STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISSION

IN RE: REVIEW OF PROPOSED TOWN OF NEW SHOREHAM PROJECT PURSUANT TO RHODE ISLAND GENERAL LAWS § 39-26.1-7

PREFILED TESTIMONY

OF

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FOR

DEEPWATER WIND BLOCK ISLAND, LLC

DECEMBER 9, 2009

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David P. Nickerson and my business address is P.O. Box 9213, Noank, CT.

Q. By whom are you employed and in what capacity?

A. I am a Managing Member of Mystic River Energy Group LLC, a consulting firm that focuses on power plant and energy market related business and economic issues, primarily in the Northeast.

Q. Please describe your qualifications and experience.

A. I have a Bachelor of Science in Electrical Engineering with a minor in Engineering Management from Tufts University and a Master of Science in Industrial Administration (MBA) from Carnegie-Mellon University. For over 29 years I have worked in the electric power industry – 9 of those years were with Westinghouse Electric in Pittsburgh, PA, 9 years with New England Power Company in Westborough; MA, 5 years with El Paso Merchant Energy, a Houston-based energy trading company, and 6 and a half years as an independent consultant. I have extensive experience over the past 20 years analyzing, evaluating and negotiating the commercial aspects of wholesale power contracts based on conventional and renewable technologies from the perspective of a regulated utility, independent power projects in both development and operation, energy trading companies, and as a consultant to power plant owners, commercial and industrial retail customers, and a state agency. My experience as a power supply analyst includes familiarity with electric system modeling, wholesale power markets and ISO rules.

Q. Have you previously testified before the Rhode Island PUC or other state or federal regulatory commissions?

A. Yes. I testified before the Rhode Island Public Utility Commission (the "Commission") in 1994 in support of a wind power contract on which I led the negotiation while at New England Power Company. In support of Pawtucket Power Company's permit to export natural gas from Canada, I have testified before the Canadian National Energy Board in the early 1990's. In 2008 I testified before the Connecticut Department of Public Utilities on behalf of the Connecticut Clean Energy Fund in support of an analysis of the market value of Class I renewable energy projects that resulted from the Project 150 renewable energy solicitation process.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to support the request of Deepwater Wind Block Island LLC's request ("Deepwater Wind") that the Commission approve the power purchase agreement ("PPA") between The Narragansett Electric Company, d/b/a National Grid (the "Company"), and Deepwater Wind with respect to the proposed offshore wind farm in the waters off New Shoreham (the "Block Island Wind Farm"), to show from the perspective of an experienced power supply analyst that it meets the objectives set out by the State Legislature and that in light of the small scale and characteristics of this offshore wind project, the PPA is commercially reasonable.

The testimony reviews the relevant Rhode Island laws and how they apply in the context of this review of the PPA. It then discusses differences between the Block Island Wind Farm and other relevant offshore wind benchmarks and the reasons for those differences. Next the testimony reviews the calculation of the pricing under the PPA and the market value of the product to be provided including energy, impacts of gas prices and carbon policy, and of renewable energy credits. Different plausible scenarios of future outcomes that could impact the value of the PPA are summarized. Finally, there is a review of the PPA's commercial reasonableness in the context of the legislation.

Q. Please summarize the key points of your testimony

A. Based on the analysis presented here:

- The estimated installed cost of the Block Island Wind Farm is approximately $6.96 million/MW, with the most rational benchmarks from other offshore wind projects and studies ranging from $6.95 to $5.01 million/MW.
- The several European projects that make up the $5.01 million/MW value likely benefit from lower costs due to economies of scale, some learning value to date, efficiency improvements, an established offshore-specific supply chain, and experienced personnel, which as discussed, possibly very meaningful but cannot be readily quantified.
- The implied cost of the PPA is:
  - $274.3 in 2013 present value $s
  - $306/MWh, levelized
- Market value of the products delivered under the PPA:
  - $142.6 to $175.6 million in 2013 present value $s
  - $158/MWh to $195/MWh levelized under a credible range of conditions
- The above market differential, and net potential cost to ratepayers is:
  - $98.7 to $124 million in 2013 present value $s
  - $110/MWh to $147/MWh levelized under the same range of conditions
- The over-market difference may be offset by hard-to-quantify but nonetheless real benefits bring value to Rhode Island. These include:
  - Direct in-State economic development benefits. Studies elsewhere indicate could be in the range of $2.4 million per year or $26 million in 2013 present value $s if the annual rate is escalated at CPI and applied to the output of the project. The same study shows indirect benefits as a result of multiplier effects could, based on other studies, amount to a similar level or higher. It is possible that with concentrated infrastructure

development and/or ship fabrication within Rhode Island, the figure could be higher still.

- Electricity price suppression (which is a no-brainer to any power analyst and can be predicted by modeling) has been estimated in a number of studies, and the recent ISO Scenario Analysis supports the premise that the benefit is real. Using this study, I've estimated the benefit at a net present value of $2.5 million
- Natural gas price suppression is difficult to quantify, and I have not attempted to do so, but studies indicate that this benefit is real and material. Some analysts have shown that this benefit can wholly or partly offset the direct incremental cost of renewable portfolio standards, as discussed further below.

- An examination of public data sources supports that if offshore wind is the only option proposed to meet the objectives, then another element of a commercially reasonable determination is whether the cost of the proposed project is in line with expectations of what it will cost to do a small scale offshore wind project. As indicated below, the costs are in-line with expectations based on scale, depth, relative to recent industry benchmarks and independent studies
- Finally, all of the benchmarks are for places where there is infrastructure in place... but none in the US... the first projects must support a range of industry first costs and bear the cost and risk of uncertainties which it is likely to resolve for subsequent projects – which in turn could be expected to reduce the cost of those subsequent projects, including Deepwater's proposed larger project

<u>II. OVERVIEW OF THE APPLICABLE LEGISLATION AND HOW DEEPWATER WIND'S PPA FOR THE BLOCK ISLAND WIND FARM MEETS THE STANDARDS SET OUT IN THE LEGISLATION</u>

Q. What elements of the Rhode Island General Laws Chapter 39-29.1 "Long-Term Contracting Standard for Renewable Energy" are relevant here?

A. There are three basic sections of law that this testimony focuses on (collectively, the "Legislation"). The Legislature, in the first section of Chapter 26.1, presented a set of well-defined objectives: *"The purpose of this chapter is to encourage and facilitate the creation of commercially reasonable long –term contracts between the electric distribution companies and* *developers and sponsors of newly developed renewable energy resources with the goals of stabilizing long-term energy prices, enhancing environmental quality, creating jobs in Rhode Island in the renewable energy sector, and facilitating the financing of renewable energy generation within the jurisdictional boundaries of the state or adjacent state or federal water or providing direct economic benefit to the state."*

Chapter 26.1-2 includes a definition and standard for the term commercially reasonable, which in addition to use in Chapter 26.1-1 above is also used in a later section of the law that led to this project. Commercially reasonable: *"means terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving newly developed renewable energy resources. Commercially reasonable shall include having a credible project operation date, as determined by the commission, but a project need not have completed the requisite permitting process to be considered commercially reasonable. If there is a dispute about whether any terms or pricing are commercially reasonable, the commission shall make the final determination after evidentiary hearings"*.

Furthermore, Chapter 26.1-7 (Town of New Shoreham Project) lays out the additional objectives, to "...solicit proposals for one newly developed renewable energy resources project of ten (10) megawatts or less that includes a proposal to enhance the electric reliability and environmental quality of the Town of New Shoreham. The electric distribution company shall select a project for negotiating a contract that shall be conditioned upon approval from the commission. Negotiations shall proceed in good faith to achieve a commercially reasonable contract." The Chapter later goes on to allow up to 8 wind turbines with a nameplate capacity of no more 30 megawatts ("MW"). If in requiring that National Grid enter negotiations to achieve a commercially reasonable contract within this paragraph, the statute requires, by extension, that the contract be a commercially reasonable approach to meeting the requirements of this paragraph as well, in other words, relative to other options available to do so.

There are few realistic options for new developed renewable energy projects on Block Island and that are less expensive. There is no hydro, biomass, or landfill gas on the Island; solar would be of such a small scale that it would be, at best, comparable in price, without the commensurate benefits of helping to launch the offshore wind industry and its associated economic development benefits; and onshore wind would be difficult to site due to setback requirements, small in scale due to land limitations, and challenging economics. Ultimately, offshore wind is the only practical, and most cost-effective, option to bring MW-scale renewables to Block Island.

Q. Does the Deepwater Wind PPA meet the stated purpose of the Rhode Island Legislature in Chapter 39-29.1 of the General Laws?

The Block Island Wind Farm clearly meets all of the elements of Chapter 26.1's Purpose:

1) *"The purpose of this chapter is to encourage and facilitate the creation of commercially reasonable long –term contracts between the electric distribution companies and developers and sponsors of newly developed renewable energy resources"*

As a 20 year contract between Deepwater Wind and the Company, this PPA is considered a long term agreement in the electric power industry and includes the intended parties – an electric distribution company and a developer. With commercial operation planned for the end of 2012, the Block Island Wind Farm will be a newly developed renewable energy resource.

As this testimony will demonstrate in later sections, I believe as an experienced power analyst and consistent with the definition set out in Chapter 26.-2, that the terms and pricing of the PPA are commercially reasonable.

2) *"with the goals of"*

a. *"stabilizing long-term energy prices"*

Deepwater Wind and the Company have been able to agree on a fixed pricing structure that is known and predictable and as such will add stability to long term energy prices. Exhibit A is a recent plot of natural gas market price data from the Federal Energy Regulatory Commission ("FERC") and helps illustrate the significant recent volatility of wholesale fuel market prices that in large part drive electricity prices. The PPA's fixed pricing structure, while higher than current market prices, functions as a hedge against escalating and volatile future energy prices and potential increases related to carbon policy or increases in the price of Renewable Energy Credits ("RECs").

Further upside for ratepayers comes from two additional elements of the PPA pricing that can act to reduce to the prices paid by the Company: 1) a component that reduces the price by the market value of capacity and essentialy functions as a hedge against increasing capacity prices; and 2) a sharing of the value of energy produced in excess of certain targets.

In addition, the Block Island Wind Farm's operation and production of energy will directly reduce the need for other generating plants to operate, and in particular the plants on the margin in a bid-based market like New England. Typically, the marginal unit in the ISO New England ("ISO-NE") market is fueled by natural gas. Usually demonstrated via a production cost or dispatch model, adding energy to the grid causes a reduction in the system-wide marginal cost of energy as more efficient units that are further down the bid stack can now be used to meet demand. If there are any transmission constraints this could be a more localized effect, thus weighting the benefits towards Rhode Island. A corresponding reduction in overall natural gas consumption puts downward pressure on natural gas prices, and because less fossil fueled generation is required to meet demand, air emissions are reduced. A discussion of electric and natural gas price suppression is provided below.

b. *"enhancing environmental quality"*

An important measure of environmental quality with respect to this project is air emissions related to the production of electricity. The operation of the Block Island Wind Farm directly reduces the need for other generators in Rhode Island and in New England to operate to meet the electricity demands of Rhode Island ratepayers. ISO-NE periodically publishes information on the marginal emissions associated with production of the next megawatt-hour of energy. Based on the marginal emission rates for 2008 made available by ISO-NE in early December[1], each year the Block Island Wind Farm operates the region will avoid other power plants emitting approximately:

- 21,192 pounds of nitrogen oxides,
- 33,302 pounds of sulfur oxides, and
- 48,641 tons of carbon dioxide.

Over the twenty year term of the PPA, these amounts could total approximately:

- 418,546 pounds of nitrogen oxides,
- 657,715 pounds of sulfur oxides, and
- 960,662 tons of carbon dioxide.

These values are slightly less than the annual numbers times twenty based on an assumption of a lower plant capacity factor in years one and two due to typical power plant start-up and commissioning issues. The actual emissions avoided will depend on the particular units backed down or not needed when the Block Island Wind Farm wind turbines are in operation.

[1] ISO New England Environmental Advisory Group (EAG) Teleconference, Final Draft Slides 12-02-09, slide 69.

c. *"creating jobs in Rhode Island in the renewable energy sector"*

The Block Island Wind Farm could help create a unique opportunity for Rhode Island to take a leading role in training and providing the skilled labor that will be needed for the offshore wind industry in the northeast to implement the possible addition of thousands of MWs of offshore capacity. ISO-NE has approximately 4,500 MWs of potential offshore wind projects in its interconnection queue. A challenge for Deepwater Wind (and a cost burden specific to this project) is that the offshore wind industry in the United States is in its infancy. There are currently no commercial offshore wind projects in construction or in operation in the U.S. The key supporting shore and port facilities, specialized installation and maintenance vessels and seasoned offshore wind personnel do not exist – in the northeast or other parts of the country. And, as the Jones Act requires that vessels working in U.S. waters be U.S. flagged, it is unlikely projects will be able to lease the offshore wind-specific construction and maintenance vessels that have been developed and are in service in Europe.

In contrast, while Europe is still in the early stages of implementing offshore wind energy, it will have about 1,900 MWs of projects in operation by the end of 2009 according to the European Wind Energy Association ("EWEA"). In 2008, 366 MW of offshore wind capacity was installed in seven different wind farms in Europe, also per EWEA. These projects to date have directly caused the creation of infrastructure and jobs. As an example, according to a February 2006 report[2] from the National Renewable Energy Lab ("NREL"), the 160 MW Horns Rev project in Denmark that began operation in 2002 created over 1,700 man-years of local jobs during the construction period. However, this figure seems a bit high and appears to include multiplier effects and other indirect effects.

[2] Energy from Offshore Wind, NREL/CP-500-39450, February 2006

Another more specific source of information on jobs creation is a November 2008 New York State Energy Research and Development Authority ("NYSERDA") study[3] of the economic benefits associated with the construction and operation of New York renewable energy projects. In New York, NYSERDA enters directly into 10-year contracts with projects for RECs in a central procurement model to meet the State's Renewable Portfolio Standard ("RPS") obligations. The NYSERDA study is an in-depth review of the first 3 solicitations for RECs which have resulted in contracts for 1,022 MWs of onshore wind capacity. These wind projects are expected to result in 1,980 man-years of short term jobs (3 years or less) and 166 long term jobs, all in New York. These estimates are likely conservative as there are consequences to the successful bidders if their values are overstated.

The NYSERDA study also quantifies the overall direct economic benefits to New York State from these projects and disaggregates the impacts by technology. Here direct benefits include short term and long term payroll, payments to municipalities and landowners, equipment and services, and other operations and maintenance expenses procured in-State. For wind projects the direct benefits totaled $23.92/MWh. Applying this rate to the Block Island Wind Farm and assuming an annual average output of about 100,915 MWh, direct benefits to Rhode Island would total just over $2.4 million annually. That rate applied in 2013 without adjustment and then escalated at CPI and then multiplied by the expected annual production has a present value of $26.0 million in 2013$s. This assumes a 8.98% discount rate as described later in the testimony. Although not broken out by technology, indirect benefits due to multiplier effects for each of the three NYSERDA solicitations were determined in the study to be slightly higher than the direct benefits.

[3] NYSERDA Main Tier RPS Economic Benefits Report, KEMA Inc. and Economic Development Research Group, Inc, November 11, 2008

d. *"facilitating the financing of renewable energy generation within the jurisdictional boundaries of the state or adjacent state or federal water or providing direct economic benefit to the state"*

Structured long term power contracts with creditworthy counterparties are necessary, particularly in the current financial environment, for an independently developed and owned project to obtain financing. This PPA is such a contract and the Company's A- rating from Standard and Poor's Corporation is a strong credit. The price schedule in the proposed PPA is expected by Deepwater Wind to provide a revenue stream for the Block Island Wind Farm that just meets the minimum debt service coverage ratio targets necessary to secure financing Although about 18 miles from the mainland, the project will be constructed just within 3 miles of Block Island and thus in State waters and will be providing direct economic benefits to the State, as illustrated in the prior section.

III. IMPACTS OF THE LEGISLATION AND THE STATUS OF DEVELOPMENT OF OFFSHORE WIND IN THE U.S.

Q. What implications are there as a result of the 30 MW upper limit in Chapter 26.1-7 on the Block Island Wind Farm?

A. The Block Island Wind Farm is limited by legislation to be under 30 MWs and at an expected nameplate rating of 28.8 MW clearly complies with that directive. However, at 28.8 MWs, this project is small in scale relative to current offshore wind projects elsewhere in the world. Some insight on relative projects sizes can be gained from a new NYSERDA study on offshore wind development in the Great Lakes ("NYSERDA-AWS")[4] that includes a good summary of cost and project details on many of these non-US facilities. The study includes 25 projects outside of the U.S. either in operation, construction or financed. Utilizing a sub-group of 2008 through 2012 vintage projects studied in that report as indicative of current commitments and trends and present cost levels in that market, there are 14 recent offshore wind projects (13 in Europe and

[4] The data is from certain pages of a pre-release draft of upcoming study prepared by AWS Truewind LLC for New York State Energy Research and Development Authority, entitled "NY's Offshore Wind Energy Development Potential in the Great Lakes", dated December 2009, and is used with permission.

1 in China) that are in commercial operation, under construction or have secured financing. These 14 projects total 2,587 MW and range in size from 60 to 630 MW on a nameplate basis. This group has an average nameplate capacity of 185 MW – over 6 times that of the Block Island Wind Farm. On average, 58 wind turbines are being installed per project – while the Block Island Wind Farm will have up to 8. In comparison, the Block Island Wind Farm needs to be considered a small scale project. Scale turns out to be a key issue in determining whether the PPA is commercially reasonable, along with some other factors.

Q. How do the project size limitations that apply to the Block Island Wind Farm impact the project in terms of installed cost in dollars per MW and can comparisons be made to full-scale commercial projects using the same technology in an established market?

A. The size limitation certainly appears to be an important factor in the project's installed cost, which is projected by Deepwater Wind to be in the range of $6.96 million/MW. In contrast, the MW-weighted average reported installed cost for the recent 14 full-scale European (and one Chinese) projects in the NYSERDA-AWS study with an average size of 185 MW is $4.52 million/MW. The smallest project of that group at 60 MW has a reported installed cost of $5.8 million/MW. Another recent report on the cost of offshore wind prepared for the UK Department of Energy and Climate Change ("UK DECC")[5] cites a "megawatt-weighted average of project capital costs for projects at or near financial close in January 2009 of £3.2m per MW." This is about $5.21 million/MW at current exchange rates. There is no identification of specific projects or details. Some caution is advised when comparing the Block Island Wind Farm's costs to those in the NYSERDA-AWS or UK DECC studies. There are several underlying differences inherent in the costs of these non-U.S. projects that suggest that the Block Island Wind Farm should be a more costly project:

- The Block Island Wind Farm could be the very first offshore wind project in the U.S. In contrast, this technology has a strong foothold in Europe with approximately 1,900 MW

[5] Ernst&Young, "Cost of and financial support for offshore wind", April 27, 2009

expected to be in operation by the end of 2009, as mentioned above. Reductions in costs due to learning curve benefits are a function of installed MWs (costs are expected to decrease by "X"% each time the installed capacity doubles). Some studies suggest "X" is 10% to 20% learning curve values for many key offshore project cost elements are possible, but a key missing driver here is of course installed MWs.

- Only two of the European projects covered in the NYSERDA-AWS study are or will be in water as deep as the Block Island Wind Farm.

- The economies of scale apply to larger projects. As noted earlier, all of these projects are much larger than the Block Island Wind Farm (more than 6 times the size on average), so it is likely these projects were able to take advantage of economies of scale in engineering, fabrication, transportation, construction, interconnection, and project development, which do not exist for the smaller Block Island Wind Farm.

- All but the very first European projects in the study were likely able to take advantage of already existing offshore wind-specific infrastructure for equipment, transport and installation expertise, which do not exist yet in the Northeast or even the U.S.

While it is true that the Block Island Wind Farm will benefit from some of the economies of scale in the earlier projects and the industry in general (such as some turbine components), it is also expected that many other components will be project-specific, with fewer economies of scale to benefit this relatively small project.

