averaged noise levels, or measuring wind speed at a single low height.

[13] Hanning 2.2.8.

Hanning notes that “sleep disturbance has been experienced by people living within 1km to 1600 km of wind turbines. . . . The experiences of the Davis (2008) and Rashleigh (2008) families from Lincolnshire whose homes were around 900m from wind turbines make salutary reading. The noise, sleep disturbance and ill health eventually drove them from their homes”.

“Surveys of residents living in the vicinity of industrial wind turbines show high levels of disturbance to sleep and annoyance. A 2005 survey of 200 residents living within 1km of a 6 turbine, 9MW installation in France showed that 27% found the noise disturbing at night (Butre 2005)”.

The Ontario WindVOiCe health survey found that 81 of 98 report their health affected’. The distances for survey results range up to 5k (2 respondents) with most under 1000m. This emphasizes the need for more 3rd party, multi-disciplinary, health studies including that of epidemiology’.

Buxton advises: the measurement methods should be reviewed to embrace ‘C’ Weighting and ‘G’ Weighting as well as the usual ‘A’ Weighting so that a proper appreciation of the extent of LFN and infrasound is achieved before, during and after the noise source is installed.

Dr. McMurtry points out that: “Quite simply national regulations do not exist in Canada. According to a November 2008 letter from Morel Oprisan, (Deputy Director S&T, Renewable Energy Technologies, Government of Canada) in an electronic mail to Professor John Harrison (Queens University) he stated:

“As you correctly noted in your letter, the issue of the wind turbine set-back from a residence, is regulated locally (municipally or provincially).”

> “’As part of the work done by the federal government in this area, we have worked together with CSA and, internationally with IEC, to bring international standards to Canada. However, these standards, at this time, are not mandatory and their use is voluntary.’”
>
> *“To add to my concern regarding this regulatory uncertainty is the fact that this Provincial Ministry of the Environment has regulations with many flaws. One of these is the failure to measure for low frequency noise (LFN). Instead regulations . . . measure in A Weighted decibels or dBA only. To measure for LFN it is necessary to screen with C Weighted decibels or dBC. It is not possible to develop authoritative guidelines for set-backs and monitoring of industrial wind turbines specifically if LFN is not taken into account”.*

For example, “the wind developer IPC Energy contracted Avalon Consulting to do Environmental Screening. I contacted Avalon who indicated to me on 2 occasions that it is ‘not necessary’ to monitor for LFN. The wind industry at large agrees as they also deny the need to monitor for LFN. The Ministry of the Environment of Ontario concurs as all its regulations are based on dBA (Decibels with A weighting) which is relatively insensitive to LFN. dBA however is adequate for higher frequency noises such as the characteristic ‘swoosh, swoosh, swoosh’ of turbine blades which are in the mid-frequency range”.

“How important is LFN? The World Health Organization in a 2000 publication (“*Community Noise*” by Berglund *et al*) made the following observations:

- "Since A-weighting underestimates the sound pressure level of noise with low frequency components, a better assessment of health effects would be to use C-weighting’".
- "It should be noted that a large proportion of low frequency components in a noise may increase considerably the adverse effects on health’".

- "The evidence on low frequency noise is sufficiently strong to warrant immediate concern'".

- "Styles *et al* observed that there is '. . . clear evidence that wind turbines generate low frequency sound (infrasound) and acoustic signals which can be detected at considerable distances (many kilometres) from wind farms on infrasound detectors and low-frequency microphones.'"

In July, 2008, U.S. acousticians Kamperman and James introduced a set of proposed sound limits to prevent health risks from wind turbines. They emphasized that "the simple fact that so many residents complain of low frequency noise from wind turbines is clear evidence that the single A-weighted (dBA) noise descriptor used in most jurisdictions for siting turbines is not adequate. The only other simple audio frequency weighting that is standardized and available on all sound level meters is the C-weighting or dBC." They proposed the following limits:

"Proposed Wind Turbine Siting Sound Limits"

1. Audible Sound Limit

   a. No Wind Turbine or group of turbines shall be located so as to cause an exceedance of the pre-construction/operation background sound levels by more than 5 dBA.
   b. The background sound levels shall be the L90A sound descriptor measured during a pre-construction noise study during the quietest time of evening or night. All data recording shall be a series of contiguous ten (10) minute measurements. L90A results are valid when L10A results are no more than 15 dBA above L90A for the same time period. Noise sensitive sites are to be selected based on wind development's predicted worst-case sound emissions (in LeqA and LeqC) which are to be provided by the developer.
   c. Test sites are to be located along the property line(s) of the receiving nonparticipating property(s).
   d. A 5 dB penalty is applied for tones as defined in IEC 61400-11.

2. Low Frequency Sound Limit

   a. The LeqC and L90C sound levels from the wind turbine at the receiving property shall not exceed the lower of either:
      1) LeqC-L90A greater than 20 dB outside any occupied structure, or
      2) A maximum not-to-exceed sound level of 50 dBC (L90C) from the wind turbines without other ambient sounds for properties located at one mile or more from State Highways or other major roads or 55 dBC (L90C) for properties closer than one mile.
   b. These limits shall be assessed using the same night time and wind/weather conditions required in 1.a. Turbine operating sound emissions (LeqA and
   c. LeqC) shall represent worst case sound emissions for stable nighttime conditions with low winds at ground level and winds sufficient for full operating capacity at the hub.

3. General Clause

   a. Not to exceed 35 dBA within 30 m. (approx. 100 feet) of any occupied structure.

4. Requirements

   a. All instruments must meet ANSI or IEC Precision integrating sound level meter performance specifications.
   b. Procedures must meet ANSI S12.9 and other applicable ANSI standards.

c. Measurements must be made when ground level winds are 2m/s (4.5 mph) or less. Wind shear in the evening and night often results in low ground level wind speed and nominal operating wind speeds at wind turbine hub heights.
d. IEC 61400-11 procedures are not suitable for enforcement of these requirements except for the presence of tones".