However, further scale economies beyond where the European projects currently have progressed is somewhat in question. The NYSERDA-AWS study states that "it is not conclusive whether larger offshore wind projects will benefit from economies of scale with lower installed per MW costs. This is due to the limited number of projects built thus far and the fact that project characteristics (location, water depth, distance from shore, foundation type) significantly differ from site to site". However, at more than 6 times Block Island Wind Farm's size on average, there is a large gap in scale to get to the economics these projects already have.

Q. What are the primary cost components of an offshore wind project?

A. To address this, it may be useful to contrast an offshore wind project with an onshore wind project which has a very different cost structure. According to the NYSERDA-AWS study, the installed cost components can be compared as follows:

	Offshore	Onshore
Wind turbines	45%	64%
Installation	7%	3%
Interconnection	8%	11%
Collection System	13%	4%
Foundations	25%	16%
Other (Eng, Dev, PM)	2%	2%

Other studies from Europe show similar cost allocations. Note the differentials in the installation, collection system and foundation costs – and the relative reduction in turbine costs as a percent of the total. These cost elements point to the large capital and infrastructure cost inherent in offshore wind.

The installation of wind turbines at sea is very different than the much simpler methods used to install wind turbines on land. Offshore foundations—either monopiles, jackets or gravity-based foundations—are qualitatively more complicated than the simple rebar-reinforced, inverted "t" foundations made of poured concrete for land based wind turbine towers. The installation of offshore foundations, towers and wind turbine generators requires the use of purpose built ships with heavy lift capacity that largely do not yet exist in US markets. The submarine cable required to collect electric energy from an offshore wind farm is considerably more expensive than the onshore equivalent, and the installation costs for submarine cable are considerably greater as well.

Q. Why are economies of scale important with offshore wind?

A. In most industries, increased scale allows for capital investments, costs to develop specially trained labor and techniques, and overhead, development and permitting costs to be spread over a larger unit base, of course reducing per unit costs. As not all elements of cost are subject to scale reductions, the scale related economies tend to trail off at a certain point. Some data suggest that the larger offshore wind projects have reached that point, and from here cost reductions will mostly be the result of learning curve and efficiency improvements as more and more turbines are installed and operated. With respect to the Block Island Wind Farm, there are some specific elements of the cost structure that burden a small project that is the first to be built – essentially creating diseconomies of scale and resulting in a relatively high installed cost on a per unit capacity basis.

Q. What are some examples of how these economies of scale apply, or don't apply, to the Block Island Wind Farm?

A. With respect to the Block Island Wind Farm, there are some specific elements of the cost structure that burden a small project and that often carry a further impact as a result of being the first to be built – essentially creating these diseconomies of scale and increasing installed costs.

For example, there are numerous mobilization payments required in this kind of complicated offshore construction that are essentially fixed (i.e., not a function of project size or number of units installed). These include mobilization payments for the different vessels needed to install the tower foundations and pin piles; the wind turbine tower; the nacelle, hub and rotor blades; and the submarine cable. Different mobilization payments may also be required by the onshore electrical contractor. With a smaller project, these costs are less spread out, and accrue more heavily on a per unit basis.

As another example, some of the costs to transport the wind turbine components from Europe, or the foundation components from the Gulf of Mexico to the assembly location in Rhode Island, are considerably higher per unit when shipping a smaller quantity.

Furthermore, as discussed above, some of the vessels required to undertake this offshore construction project will need to be purpose built, with higher cost consequences for the initial project. And the small number of specialized tower foundations for the Block Island Wind Farm will essentially be custom built, as the quantity is insufficient to justify investment in a system of serial production.

Unlike the Block Island Wind Farm, the offshore wind projects under construction (or already in operation) in Europe benefit from larger scale, a better established supply chain and proximity to the source of the wind turbine components.

Q. Does the Block Island Wind Farm project also essentially represent a new type of project and/or technology for the region?

A. So far, yes. A distinguishing characteristic of this project is its location in relatively deep water, around 30 or more meters. This water depth is uncommon for offshore projects, even with respect to the existing fleet of European projects. Of the total group of 25 European projects reviewed in the NYSERDA-AWS study, only two projects have been developed at sites as deep or deeper than the Block Island Wind Farm. Although this project is located relatively close to Block Island in light of the Legislative intent to "enhance the electric reliability and environment quality of the Town of New Shoreham" as expressed in Chapter 26.1-7 and to minimize some of the controversies that have impacted other projects, sites for future U.S. development are likely to be well offshore from the mainland and in deep water.

Offshore deep water sites typically have stronger, more consistent winds that result in higher wind farm capacity factors and greater contributions to power system reliability. Sites farther from shore are also less likely to be impacted by view shed concerns and to encounter the associated possible delays.

The State's Office of Energy Resources in conducting the 2008 Rhode Island Energy Independence 1 Project solicitation identified that its preferred sites were well offshore, south and west of Block Island.

It could be inferred that the State selected Deepwater Wind as a preferred developer based in part on its proposal to develop deep water sites.

In addition, no offshore wind projects currently in development in the U.S. incorporate the deep water jacket technology intended to be used for the Block Island Wind Farm's foundations. Proven in the oil and gas industry, this technology could be important to a future build-out of the offshore wind in deep water.

Q. Is there any way to quantify how the water depth at a project site impacts installed costs?

A. As noted earlier, the depth of the water where the project is constructed is an important cost factor. Almost all of these European projects, and the one Chinese project, discussed above are sited in much shallower water than the 30-plus meter depths typical of Rhode Island Sound. Shallower water allows for the use of shorter, lighter and easier to install monopile foundations, saving on the cost of material, the cost to transport and the cost to install these smaller structures. Projects further from the mainland are also more expensive to install, with longer transits for construction and maintenance vessels and crews, and likely rougher and more challenging wave and weather conditions.

However, it is possible to scale or adjust the installed cost of these other projects and put them on a similar basis to Block Island Wind Farm relative to water depth. A recent report from the European Environmental Agency[6] (the "EEA Report") includes the results of a study on this factor and its historic impact on installed project cost. These scale factors are as follows:

[6] EEA Technical Report No 6/2009. "Europe's onshore and offshore wind energy potential"

Depth (m)	Factor
10-20	1.000
20-30	1.067
30-40	1.237
40-50	1.396

Using lineal interpolation, I have calculated the EEA Report scale factor that would be appropriate for the depth of each of the projects in the NYSERDA-AWS study. Shallow water projects are prevalent and accepted in Europe, and only two projects have a scale factor higher than the Block Island Wind Farm, though that may point to these factors not being fully vetted by many projects' worth of experience. A summary of the analysis is attached as Exhibit B.

By taking a ratio of the Block Island Wind Farm's scale factor to each other project's and multiplying by their installed cost in $/MW, we can derive an estimate of what these other projects would have cost if they were built at the same depth as the Block Island Wind Farm. For the 14 projects in the 2008 through 2012 timeframe we have been discussing, the MW-weighted installed costs would increase from $4.52 to $5.01 million/MW, an increase of 11%, after "normalizing" that data to account for the greater water depths of the Block Island Wind Farm.

Q. Are there any another current benchmarks for the installed cost of offshore wind projects at different scales?

A. A recent detailed study of the cost of several generation technologies was prepared for the California Energy Commission in August 2009 by KEMA[7]. Their future installed cost projections including an expectation of cost reductions due to learning rates for an offshore wind project in a Class 5 wind regime operational in 2013 are as follows:

[7] "Renewable Energy Cost of Generation Update", Prepared for California Energy Commission by KEMA, Inc. , August 2009 CEC-500-2009-084

350 MW	$5.43 million/MW
100 MW	$5.76
50 MW	**$6.95**

This projections for a 50 MW project is almost identical to the estimated installed cost of the Block Island Wind Farm and with the same underlying schedule.

So, to summarize, we can reasonably contrast Deepwater Wind's estimated installed cost of the Block Island Wind Farm of **$6.96 million/MW** with:

A. **$6.95 million/MW**, the KEMA estimated values for a 50 MW California project above;
B. **$5.21 million/MW**, the UK DECC value for European projects financed or about to be financed in early 2009;
C. **$4.52 million/MW**, the MW-weighted average of 14 recent full-scale European (and one Chinese) projects in the NYSERDA-AWS study with an average size of 185 MW; and
D. **$5.01 million/MW**, for the same 14 recent full-scale projects in the NYSERDA-AWS study, as "normalized" to put the other projects' costs on an estimated equivalent basis to the Block Island Wind Farm with respect to depth.

However, note that the values identified as B, C and D likely include lower costs due to economies of scale, some learning value to date, efficiency improvements, an established offshore-specific supply chain, and experienced personnel, as discussed, that are possibly very meaningful but cannot be readily quantified.

Q. **Based on this information and all of the reasons described that the Block Island Wind Farm's installed cost for a newly developed renewable resource could be higher than full-scale current projects outside of the U.S, do you consider that the project's installed costs are commercially reasonable?**

A. Yes.

IV. PPA PRICING AND PPA VALUE

Q. Have you reviewed the PPA and developed projections of the net price that would be paid by the Company?

A. Yes, I have reviewed an unexecuted copy of the final draft of the PPA. I understand that Deepwater Wind is filing an executed copy of the PPA with the Commission.

Q. How is the PPA pricing structured under the most recent version of the PPA?

A. I understand that the December 9th "final" draft I reviewed was essentially the execution version and that no further changes were expected with respect to pricing. Exhibit E of the PPA sets out a formula based price in dollars per megawatt-hour ("$/MWh") that is paid in a given month based on the amount of energy actually produced in that month. This is an important construct from the perspective of ratepayers because it leaves all operational and delivery risk with the Block Island Wind Farm. The Company only pays for what is delivered. If, for whatever reason, there is a problem with the generation of energy at the project, there would be no costs incurred by the Company or its ratepayers.

This price is called the Bundled Price in Exhibit E of the PPA and is set at $237.75/MWh, starting in 2012 and then escalates at 3.5% annually on the first of January. For 2013, which I have assumed as the project's first year of operation, the effective Bundled Price will be $244/MWh. In the event that Deepwater Wind elects to delay commercial operations under certain provisions of the PPA, this escalation stops for the duration of the delay.

Q. Do you consider that the Block Island Wind Farm has a credible project operation date?

A. Yes, I do. Rhode Island has exhibited thoughtful leadership in laying the ground work for this project and others to follow via the Wind Farm Siting Study, the SAMP process and focused Legislative direction. The issues and delays often associated with conflicting state and federal jurisdictional issues, differing interdepartmental objectives, and unclear legislative or executive branch support have largely been or will be addressed and should greatly reduce the uncertainty that those issues can contribute to the project development process. That said, project development is never easy and delays and challenges often arise in the execution of any project.

I have also reviewed a detailed project schedule provided by Deepwater Wind and the tasks and durations appear reasonable. In the end if the project is delayed, payments only start with the delivery of power, so as noted earlier, ratepayers are not at risk. Deepwater Wind has said it expects the project to operate at 75% of expected levels for the equivalent of one quarter in 2012 and expects 2013 and 2014 outputs to be reduced by 15% and 5%, respectively. I've discounted these assumptions somewhat and have modeled the project as starting at the very end of 2012 and expect for modeling purposes no meaningful energy deliveries in 2012. Based on my experience and the fact that this would be a first-in-fleet type of project, I have approached these values a bit more conservatively and assumed 25% and 10% output reductions in 2013 and 2014, respectively.

Q. **Are there any expected reductions to the Bundled Price in the PPA?**

A. There are two. The first reduction lowers the Bundled Price by the market value of capacity. Under this PPA, capacity is part of the agreement but any payment for the product to the Block Island Wind Farm and its value is actually settled financially. Under this structure the Block Island Wind Farm retains the capacity and participates in the ISO-NE Forward Capacity Market ("FCM"). Correspondingly, the Bundled Price is reduced by the market value of that capacity and what the project would have been able to receive if it offered its capacity into the FCM. This places on the project the risk of qualifying to participate in the FCM market and also the risk of being successful in the periodic FCM auctions. Here it is assumed that capacity price is the FCM clearing price, less any ISO-NE adjustments due to excess supply that clears in the FCM auctions. The PPA price reductions start getting calculated in the fourth contract year, which is when the project could first participate in the FCM auctions. So, functionally, as the FCM prices increase, the PPA price will decrease.

The second reduction is called the Outperformance Adjustment Credit which is effectively a 50% discount to the Bundled Price that applies to energy the project generated above an assumed 40% capacity factor, on a cumulative basis. Using an installed capacity of 28.8 MW, the project in a typical year would generate 100,925 MWh at a 40% capacity factor (28.8 MW x 8,760 hrs x .40). This becomes an annual target output and to the extent over the term of the contract the actual cumulative generation exceeds the amount of the cumulative target, a production surplus is calculated. Half of this surplus then becomes a credit at the then current Bundled Price in $/MWh, as adjusted for the FCM payments.

The site's offshore wind resource has been estimated, but when this project goes into operation, it can be accurately measured and demonstrated. Deepwater Wind 's estimates of production may prove to be conservative. The net effect of the PPA and this credit is that the project takes the risk of energy deliveries being less than the 40% projected, as payments are not made unless energy is delivered, and ratepayers share in the value of the project generating more electricity than expected via a 50% price credit.

There is also an allocation in the PPA of the Bundled Price between energy and RECs, with RECs priced at the Alternative Compliance Payment Rate in effect under the Renewable Energy Standard. This allocation has no impact on the overall rate actually paid.

Q. What assumptions are used in your calculation of the effective PPA price?

A. I assumed that the project begins commercial operation at the very end of 2012. For modeling purposes, any energy deliveries start in 2013. Later as sensitivity cases, one and two year delays are evaluated.

Next, the project's capacity value for FCM purposes was determined. Based on an estimated hourly production profile developed for the project by AWS TrueWind, the project's output in certain key hours of each summer and winter day is determined in accordance with ISO-NE rules. This output profile is for energy at the delivery point and is inclusive of electrical losses to the delivery point, any wake or array losses from the configuration of the turbines in the wind farm, and average forced and maintenance outages. While the expected overall annual capacity factor is 40% on an energy basis, for FCM purposes the project has a 36.1% capacity factor in the summer (June through September under ISO-NE rules) and a 50.0% winter value. On a seasonally weighted basis the capacity factor is 45.3% and multiplied by 28.8 MW, the project's FCM value is about 13 MW.

Then a forecast of FCM prices was developed. This was initially based on a detailed publicly available capacity price forecast in the Synapse Energy Economics, Inc. "Avoided Energy Supply Cost in New England: 2009 Report"[8] (the "AESC 2009"). However, since this report was issued there have been some important developments in the FCM market that led to some substantial changes to that model. First, the third Forward Capacity Auction ("FCA") has been concluded so there is one more year of auction results with actual data on delisted bids, surplus amounts and the clearing and prorated prices. Second, ISO-NE has issued the most recent Regional System Plan which includes an updated estimate of the Net Installed Capacity Requirement, or capacity need that the FCAs are conducted to meet. Third, the NEPOOL Participants Committee has voted in favor of a set of changes to the FCM market rules that would, among other things, continue an effective floor on the FCM price that can result from the FCAs. These changes, while still being refined in the NEPOOL Markets Committee, are the result of recommendations from the ISO's Internal Market Monitoring Unit following a review of the results of FCA 1 and FCA 2 and subsequent negotiations among the market participants. They are expected to be filed at FERC sometime in the first quarter 2010. Here it is assumed that FERC will accept the modifications and that they will be in effect for FCA 4 which will be conducted in August 2010 for the capacity needed for the one year period beginning June 1, 2013.

Essentially this forecast assumes that the new floor structure will set the FCM price in FCA 4, 5 and 6 and then end per the proposed new rule changes. During this 3 year period, the current level of excess capacity is assumed to remain in the market with some new additions of renewables needed to meet escalating regional Renewable Energy Portfolio Standards ("RPS")

[8] Synapse Energy Economics, Inc., "Avoided Energy Supply Cost in New England: 2009 Report", Revised October 23, 2009

and minor additions for demand resources, import and other new generation. In FCA 3, new demand additions exceeded demand resources leaving the market (via delisting) by about 50 MW. Any other additions above this level are assumed to result in an equal amount of market exit through delisting. Prices fall after the floor ends as capacity leaves the market and supply demand equilibrium is assumed to be reached in three years, at which point capacity prices start to build towards the cost of new entry. The FCM forecast utilized and the detailed assumptions are shown in Exhibit C.

To adjust the Block Island Wind Farm Bundled Price, the payments expected from FCM participation are calculated and then converted to a $/MWh value based on assumed project energy production in that year.

Finally, the reduction for the Outperformance Adjustment Credit is determined. At the base case assumed capacity factor of 40%, this credit is zero. The value of this credit at a 41% capacity factor is also calculated later in the sensitivity cases.

Q. **Can you summarize your assumptions about the project's energy deliveries?**

A. Yes. As discussed above, the key assumptions are a January 1, 2013 project start date, a 20 year term, a 28.8 MW nameplate rating, a 40% net capacity factor and assumed 25% and 10% output reductions in 2013 and 2014, respectively, due to typical project startup issues that will be resolved and addressed during this period.

Q. **Combining the expected PPA pricing and energy deliveries, what are the projected payments under the PPA?**

A. Because this project has a start date in the future, a 20 year term and price streams that vary over time, it is useful and appropriate to present value these future payment streams and consider them on a consistent basis. The PPA payments and the associated market value of the all the products provided under the PPA at the delivery point have been present valued to

January 1, 2013. The levelized price of the PPA and associated market value of all the products delivered has also been calculated.

The discount rate used in these calculations was assumed at the Company's proposed overall cost of capital of 8.98% as shown on page 1 of Schedule NG-PRM-9 in Commission Docket 4065. While the Commission has not issued a decision in this Docket to date, this estimate of the Company's cost of capital reasonably reflects market conditions and expectations. Some rating agencies have inferred an impact on the PPA purchaser's borrowing capacity from contracts like these. However, the incentive to the Company included in the legislation of 2.75% of the actual annual PPA payments is assumed to offset any potential impairment or impact on the Company's cost of capital associated with this PPA.

Under the base case assumptions we have developed, the present value cost of the PPA is $274.3 million, with a levelized price of $306/MWh, both as of January 1, 2013.

V. PPA Value Determination

Q. What products are delivered under the PPA?

A. The products provided under the PPA and evaluated at the delivery point are energy and RECs. While capacity is part of the contract, the product is actually retained by the project and the capacity is valued via financial settlement and as a direct reduction of the Bundled Price as described above.

Q. What is your projection of the value of the energy being provided under the PPA at the delivery point, before the consideration of REC values and the possible impacts of carbon policy energy prices?

A. The value of the energy delivered has been derived based on the following methodology and steps:

- Based on the very high correlation between natural gas and electricity prices in New England, the energy price forecast is built up from a forecast of annual average natural gas prices in dollars per MMBtu and then multiplied by the market's marginal heat rate in MMBtu/MWh.
- Two gas price forecasts were used. NYMEX Henry Hub futures prices anchor the near term forecast starting in 2013 and the projection blends into the Energy Information Administration's ("EAI") longer term Annual Energy Outlook ("AEO") projection for Henry Hub by 2019. The EIA forecast is increased slightly to account for the typical premium that NYMEX trades at relative to the corresponding AEO. The most recent annual analysis[9] from Lawrence Berkeley Lab of this effect, essentially the value of being able to lock-in prices via a futures contract, is $0.16/MMBtu.
- Then the natural gas basis from Henry Hub to New England is added. Here a recent study of basis from the AESC 2009 Report was utilized. Average monthly basis differentials were calculated from Henry Hub to Tennessee Zone 6 and the Algonquin City Gate and expressed as a multiplier. The average is 1.15, very close to the same value in 2007.
- The resultant annual New England gas price is multiplied by the New England marginal heat rate of 8,095 Btu/kWh from the ISO-NE 2007 NE Marginal Emissions Rate Analysis Report issued in July 2009. As a check, these prices were then compared to the NYMEX electricity price for the ISO-NE Internal Hub Swap Futures.
- Next, the $/MWh price in each year is multiplied by a factor that represents the Block Island Wind Farm's expected equivalent production factor in each year. To develop this, the expected hourly generation from the project as estimated by AWS TrueWind was multiplied by the corresponding day ahead and real time locational marginal prices ("LMPs") from ISO-NE in the Rhode Island Load Zone for each hour of 2006, 2007, 2008 and through October 2009. The product is then divided by the total annual energy delivered each respective year to get a production weighted annual average price. This is then divided by the respective all hours annual average day ahead and real time LMPs to get a factor. The average of these factors is 1.022. This indicates that the project's production weighted value of the energy is projected to

[9] LBNL Memorandum, Bolinger and Wiser, "Comparison of AEO 2009 Natural Gas Price Forecast to NYMEX Futures Prices", February 4, 2009

be worth more than the annual average market price by a factor of 1.022. This is multiplied by the energy price in the model. The concept that the project could be valuable during peak periods is supported by a recent ISO-NE study (as part of its ongoing Wind Integration Study) showing a very high coincidence expected between offshore wind generation and load during the 20 highest peak historical hours on the ISO-NE system a three year period from 2004 through 2006. While not specific to Rhode Island, the offshore Massachusetts data is illustrative and would be expected to have a similar profile. See Exhibit D.