6.1. WHO Guidelines

The World Health (WHO) 2007 reference recommends a night time limit outside a home(Lnight,outside) of 30 dBA.

The 2007 WHO guidelines state:

> "Therefore, Lnight, outside 30 dB is the ultimate target of Night Noise Guideline (NNGL) to protect the public, including the most vulnerable groups such as children, the chronically ill and the elderly, from the adverse health effects of night noise."

The full report can downloaded at
http://ec.europa.eu/health/ph_projects/2003/action3/docs/2003_08_frep_en.pdf

7.0 LOW FREQUENCY NOISE AS A WEAPON

Those engaged in political torture have long been aware that low frequency noise is a powerful "weapon" with devastating effects upon human beings.

The Israeli army used the sound weapon to disperse a crowd by causing dizziness and nausea.

"Professor Hillel Pratt, a neurobiologist specializing in human auditory response at Israel's 'Technion Institute', says 'It doesn't necessarily have to be a loud sound. The combination of low frequencies at high intensities, for example, can create discrepancies in the input to the brain.' Later he explained, 'that by stimulating the inner ear, which houses the auditory and vestibular (equilibrium) sensory organs with high intensity acoustic signals that are below the audible frequencies (<20Hz), the vestibular organ can be stimulated and create a discrepancy between inputs from the visual system and somatosensory system (that report stability of the body relative to the surroundings) and the vestibular organ that will erroneously report acceleration (because of the low-frequency inaudible sound). This will create a sensation similar to sea or motion sickness. Such cases have been reported and a famous example is workers in a basement with a new air-conditioning system that all got sick because of low frequency noise from the new system.'[14]

8.0 FLAWED PUBLIC CONSULTATION PROCESS IN ONTARIO

The government of Ontario has been advised of health problems being experienced in Ontario and has not responded to widespread requests to stop building more wind turbines until the 3rd party evidence based health studies are conducted in order to determine authoritative noise levels. Many requests have also been made for realistic cost/benefit accounting but the Government has not disclosed the real cost or actual benefit of wind power.

There have been substantial sums invested in extensive social marketing and lobbying in order to:

- enable rapid policy action in favour of the industry
- convince the public of the benefits of industrial wind turbines while ignoring the health risks and cost/benefits

[14] *Toronto Star*, 6 June, 2005.

- stereotype as NIMBYs those concerned about the serious consequences of industrial-scale wind turbines so that people who have fallen victim to the technology are invalidated at the outset.

Public input critical of Bill 150, the Green Energy Act has been almost entirely disregarded. Hundreds of submissions to the EBR and MOE have never been made public nor have those on the proposed regulations.

Of the 300 applications to present information to the Standing Committee on Government Affairs reviewing the legislation, less than half were allowed to speak. Selection of speakers was carefully manipulated by the Government to allow mostly those in support of the bill. Some of those opposed were invited to present their concerns at Sault Ste. Marie, a journey of 8-10 hours for people living in Southern Ontario.

Facilitation notes on MOE workshops have never been produced. Requested corrections of policy have not been implemented.

Elevation requests for full environmental screening for all 19 existing wind turbine projects currently installed in Ontario have been categorically denied. A host of project approvals has been passed during the interim between the passing of the GEA and the establishment of new regulations. Detailed public requests for review of these proposals have similarly been denied.

An application to install a wind turbine at the Canadian Autoworkers Centre in Port Elgin has recently been allowed even though it is well within the new regulation 550 metre setback—by a "special amendment" of the regulations.

In short, Bill 150, the Green Energy Act, designed to facilitate rapid installation of industrial wind turbines across Ontario was railroaded through the legislature in so short a period of time that no meaningful public discussion was allowed to take place—an unprecedented situation for a bill that amended so many other acts and removed democratic rights from local communities.

8.1. In Review

1. Evidence-based health studies were not conducted prior to the implementation of the provincial policy to determine authoritative setbacks and noise levels for installation of industrial wind turbines.

2. Provision for vigilance monitoring was not provided.

3. Provision for long term post-market surveillance was not provided to monitor adverse health effects and post-traumatic stress consequences.

4. The Green Energy Act, Bill 150 removes rights of Ontarians including the ability to protect their health.

5. There are many flaws and inadequacies regarding the approval process.

6. The government of Ontario has been advised of these issues and has continued development at a rapid pace.

7. Indications are there is no authoritative oversight or detailed review of the health information cited in the community response.

On November 24, 2004, the Ontario Government announced the results of its Request for Proposals for 300 megawatts of renewable energy. *Noise guidelines were developed from the*

suggestions of the wind energy industry; however, there were no authoritative guidelines determined for setbacks.

In a May 2004 letter to the Ontario Government, the Canadian Wind Energy Association (CanWEA) lobbied for higher noise limits "as noise regulations can have a significant impact on wind turbine spacing, and therefore the cost of wind generated electricity."

Prior to June 2004 wind turbine noise may have been limited to 40 dBA. In June 2004 the limit was increased to 53 dBA. In October 2008 the limit was reduced to 51 dBA for new projects possibly in response to ongoing problems. Less than 9 months later, on Tuesday June 9, 2009 the Ministry of the Environment (MOE) released new draft setback regulations which according to the Minister Mr Gerretsen "… best protect the health and safety of Ontarians". The MOE's draft setback regulations propose a wind turbine noise limit of 40 dBA. This reduction is very significant as a 10 dBA increase is subjectively heard by the human ear as an approximate doubling in loudness.

The new draft setback regulations had provisions to monitor and address low frequency noise, which has been known for many decades in the medical and health care community as causing adverse health effects.

The proposed regulations contained a matrix for setbacks with respect to multiple IWTs (Industrial Wind Turbines). If these proposed setbacks were applied to existing Ontario wind turbine projects some IWTs may have been set back up to three times further than they currently are. Under the proposed setback matrix one of the victims in Ontario would likely have the closest wind turbine at about 1.5 km as opposed to slightly more than 450 m.

Researchers are stating it is important to ensure sufficient set-backs. Some set-backs of up to 1.5 miles (about 2.5 km) are being proposed in the references dealing with health risks. In New Zealand, suggestions are that set-backs should be 1.9 miles (3.1 km) in order to reduce the impact on people. Dr. Pierpont says it could be 2 to 3.5 km based on recent studies. It is important that the set-backs do not overlap property lines so that property owners who do not have turbines can still enjoy their property to the full area that they own.

Time is needed for the researchers and clinicians to study the effects of wind generation on people. Time is needed for the decision-makers and the public to understand the consequences of introducing these industrial complexes into areas where people live.

Once these giant turbines are built, they will be here for a long time so great care needs to be exercised in order to protect the health and quality of life of our population.

It is clear that the final regulations are not adequate to protect human health. These regulations are not founded on evidence-based medical research and are lacking studies on humans. They are based on conservative computer-modeling which in other parts of the world is used only in worse case scenarios.

A growing number of health care professionals and many organizations and rural Ontario families are urging that *independent* evidence-based studies (epidemiology) be conducted to determine authoritative set backs and noise levels, including that of low frequency/infrasound.

The final Regulations which state they are 'unofficial'[15] *were released September 24, 2009. References to the promised 40 dBA noise limits for wind turbines and low frequency / infrasound monitoring are lacking.* Solar energy will limit noise to 40 dBA.

[15] They are not Gazetted yet and until they are, they are unofficial.

While it is obviously unproductive even to speculate on a setback that would satisfy 100% of those who are complaining of adverse health effects from wind turbines, it is certainly not impossible to determine ways to protect a significant number of those affected.

9.0 MITIGATION

"The only mitigation for wind turbine noise is to place a sufficient distance between the turbines and places of human habitation." – Dr Christopher Hanning

10.0 CONCLUSION

10.1 There is widespread consensus that wind turbines cause noise pollution which frequently leads to sleep disturbance for those living nearby.

10.2 There is growing documentation from medical professionals about the related adverse health effects on humans and animals living within affected areas.

10.3 The Ontario Agency for Health Protection and Promotion has an obligation under its mandate for Health promotion, chronic disease prevention, and injury prevention to thoroughly investigate the growing number of complaints being received from people in Ontario living near wind turbines. Elected members of the legislature have a responsibility to exercise due diligence to protect the health or rural Ontarians.

10.4 Researchers are stating it is important to ensure sufficient set-backs. Some set-backs of up to 1.5 miles (about 2.5 km) are being proposed in the references dealing with health risks.

To repeat Dr. Nissenbaum's warning:

> "There are many issues that need to be worked out. A moratorium is logical, unless we quickly move to adopt more stringent European and Australian standards. *Otherwise, the state's failure to act responsibly on this issue is the equivalent of abandoning its responsibility to protect public health, which would leave the people with few options other than seeking remedy and redress through the courts".*

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January 27, 2010

RECEIVED
2010 JAN 27 PM 1:34
PUBLIC UTILITIES COMMISSION

Luly E. Massaro
Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: PUC Docket No. 4111
Review of Proposed Town of New Shoreham
Project Pursuant to R.I. Gen. Laws
§39-26.1-7

Dear Ms. Massaro,

Enclosed herewith you will find an original and nine copies of "Cost and Quantity of Greenhouse Gas Emissions Avoided by Wind Generation", article by Peter Lang. The same is an exhibit that was inadvertently not included with the hard copies of Prefiled Testimony of Expert Witness William P. Short, III in the above matter. This exhibit was sent electronically to the attached service list on January 19, 2010, the original date of filing.

Thank you for your assistance.

Very truly yours,

Joseph J. McGair, Esq.

JJM:dd
Enc.
HAND-DELIVERED

Cost and Quantity of Greenhouse Gas Emissions Avoided by Wind Generation

By

Peter Lang

This paper contains a simple analysis of the amount of greenhouse gas emissions avoided by wind power and the cost per tonne of emissions avoided. It puts these figures in context by comparing them with some other ways of reducing greenhouse gas emissions from electricity generation.

The conclusion: wind farms connected to the National Grid provide low value energy at high cost, and avoid little greenhouse gas emissions.

The paper covers the following:

Background

Wind power is intermittent, so either energy storage or constantly, instantly available back-up generation is required to provide constant power.

Wind power is proportional to the cube of the wind speed. So a small drop in wind speed causes a large drop in the power output. For a modern 2.1 MW wind turbine a 2 m/s drop in wind speed from 9 to 7 m/s halves the power output.

The wind speed is very variable. Figures 1 and 2 give examples of how variable it is.