- And finally, the price is adjusted to account for the difference in value of the energy to the Rhode Island Zone. This is calculated based on the annual average difference between the hourly day ahead and real time LMPs for the ISO-NE control area and the Rhode Island Load Zone. That average from 2006 through October 2009 is 2.0%.
- Next, a value of carbon to be included in the market price is determined.

VI. GREENHOUSE GAS REGULATION - PPA VALUE IMPACT

Q. What is the role of greenhouse gas regulation on the market value of products purchased by National Grid under the proposed Deepwater PPA?

A. The Regional Greenhouse Gas Initiative ("RGGI") currently in effect throughout the northeast is a 'cap and trade' regulation requiring emitters of carbon dioxide ("CO_2") and other greenhouse gases to purchase allowances to emit greenhouse gases, under an industry-wide carbon cap. Federal greenhouse gas cap regulations passed by the U.S. House of Representatives and being considered by the U.S. Senate at this time would impose tighter carbon limitations, expected to result in higher CO_2 allowance prices. Because fossil fueled generators in the ISO New England market constitute the marginal generators, and must purchase emission allowances to operate under a cap and trade, the cost of CO_2 allowances represents an increase in marginal costs, to be reflected as increased bids in the ISO day-ahead and real-time markets. The net effect is the translation of prevailing CO_2 allowance prices into higher locational marginal energy prices (LMPs) than would have otherwise prevailed in the absence of a greenhouse gas cap and trade regime.

Q. What are your assumptions regarding CO_2 allowance prices?

A. At this juncture, there is considerable uncertainty as to the future CO_2 allowance prices that will prevail in the region. While RGGI is the current law of the land, it is reasonable to assume, given the priority placed on addressing global climate change concerns by both the administration and Congress, that a more aggressive Federal greenhouse gas cap and trade will be adopted. What is more uncertain is the timing and stringency of any cap. I have examined the projections from several sources of projected CO_2 allowance prices, including a 'study of studies' conducted by Synapse Energy Economics in July 2008[10], the AESC 2009, and the Energy Information Administration's August 4, 2009 Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009.[11] I have also examined recent prices for RGGI futures on the Chicago Climate Futures Exchange. Based on this examination, I believe the AESC 2009 Reference Allowance Case, the Synapse 2009 High CO_2 Allowance Case, and the EIA 'Basic Case' Forecast of Markey Waxman Climate Bill all represent reasonable futures. I have developed and included projections of the LMP price impact of each of these cases, along with the AESC 2009 RGGI Only Case for comparison purposes. These alternative futures are depicted below in Figure 1.

[10] Schlissel, D., et al, Synapse 2008 CO2 Price Forecasts, Synapse Energy Economics, Inc., July 2008.
[11] See http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

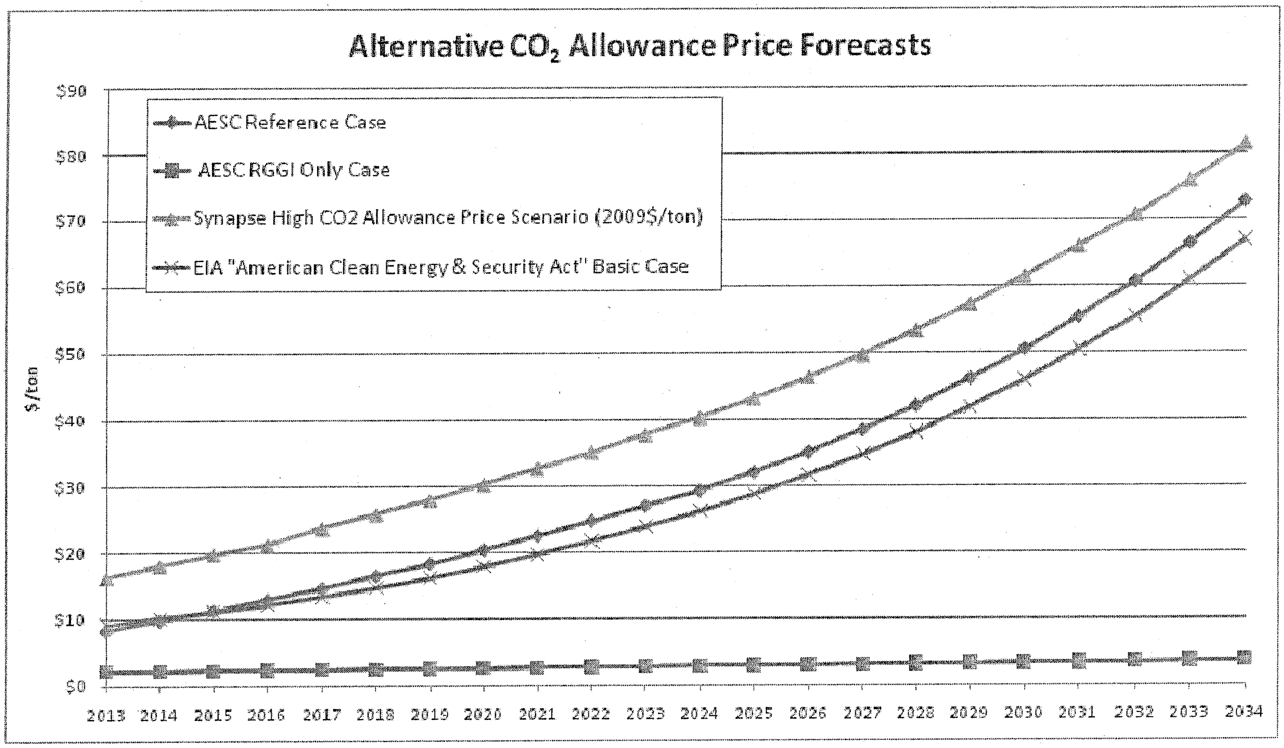

Figure 1

Q. How do these allowance price assumptions translate into LMP prices?

A. A $/MWh adder to the electric energy price forecasts derived via a natural gas trend methodology as described was created by translating the nominal dollars per ton ($/ton) CO_2 price forecast using the ISO New England 2008 average all-hours marginal CO_2 emission rate of 964 lbs/MWh.[12] This methodology, using the AESC 2009 RGGI Only Case, was benchmarked against the NYMEX electricity futures market, which would be expected to reflect RGGI allowance requirements. The results aligned quite well. My assumptions are summarized in Exhibit E.

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[12] ISO New England's most recent marginal emissions analysis (footnote: ISO New England Environmental Advisory Group (EAG) Teleconference, Final Draft Slides 12-02-09, slide 69.

Q. For just Rhode Island, the AESC 2009 Report avoided electricity supply costs assumed carbon regulation according to only RGGI for the entire study period. Avoided costs for all other states were based on the Reference Allowance Case. Why is it appropriate to consider a Federal CO_2 cap and trade for the purposes of this testimony?

A. As noted earlier, the U.S. House of Representatives has passed a greenhouse gas cap and trade bill and the Senate is considering alternatives. Reflecting the administration's priorities, the U.S. Environmental Protection Agency (EPA) has taken steps - starting with proposed new thresholds for greenhouse gas emissions at large industrial facilities - to assure that greenhouse gases can be regulated in the event that a cap and trade bill is not adopted. Recent press reports indicate that EPA plans to officially declare, as soon as this week, that CO_2 is a public danger, a trigger that could mean regulation for emitters across the economy. According to a Wall Street Journal article, EPA Administrator Lisa Jackson has said it could also mean large emitters such as power stations would have to curb their greenhouse gas output.[13] In this context, any assessment of a commercially reasonable commitment to new electricity generation resources must consider the likelihood, if not the inevitability, of greenhouse gas regulation at the Federal level.

Furthermore, the Legislative Findings in §39-26-1, of R.I. Gen. Laws § 39-26 (the Renewable Energy Standard), within which the enabling statute governing the Block Island Offshore Wind contract has been codified as law (R.I. Gen. Laws § 39-26.1 et seq, Ch. 26.1 (LONG-TERM CONTRACTING STANDARD FOR ENEWABLE ENERGY), specifies that "(c) Increased use of renewable energy can reduce air pollutants, including carbon dioxide emissions, that adversely affect public health and contribute to global warming".

Q. What is the interaction of REC and CO_2 allowance prices?

A. The Long-term REC cost of entry is driven by the revenue needs of the marginal eligible renewable energy resource: any shortfall in revenues available through other markets must be made up with by REC revenues, or the marginal, or next lowest cost, resource available required

[13] EPA Poised to Declare CO2 a Public Danger, Wall Street Journal, December 5, 2009.

to meet demand will be unlikely to attract capital and be developed. As stated in AESC 2009 (at p. 6-42), the "levelized REC premium for market entry by subtracting the nominal levelized value of production consistent with the AESC 2009 projection of wholesale electric energy prices from the nominal levelized cost of marginal resources". As indicated earlier, CO_2 allowance prices will increase energy prices (LMPs). If CO_2 allowance prices are high, all else equal, REC prices will be lower because the revenue gap between cost and commodity electric market revenues will be lower. Likewise, holding all else constant, if CO_2 allowance prices are low, REC prices would be expected to be higher. I would expect that in or near equilibrium, REC and CO_2 allowance prices would tend to move in opposite directions, at or near a one-to-one basis. As I will describe more fully below, this relationship would be unlikely to hold in short-term markets in which supply is inadequate – prices in a shortage will still rise to near the ACP - and to be dampened when there is a supply surplus. (The same can be said for the relationship between natural gas & electricity prices, and RECs)

It is important for the purposes of this testimony to observe that, all else equal and with today's recession-suppressed energy prices, it would be unlikely for the absence of a Federal greenhouse gas cap and trade and lower REC prices to coexist, because RGGI CO_2 allowance prices alone tend to leave a large revenue gap for most newly developed renewable energy resources. Conversely, an aggressive Federal greenhouse gas cap and trade would be likely to reduce REC prices from the level that might otherwise prevail.

VII. RENEWABLE ENERGY CREDITS AND IMPACTS ON PPA VALUE

Q. What is the role of Renewable Energy Credits in the value of the Block Island Wind Farm PPA?

A. Renewable Energy Credits ("REC"), or to be more specific, NEPOOL Generation Information System ("GIS") Certificates, are credits tradable together with or separately from the associated energy, according to the NEPOOL GIS operating rules. One REC is created for each megawatt hour (MWh) generated. RECs associated with eligible generation are required by obligated entities – the retail load-serving entities - for compliance with the PUC's Renewable Energy Standard rules. As such they have a market value. The Block Island Wind Farm RECs will be eligible for Rhode Island's New Renewables requirement, as well as the "Class I" requirements in Massachusetts, Connecticut, New Hampshire and Maine.

Q. What information is available regarding the market value of Renewable Energy Credits?

A. The REC market can be thought of as a spot market, associated with trading within each calendar quarter's GIS trading period, and a longer-term market in which RECs may be transacted over one to several years. Due to a range of factors including regulatory uncertainty, credit requirements, risk profiles, customer migration risk, and lack of regulatory incentives, there are very few long-term transactions exceeding a few years.

Rhode Island's REC market is a small and illiquid market: the REC volumes are small, and there are few buyers, shopping sporadically (for instance, via the Company's periodic REC requests for proposals). REC price visibility is limited. There is no central exchange; rather, RECs are typically traded via the bilateral, "over the counter" market directly or through REC brokers. The primary avenue of price discovery is via broker quotes made available to market participants, either on a subscription basis (for a fee), or provided to registering entities for their own use only. These REC broker quotes can provide some visibility to the spot market's short-term valuation, as well as expectations for the next few years. Frequently, brokers list 'bid' and 'ask' prices without recent trade prices due to the lack of market liquidity; in such cases, an average between the bid and ask prices over a period of time is the best indication of market prices, as weeks or months can sometimes pass between a broker's settled transaction. Beyond two to three years from the current compliance year, there are very few if any transactions, with negligible liquidity and visibility.

Because of the small size and illiquidity of the Rhode Island REC market, few brokers offer Rhode Island REC price quotes. Due to similar eligibility, Rhode Island Class I REC market spot prices have historically closely tracked the larger market in Massachusetts, and to a lesser extent the New Hampshire and Maine Class I markets. The Rhode Island New REC market price correlation with Connecticut Class I REC prices has been weaker, due to differing eligibility, the lack of a "new" commercial operation date threshold, and the lack of banking to keep prices from falling (although, Connecticut is on the verge of adopting REC banking regulations similar to those in Rhode Island and elsewhere).

The Massachusetts RPS eligibility and rules are very similar to those for the Rhode Island RES, and as such, Massachusetts REC prices represent a good and more available proxy for Rhode Island New RECs. The Massachusetts Class I market is larger, with somewhat more liquidity and price visibility; as a result, there are more brokers trading in the Massachusetts Class I REC product, and a futures market has been at the Chicago Climate Futures Exchange. The CCFE currently trades Massachusetts Class I RECs through 2015.

For the longer-term REC market, transactions are few, tend to be non-standardized, and transaction price discovery beyond a few years is negligible. In addition, when they happen, longer-term REC transactions may often convey electricity commodities bundled with RECs when they do occur, making explicit REC values dependent on one's view of the commodity market value. There are few available perspectives on longer-term REC price trends beyond consideration of market fundamentals, such as may be offered via proprietary forecasts available through industry consultants. The AESC 2009 involved a projection of REC prices based on a fundamentals analysis of supply, demand and cost for a single set of input assumptions, through 2024 (while the report shows prices beyond 2024, the post 2024 prices have no analytical basis, but are extrapolations).

Q. **Please explain your assumptions regarding the value of Renewable Energy Credits.**

A. While Rhode Island's Renewable Energy Standard is still relatively new, we now have several years of experience to observe the behavior of REC prices in the ISO New England marketplace, and confirm that the market appears to behave as one would expect, like electricity, capacity or other markets in the broader economy subject to similar rules, dynamics and constraints. For example, empirical evidence has shown that in time of shortage, spot REC prices shoot up to a level just under the applicable price cap (in Rhode Island and several other states, this is the level of the 'alternative compliance payment', or ACP). In shortage, prices have tended to fall below the ACP by an amount reflective of transaction costs: Since obligated entities may comply by paying the ACP, in order for generators to sell their RECs, they must, even in shortage, reduce their price by enough to entice obligated entities to negotiate and enter a contract, a more costly exercise than simply writing a check.

Similarly, we are now experiencing the third year in a row of RPS regional surplus, indicated by softening prices and the use of REC banking, where allowed, on a growing basis. Prices during this period of surplus have been between the mid-$30s/MWh and the high $20/MWh, with the most recent RI New broker quotes suggesting a price of approximately $28.75/MWh. Without the ability to bank, a material REC surplus will tend to drive spot REC prices towards zero, likely hitting a floor in the range of $1-3/MWh which has been seen in other REC markets with substantial surplus. With banking, however, the value of RECs is determined, in principle, by the future value attributable to purchasing RECs today as insurance against paying higher prices in the future. Prices expected would represent effectively a discount to the shortage price to the extent that the market perceives an impending shortage, or otherwise, the cost of entry. The discount would represent the time value of money, and some expected savings compared to the expected future REC cost.

Market imperfections can lead to under-utilization of banking, allowing REC prices to fall below prices an experienced power market analyst would expect to see. Anecdotal evidence suggests that the current market structure contains disincentives for obligated entities to bank the full degree of surplus, artificially suppressing REC prices below what market fundamentals would suggest, and below what would be suggested by consumer/ratepayer discount rates. A consideration of the incentives and costs associated with REC banking shed light on this effect. Banking comes at a cost to competitive retail electricity suppliers, tying up their scarce capital. Combined with the exposure to customer migration risk, it appears that there are few competitive buyers and limited appetite for banking among those who do bank. Similarly, RPS/RES compliance reports show that regulated entities throughout the region are banking at a lower rate than their competitive counterparts, not banking RECs in any significant amounts.

This behavior is consistent with the lack of commercial incentive or regulatory impetus or imperatives to take risk in order to minimize ratepayer REC cost. Finally, Connecticut has not had REC banking, but new banking regulations are about to go into effect within the next month.

In addition, it appears, based on the spot market price trajectory over time of Massachusetts REC prices in the 2008 compliance period, that banking may often be put off until the very end of the year, causing a mid-year drop (when sellers are willing to sell but buyers hold out) with a bounce-back late in the year, as buyers re-enter the market. This suggests that spot prices currently observed in the market are likely to again be surpassed by the quarter four 2009 trading period.

Long-term REC price trends will be influenced by the cost of entry - the revenue shortfall after considering commodity electricity revenue (which I'll call the REC premium) for the marginal, or next least expensive, eligible renewable energy resource required to fulfill demand. The marginal resource is dictated by the cost and quantity of eligible resources available to the region. Eligible resources can be considered in a 'supply curve', a depiction of the REC revenue requirements and cumulative quantities of various available eligible resources, sorted from low to high REC premium.[14] This analysis, while exploring the renewable energy development implications of policies above and beyond regional RPS requirements currently in effect, uses an approach similar to that used for Renewable Portfolio Standard cost analyses in Massachusetts, New York and elsewhere. The implied REC cost of entry can be found at the intersection of demand (which is fixed as a percentage of load, represented by a vertical line) and the incremental supply curve made up of remaining undeveloped resources available to be developed during the year in question.

Over time, the market is likely to vacillate between periods of surplus and shortage, centered around a long-term trend influenced by the cost of entry, with short-term REC prices likely to

[14] An example of a New England REC supply curve can be found in an October 30, 2007 presentation of the results of a New England REC supply curve analysis, the only recent public analysis of this type that I am aware of. See: http://www.maine.gov/doc/mfs/windpower/meeting_summaries/103007_summary_files/Grace_Wind_Task_Force_103007.pdf

fluctuate between a high capped by ACP, during times of shortage, and low-end consistent with a temporary surplus and banking environment.

Q. What prices should be expected in shortage?

A. As described above, during a shortage I would expect prices to fall just below the applicable ACP rate by an amount indicative of buyer transaction costs. Rhode Island's ACP is $60.92 per MWh in 2009, which escalates with the Consumer Price Index over time. Observed REC market prices of approximately $54.50/MWh when the ACP was $57.12 during the last period of perceived shortage (early 2007, just before spot REC prices fell) suggest an approximate value indicative of transaction costs of $2.63/MWh. A projection of REC prices expected in shortage conditions is shown in Exhibit F, using the CPI projection from EIA's 2009 post-stimulus Annual Energy Outlook as an escalator. This trajectory represents a high case for REC prices.

Q. What prices should be expected in surplus?

A. For the reasons discussed above, the lower end of what we've seen recently, absent major shifts in incentives or energy prices, represents the best empirical evidence for the conditions of a several-year surplus and as such represent a reasonable low case, due to the under-utilization of banking. So long as such surplus-induced prices fall below the marginal cost of entry, prices are unlikely to go much lower, as investment will slow until costs rise to the cost-of-entry with rising demand. A projection of REC prices expected in periods of surplus, representing a low case for REC prices, is shown in Exhibit F. These values are escalated at the same CPI rate as the High REC case.

Q. What are your expectations for the REC cost of entry, or long-term REC price trend?

A. There are many factors that I would expect to influence the long-term REC price trend. Some of these factors work in opposing directions. For instance, technological improvement would be expected to reduce the cost of less mature technologies over time, such as solar and offshore wind, relative to more mature generation types such as biomass combustion and conventional hydro.