Figure 1 – The variability of wind power

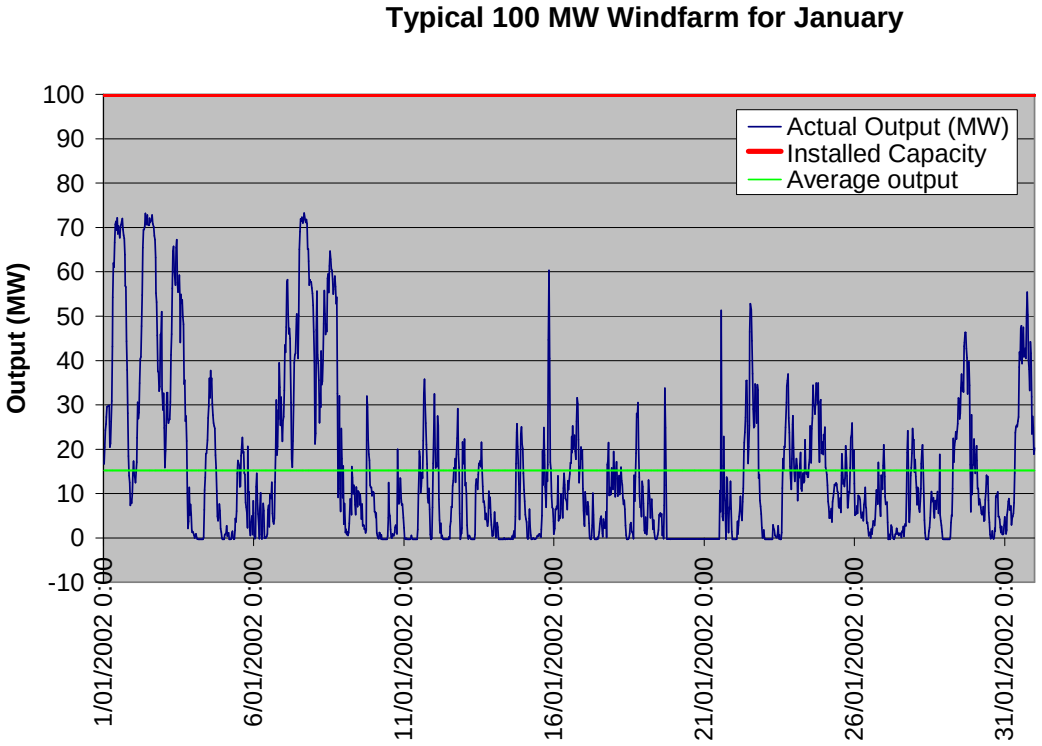
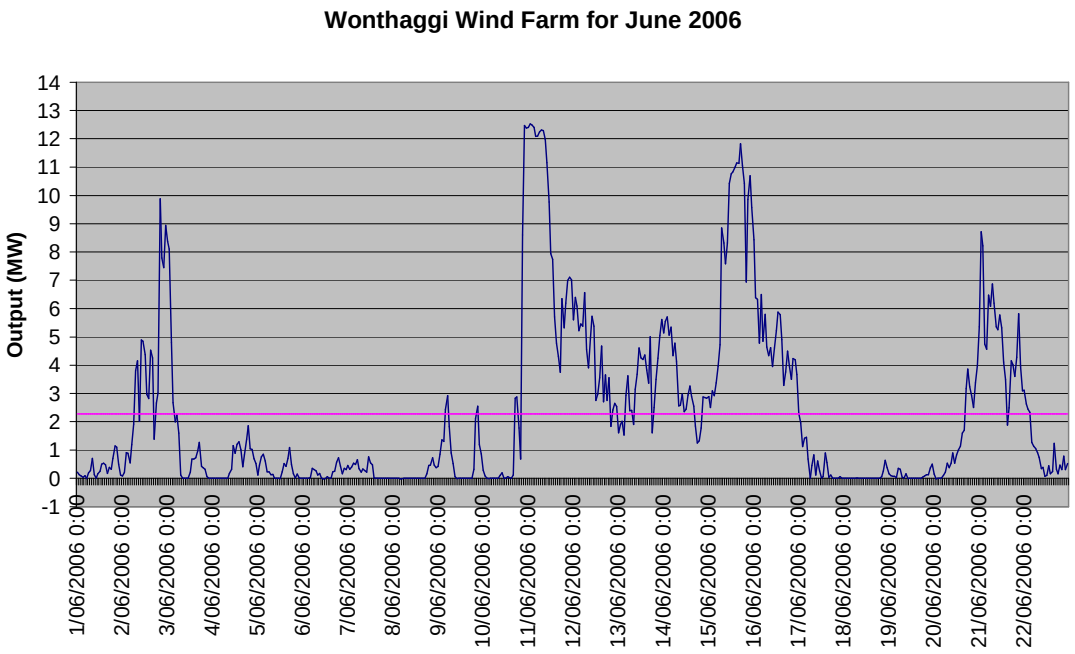


Figure 2 – the variability of wind power



Energy storage[1] is completely uneconomic for the amounts of energy required. So we must use back-up generation.

Constantly, instantly available back-up must be provided by reliable energy sources (to provide power whenever the wind speed drops). Coal, gas, hydro and nuclear power provide reliable power, but not all are suitable as back up generators for wind power.

Back-up generation is mostly provided by gas turbines in Australia. The reasons why gas provides the back-up rather than one of the other energy sources are:

1. We have insufficient hydro resources to provide peak power let alone provide back-up for wind power. Hydro energy has high value for providing peak power and for providing rapid and controllable responses to changes in electricity demand across the network. So our very limited hydro resource is used to generate this high value power.

2. Coal generates the lowest cost electricity and, therefore, coal generation is the last to be displaced when a new source of electricity becomes available (such as when the wind blows). That is, when wind energy is available it displaces the highest cost generator first. Coal is displaced last.

3. Coal generators cannot follow load changes rapidly. Brown coal power stations (as used in Victoria) are designed to run at full power all the time. They can only reduce power by venting steam, but they continue to burn the same amount of coal and hence produce the same amount of emissions whether or not they are generating electricity. Black coal power stations have some limited capability to follow the load but cannot follow the rapid changes in wind power.