On the other hand, renewable resources are by their nature resource limited. There are locations with the best characteristics, and those with less desirable characteristics. For instance, with onshore wind power, the best sites are large, windy, and located close to transmission. But the number of the developable best sites (typically mountain tops and shorelines) is limited, and as these are exploited, developers must make do with sites with poorer economies of scale, high transmission costs and/or weaker winds. Similar limitations apply to most other resources. Where possible (and there are many factors – such as permitting constraints - which cause building out of this economic order), the marketplace will build the least expensive first. The transition from best resources to those with diminishing returns in a supply curve means that supply curves have an ascending slope... the more resource demanded, the higher the cost.

The aforementioned study performed for the Maine Wind Energy Task Force[15] at the end of 2007 sheds light on the shape, content and depth of the New England REC supply curve. The study contains REC supply curves. These are illustrative, for the purposes of this testimony, in that the cost per MWh is not shown (the study's purpose was to focus on what resources would be built where based on available supply and relative cost). The blend and relative cost shown sheds light on what would be built and where, as well as sensitivity to variables such as Federal Incentives. The study was performed at a time of higher LMPs, suggesting lower REC prices than currently anticipated. The supply curve indicates that onshore and offshore wind represent the largest resource categories available, with very limited incremental hydro and negligible incremental landfill gas. Most commercial-scale onshore wind resources are expected to be tapped out at some level of demand, and the study shows incremental biomass and offshore wind to be the next most voluminous resources in the supply curve, whose prices become competitive with each other in the 2015-2020 timeframe.

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15 http://www.maine.gov/doc/mfs/windpower/meeting_summaries/103007_summary_files/Grace_Wind_Task_Force_103007.pdf (see slides 35 and 36)

The study highlights one of the key uncertainties influencing the REC cost of entry, that is, how much of the land-based wind technical potential can ultimately be developed? While the developable quantity is certainly less than the potential, increasing pressures and resistance by abutters to land-based wind projects may lead to practical limits more or less stringent than assumed for purposes of that study.

Another factor influencing the anticipated supply curve for REC cost of entry is the role of biomass. A letter[16] issued by the Massachusetts Department of Energy Resources ("DOER") on December 3, 2009 announced DOER's suspension of considerations of pending or new Statements of Qualification for biomass plants until after development of an independent report to examine the sustainability and carbon-neutrality of biomass, and a subsequent rulemaking to implement changes to RPS eligibility.

The market's reaction to this announcement by the largest available market for biomass plants (Connecticut is largely committing to in-state biomass through its Project 150 contracts) is that investment in biomass development throughout the region is likely to stall, pending resolution of this substantial regulatory uncertainty. Projects will be delayed, missing opportunities to secure long-term contracts under the pending Massachusetts long-term renewable energy contracting pilot program (DPU Docket 08-88 and 09-77) and potentially causing projects to miss out on the window for a variety of expiring Federal incentives (PTC, ITC, loan guarantees, etc.). It is reasonable to expect that this DOER policy statement, along with any narrowing of eligibility to come out of the anticipated rulemaking, will severely curtail the future role of biomass-to-electricity.

Prior to the potential for severe biomass restrictions, the supply curve shows marginal resources tend to be moderate size/wind onshore wind in the near-term (the best wind sites tending to be submarginal or fully exploited early), and as these are used up, more marginal onshore wind, biomass repowering, poorer onshore wind resources, Greenfield biomass and ultimately, offshore wind. The Maine study (slide 43) shows 242 MW and 1820 GWh per year of new

[16] (see http://www.mass.gov/Eoeea/docs/doer/rps/Mass%20Biomass%20Energy%20Stakeholders.pdf)

biomass by 2020 to meet the study's demands; the AESC 2009 report (see AESC 2009 Exhibit 6-29) shows 4654 GWh/yr of new biomass contributions to meeting the regional RPS demand (equivalent to about 590 MW of biomass supply). I would expect these recent biomass restrictions to have the potential to remove much of the biomass from the supply curve, hastening the likelihood and date by which, if RES/RPS demand is to be met with in-region resources (as opposed to accessing distant resources from the Midwest or eastern Canada via new transmission investment), substantial offshore wind will be required.

Prior to the DOER announcement, I accessed the Massachusetts Class I REC futures prices on the Chicago Climate Futures Exchange ("CCFE"). As noted earlier, this price is a good proxy for Rhode Island new renewables REC price. The CCFE futures trajectory, available through 2015, represents one of the few publically available indicators of market trend expectations, and in the absence of a current publically available REC market price analysis, is a reasonable proxy for the cost of entry absent major shifts in factors that would alter REC prices (discussed further below). Exhibit F shows the CCFE REC Futures price as of 12/2/09, escalated at CPI. While at the time of this testimony I would expect this to be a reasonable proxy for the cost of entry, I would expect upward pressure on these prices as the market internalizes the implications of the new biomass restrictions, and that the removal or delay of such a large quantity of resources from the supply curve may tend to (a) counteract to an unknown degree the downward cost pressure from technological advance, and (b) increase the likelihood of shortage.

Q. What factors can influence REC prices, and how?

A. The following table summarizes a range of factors that can influence REC prices, and their directionality.

Varying....	Implications
• Energy, carbon or FCM price down • Project or finance costs higher, inflation higher • Less imports into ISO NE • Project delays • High demand • Transmission expansion not completed or delayed • Regional offshore wind project commercial operation delayed • **Biomass-to-electricity restrictions and delays** • **Restrictions/limitations on developing wind power on windy land**	REC Price up
• Energy, carbon or FCM price up • More imports into ISO NE • Project or finance costs lower, inflation lower • Disincentives to bank (lower in short-term, but suppress supply investment in longer term) • Low demand • Transmission expansion accelerated, or new transmission ties built to neighboring control areas • Regional offshore wind commercialization accelerated • Production Tax Credits, Investment Tax Credits, Federal Stimulus Grants and/or Loan Guarantees extended beyond current expirations	REC Price down

Q. In your opinion, what is the probability that REC prices will be at each of the trajectories identified in Exhibit F?

A. In the absence of physical limits on available resources, I would expect volatility, but a tendency towards reversion to the marginal cost of entry, like other markets. This is particularly true in a market where demand is escalating annually by a substantial percentage, where the market is unlikely to get overbuilt and then stagnate. If prices stayed lower than the cost of entry for a substantial period of time, then investment will be delayed/curtailed until surpluses abate; if REC prices stayed higher, this would attract investment until shortage is suppressed, so long as sufficient resources were available and developable in a timely manner to keep up with escalating demand.

As an alternative scenario, I have created a set of probabilities to apply to each of the three REC price trajectories described above, shown in Exhibit F. Given the current surplus, I have started with a probability weighting of 45% for the Low trajectory and 45% for the Current Futures trajectory, with the remaining 10% for the High Trajectory. Over time, I have migrated these probability weights by 2018 to 25% Low, 25% for Current Futures trajectory, and 50% for High. While these weightings are necessarily subjective, there are many possible futures and many arguments that could be made for a different probability weighting by an experienced analyst, I believe these are consistent with the prior discussion including on-shore wind siting limitations, biomass restrictions, and the ultimate characteristics of the supply curve. While additional imports from outside of New England over newly constructed ties could allow access to additional supply which may broaden the supply curve and yield somewhat lower REC prices, such a future is not consistent with the intent and purposes of statute governing the Block Island Wind Farm PPA. I have included a Probability-Weighted trajectory, bases on these probabilities, shown in Exhibit F.

Q. If a Federal CO_2 Cap and Trade regime was passed into law, how would that impact REC prices?

A. I would expect only the non-shortage trajectories; a market short on supply would still gravitate towards the High Trajectory. For non-shortage trajectories, there are many possible futures. In the event of an aggressive Federal CO_2 Cap and Trade regime, I believe it is unlikely that the current tax-based incentives (Production Tax Credit (PTC), Investment Tax Credit in lieu of PTC, etc.) would continue indefinitely, especially once the value of carbon allowances outstripped the value of the PTC. One credible case would be a 10-year phase-out of the PTC after 2013 (AESC used a 5-year phase-out, which would result in higher REC prices than indicated here), in concert with a cap and trade regime consistent with the AESC 2009 Reference Case CO_2 allowance price forecast. I have modeled the projected impact of these shifting incentives, by subtracting the difference between the full PTC and the LMP impact of the AESC 2009 Reference Case CO_2 allowance price, from the REDC price (recalling, that reducing the gap between cost and market electricity revenue would yield lower REC prices), as shown in Exhibit F. The resultant Low, High, Current Futures, and Probability-weighted Trajectories are reproduced under these assumptions, in Exhibit F.

Q. Are the REC prices developed for the AESC 2009 study appropriate for this purpose?

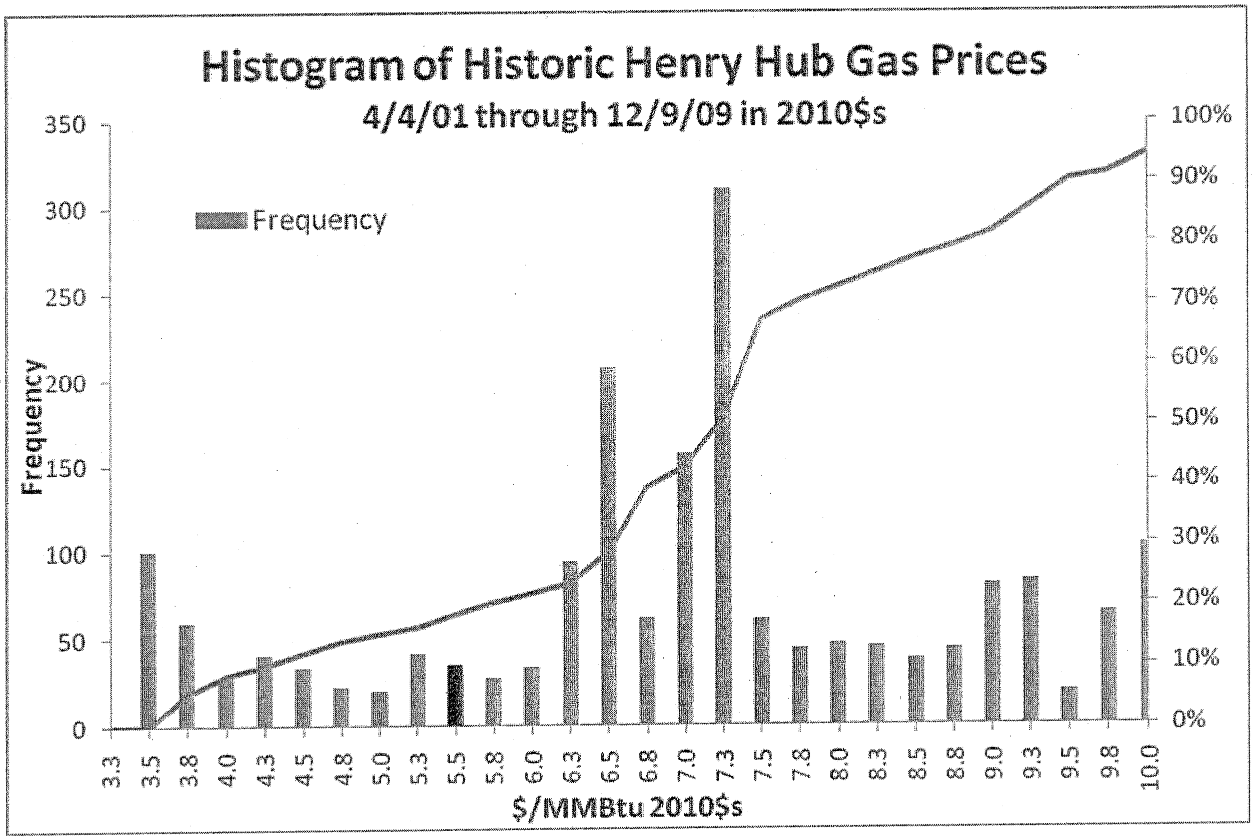
A. No. While the analytical methodology is sound, and consistent with my description of REC markets, the analysis depends on the underlying assumptions, and was created under a different set of assumptions. More importantly, conditions have changed. The underlying natural gas price trajectory differs. At the time of the AESC analysis, the project finance market was essentially broken, with no financing taking place. Now, the impact of the recession is clearer, with financing more expensive and restrictive, and the availability of Federal stimulus incentives more difficult to qualify for. Federal carbon legislation has not moved as quickly as envisioned at the time. Purchases power agreements have become scarcer, delaying financing of projects otherwise ready to move forward until such PPAs can be secured. Wind projects are increasingly being delayed through appeal, and, as discussed above, development of most biomass plants is grinding to a halt, at least for now. The FCM market has undergone a major change (as described herein). If the same analysis were conducted today, eight months later than the underlying REC analysis in the AESC report, I believe it would yield higher REC prices as a result of changes merited in underlying assumptions.

VIII. PPA VALUE UNDER DIFFERENT SCENARIOS

Q. What different scenarios were evaluated and what were the key outcomes?

A. The different scenarios and the key outcomes are set forth in the table below. In addition, see Exhibit G, which shows the base case.

Assumptions				Market Value		Above-Market Value	
Case	Natural Gas	Carbon	REC	Levelized Price as of 1/1/2013 ($/MWh)	NPV (2013$, 000)	Levelized Price as of 1/1/2013 ($/MWh)	NPV (2013$, 000)
Base	Base	AESC Reference	Prob-Wtd +PTC Phase-Out+Reference Carbon	$166	$149,893	$139	$124,423
High Gas	High	AESC Reference	Prob-Wtd +PTC Phase-Out+Reference Carbon	$195	$175,572	$111	$98,744
Low Gas	Low	AESC Reference	Prob-Wtd +PTC Phase-Out+Reference Carbon	$158	$142,556	$148	$131,760
High Gas+Carbon	High	AESC High CO2 Allowance Case	Prob-Wtd +PTC Phase-Out+Reference Carbon	$176	$157,943	$130	$116,374
High Gas+Carbon+REC	High	AESC High CO2 Allowance Case	High Case - Shortage (ACP less transaction costs)	$197	$176,939	$109	$97,377
High REC (Shortage)	Base	AESC Reference	High Case - Shortage (ACP less transaction costs)	$188	$168,889	$118	$105,427



Q. What if the project were delayed? What is the impact on the present value cost of the project to the Company?

A. Under the PPA, in the event of a delay, the fixed escalation of the Bundled Price is stopped for the duration of the delay, which is modeled. Also, there is no price reduction for the value to capacity in the first three years of the contract, so the start of those reductions is also pushed back. On that basis, the impacts of delays are as follows:

	PV Above Market Cost (2013$)
Base case	$124.4 million
One year delay	$106.7 million
Two year delay	$90.7 million

IX. TERMS AND CONDITIONS

Q. Are the terms and conditions of this PPA reasonable?

A. Yes. From a commercial perspective (and not a legal one) the PPA terms are reasonable. The important terms that dictate how the payments would (or would not) flow through the PPA are reasonably structured and most are customary. It could be clearer that the project is not actually delivering Capacity to the Company, but a careful reading of Section 4.10 clarifies that issue. The draft I have reviewed still has some different positions on issues noted in footnotes. I have not had the opportunity to review how those issues were resolved.

Q. How can a PPA with a RE project with cost exceeding market-based pricing be considered commercially reasonable?

A. Based on today's market price of electricity, capacity and RECs, if the decision were between contracting for the output and RECs from the Block Island Wind Farm versus the least-cost newly developed renewable energy alternative available today (likely the production from a large-scale wind farm several states or provinces away), without any further considerations, a determination of commercial reasonableness may be different in this instance. However, there are several statutory and policy considerations which must be assessed in determining what is commercially reasonable.

The governing statute - S0111 and H 5002 Substitute A as Amended – identified a series of additional goals, including stabilizing long-term energy prices, enhancing environmental quality, creating jobs in Rhode Island in the renewable energy sector, and facilitating the financing of renewable energy generation within the jurisdictional boundaries of the state or adjacent state or federal water or providing direct economic benefit to the state. In addition, the contract must enhance the electric reliability and environmental quality of the Town of New Shoreham. These goals must be factored in to an evaluation of commercial reasonableness for a newly developed renewable energy project. More broadly, the state has established a comprehensive set of policy initiatives to encourage, enable and grow the offshore wind industry, the support infrastructure and associated economic development. To the extent that the Block Island Wind Farm will help initiate the development of the necessary infrastructure, experience and learning to enable the broader offshore energy goals, then those goals must be factored into the criteria. It should be expected that, over time, the overall costs of offshore wind generation available to the state and the region will come down with experience, scale, and the development of necessary infrastructure.

While Deepwater Wind and National Grid have had differences during the negotiation of the PPA, it is expected that the parties can agree on the challenges faced by newly developed renewable energy projects. Earlier this year, National Grid made arguments similar to those set forth by Deepwater Wind with another emerging technology of similar scale and expense, in a filing before the Massachusetts Department of Public Utilities, within the context of statutory directives and administration initiatives. In April, National Grid filed for approval to construct, own and operate 5 MW of solar photovoltaic generation at several of its facilities. In seeking the DPU's approval, National Grid:

- Indicated its general support for signing long term power purchase agreements for renewable generation (testimony of Testimony of Edward H. White, Jr., p. 11);
- Indicated its belief that development of solar generation needs to be one of many efforts to lower harmful emissions and reduce dependence on fossil fuel generation (white, p. 7);
- Stated that "this initiative is being proposed to help move and grow the solar generation market in the Commonwealth. It is National Grid's expectation that, over time, the overall

costs of solar generation will come down. However, foundational market action is needed to advance the solar generation market, including investment in the local solar industry. National Grid hopes that by entering the market, the Company will have a positive impact on the establishment of a long-term solar industry. (White, p. 12)

- In response to the question of whether, given the market price of electricity today, the Company's proposal is cost effective, by stating that "If the Company were making a decision to build solar generation versus buying fossil fueled power for our customers, and there were no other considerations, the solar projects would not be cost effective. However, there are other considerations that need to be taken into account", including statutory framework of the Green Communities Act which set forth a comprehensive state policy to encourage solar the development, even though it cannot compete against current market prices. (White, p. 16)
- Stated it belief that "the driving force behind such policy is the environmental benefit and the need to transform the energy industry. This is difficult to quantify in traditional terms. However, the Company believes five megawatts is a modest amount to contribute toward jumpstarting this important policy initiative." (White, p. 17); and
- Acknowledged that while "National Grid ultimately does not know with certainty how energy prices will change over the long term", it "believes that over time energy purchased from traditional fossil fueled generation is likely to become more and more expensive, as environmental policy evolves to address climate change. In turn, this may mean that renewable generation will become less expensive as technology improves. However, it is not possible to say today when solar generation will be less costly than the market price of electricity from the prevailing fossil-fuel driven market. But what is most important is taking initial steps to utilize new technologies that prepare us for a cleaner energy future, and solar can be an important part of that societal preparation." (White, p. 17)

The DPU determined National Grid's proposal to be in the public interest, acknowledging the "benefits of the Company's solar proposal which include (1) producing electricity without emissions, thus avoiding future costs to electric consumers associated with the control of greenhouse gas emissions, (2) stimulating markets forces in creating additional solar generation in the Commonwealth, and (3) producing valuable information on the costs and benefits of installing solar generation facilities in Massachusetts." (DPU Oder in Docket 09-38, p. 35) While the actions of the DPU certainly create no precedent for the Commission, the analogies are hard to ignore. The words "offshore wind" could be substituted for "solar" and, as they apply to the statutory and policy regimes in Rhode Island, would be equally applicable.[17]

Q. Electricity and natural gas price suppression benefits are often cited as benefits of new adding low-marginal cost renewable energy generation. What is the potential impact of these benefits?

A. Because the marginal cost of wind power is at or near zero, wind generators typically enter the market as a price taker, displacing more costly fossil-fuel fired generation at the margin, effectively pushing some of the most costly generation off the top of the bid stack. A recent New York Department of Public Service report described the applicable theory, the conventional methodology for estimating this benefit, and the impact of their recent analysis for New York.[18]

[17] Note that the approximate per-unit cost of the solar installations indicated in National Grid's filing, $300/MWh, is in the same order of magnitude as the pricing in the Block Island Wind Farm contract. However, the method of derivation of costs in the National Grid filing, not being defined or calculated in a comparable manner, cannot be directly compared to the Block Island Wind Farm contract pricing.