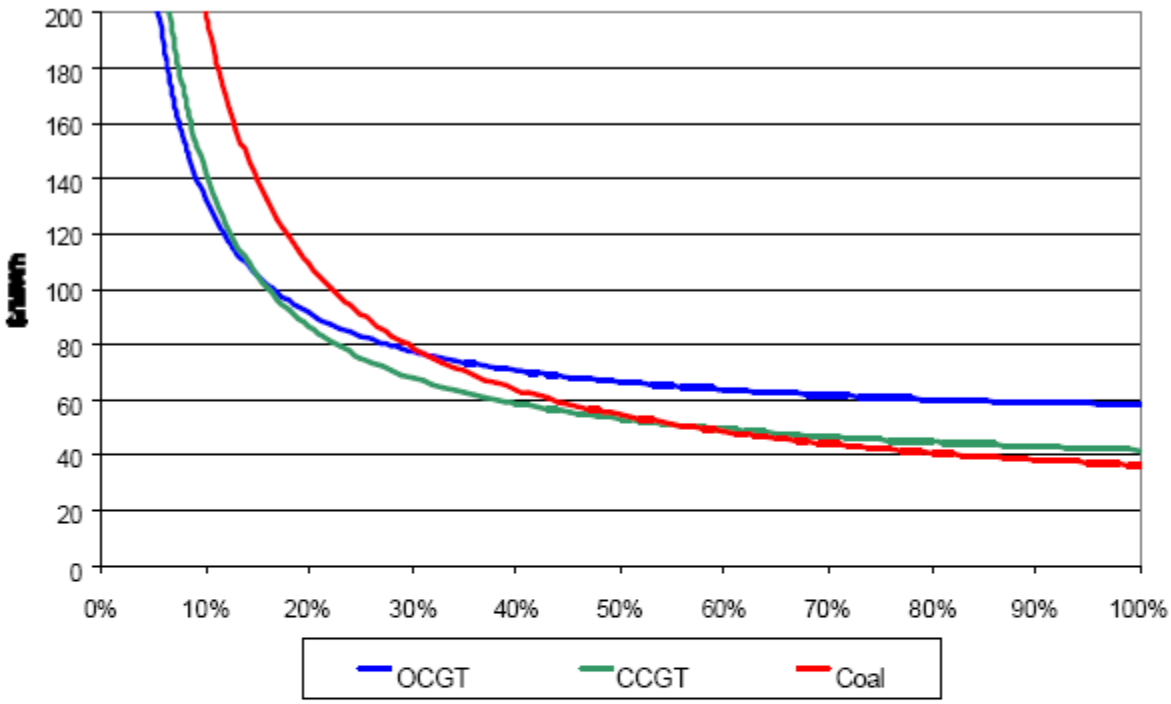
4. Gas turbines can follow load changes fairly well but not as rapidly as the wind power changes. Gas turbines power up and down like a turbo-prop aircraft engine, but with slower response. Next to hydro, gas turbines are best able to follow the load changes created by wind power.

5. There are two classes of gas turbine: Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT). OCGT has lower capital cost, higher operating costs, uses more gas and produces more greenhouse emissions than CCGT per MWh of electricity generated. OCGT follows load changes better than CCGT. OCGT produces electricity at less cost than CCGT at capacity factors less than about 15% (ie 15% of the energy it would produce if running full time at full power). CCGT has higher capital cost and needs to run at higher power and run for longer to be economic. CCGT is more efficient so it uses less gas and produces less greenhouse emissions. CCGT produces electricity at less cost than OCGT for capacity factors above about 15%. (See figure 3).

[1] http://www.greenhouse.gov.au/renewable/aest/pubs/aest-review.pdf , Fig 13, p28

Figure 3
Source: "Long Run Marginal Cost of Electricity Generation in NSW, A report to the Independent Pricing and Regulatory Tribunal, Feb 2004"

Exhibit 1-2 Medium New Entry Cost Scenario as a Function of Capacity Factor (Medium Scenario)



The study noted the cross over points in the cost versus capacity factor characteristic. These cross over points represent the capacity factors where one technology becomes more economic than the next. The optimal capacity factors and the corresponding new entry costs for each technology are shown in Exhibit 1-3 below.

Exhibit 1-3 Optimal Capacity Factors and Associated New Entry Cost (Medium Scenario)

	Thermal Coal	CCGT	OCGT
CF	100%	55%	14%
New Entry Cost	$36.2/MWh	$50.9/MWh	$109.0/MWh

6. The ideal arrangement (grossly simplified) is:

    a. Coal (and/or nuclear) generates base load power (24 hours per day);

    b. CCGT generates shoulder power (approximately 12 hours per day, but variable duration);

c. OCGT generates shoulder and peak power and follows the load changes (average less than 15% capacity factor);

d. Hydro generates peak power and provides stability to the grid.

7. If wind generation is available the power produced is highly variable and unscheduled so it needs to be backed up by OCGT. Although OCGT is called up to back up for wind, the energy produced by wind actually displaces CCGT generation mostly (see next section for explanation).

8. Because wind energy is variable, unreliable and cannot be called up on demand, especially at the time of peak demand, wind power has low value.

9. Because wind cannot be called up on demand, especially at the time of peak demand, installed wind generation capacity does not reduce the amount of installed conventional generating capacity required. So wind cannot contribute to reducing the capital investment in generating plant. Wind is simply an additional capital investment.

The Basis for Comparison

Wind generation displaces CCGT mostly. If we did not have wind power, CCGT would be the most economical and least greenhouse intensive way to generate shoulder power (non-continuous power). To explain, consider the following.

If governments did not mandate and subsidise wind power (by Mandatory Renewable Energy Targets and State based regulations and subsidies) then CCGT and OCGT would be installed in the optimum proportions to provide shoulder and peak generation (in excess of available hydro energy).

If governments mandate wind power then we will need more OCGT and less CCGT than without wind power. The substitution of OCGT for CCGT is (nearly) in proportion to the amount of wind capacity installed, not the amount of wind energy that will be generated. The reason is that the OCGT is required to back up for most of the wind power's maximum capacity, not for its average energy production. For example, if we install 100 MW of wind power, nearly 100 MW of OCGT must be installed instead of 100 MW of CCGT. (For more detailed explanation see "Security Assessment of Future UK Electricity Scenarios"[2]).

To estimate the cost of, and greenhouse emissions avoided by, wind generation we need to compare CCGT versus wind generation plus OCGT back-up.

[2] http://www.tyndall.ac.uk/research/theme2/final_reports/t2_24.pdf

Electricity Generation Cost per MW/h

The cost of electricity generation by gas turbines for various capacity factors[3] is listed below:

	Generation Cost ($/MWh)	
CF	**OCGT**	**CCGT**
100%	60	40
45%	70	54
30%	78	67
15%	105	100

The cost of wind generation at 30% capacity factor is about $90/MWh (this figure does not include the cost of back-up). The figure is derived from the proponent's case to the NSW Land and Environment Court for a Wind Farm at Taralga, from ESAA[4], and from actual costs for wind generation in South Australia and New Zealand.