[18] *The Renewable Portfolio Standard: Mid Course Report,* prepared by the New York State Department of Public Service Staff, October 26, 2009. See: http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={230CE88F-60A5-475B-A24A-6FC9B2780DEF} (pp. 80-81)

ISO New England recently performed an analysis of different wind power scenarios[19], which provides a basis for estimating the price suppression benefit to Rhode Island from the Block Island Wind Farm. Considering a scenario exploring the impact of an increment 4000 MW of offshore wind above a base case with 4000 MW of onshore wind, compared to the base case, shows a reduction in regional energy LMP from $75.76/MWH to $73.12/MWh. Prorating this impact for a 30 MW offshore project yields an estimated impact of $0.0198/MWh (IN today's dollars), which would apply across all of the load in the region. Escalated with the price of electricity projected in my model, and applied to the Rhode Island wholesale load of approximately 8,280,000 MWh/yr[20] , I calculate a savings of $164,000 per year for Rhode Island. Over the life of the project the net present value of this benefit would be almost $2.5 million for Rhode Island ratepayers, and a much larger figure for the region as a whole.

Similarly, wind power is expected to displace primarily natural gas-fired generation in ISO New England. Based on microeconomic theory, one would expect reduced demand to lower the price of natural gas. This presumption has been studied extensively. Ryan H. Wiser of Lawrence Berkeley National Labs has studied this phenomenon. Testimony prepared for the Senate Committee on Energy and Natural Resources[21] describes the economic theory, and makes the following conclusion:

> *"We find that, by displacing natural-gas-fired electricity generation, increased levels of renewable energy and energy efficiency will reduce demand for natural gas and thus put downward pressure on gas prices. These price reductions hold the prospect of providing consumers with significant natural gas bill savings. In fact, although we did not analyze*

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[19] Draft New England 2030 Power System Study Report to the New England Governors 2009 Economic Study: Scenario Analysis of Renewable Resource Development (ISO New England Inc. September 8, 2009) http://www.nescoe.com/uploads/iso_eco_study_report_draft_sept_8.pdf . (for example, Figure 5 and Table 7 shows the reduction to average clearing prices from the addition of large quantities of on-shore and/or offshore wind)

[20] Retail load of 7,662,969 MWh from recent rate case filing, grossed up by 8% to approximate losses).

[21] Wiser, Ryan. (2005). *Easing the Natural Gas Crisis: Reducing Natural Gas Prices Through Electricity Supply Diversification -- Testimony*. Lawrence Berkeley National Laboratory: Lawrence Berkeley National Laboratory. Retrieved from: http://www.escholarship.org/uc/item/7j57w7kt

in detail the electricity price impacts reported in the studies, the studies often show that any predicted increase in the price of electricity caused by greater use of renewable energy or energy efficiency is largely or completely offset by the predicted natural gas price savings. We conclude that policies to encourage fuel diversification within the electricity sector should consider the potentially beneficial cross-sector impact of that diversification on natural gas prices and bills."

The dataset studied includes all such studies performed at that time, including studies performed by Tellus Institute for the Rhode Island Greenhouse Gas Working Group under contract to DEM. Without further analysis, I cannot at this time venture an estimate to quantify this benefit, other to observe that in many of the cited studies in the Wiser testimony, this benefit wholly or partially negated the cost of the RPS being studied, and therefore may be substantial.

<u>X. Commercially Reasonable</u>

Q. Based on your review of the Block Island Wind Farm project, do you find that the PPA submitted by Deepwater Wind and National Grid to be "commercially reasonable" as defined by R.I.G.L. § 39-26.1-2 (1)

A. Yes I do.

Q. Q. Can you summarize the basis for your opinion?

A. Yes. My opinion is based on the factors set forth herein above in my testimony, which include my review of this project, the PPA, its pricing, the installed cost of the project compared to other similar projects, the market value for the products being purchased and the underlying Rhode Island legislation.

Thus, when considering all the aspects of this project, the proposed PPA is commercially reasonable. Initially, compared to current energy-only wholesale market prices, the project appears expensive. When the expected PPA pricing is compared to total delivered value of the products the differential becomes more reasonable as shown and the above market net result is approximately $95.9 million in 2010 dollars or about $107/MWh in the same year. The known structured price provides a hedge against possible high energy prices, whether due to high REC prices in the event of tight supply in that market, high carbon prices as a result of carbon policy initiatives, or high gas prices twice that level assumed. While this seems unlikely today, recall that average 2008 prices were more than twice where they are currently. Because of the credit in the price structure for the market value of capacity, the price actually decreases in the future as capacity prices rise.

The project's costs on an installed $/MW basis are almost identical to costs projected in a study for the California Energy Commission for a small 50 MW offshore wind project. The small scale of this project creates diseconomies of scale that are very intuitive to acknowledge and describe, but with no other recent projects in this size range anywhere in the world, the comparable actual project data to confirm this is just not available.

Q. Does this conclude your testimony?

A. Yes. Aside from reviewing testimony from the Division or any other party in this Docket, yes it does.

CERTIFICATION

I hereby certify that on December 9, 2009, I sent a copy of the within to all parties set forth on the attached Service List by electronic mail and copies to Luly Massaro, Commission Clerk, by electronic mail and regular mail.

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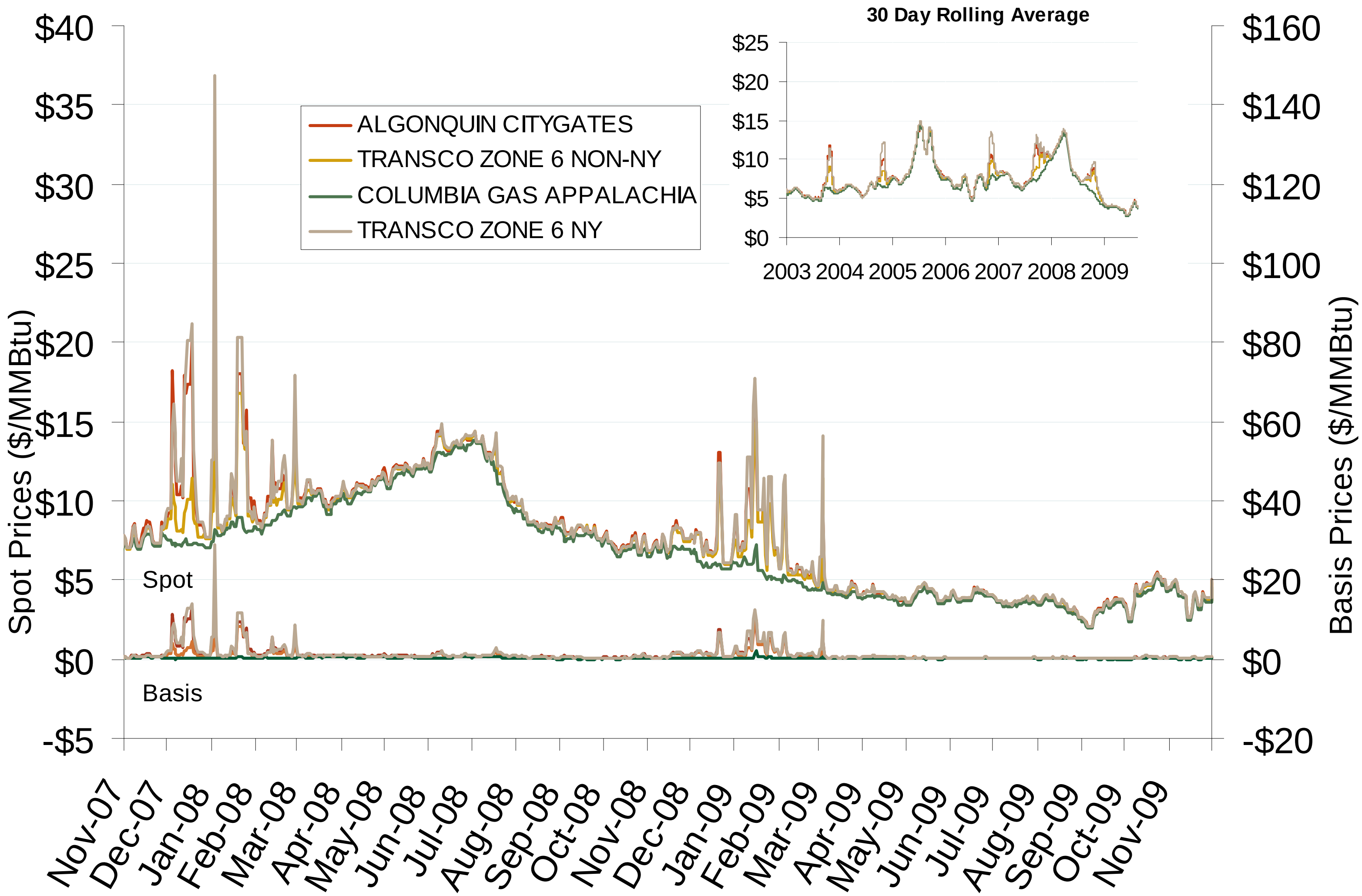
EXHIBIT A

Northeastern Spot Prices and Basis



Source: Derived from *Platts* data.

Updated December 8, 2009

EXHIBIT B

Offshore Wind Project Installed Costs and Statistics

MREG LLC 12/9/09

Source:

From a pre-release draft of upcoming study prepared by *AWS Truewind, LLC for New York State Energy Research and Development Authority*

"NY's Offshore Wind Energy Development Potential in the Great Lakes"

Dated December 2009

Used with permission

Project Name	Country	Status	Operating Year	Project Cost ($M)	Project Capacity (MW)	Project Cost per MW ($M)	No. of Turbines	Turbine Size (MW)	Turbine Model	Water Depth (m)	Distance from Shore (km)	Interpolation Input Water Depth (m)	Scale Factor	Project Cost per MW On same basis as Deepwater ($M)	Updated Project Cost ($M)
Middelgrunden	Denmark	Commissioned	2001	$51	40.0	$1.28	20	2	Bonus_2_MW	5 to 10	2 to 3	7.5	**1.000**	$1.47	$59
Horns_Rev	Denmark	Commissioned	2002	$295	160.0	$1.84	80	2	Vestas_V80	6 to 14	14 to 17	10	**1.000**	$2.12	$339
North_Hoyle	United_Kingdom	Commissioned	2003	$138	60.0	$2.30	30	2	Vestas_V80	5 to12	7.5	8.5	**1.000**	$2.65	$159
Nysted	Denmark	Commissioned	2004	$316	165.6	$1.91	72	2.3	Siemens_2.3	6 to 10	6 to 10	8	**1.000**	$2.20	$364
Scroby_Sands	United_Kingdom	Commissioned	2004	$136	60.0	$2.27	30	2	Vestas_V80	2 to 10	3	6	**1.000**	$2.62	$157
Kentish_Flats	United_Kingdom	Commissioned	2005	$179	90.0	$1.98	30	3	Vestas_V90	5	8.5	5	**1.000**	$2.28	$205
Barrow	United_Kingdom	Commissioned	2006	$172	90.0	$1.91	30	3	Vestas_V90	15	7	15	**1.000**	$2.20	$198
Burbo_Bank	United_Kingdom	Commissioned	2007	$170	90.0	$1.89	25	3.6	Siemens_3.6	10	5.2	10	**1.000**	$2.18	$196
Egmond_aan_Zee	Netherlands	Commissioned	2007	$300	108.0	$2.77	36	3	Vestas_V90	17 to 23	8 to 12	20	**1.034**	$3.09	$333
Inner_Dowsing	United_Kingdom	Commissioned	2008	$289	97.2	$2.97	27	3.6	Siemens_3.6	10	5.2	10	**1.000**	$3.42	$333
Lillgrund	Sweden	Commissioned	2008	$254	110.4	$2.30	48	2.3	Siemens_2.3	2.5 to 9	10	5.75	**1.000**	$2.65	$293
Princess_Amalia	Netherlands	Commissioned	2008	$582	120.0	$4.85	60	2	Vestas_V80	19 to 24	>23	21.5	**1.044**	$5.35	$642
Alpha_Ventus	Germany	Under_construction	2009	$350	60.0	$5.83	12	5	Multibrid&REpower	30	45	30	**1.152**	$5.83	$350
Gunfleet_Sands_I	United_Kingdom	Under_construction	2009	$406	108.0	$3.76	30	3.6	Siemens_3.6	2 to 15	7	8.5	**1.000**	$4.33	$468
Horns_Rev_Expansion	Denmark	Under_construction	2009	$854	209.3	$4.08	91	2.3	Siemens_2.3	9 to 17	30	13	**1.000**	$4.70	$984
Rhyl_Flats	United_Kingdom	Under_construction	2009	$358	90.0	$3.98	25	3.6	Siemens_3.6	8	8	8	**1.000**	$4.58	$413
Robin_Rigg	United_Kingdom	Under_construction	2009	$651	180.0	$3.62	60	3	Vestas_V90	>5	9.5	6	**1.000**	$4.17	$751
Gunfleet_Sands_II	United_Kingdom	Financing_secured	2010	$275	64.8	$4.24	18	3.6	Siemens_3.6	2 to 15	7	8.5	**1.000**	$4.88	$317
Nordergrunde	Germany	Financing_secured	2010	$440	90.0	$4.89	18	5	Repower_5M	4 to 20	30	12	**1.000**	$5.63	$507
Sea_Bridge	China	Under_construction	2010	$345	102.0	$3.38	34	3	Sinovel_3_MW	8 to 10	8 to 14	9	**1.000**	$3.89	$397
Walney	United_Kingdom	Financing_secured	2010	$746	151.2	$4.93	42	3.6	Siemens_3.6	20	7	20	**1.034**	$5.50	$831
Belwind	Belgium	Financing_secured	2011	$897	165.0	$5.44	55	3	Vestas_V90	20 to 35	46	27.5	**1.110**	$5.65	$932
Thanet	United_Kingdom	Financing_secured	2011	$1,200	300.0	$4.00	100	3	Vestas_V90	20 to 25	7 to 8.5	22.5	**1.050**	$4.39	$1,316
London_Array	United_Kingdom	Financing_secured	2012	$3,095	630.0	$4.91	175	3.6	Siemens_3.6	23	>20	23	**1.054**	$5.37	$3,382
Sheringham_Shoal	United_Kingdom	Financing_secured	2012	$1,500	316.8	$4.73	88	3.6	Siemens_3.6	16 to 22	17 to 23	19	**1.027**	$5.31	$1,681
Recent projects after reflecting		**2008 thru 2012**	**14**	**$11,699**	**2587**	**$4.52**	**808**							**$5.01**	$12,970
current cost levels after mid '08 changes		Average			185		58							10.9%	
		Relative to DW			6.4 times										
For Comparison															
Deepwater Wind BI	Rhode Island, USA	In Development	2013	$200	28.8	$6.96	8	3.6	3.6 MW vendor TBD	27 to 33	29	30	**1.152**	**$6.96**	$200

Deepwater cable length is planned to be 29 miles (47 km), ignoring BI, Deepwater's distance to the mainland is about 18 miles (29 km)

Scale Factors for Cost Increases as a Function of Water Depth

Source:

European Evniromental Agency Technical Report

"Europe's onshore and offshore wind energy potential"

2009

Depth (m)	Factor
0	1.000
15	1.000
25	1.067
35	1.237
45	1.396

EXHIBIT C

Capacity Price Forecast

12/6/2009
MREG LCC

Update of forecast from Synapse Energy Economics, Inc. "Avoided Energy Supply Cost in New England: 2009 Report" Revised 10/23/09, Exhibit 6-3

Capacity Commitment Period Starting	FCA	Peak Demand (CELT 09)	Reserve Margin including HQ	Net Installed Capacity Req	NICR % chg	Surplus Cleared	Resource Adjustments: New Additions: Non-renewable	Renewable	Removals: Retirements	Delist	DSM	Capacity Cleared	FCM Prices Clearing Price: Nominal$	2009$	FCM Prices Prorated Price: Nominal$	2009$	Cal Year	FCM Prices Prorated Cal. Year: Nominal$	2009$
		MW	*MW*	*MW*		*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*$/kw-month*		*$/kw-month*			*$/kw-month*	
		a	b	c		d = j - c	e	f	g	h	i	j = prior yr + (e+f+g+h+i)	k	l	m	n		p	q
6/1/2010	1	28,160	14.7%	32,305		1,772				(324)		34,077	$4.50	$4.45	**$4.25**	$4.21			
6/1/2011	2	28,575	13.8%	32,528	*0.7%*	4,755				(890)		37,283	$3.60	$3.47	**$3.12**	$3.01	2011	**$3.59**	$3.47
6/1/2012	3	29,020	10.1%	31,965	*-1.8%*	5,031				(1,710)		37,026	$2.95	$2.79	**$2.54**	$2.40	2012	**$2.78**	$2.63
6/1/2013	4	29,365	10.4%	32,411	*1.4%*	4,615	50	310	(10)	(350)		37,026	$2.95	$2.73	$2.58	$2.39	2013	**$2.56**	$2.37
6/1/2014	5	29,750	10.6%	32,901	*1.5%*	4,125	50	282	(10)	(322)		37,026	$3.03	$2.73	$2.69	$2.42	2014	**$2.65**	$2.38
6/1/2015	6	30,115	10.8%	33,370	*1.4%*	3,656	50	228	(10)	(268)		37,026	$3.12	$2.73	$2.81	$2.46	2015	**$2.76**	$2.41
6/1/2016	7	30,415	11.0%	33,757	*1.1%*	894	50	327	(10)	(2,742)		34,651	$1.56	$1.33	$1.52	$1.29	2016	**$2.06**	$1.75
6/1/2017	8	30,695	11.2%	34,120	*1.1%*	98	50	197	(10)	(671)		34,218	$1.60	$1.33	$1.60	$1.32	2017	**$1.57**	$1.30
6/1/2018	9	30,960	11.3%	34,454	*1.0%*	-	50	281	(10)	(85)		34,454	$4.61	$3.71	$4.61	$3.71	2018	**$3.36**	$2.70
6/1/2019	10	*31,270*	*11.3%*	34,799	*1.0%*	-	50	274	(10)	31		34,799	$6.17	$4.82	$6.17	$4.82	2019	**$5.52**	$4.31
6/1/2020	11	*31,582*	*11.3%*	35,147	*1.0%*	-	50	262	(10)	46		35,147	$8.29	$6.30	$8.29	$6.30	2020	**$7.41**	$5.63
6/1/2021	12	*31,898*	*11.3%*	35,498	*1.0%*	-	100	207	(10)	54		35,498	$8.53	$6.30	$8.53	$6.30	2021	**$8.43**	$6.23
6/1/2022	13	*32,217*	*11.3%*	35,853	*1.0%*	-	100	87	(10)	178		35,853	$8.77	$6.30	$8.77	$6.30	2022	**$8.67**	$6.23
6/1/2023	14	*32,539*	*11.3%*	36,212	*1.0%*	-	150	169	(10)	50		36,212	$9.00	$6.30	$9.00	$6.30	2023	**$8.90**	$6.24
6/1/2024	15	*32,865*	*11.3%*	36,574	*1.0%*	-	200	153	(10)	19		36,574	$9.23	$6.30	$9.23	$6.30	2024	**$9.13**	$6.24
6/1/2025	16	*33,193*	*11.3%*	36,939	*1.0%*	-	250	154	(10)	(28)		36,939	$9.44	$6.30	$9.44	$6.30	2025	**$9.35**	$6.24
6/1/2026	17	*33,525*	*11.3%*	37,309	*1.0%*	-	250	158	(10)	(28)		37,309	$9.67	$6.30	$9.67	$6.30	2026	**$9.57**	$6.24
6/1/2027	18	*33,860*	*11.3%*	37,682	*1.0%*	-	250	162	(10)	(28)		37,682	$9.90	$6.30	$9.90	$6.30	2027	**$9.80**	$6.24
6/1/2028	19	*34,199*	*11.3%*	38,059	*1.0%*	-	250	166	(10)	(29)		38,059	$10.15	$6.30	$10.15	$6.30	2028	**$10.04**	$6.24
6/1/2029	20	*34,541*	*11.3%*	38,439	*1.0%*	-	250	170	(10)	(29)		38,439	$10.40	$6.30	$10.40	$6.30	2029	**$10.29**	$6.24
6/1/2030	21	*34,887*	*11.3%*	38,824	*1.0%*	-	250	174	(10)	(29)		38,824	$10.65	$6.30	$10.65	$6.30	2030	**$10.55**	$6.24
6/1/2031	22	*35,235*	*11.3%*	39,212	*1.0%*	-	250	178	(10)	(30)		39,212	$10.91	$6.30	$10.91	$6.30	2031	**$10.80**	$6.24
6/1/2032	23	*35,588*	*11.3%*	39,604	*1.0%*	-	250	182	(10)	(30)		39,604	$11.18	$6.30	$11.18	$6.30	2032	**$11.07**	$6.24
6/2/2033	24	*35,944*	*11.3%*	40,000	*1.0%*	-	250	187	(10)	(31)		40,000	$11.45	$6.30	$11.45	$6.30	2033	**$11.34**	$6.24
6/3/2034	25	*36,303*	*11.3%*	40,400	*1.0%*	-	250	191	(10)	(31)		40,400	$11.73	$6.30	$11.73	$6.30	2034	**$11.61**	$6.24