Cost of Back up Generation for Wind

The figure of $90/MWh for wind does not include the cost of back up, nor the cost imposed on the generators, the grid, and distributors caused by the variable and unreliable power. Some of the costs not included in the figure for wind power are:

1. The cost of the investment in generator capacity required to meet peak demand. Nearly the full amount of fossil fuel and hydro generating capacity must be maintained to meet peak demand. The investment in wind displaces almost no capital investment in conventional generating plant.

2. The fossil fuel generators must charge a higher price for their electricity to recoup the fixed costs of their plant over a lesser amount of electricity supplied (ie as they power down when the wind blows)

3. The cost of maintaining 'spinning reserve' - keeping the generators running ready to power up as soon as the wind speed drops. The costs are: fuel, operation and maintenance, and return on capital invested.

4. The cost of fuel for powering up each time the wind changes.

5. Higher gas costs. Most of the gas price is in the pipes, not the price of the gas at the well head. The gas supply pipes need to be sized to run the gas turbines at full power. When the OCGT is operating as back-up for wind it produces less power than optimum. The fixed cost of the gas pipes is spread over less MWh generated by the gas turbine. So the cost of gas and hence the cost of electricity generated must be higher to give an economic return for the generator.

[3] "Long Run Marginal Cost of Electricity Generation in NSW; A report to the Independent Pricing and Regulatory Tribunal, Feb 2004", Exhibit 1.2.
[4] http://www.esaa.com.au/images/stories//energyandemissionsstudystage2.pdf

6. High-value, hydro-energy is wasted. With wind power connected to the grid extra hydro energy (some of it pumped to storage by coal fired plants during off-peak hours) has to be used to stabilise the grid, to provide fast response power when the OCGTs cannot power up fast enough, and to maintain a greater amount of spinning reserve. The rapid changes in wind power causes instability in the network. Some wind changes occur faster than the OCGT's can ramp up. Fast response hydro energy, from our limited reserves, is used to balance these load fluctuations.

7. The grid must be stronger to accommodate the greater variability imposed by the wind generators.

8. There are higher operational costs for the grid operators and distributors. For example, each distributor has a group dedicated to ensure the distributor buys enough renewable energy to meet its government mandated obligations. The full additional cost is millions of dollars per year and this is passed on to consumers in a higher price of electricity.

Assume that the cost of maintaining back up for wind generation is 50% of the cost of generating with the OCGT (i.e., $39/MWh based on the preceding figures and assumptions). Now we can calculate a cost of having wind power in the generation mix.

Option 1 – No Wind. CCGT generates 45% capacity factor – Cost: $54/MWh

Option 2 – Wind plus OCGT generates 45% capacity factor - Cost: $121/MWh (see table below)

	Capacity Factor	**Rate $/MWh**	**Cost/MWh $/MWh**
OCGT	15%	$105	$35
Wind	30%	$90	$60
OCGT Back-up for wind	30%	$39	$26
Total Wind and OCGT	45%		$121

The cost of CCGT is $54/MWh. The cost of wind including back-up is about $121/MWh. The difference is $67/MWh. This is the cost per MWh to avoid some CO2 emissions.

Analysis of a report by the UK Royal Academy of Engineering "The Costs of Generating Electricity"[5] gives similar figures.

	UK p/kWh	**A$/MWh**
CCGT	2.2	$51
OCGT	3.2	$74
Wind	3.7	$86
back up	1.7	$40
Wind with back up	5.4	$126

[5] http://www.raeng.org.uk/news/publications/list/reports/Cost_Generation_Commentary.pdf

Greenhouse Emissions per MWh

The University of Sydney's Integrated Sustainability Analysis report[6] provides the greenhouse gas emission intensity factors for wind in columns 2 and 3 below. The fourth column (for 30% capacity factor and 20 year economic life) is calculated by factoring from columns 2 and 3.

Capacity Factor	31.2%	23.1%	30%
Economic life (yr)	25	20	20
Emissions Factor (t CO2-e/MWh)	0.021	0.040	0.027

Source: http://www.pmc.gov.au/umpner/docs/commissioned/ISA_report.pdf

The greenhouse gas emission factors for gas turbines from the same report are:

Generator technology	**OCGT**	**CCGT**
Greenhouse gas emissions factor (t CO2-e/MWh)	0.751	0.577

Emissions Avoided per MWh

If CCGT generated the power, the emissions would be 0.577 t CO2-e/MWh.

If Wind and OCGT generate the same amount of power, the emissions would be 0.519 t CO2-e/MWh (see table below).

	CF	**Factor t CO2e/MWh**	**Emissions t CO2e/MWh**
OCGT	15%	0.751	0.250
Wind	30%	0.027	0.018
Back-up for wind (assumed 50% of OGCT)	30%	0.376	0.250
Total Wind and OCGT	45%		0.519

Therefore, the emissions avoided by wind are: 0.577 – 0.519 = 0.058 t CO2-e/MWh

We can compare this figure with figures derived from two other sources.

First, the "South Australian Wind Power Study"[7] provides an upper bound figure. This study modelled the effect of introducing wind generation in South Australia on the amount of fossil fuel generation and the long run and short run marginal costs of generation across the whole National Electricity Market. The study also modelled the amount of greenhouse gas emissions saved, but points out that several factors are not included in the analyses. The study determined the amount of CO2 emissions avoided by wind, excluding emissions from providing back up, is about 0.5 t CO2-e/MWh. This can be considered as an upper bound, because the modelling does not consider:

- Emissions from maintaining 'spinning reserve' with back up generators;

[6] http://www.pmc.gov.au/umpner/docs/commissioned/ISA_report.pdf
[7] "South Australia Wind Power Study" by Electricity Supply Industry Planning Council, March 2003.