Notes:

For FCA 1, 2 & 3: NICR, Surplus Cleared, Delist, Capacity Cleared, Clearing Price and Prorated Price are actuals

a. CELT 2009. Summer reference load through 6/1/18. From there, calculated as c / (1+b)

b. RSP 2009 to 2018, assumed flat there after

c. Representitive Future Net ICR from 2009-2018 RSP through FCA 9. Estimated to grows at 1% annually thereafter

d. Suplus from actual auction results through FCA 3. d = j - c thereafter

e. New net generation, demand or import resources
From FCA 4 on, assume 50 MW per year of additional demand, generation or import resources are added by the market. Increasing amounts once Surplus Cleared is 0

f. Annual incremental renewables at FCM capacity values necessary to meet RPS requirements from AESC Exhibit 6-4 through FCA 15, prior 4 year average esc at CPI thereafter

g. Older combustion turbine attrition

h. Amount of MWs that delist. Actuals for FCA 1-3. With a new floor (see note k), assume delists only equal to net addions while floor is in place
Assumption is that if the FCA3 price was acceptable, no futher resources would delist if that price is the same or slightly higher, other than to offset additions.
Starting with FCA 7 when the new floor goes away, assume that 75% of the surplus delists in FCAs 7 and 8
Once suplus clears, h = NICR - (prior auction's capacity cleared capacity + e + f + g + h)

i. This column in AESC analys removed energy efficiency resources and reserve margin on demand response that was no longer counted by ISO after FCA2.
Any further net demand additins and reductions for economic reasons are included as part of non-renewable additions and the delist total
In FCA3 new demand resouces that cleared exceeded demand delistings by 52 MW.

j. Actuals for FCA 1-3. j = prior yr + (e+f+g+h+i) thereafter

k. Includes new floor price from Participants Committee Supported FCM Working Group Design Basis Document. Expected to be filed at FERC in 2/2010.
Assumed effective for FCA 4. Floor set at $2.95/kw-mo and escalates using a 3 year rolling average of the Handy-Whitman, used CPI here
Assumes floor is not continued for FCA 6 and price drops. Could go to $0 or the floor could be extend. This is Price here is an estimate in-between, escalates at CPI until surplus clears
Once the Surplus cleared in 0, clearing priced assumed to be 50% of CONE ($7.50 in 2009 and esc @ CPI) the first year, 65% the second year and 85% the third year
From there, the Clearing Price escalates at CPI

l. K deflated to 2009$

m. For FCA 4 on, prorated price is Clearing Price X (NICR / Capacity Cleared)

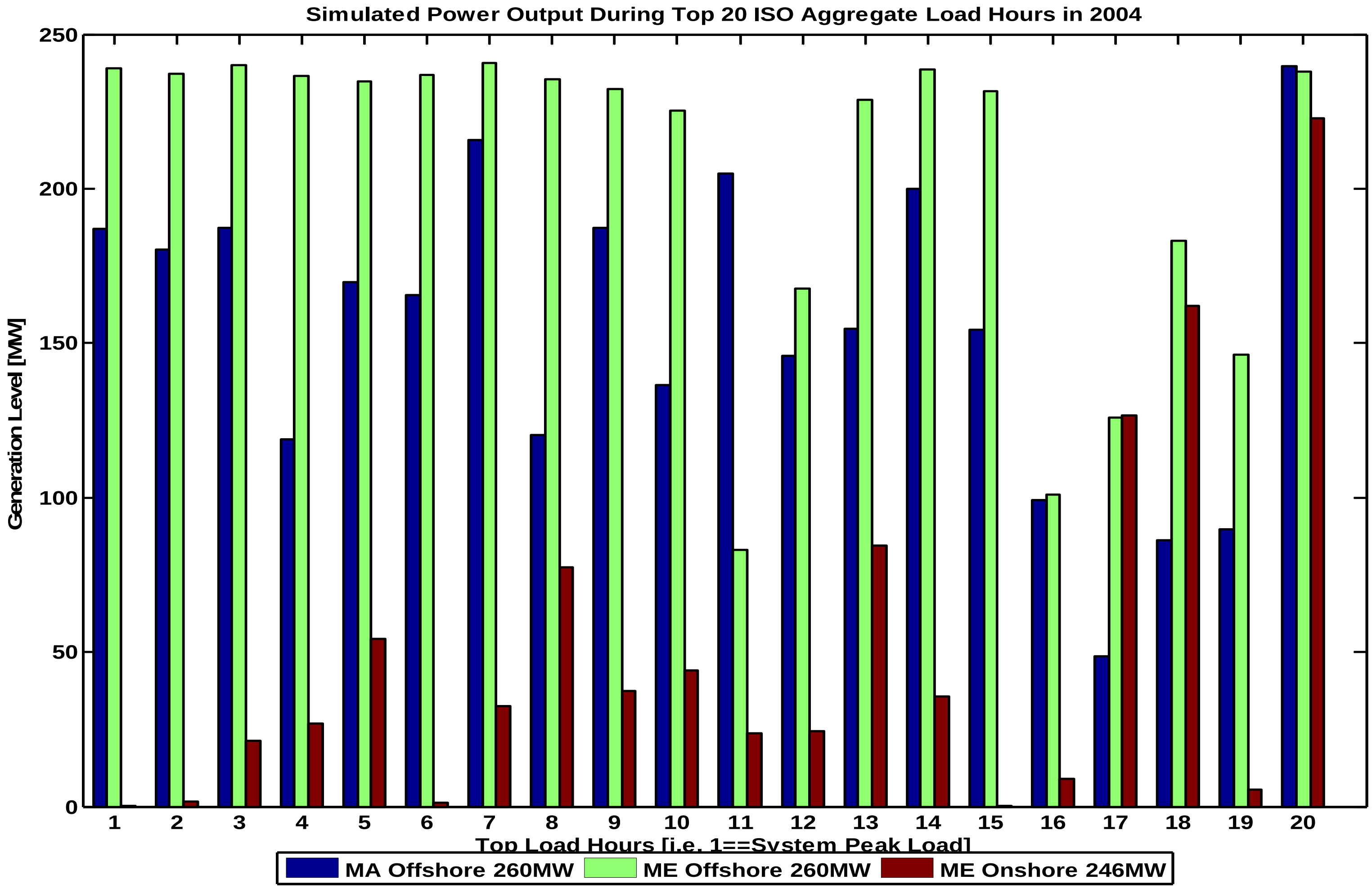
n. m deflated to 2009$

p. FCM Price used. Price from m converted from a Capacity Commitment Period to a calendar year

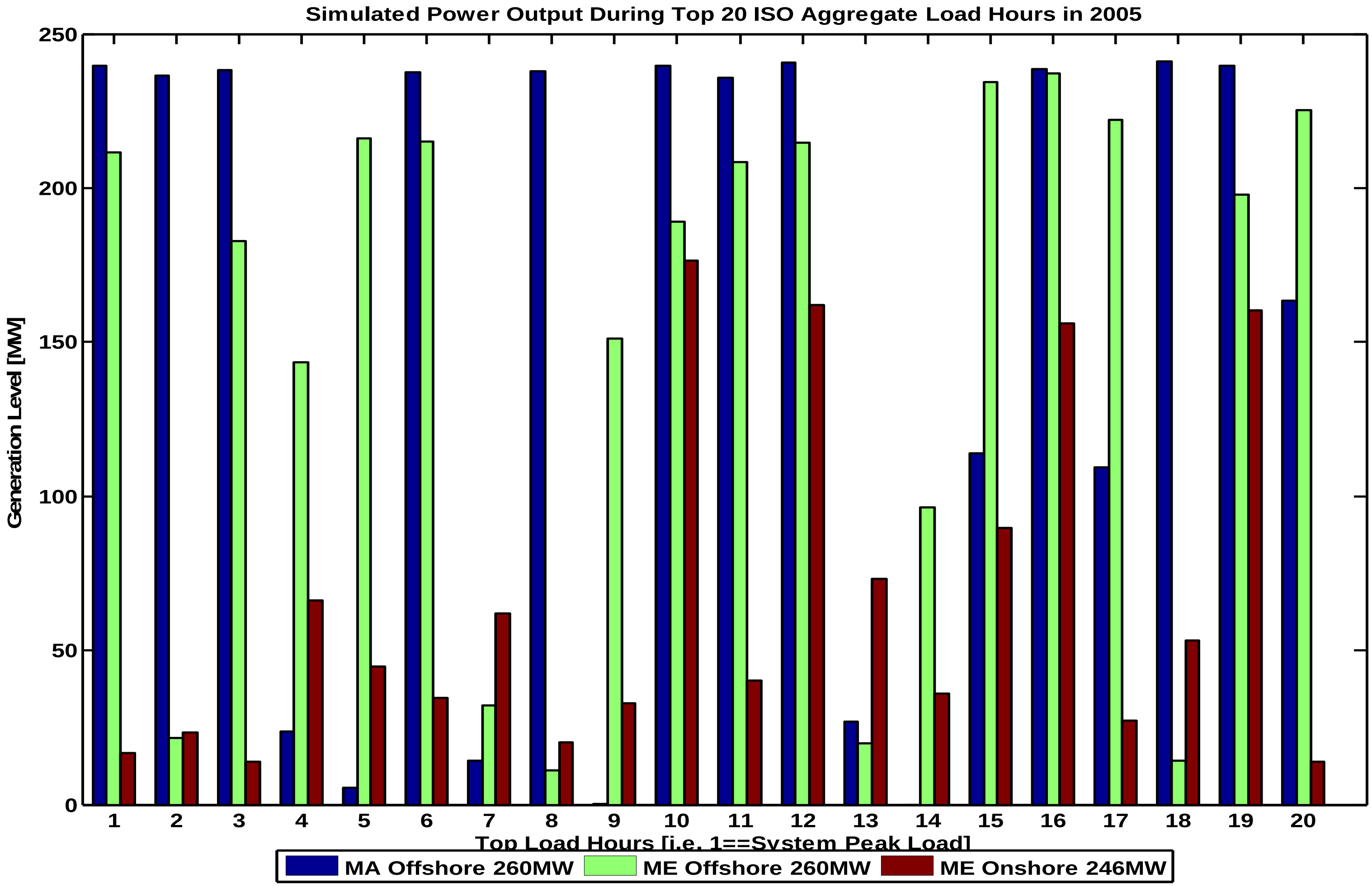
n. p deflated to 2009$

EXHIBIT D

Offshore Load Correlation On Peak (2004 preliminary)



Offshore Load Correlation On Peak (2005 preliminary)



Offshore Load Correlation On Peak (2006 preliminary)

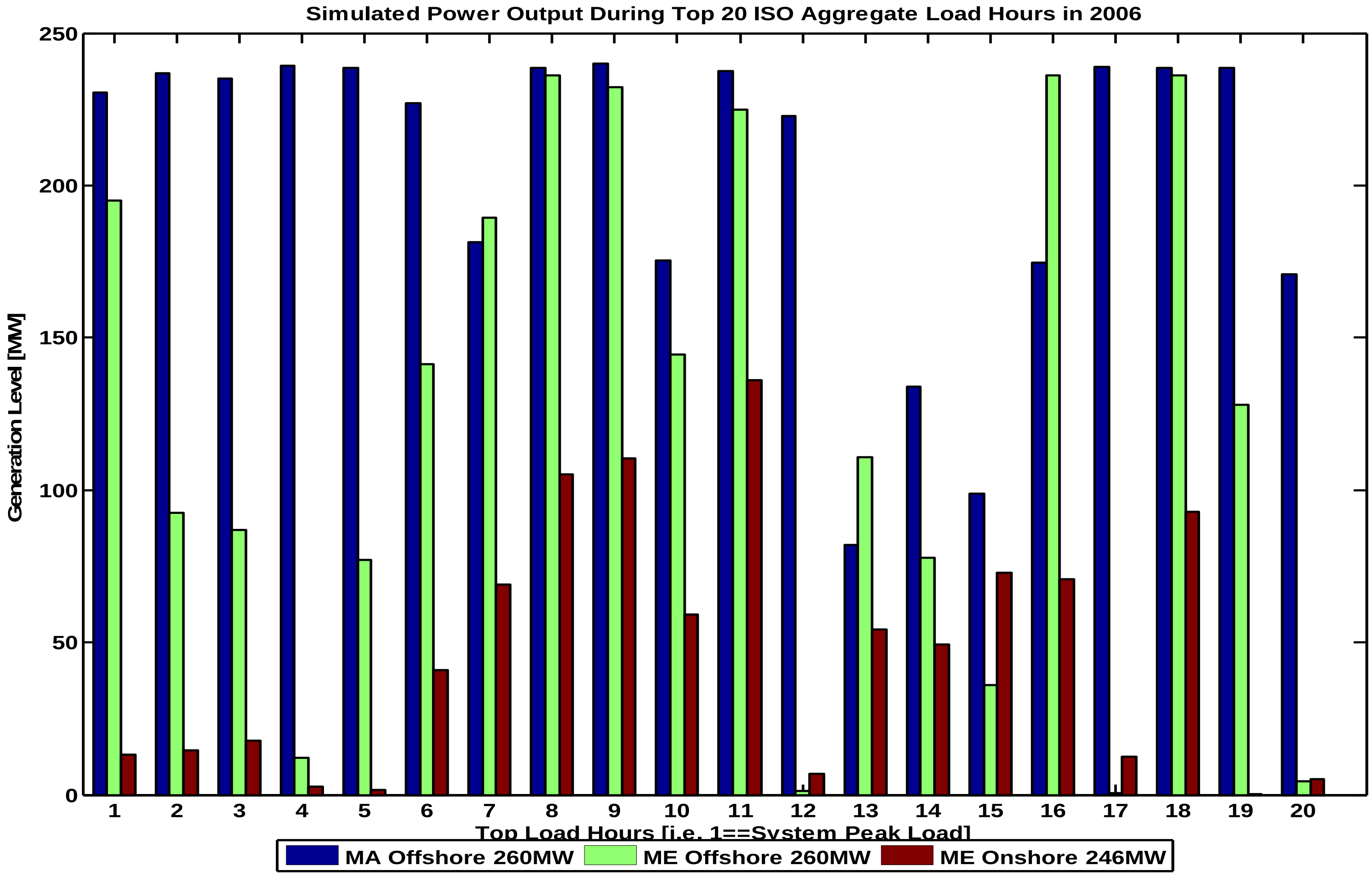


EXHIBIT E

Carbon Adder

Raw Data

	AESC 2009 Carbon Dioxide Price Sensitivity Scenarios (from Exh. 7-4): AESC Reference Case (2009$/ton)	Real Escalation	AESC RGGI Only Case (2009$/ton)	Real Escalation	Synapse High CO2 Allowance Price Scenario (2009$/ton)	Real Escalation	Chicago Climate Futures Exchange: RGGI Futures 12/3/09 prices Nominal $	EIA forecasts for Markey Waxman Climate Bill: EIA "American Clean Energy & Security Act" Basic Case ($/ton CO_2) Nominal	Real Escalation
2007									
2008									
2009	$3.85		$3.85		$3.85		$2.11		
2010	$3.91	1.6%	$3.91	1.6%	$3.91	1.6%	$2.13		
2011	$4.02	2.8%	$4.02	2.8%	$4.02	2.8%	$2.26		
2012	$4.00	-0.5%	$4.00	-0.5%	$4.00	-0.5%	$2.06	$17.34	
2013	$15.63	290.8%	$4.00	0.0%	$31.26	681.5%		$18.98	9.5%
2014	$18.03	15.4%	$4.00	0.0%	$33.66	7.7%		$20.86	9.9%
2015	$20.32	12.7%	$4.00	0.0%	$35.95	6.8%		$22.93	9.9%
2016	$22.72	11.8%	$4.00	0.0%	$37.31	3.8%		$25.21	10.0%
2017	$25.01	10.1%	$4.00	0.0%	$40.64	8.9%		$27.73	10.0%
2018	$27.41	9.6%	$4.00	0.0%	$43.04	5.9%		$30.52	10.1%
2019	$29.70	8.4%	$4.00	0.0%	$45.33	5.3%		$33.60	10.1%
2020	$32.10	8.1%	$4.00	0.0%	$47.73	5.3%		$37.02	10.2%
2021	$34.49	7.4%	$4.00	0.0%	$50.13	5.0%		$40.79	10.2%
2022	$36.79	6.7%	$4.00	0.0%	$52.42	4.6%		$44.93	10.1%
2023	$39.18	6.5%	$4.00	0.0%	$54.82	4.6%		$49.41	10.0%
2024	$41.48	5.9%	$4.00	0.0%	$57.11	4.2%		$54.29	9.9%
2025	*$44.35*	*6.9%*	*$4.00*	*0.0%*	*$59.81*	*4.7%*		$59.64	9.9%
2026	*$47.41*	6.9%	*$4.00*	0.0%	*$62.64*	4.7%		$65.50	9.8%
2027	*$50.69*	6.9%	*$4.00*	0.0%	*$65.60*	4.7%		$71.91	9.8%
2028	*$54.19*	6.9%	*$4.00*	0.0%	*$68.70*	4.7%		$78.98	9.8%
2029	*$57.94*	6.9%	*$4.00*	0.0%	*$71.95*	4.7%		$86.77	9.9%
2030	*$61.94*	6.9%	*$4.00*	0.0%	*$75.36*	4.7%		$95.23	9.8%
2031	*$66.23*	6.9%	*$4.00*	0.0%	*$78.92*	4.7%		*$104.58*	*9.8%*
2032	*$70.80*	6.9%	*$4.00*	0.0%	*$82.65*	4.7%		*$114.84*	9.8%
2033	*$75.70*	6.9%	*$4.00*	0.0%	*$86.56*	4.7%		*$126.11*	9.8%
2034	*$80.93*	6.9%	*$4.00*	0.0%	*$90.66*	4.7%		*$138.48*	9.8%

Nominal $/ton / **Nominal $/MWh Carbon Adder**

	Nominal $/ton — AESC 2009 Carbon Dioxide Price Sensitivity Scenarios (from Exh. 7-4): AESC Reference Case (2009$/ton)	AESC RGGI Only Case (2009$/ton)	Synapse High CO2 Allowance Price Scenario (2009$/ton)	Chicago Climate Futures Exchange: RGGI Futures 12/3/09 prices Nominal $	EIA forecasts for Markey Waxman Climate Bill: EIA "American Clean Energy & Security Act" Basic Case ($/ton CO_2) Nominal	2008 NEPOOL Marginal CO_2 Emission Rate (lbs/MWh)		Nominal $/MWh Carbon Adder — AESC 2009 Carbon Dioxide Price Sensitivity Scenarios (from Exh. 7-4): AESC Reference Case	AESC RGGI Only Case	Synapse High CO2 Allowance Price Scenario (2009$/ton)	Chicago Climate Futures Exchange: RGGI Futures 12/3/09 prices	EIA forecasts for Markey Waxman Climate Bill: EIA "American Clean Energy & Security Act" Basic Case
2007												
2008						964						
2009	$ 3.85	$ 3.85	$ 3.85	$2.11	$0.00	964		$1.86	$1.86	$1.86	$1.02	$0.00
2010	$ 3.96	$ 3.96	$ 3.96	$2.13	$0.00	964		$1.91	$1.91	$1.91	$1.03	$0.00
2011	$ 4.17	$ 4.17	$ 4.17	$2.26	$0.00	964		$2.01	$2.01	$2.01	$1.09	$0.00
2012	$ 4.23	$ 4.23	$ 4.23	$2.06	$17.34	964		$2.04	$2.04	$2.04	$0.99	$8.36
2013	$ 16.93	$ 4.33	$ 33.86		$18.98	964	2013	$8.16	$2.09	$16.32		$9.15
2014	$ 20.05	$ 4.45	$ 37.42		$20.86	964	2014	$9.66	$2.14	$18.04		$10.05
2015	$ 23.23	$ 4.57	$ 41.09		$22.93	964	2015	$11.20	$2.20	$19.81		$11.05
2016	$ 26.71	$ 4.70	$ 43.86		$25.21	964	2016	$12.87	$2.27	$21.14		$12.15
2017	$ 30.23	$ 4.84	$ 49.12		$27.73	964	2017	$14.57	$2.33	$23.68		$13.37
2018	$ 34.10	$ 4.98	$ 53.54		$30.52	964	2018	$16.44	$2.40	$25.81		$14.71
2019	$ 38.00	$ 5.12	$ 57.99		$33.60	964	2019	$18.31	$2.47	$27.95		$16.19
2020	$ 42.24	$ 5.26	$ 62.81		$37.02	964	2020	$20.36	$2.54	$30.28		$17.84
2021	$ 46.66	$ 5.41	$ 67.82		$40.79	964	2021	$22.49	$2.61	$32.69		$19.66
2022	$ 51.19	$ 5.57	$ 72.93		$44.93	964	2022	$24.67	$2.68	$35.15		$21.65
2023	$ 55.95	$ 5.71	$ 78.28		$49.41	964	2023	$26.97	$2.75	$37.73		$23.82
2024	$ 60.72	$ 5.86	$ 83.61		$54.29	964	2024	$29.27	$2.82	$40.30		$26.17
2025	$ 66.42	$ 5.99	$ 89.58		$59.64	964	2025	$32.01	$2.89	$43.18		$28.75
2026	$ 72.74	$ 6.14	$ 96.10		$65.50	964	2026	$35.06	$2.96	$46.32		$31.57
2027	$ 79.62	$ 6.28	$ 103.04		$71.91	964	2027	$38.38	$3.03	$49.67		$34.66
2028	$ 87.26	$ 6.44	$ 110.62		$78.98	964	2028	$42.06	$3.10	$53.32		$38.07
2029	$ 95.60	$ 6.60	$ 118.73		$86.77	964	2029	$46.08	$3.18	$57.23		$41.82
2030	$ 104.69	$ 6.76	$ 127.35		$95.23	964	2030	$50.46	$3.26	$61.38		$45.90
2031	$ 114.66	$ 6.93	$ 136.64		$104.58	964	2031	$55.27	$3.34	$65.86		$50.41
2032	$ 125.58	$ 7.09	$ 146.60		$114.84	964	2032	$60.53	$3.42	$70.66		$55.35
2033	$ 137.55	$ 7.27	$ 157.29		$126.11	964	2033	$66.30	$3.50	$75.81		$60.78
2034	$ 150.65	$ 7.45	$ 168.75		$138.48	964	2034	$72.61	$3.59	$81.34		$66.75

EXHIBIT F

Analysis of REC Future Values - Status Quo Federal Incentives

Note: Rationalle for probability weights: current modest surplus attenuated by increasing difficulty in siting, reliance on poorer resource quality over time... working up the supply curve, and exacerbated by the apparent removal of biomass as a substantial future (and potential current) contributor, moderated by technoilogical advance

Scenario	ACP	High	Low	Current Futures	High	Low	Current Futures	Probability-Weighted Avg.
		Shortage	Surplus & Banking					
	ACP	ACP less Transaction Cost	Recent Spot Esc. @ CPI	Chicago Climate Futures Exchange				
		$2.62						
2007			52					
2008			37					
2009	$60.92	$58.30	28.75					
2010	$ 61.62	$59.00	$29.08	$32.63	10%	45%	45%	$ 33.67
2011	$ 63.14	$60.52	$29.80	$35.67	15%	40%	45%	$ 37.05
2012	$ 64.47	$61.85	$30.42	$37.07	20%	35%	45%	$ 39.70
2013	$ 65.99	$63.37	$31.14	$38.34	25%	30%	45%	$ 42.44
2014	$ 67.73	$65.11	$31.96	$39.61	30%	25%	45%	$ 45.35
2015	$ 69.64	$67.02	$32.86	$40.87	35%	25%	40%	$ 48.02
2016	$ 71.61	$68.99	$33.79	$ 42.02	40%	25%	35%	$ 50.75
2017	$ 73.64	$71.02	$34.75	$ 43.21	45%	25%	30%	$ 53.61
2018	$ 75.78	$73.16	$35.77	$ 44.47	50%	25%	25%	$ 56.64
2019	$ 77.94	$75.32	$36.78	$ 45.74	50%	25%	25%	$ 58.29
2020	$ 80.17	$77.55	$37.84	$ 47.05	50%	25%	25%	$ 60.00
2021	$ 82.42	$79.80	$38.90	$ 48.37	50%	25%	25%	$ 61.72
2022	$ 84.76	$82.14	$40.00	$ 49.74	50%	25%	25%	$ 63.50
2023	$ 86.99	$84.37	$41.05	$ 51.05	50%	25%	25%	$ 65.21
2024	$ 89.18	$86.56	$42.09	$ 52.34	50%	25%	25%	$ 66.89
2025	$ 91.24	$88.62	$43.06	$ 53.54	50%	25%	25%	$ 68.46
2026	$ 93.46	$90.84	$44.11	$ 54.85	50%	25%	25%	$ 70.16
2027	$ 95.69	$93.07	$45.16	$ 56.15	50%	25%	25%	$ 71.86
2028	$ 98.09	$95.47	$46.29	$ 57.56	50%	25%	25%	$ 73.70
2029	$ 100.52	$97.90	$47.44	$ 58.99	50%	25%	25%	$ 75.56
2030	$ 102.96	$100.34	$48.59	$ 60.42	50%	25%	25%	$ 77.42
2031	$ 105.47	$102.85	$49.78	$ 61.89	50%	25%	25%	$ 79.34
2032	$ 108.05	$105.43	$50.99	$ 63.41	50%	25%	25%	$ 81.32
2033	$ 110.69	$108.07	$52.24	$ 64.96	50%	25%	25%	$ 83.34
2034	$ 113.40	$110.78	$53.52	$ 66.55	50%	25%	25%	$ 85.41

Impact of Incentives on Non-Shortage REC Prices

change from current conditions influencing "Low" and "Current Futures"

	PTC Status Quo (indefnite Extension) Full Value = Levelized After-Tax Value of 10-yr PTC stream over 20 years	**PTC Phase Out** *assumed to be phased out over a 10-yr period following 2013*	**Federal GHG C&T Influence on LMPs, from RGGI-Only Baseline** AESC Reference Case - AESC RGGI Case	**Sum Net Value of Federal PTC & GHG Incentives**	**Net Impact on REC Prices** Higher Incentives Reduce REC Prices, all else equal
2007	$ 20.40	$ 20.40	$0.00	$ 20.40	$ -
2008	$ 20.85	$ 20.85	$0.00	$ 20.85	$ -
2009	$ 21.05	$ 21.05	$0.00	$ 21.05	$ -
2010	$ 21.17	$ 21.17	$0.00	$ 21.17	$ -
2011	$ 21.42	$ 21.42	$0.00	$ 21.42	$ -
2012	$ 21.69	$ 21.69	$0.00	$ 21.69	$ -
2013	$ 22.08	$ 22.08	$6.07	$ 28.15	$ (6.07)
2014	$ 22.54	$ 20.29	$7.52	$ 27.81	$ (5.26)
2015	$ 23.05	$ 18.44	$8.99	$ 27.43	$ (4.38)
2016	$ 23.57	$ 16.50	$10.61	$ 27.11	$ (3.53)
2017	$ 24.12	$ 14.47	$12.24	$ 26.71	$ (2.59)
2018	$ 24.69	$ 12.34	$14.04	$ 26.38	$ (1.69)
2019	$ 25.27	$ 10.11	$15.85	$ 25.96	$ (0.68)
2020	$ 25.90	$ 7.77	$17.82	$ 25.60	$ 0.31
2021	$ 26.56	$ 5.31	$19.88	$ 25.20	$ 1.37
2022	$ 27.24	$ 2.72	$21.99	$ 24.71	$ 2.53
2023	$ 27.89		$24.21	$ 24.21	$ 3.68
2024	$ 28.52		$26.45	$ 26.45	$ 2.07
2025	$ 29.12		$29.13	$ 29.13	$ (0.00)
2026	$ 29.73		$32.10	$ 32.10	$ (2.37)
2027	$ 30.35		$35.35	$ 35.35	$ (5.00)
2028	$ 30.99		$38.95	$ 38.95	$ (7.97)
2029	$ 31.63		$42.90	$ 42.90	$ (11.27)
2030	$ 32.28		$47.20	$ 47.20	$ (14.92)
2031	$ 32.96		$51.93	$ 51.93	$ (18.97)
2032	$ 33.64		$57.11	$ 57.11	$ (23.47)
2033	$ 34.34		$62.79	$ 62.79	$ (28.45)
2034	$ 35.06		$69.02	$ 69.02	$ (33.97)

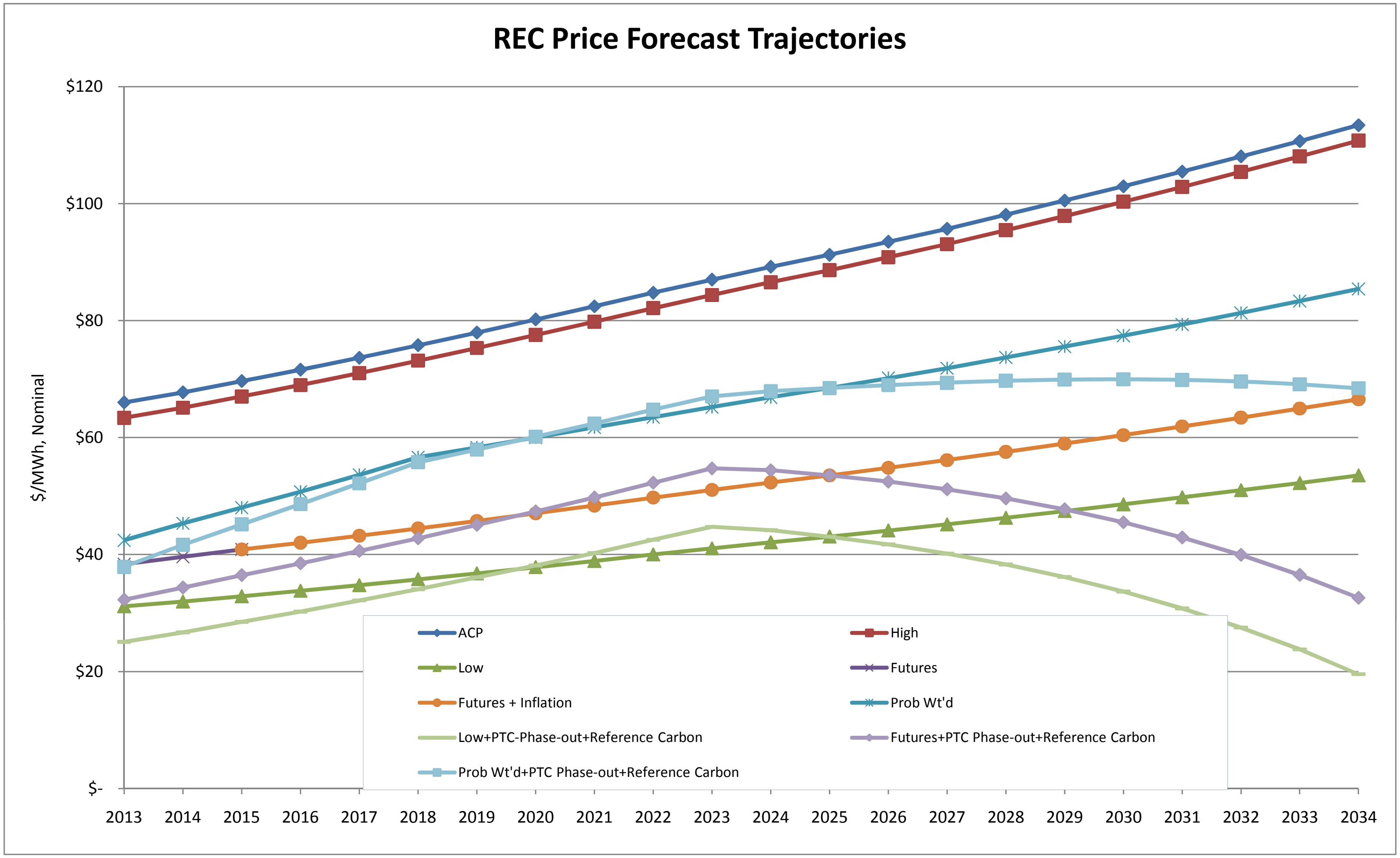
Because the PTC directly reduces the amount of Federal income taxes paid, it should be thought of as providing $20/MWh of after-tax income (in 2007 dollars). The amount of pre-tax income required to yield $20/MWh of aftertax income is $20/(1-marginal tax rate), or $30.8/MWh assuming a 35% marginal income tax rate. At a 7% real discount rate, $30.8/MWh for 10 years provides an equivalent PTC value of $20.4/MWh (in 2007 dollars) levelized over 20 years. See http://eetd.lbl.gov/EA/emp/reports/63583.pdf

Analysis of REC Future Values -- with Impact of Federal Incentives on non-shortage REC prices

			3a	4a					5a
Scenario	ACP	High	Low	Current Futures		High	Low	Current Futures	Probability-Weighted Avg.
		Shortage	Surplus & Banking						
	ACP	ACP less Transaction Cost	Recent Spot Esc. @ CPI	Chicago Climate Futures Exchange					
		$0.00							
2007			52						
2008			37						
2009	$60.92	$58.30	28.75						
2010	$ 61.62	$59.00	29.08	$32.63		10%	45%	45%	$ 33.67
2011	$ 63.14	$60.52	29.80	$35.67		15%	40%	45%	$ 37.05
2012	$ 64.47	$61.85	30.42	$37.07		20%	35%	45%	$ 39.70
2013	$ 65.99	$63.37	25.07	$32.27	**2013**	25%	30%	45%	$ 37.88
2014	$ 67.73	$65.11	26.70	$34.34	2014	30%	25%	45%	$ 41.66
2015	$ 69.64	$67.02	28.48	$36.48	2015	35%	25%	40%	$ 45.17
2016	$ 71.61	$68.99	30.26	$38.49	2016	40%	25%	35%	$ 48.63
2017	$ 73.64	$71.02	32.16	$40.62	2017	45%	25%	30%	$ 52.18
2018	$ 75.78	$73.16	34.07	$42.78	2018	50%	25%	25%	$ 55.80
2019	$ 77.94	$75.32	36.10	$45.05	2019	50%	25%	25%	$ 57.95
2020	$ 80.17	$77.55	38.14	$47.35	2020	50%	25%	25%	$ 60.15
2021	$ 82.42	$79.80	40.27	$49.73	2021	50%	25%	25%	$ 62.40
2022	$ 84.76	$82.14	42.53	$52.26	2022	50%	25%	25%	$ 64.77
2023	$ 86.99	$84.37	44.73	$54.72	2023	50%	25%	25%	$ 67.05
2024	$ 89.18	$86.56	44.16	$54.41	2024	50%	25%	25%	$ 67.92
2025	$ 91.24	$88.62	43.06	$53.54	2025	50%	25%	25%	$ 68.46
2026	$ 93.46	$90.84	41.74	$52.47	2026	50%	25%	25%	$ 68.97
2027	$ 95.69	$93.07	40.16	$51.15	2027	50%	25%	25%	$ 69.36
2028	$ 98.09	$95.47	38.32	$49.59	2028	50%	25%	25%	$ 69.71
2029	$ 100.52	$97.90	36.17	$47.72	2029	50%	25%	25%	$ 69.92
2030	$ 102.96	$100.34	33.67	$45.50	2030	50%	25%	25%	$ 69.96
2031	$ 105.47	$102.85	30.80	$42.92	2031	50%	25%	25%	$ 69.86
2032	$ 108.05	$105.43	27.52	$39.94	2032	50%	25%	25%	$ 69.58
2033	$ 110.69	$108.07	23.79	$36.51	2033	50%	25%	25%	$ 69.11
2034	$ 113.40	$110.78	19.55	$32.58	2034	50%	25%	25%	$ 68.42

Note: Rationalle for probability weights: current modest surplus attenuated by increasing difficulty in siting, reliance on poorer resource quality over time... working up the supply curve, and exacerbated by the apparent removal of biomass as a substantial future (and potential current) contributor,

* = escalated at CPI Forecast from AEO2008


REC Price Forecast Trajectories
$120
$100
$80
$60
$40
$20
$-
$/MWh, Nominal
2013
2014
2015
2016
2017
2018
2019
2020
2021
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2033
2034
ACP
High
Low
Futures
Futures + Inflation
Prob Wt'd
Low+PTC-Phase-out+Reference Carbon
Futures+PTC Phase-out+Reference Carbon
Prob Wt'd+PTC Phase-out+Reference Carbon

EXHIBIT G

Deepwater Wind - Block Island Wind Farm - PPA Valuation

Assumed Energy Deliveries			**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Contract Year			1	2	3	4	5	6	7	8	9	10	11	12
Project Commercial Operation Date (2013, 2014 or 2015)	2013													
Capacity Factor, Net of Losses to BI & Array and Outages	40%	%	30%	36%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Percent of Output Year 1 (reductions due to startup issues)	75%													
Percent of Output Year 2 (reductions due to startup issues)	90%													
Total Nameplate Rating of Project	28.8	MW												
PPA Energy Deliveries (year 1 CF = 25%)		MWh	75,686	90,824	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915
Annual Production Target (40%) for Outperfomace Adj.		MWh	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915
Aggregate Production Target		MWh	100,915	201,830	302,746	403,661	504,576	605,491	706,406	807,322	908,237	1,009,152	1,110,067	1,210,982
Actual Aggregate Production		MWh	75,686	166,510	267,425	368,340	469,256	570,171	671,086	772,001	872,916	973,832	1,074,747	1,175,662
Aggregate Production Surplus without Adjustment for Credits		MWh	(25,229)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)
less, Aggregate Prior Surplus		MWh	-	-	-	-	-	-	-	-	-	-	-	-
Production Surplus		MWh	-	-	-	-	-	-	-	-	-	-	-	-