- Emissions from powering up and running down the generators;
- Emissions from coal power stations when they are required to reduce power by venting steam (while they continue to burn coal and emit CO2 at their full rate);
- Emissions from generating the energy to provide reactive and feed-in power for the wind generators;
- Emissions from building, operating and maintaining the strengthened grid needed to support the distributed wind power generators;
- Emissions from the additional work required by the distributors;
- Emissions from coal power stations pumping water to pumped storage that then has to be used for rapid response back-up, for extra 'spinning reserve' and for stabilising the grid because of the variable power from wind turbines;
- The hydro energy resource on mainland Australia is limited and insufficient to provide for even our peak load energy needs. Any hydro energy used as back up for wind power must be replaced with OCGT generation. In effect, any hydro energy used for back up for wind has the same emissions as OCGT running as back up for wind.

The second source for comparison is the Royal Academy of Engineering report "The Cost of Generating Electricity"[8]. We can calculate the amount of emissions avoided by wind with back up from the information provided in the report.[9]

	Generation cost (UK p/kWh)			Emissions
	Carbon tax £0 / t CO2-e	Carbon tax £30 / t CO2-e	Difference	kg CO2e / kWh
CCGT	2.2	3.4	1.2	0.400[10]
OCGT	3.2	4.8	1.6	0.533
Wind	3.7	3.7	0	0.027
back up	1.7	1.7	0	0.283[11]
Wind with back up	5.4	5.4	0	0.310
Emissions avoided				**0.090**

So, we have three values for the amount of greenhouse gas emissions avoided by wind generation per MWh.

Basis of estimate	**t CO2 avoided /MWh**
Wind with OCGT back up displacing CCGT	0.058
Wind, excluding back up (SA Wind Power Study)[12]	0.5
Wind including back up (Royal Academy of Engineering, UK)	0.09

[8] http://www.raeng.org.uk/news/publications/list/reports/Cost_Generation_Commentary.pdf

[9] Using cost data from the Royal Academy of Engineering report (with and without a carbon tax), we can infer the emissions per kWh factor they used by taking the difference in cost per tonne CO2 and dividing it by the carbon tax cost per tonne CO2 (first two rows). Emissions for wind, back-up and wind with back-up are taken from the previous page. Emissions avoided (last row) are calculated by CCGT emissions minus emissions from wind with back-up.

[10] calculated as: Difference converted from p to £, divided by carbon tax, converted from t to kg

[11] calculated as: emissions from OCGT x cost of back-up / cost of OCGT

[12] "South Australia Wind Power Study" by Electricity Supply Industry Planning Council, March 2003.

Cost of emissions avoided per MWh

The cost of emissions avoided by wind power can be calculated from the figures in the preceding sections. The cost of emission avoided by wind is the cost of substituting wind power plus OCGT back-up for CCGT. We have three figures for the amount of emissions avoided. The higher emissions avoided (lower avoidance cost) is calculated from the results of a modelling analysis which does not include the emissions from back up. The two low figures for emissions avoided (higher avoidance cost) do include an allowance for the emissions from back up. The first is a simple analysis. The other is from a sophisticated study by the UK Royal Academy of Engineering.

Cost per MWh to substitute Wind with back-up for CCGT ($/MWh)	$67	$67	$74
Emissions avoided (t CO2-e/MWh)	0.058	0.5	0.09
Cost of emissions avoided ($t CO2-e avoided)	$1,149	$134	$830

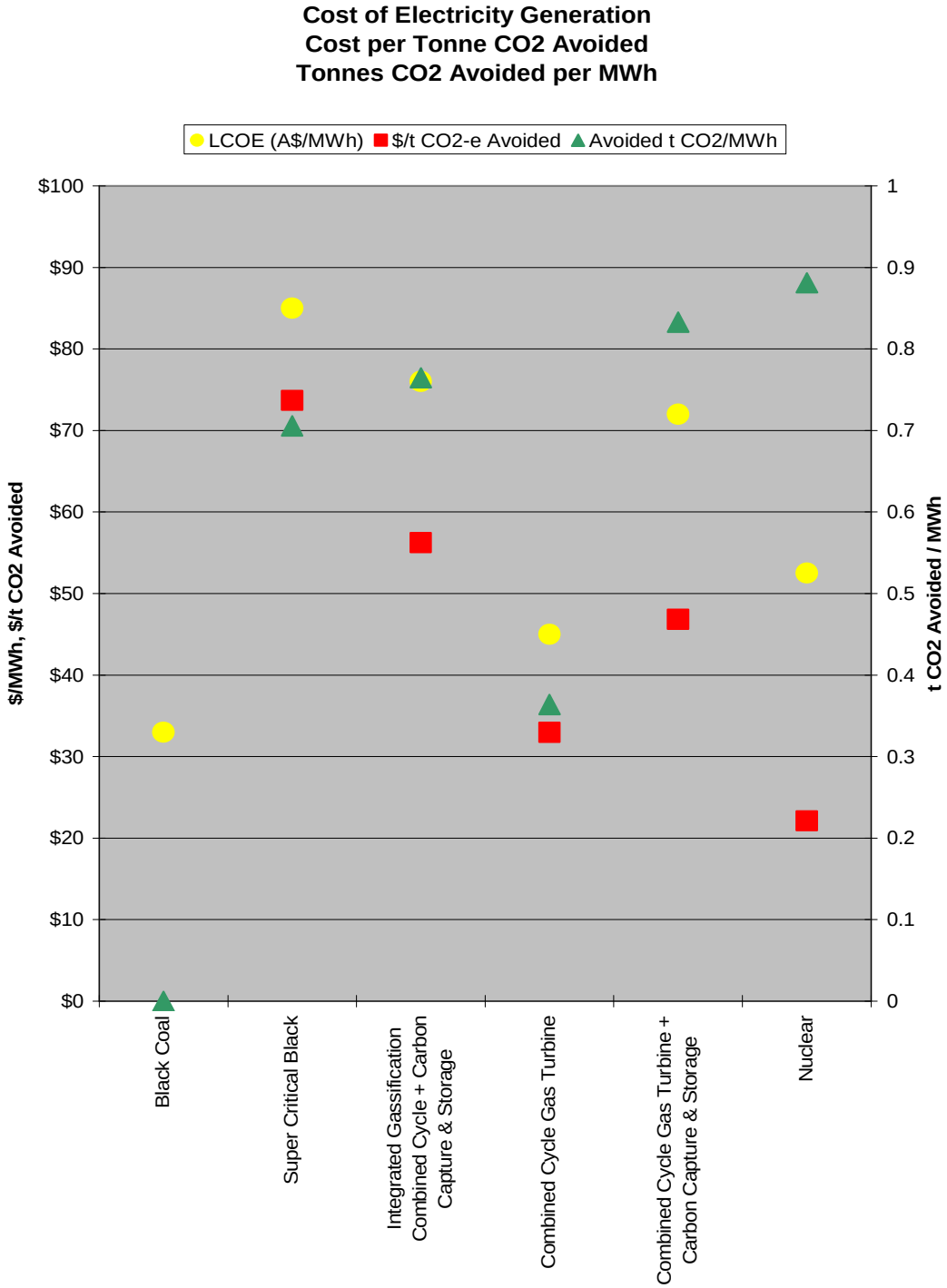
All three figures for the cost of emissions avoided by Wind power are high compared with alternatives.

Comparison with Other Options to Reduce Emissions from Electricity Generation

Figure 4 shows the cost of avoiding emission, and the amount of emissions avoided per MWh, by some new base load electricity generating technologies. Wind contributes to generating for shoulder (or non-continuous) power rather than base load so the figures are not directly comparable. But the figures do indicate that wind power is a costly way to reduce CO2 emissions (i.e., $134 to $1149 per tonne CO2-e avoided), and that the amount of emissions avoided by wind is negligible.

Nuclear power avoids the most emissions per MWh and is the least cost for doing so at about $22 per tonne of CO2 avoided (Figure 4).

Figure 4 - Projected cost of electricity, amount of emissions avoided and avoidance cost per MWh for future base load electricity generation technologies.
Source: calculated from the reports by EPRI[13] and University of Sydney Integrated Sustainability Analysis[14].



[13] http://www.pmc.gov.au/umpner/docs/commissioned/EPRI_report.pdf
[14] http://www.pmc.gov.au/umpner/docs/commissioned/ISA_report.pdf

The table below compares some technology options for reducing emissions. The technologies are ordered from highest to lowest cost of avoiding emissions (column 3).

	Emissions (t CO2-e / MWh	Emissions Avoided (t CO2-e avoided / MWh	Cost of Emissions avoided ($/t CO2-e avoided)
Wind (including back up generation) (Aus)[15]	0.519	0.058	$1149
Wind (including back up generation) (UK)	0.310	0.090	$830
'Clean Coal' (IGCC + CCS)	0.176	0.765	$56
Combined Cycle Gas Turbine + CCS	0.108	0.833	$47
Combined Cycle Gas Turbine	0.577	0.364	$33
Nuclear	0.060	0.880	$22

The table shows:

1. Wind power is the highest cost and nuclear the lowest cost for avoiding emissions (by a factor of about 50) (Column 3);
2. Wind power does not meet the Clean Energy Targets'[16] 200 kg/MWh test (Column 1);
3. Only nuclear and the fossil fuel technologies with carbon capture and storage meet the '200 kg/MWh test' (Column 1);
4. Only nuclear and the fossil fuel technologies with carbon capture and storage can make substantial reductions in emissions - i.e., can avoid more than 750 kg/CO2-e/MWh (Column 2). To put this in perspective, 750 kg/CO2-e/MWh is about 75% of the emissions from conventional coal fired generation. Coal fired generation produces about 76% of Australia's electricity and 89% of electricity's greenhouse gas emissions.

Discussion

The results are sensitive to the input parameters (capacity factors, emissions per MWh, costs per MWh, and the cost and emissions from back-up).

The capacity factor for wind generation in NSW should be less than the 30% used in this analysis (for example Crookwell 14.7% over 5 years and Blayney 22%).

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[15] For wind back up generation the figures are:

Wind (excluding back up generation) (Aus)	0.027	0.500	$134

[16] The Federal Government recently announced national Clean Energy Targets to replace the state based renewable energy and emissions reductions schemes. The new national Clean Energy Target, requires that 30,000 GWh each year must come from low emissions sources by 2020. Low emission sources are those technologies that emit less than 200 kg of greenhouse gases per MWh of electricity generated.

These calculations suggest that wind generation saves little greenhouse gas emissions when the emissions from the back-up are taken into account.

Wind power, with emissions and cost of back-up generation properly attributed, avoids 0.058 to 0.09 t CO2-e/MWh compared with about 0.88 t CO2-e/MWh avoided by nuclear. The cost to avoid 1 tonne of CO2-e per MWh is $830 to $1149 with wind power compared with $22 with nuclear power. If the emissions and cost of back up generation are ignored then win power avoids about 0.5 t CO2-e/MWh at a cost of about $134/t CO2-e avoided. Even if the costs of and emissions from back up generation are ignored, wind is still over six time more costly that nuclear as a way to avoid emissions.

A single 1000 MW nuclear plant (normally we would have four to eight reactors together in a single power station) would avoid 6.9 million tonnes of CO2 equivalent per year. Five hundred 2 MW wind turbines (total 1000 MW) would avoid 0.15 to 1.3 million tonnes per year – just 2 to 20% as much as the same amount of nuclear capacity. When we take into account that we could have up to 80% of our electricity supplied by nuclear (as France has), but only a few percent can be supplied by wind, we can see that nuclear can make a major contribution to cutting greenhouse emissions, but wind a negligible contribution and at much higher cost.

Conclusions:

1. Wind power does not avoid significant amounts of greenhouse gas emissions.
2. Wind power is a very high cost way to avoid greenhouse gas emissions.
3. Wind power, even with high capacity penetration, can not make a significant contribution to reducing greenhouse gas emissions.

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About the Author

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