Effective PPA Rate			**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Contract Year			1	2	3	4	5	6	7	8	9	10	11	12
Step 1: Contract energy price	starting $ 235.75													
Bundled Price with Annual Escalation - starts in 2012, stops if delay	3.5%	$/MWh	$ 244.00	$ 252.54	$ 261.38	$ 270.53	$ 280.00	$ 289.80	$ 299.94	$ 310.44	$ 321.30	$ 332.55	$ 344.19	$ 356.23
Step 2: Reduce payments by the market value of capacity														
Projected Forward Capacity Market Price - Prorated, Cal. Yr.		$/kw-mo	$ 2.56	$ 2.65	$ 2.76	$ 2.06	$ 1.57	$ 3.36	$ 5.52	$ 7.41	$ 8.43	$ 8.67	$ 8.90	$ 9.13
Projected Forward Capacity Market Price		$/kw-yr	$ 30.76	$ 31.77	$ 33.11	$ 24.68	$ 18.80	$ 40.28	$ 66.22	$ 88.89	$ 101.16	$ 104.01	$ 106.84	$ 109.58
Wind capacity credit (% of nameplate)		%	45.3%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Assumed Project Capacity Factor		%	30%	36%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
FCM Capacity Value ($0 for first 3 contract years)		$/MWh	$ -	$ -	$ -	$ 3.19	$ 2.43	$ 5.21	$ 8.56	$ 11.49	$ 13.08	$ 13.45	$ 13.81	$ 14.17
Adjusted PPA Price		$/MWh	$ 244.00	$ 252.54	$ 261.38	$ 267.34	$ 277.57	$ 284.59	$ 291.38	$ 298.95	$ 308.23	$ 319.10	$ 330.38	$ 342.07
Step 3: Reduce payments Wind Outperformance Adjustment Credit														
50% of Production Surplus		MWh	-	-	-	-	-	-	-	-	-	-	-	-
Value of Credit at Adjusted PPA Price (above)		$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Vaule of Credit divided by MWh Delivered		$/MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted PPA Price		$/MWh	$ 244.00	$ 252.54	$ 261.38	$ 267.34	$ 277.57	$ 284.59	$ 291.38	$ 298.95	$ 308.23	$ 319.10	$ 330.38	$ 342.07
Total PPA Rate ($/MWh at Delivery Point)		$/MWh	**$ 244.00**	**$ 252.54**	**$ 261.38**	**$ 267.34**	**$ 277.57**	**$ 284.59**	**$ 291.38**	**$ 298.95**	**$ 308.23**	**$ 319.10**	**$ 330.38**	**$ 342.07**

Market Value of Products Delivered to Narragansett Electric			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Contract Year			1	2	3	4	5	6	7	8	9	10	11	12
Step 1: forecast all-hours energy prices														
Enter														
2 Gas Price Case; 1 -High (+35%), 2- Base, 3- Low (-10%)		$/MMBtu	$ 6.21	$ 6.54	$ 6.96	$ 7.37	$ 7.80	$ 8.26	$ 8.82	$ 9.49	$ 10.06	$ 10.34	$ 10.32	$ 10.57
AEO 2009 Henry Hub Natural Gas Price (nominal)		$/MMBtu	$ 6.21	$ 6.54	$ 6.96	$ 7.37	$ 7.80	$ 8.26	$ 8.82	$ 9.49	$ 10.06	$ 10.34	$ 10.32	$ 10.57
Avg. Monthly Basis-Differential Ratios to from HH to NE			1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
AEO 2009 Natural Gas Price Adj. to NE		$/MMBtu	$ 7.35	$ 7.68	$ 8.10	$ 8.51	$ 8.94	$ 9.40	$ 9.96	$ 10.63	$ 11.20	$ 11.48	$ 11.46	$ 11.71
AEO 2009 Henry Hub ***adjustment*** per LBNL 2/09 memo (nominal)		$/MMBtu	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
AEO		$/MMBtu	$ 7.51	$ 7.84	$ 8.26	$ 8.67	$ 9.10	$ 9.56	$ 10.12	$ 10.79	$ 11.36	$ 11.64	$ 11.62	$ 11.87
NYMEX Gas Price Case; 1 -High, 2- Base, 3- Low, switched with AEO		$/MMBtu	$ 6.98	$ 7.17	$ 7.38	$ 7.56	$ 7.75	$ 7.96						
NYMEX Henry Hub Natural Gas Futures (nominal)		$/MMBtu	$ 6.98	$ 7.17	$ 7.38	$ 7.56	$ 7.75	$ 7.96						
Avg. Monthly Basis-Differential Ratios to from HH to NE			1.15	1.15	1.15	1.15	1.15	1.15						
NYMEX Futures Natural Gas Price Adj. to New England		$/MMBtu	$ 7.99	$ 8.21	$ 8.44	$ 8.65	$ 8.87	$ 9.11						
Weighting AEO adjusted forecast		%	0%	0%	0%	25%	50%	75%	100%	100%	100%	100%	100%	100%
Weighting NYMEX forecast		%	100%	100%	100%	75%	50%	25%	0%	0%	0%	0%	0%	0%
Resultant Natural Gas Price Forecast		$/MMBtu	$ 7.99	$ 8.21	$ 8.44	$ 8.66	$ 8.99	$ 9.44	$ 10.12	$ 10.79	$ 11.36	$ 11.64	$ 11.62	$ 11.87
Average Market Marginal Heat Rate	8,095	Btu/KWh	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095
All-Hours Average Value (New England)		$/MWh	$ 64.68	$ 66.44	$ 68.36	$ 70.09	$ 72.74	$ 76.46	$ 81.89	$ 87.35	$ 91.92	$ 94.21	$ 94.05	$ 96.11
NYMEX ISO-NE Internal Hub LMP Swap Futures - for comparison		$/MWh	$ 64.38	$ 66.55										
Step 2: Adjustment for Project's Production Profile														
Adjustment Factor (hourly energy delivered x LMP) / avg LMP			1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022
Raw Production Profile-Adjusted Value		$/MWh	$ 66.10	$ 67.90	$ 69.87	$ 71.63	$ 74.34	$ 78.14	$ 83.69	$ 89.27	$ 93.94	$ 96.28	$ 96.12	$ 98.23
Step 3: Adjustement for differential between NE avg and RI Load Zone														
Average differential 2006-10/2009 = 2.0%,	2.0%													
Adjustment to RI Load Zone		$/MWh	$ 1.32	$ 1.36	$ 1.40	$ 1.43	$ 1.49	$ 1.56	$ 1.67	$ 1.79	$ 1.88	$ 1.93	$ 1.92	$ 1.96
Adjusted Energy Market Value		$/MWh	$ 67.42	$ 69.26	$ 71.26	$ 73.06	$ 75.83	$ 79.70	$ 85.36	$ 91.06	$ 95.82	$ 98.21	$ 98.04	$ 100.19
Step 4: Carbon Allowance Adder														
Case 1: AESC Reference Case		$/MWh	$ 8.16	$ 9.66	$ 11.20	$ 12.87	$ 14.57	$ 16.44	$ 18.31	$ 20.36	$ 22.49	$ 24.67	$ 26.97	$ 29.27
Case 2: AESC RGGI Only Case		$/MWh	$ 2.09	$ 2.14	$ 2.20	$ 2.27	$ 2.33	$ 2.40	$ 2.47	$ 2.54	$ 2.61	$ 2.68	$ 2.75	$ 2.82
Case 3: AESC High CO2 Allowance Case		$/MWh	$ 16.32	$ 18.04	$ 19.81	$ 21.14	$ 23.68	$ 25.81	$ 27.95	$ 30.28	$ 32.69	$ 35.15	$ 37.73	$ 40.30
Case 4: EIA Forecast of Markey Waxman Climate Bill		$/MWh	$ 9.15	$ 10.05	$ 11.05	$ 12.15	$ 13.37	$ 14.71	$ 16.19	$ 17.84	$ 19.66	$ 21.65	$ 23.82	$ 26.17
Enter														
1 Case # and Carbon Allowance Cost Assumed		$/MWh	$ 8.16	$ 9.66	$ 11.20	$ 12.87	$ 14.57	$ 16.44	$ 18.31	$ 20.36	$ 22.49	$ 24.67	$ 26.97	$ 29.27
Adjusted Energy Market Value		$/MWh	$ 75.58	$ 78.92	$ 82.46	$ 85.93	$ 90.40	$ 96.14	$ 103.68	$ 111.42	$ 118.31	$ 122.88	$ 125.01	$ 129.46
Step 5: REC Value														
Case 1: ACP Case - $60.92 in 2009, esc @ CPI		$/MWh	$ 65.99	$ 67.73	$ 69.64	$ 71.61	$ 73.64	$ 75.78	$ 77.94	$ 80.17	$ 82.42	$ 84.76	$ 86.99	$ 89.18
Case 2: High Case - Shortage (ACP less transaction costs)		$/MWh	$ 63.37	$ 65.11	$ 67.02	$ 68.99	$ 71.02	$ 73.16	$ 75.32	$ 77.55	$ 79.80	$ 82.14	$ 84.37	$ 86.56
Case 3: Low Case - Surplus and Banking		$/MWh	$ 31.14	$ 31.96	$ 32.86	$ 33.79	$ 34.75	$ 35.77	$ 36.78	$ 37.84	$ 38.90	$ 40.00	$ 41.05	$ 42.09
Case 4: Current Futures		$/MWh	$ 38.34	$ 39.61	$ 40.87	$ 42.02	$ 43.21	$ 44.47	$ 45.74	$ 47.05	$ 48.37	$ 49.74	$ 51.05	$ 52.34
Case 5: Probability Weighted Average of Cases 2, 3, and 4		$/MWh	$ 42.44	$ 45.35	$ 48.02	$ 50.75	$ 53.61	$ 56.64	$ 58.29	$ 60.00	$ 61.72	$ 63.50	$ 65.21	$ 66.89
Case 3a: Low+PTC Phase-Out+Reference Carbon		$/MWh	$ 25.07	$ 26.70	$ 28.48	$ 30.26	$ 32.16	$ 34.07	$ 36.10	$ 38.14	$ 40.27	$ 42.53	$ 44.73	$ 44.16
Case 4a Futures +PTC Phase-Out+Reference Carbon		$/MWh	$ 32.27	$ 34.34	$ 36.48	$ 38.49	$ 40.62	$ 42.78	$ 45.05	$ 47.35	$ 49.73	$ 52.26	$ 54.72	$ 54.41
Case 5a: Prob-Wtd +PTC Phase-Out+Reference Carbon		$/MWh	$ 37.88	$ 41.66	$ 45.17	$ 48.63	$ 52.18	$ 55.80	$ 57.95	$ 60.15	$ 62.40	$ 64.77	$ 67.05	$ 67.92
Enter														
5a Case # and REC Value Assumed		$/MWh	$ 37.88	$ 41.66	$ 45.17	$ 48.63	$ 52.18	$ 55.80	$ 57.95	$ 60.15	$ 62.40	$ 64.77	$ 67.05	$ 67.92
Adjusted Energy Market Value		$/MWh	$ 113.47	$ 120.58	$ 127.63	$ 134.56	$ 142.58	$ 151.93	$ 161.62	$ 171.57	$ 180.71	$ 187.65	$ 192.06	$ 197.38
Aggregate Market Value at Delivery Point)		$/MWh	**$ 113.47**	**$ 120.58**	**$ 127.63**	**$ 134.56**	**$ 142.58**	**$ 151.93**	**$ 161.62**	**$ 171.57**	**$ 180.71**	**$ 187.65**	**$ 192.06**	**$ 197.38**
Total Above Market Value at Delivery Point)		$/MWh	**$ 130.53**	**$ 131.96**	**$ 133.75**	**$ 132.77**	**$ 134.99**	**$ 132.66**	**$ 129.75**	**$ 127.37**	**$ 127.51**	**$ 131.46**	**$ 138.32**	**$ 144.68**

Summary			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Contract Year			1	2	3	4	5	6	7	8	9	10	11	12
Energy Delivered		MWh	75,686	90,824	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915
Effective PPA Rate		$/MWh	$ 244	$ 253	$ 261	$ 267	$ 278	$ 285	$ 291	$ 299	$ 308	$ 319	$ 330	$ 342
PPA Payments		$000	$ 18,468	$ 22,937	$ 26,377	$ 26,979	$ 28,011	$ 28,719	$ 29,405	$ 30,168	$ 31,105	$ 32,202	$ 33,340	$ 34,520
PV @ Narragansett Electric WACC from pending rate case	8.98%	$000												
Levelized Price as of 1/1/2013	**$306**	$/MWh	**$ 274,316**	PV million as of 1/1/2013										
Market Value of Products Delivered		$/MWh	$ 113	$ 121	$ 128	$ 135	$ 143	$ 152	$ 162	$ 172	$ 181	$ 188	$ 192	$ 197
Market Value of Products Delivered		$000	$ 8,588	$ 10,952	$ 12,880	$ 13,580	$ 14,389	$ 15,332	$ 16,310	$ 17,314	$ 18,237	$ 18,936	$ 19,381	$ 19,919
PV @ Narragansett Electric WACC from pending rate case	8.98%	$000												
Levelized Price as of 1/1/2013	**$166**	$/MWh	**$ 149,893**	PV million as of 1/1/2013										
Above Market Amount		$/MWh	$ 131	$ 132	$ 134	$ 133	$ 135	$ 133	$ 130	$ 127	$ 128	$ 131	$ 138	$ 145
Above Market Amount		$000	$ 9,880	$ 11,985	$ 13,498	$ 13,399	$ 13,622	$ 13,387	$ 13,094	$ 12,854	$ 12,868	$ 13,266	$ 13,959	$ 14,601
PV @ Narragansett Electric WACC from pending rate case	8.98%	$000												
Levelized Price as of 1/1/2013	**$139**	$/MWh	**$ 124,423**	PV million as of 1/1/2013										

Deepwater Wind - Block Island Wind Farm - PPA Valuation

Assumed Energy Deliveries			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contract Year			13	14	15	16	17	18	19	20	-	-
Project Commercial Operation Date (2013, 2014 or 2015)	2013											
Capacity Factor, Net of Losses to BI & Array and Outages	40%	%	40%	40%	40%	40%	40%	40%	40%	40%	0%	0%
Percent of Output Year 1 (reductions due to startup issues)	75%											
Percent of Output Year 2 (reductions due to startup issues)	90%											
Total Nameplate Rating of Project	28.8	MW										
PPA Energy Deliveries (year 1 CF = 25%)		MWh	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	-	-
Annual Production Target (40%) for Outperfomace Adj.		MWh	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915
Aggregate Production Target		MWh	1,311,898	1,412,813	1,513,728	1,614,643	1,715,558	1,816,474	1,917,389	2,018,304	2,119,219	2,220,134
Actual Aggregate Production		MWh	1,276,577	1,377,492	1,478,408	1,579,323	1,680,238	1,781,153	1,882,068	1,982,984	1,982,984	1,982,984
Aggregate Production Surplus without Adjustment for Credits		MWh	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(35,320)	(136,236)	(237,151)
less, Aggregate Prior Surplus		MWh	-	-	-	-	-	-	-	-	-	-
Production Surplus		MWh	-	-	-	-	-	-	-	-	-	-

Effective PPA Rate			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contract Year			13	14	15	16	17	18	19	20	-	-
Step 1: Contract energy price	starting $ 235.75											
Bundled Price with Annual Escalation - starts in 2012, stops if delay	3.5%	$/MWh	$ 368.70	$ 381.61	$ 394.96	$ 408.79	$ 423.09	$ 437.90	$ 453.23	$ 469.09	$ 485.51	$ 502.50
Step 2: Reduce payments by the market value of capacity												
Projected Forward Capacity Market Price - Prorated, Cal. Yr.		$/kw-mo	$ 9.35	$ 9.57	$ 9.80	$ 10.04	$ 10.29	$ 10.55	$ 10.80	$ 11.07	$ 11.34	$ 11.61
Projected Forward Capacity Market Price		$/kw-yr	$ 112.21	$ 114.88	$ 117.64	$ 120.53	$ 123.53	$ 126.55	$ 129.64	$ 132.81	$ 136.05	$ 139.38
Wind capacity credit (% of nameplate)		%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Assumed Project Capacity Factor		%	40%	40%	40%	40%	40%	40%	40%	40%	0%	0%
FCM Capacity Value ($0 for first 3 contract years)		$/MWh	$ 14.51	$ 14.85	$ 15.21	$ 15.58	$ 15.97	$ 16.36	$ 16.76	$ 17.17	$ -	$ -
Adjusted PPA Price		$/MWh	$ 354.20	$ 366.76	$ 379.75	$ 393.20	$ 407.12	$ 421.54	$ 436.47	$ 451.92	$ 485.51	$ 502.50
Step 3: Reduce payments Wind Outperformance Adjustment Credit												
50% of Production Surplus		MWh	-	-	-	-	-	-	-	-	-	-
Value of Credit at Adjusted PPA Price (above)		$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Vaule of Credit divided by MWh Delivered		$/MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjusted PPA Price		$/MWh	$ 354.20	$ 366.76	$ 379.75	$ 393.20	$ 407.12	$ 421.54	$ 436.47	$ 451.92	$ 485.51	$ 502.50
Total PPA Rate ($/MWh at Delivery Point)		$/MWh	**$ 354.20**	**$ 366.76**	**$ 379.75**	**$ 393.20**	**$ 407.12**	**$ 421.54**	**$ 436.47**	**$ 451.92**	**$ 485.51**	**$ 502.50**

Market Value of Products Delivered to Narragansett Electric			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contract Year			13	14	15	16	17	18	19	20	-	-
Step 1: forecast all-hours energy prices												
Enter												
2 Gas Price Case; 1 -High (+35%), 2- Base, 3- Low (-10%)		$/MMBtu	$ 10.72	$ 11.14	$ 11.78	$ 12.59	$ 13.24	$ 13.97	$ 15.03	$ 16.18	$ 17.42	$ 18.75
AEO 2009 Henry Hub Natural Gas Price (nominal)		$/MMBtu	$ 10.72	$ 11.14	$ 11.78	$ 12.59	$ 13.24	$ 13.97	$ 15.03	$ 16.18	$ 17.42	$ 18.75
Avg. Monthly Basis-Differential Ratios to from HH to NE			1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
AEO 2009 Natural Gas Price Adj. to NE		$/MMBtu	$ 11.86	$ 12.28	$ 12.92	$ 13.73	$ 14.38	$ 15.11	$ 16.17	$ 17.32	$ 18.56	$ 19.89
AEO 2009 Henry Hub ***adjustment*** per LBNL 2/09 memo (nominal)		$/MMBtu	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
AEO		$/MMBtu	$ 12.02	$ 12.44	$ 13.08	$ 13.89	$ 14.54	$ 15.27	$ 16.33	$ 17.48	$ 18.72	$ 20.05
NYMEX Gas Price Case; 1 -High, 2- Base, 3- Low, switched with AEO		$/MMBtu										
NYMEX Henry Hub Natural Gas Futures (nominal)		$/MMBtu										
Avg. Monthly Basis-Differential Ratios to from HH to NE												
NYMEX Futures Natural Gas Price Adj. to New England		$/MMBtu										
Weighting AEO adjusted forecast		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Weighting NYMEX forecast		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Resultant Natural Gas Price Forecast		$/MMBtu	$ 12.02	$ 12.44	$ 13.08	$ 13.89	$ 14.54	$ 15.27	$ 16.33	$ 17.48	$ 18.72	$ 20.05
Average Market Marginal Heat Rate	8,095	Btu/KWh	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095	8,095
All-Hours Average Value (New England)		$/MWh	$ 97.30	$ 100.70	$ 105.89	$ 112.45	$ 117.73	$ 123.59	$ 132.22	$ 141.51	$ 151.51	$ 162.27
NYMEX ISO-NE Internal Hub LMP Swap Futures - for comparison		$/MWh										
Step 2: Adjustment for Project's Production Profile												
Adjustment Factor (hourly energy delivered x LMP) / avg LMP			1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022	1.022
Raw Production Profile-Adjusted Value		$/MWh	$ 99.44	$ 102.91	$ 108.22	$ 114.92	$ 120.32	$ 126.31	$ 135.13	$ 144.62	$ 154.84	$ 165.84
Step 3: Adjustement for differential between NE avg and RI Load Zone												
Average differential 2006-10/2009 = 2.0%,	2.0%											
Adjustment to RI Load Zone		$/MWh	$ 1.99	$ 2.06	$ 2.16	$ 2.30	$ 2.41	$ 2.53	$ 2.70	$ 2.89	$ 3.10	$ 3.32
Adjusted Energy Market Value		$/MWh	$ 101.43	$ 104.97	$ 110.38	$ 117.22	$ 122.73	$ 128.83	$ 137.83	$ 147.51	$ 157.94	$ 169.15
Step 4: Carbon Allowance Adder												
Case 1: AESC Reference Case		$/MWh	$ 32.01	$ 35.06	$ 38.38	$ 42.06	$ 46.08	$ 50.46	$ 55.27	$ 60.53	$ 66.30	$ 72.61
Case 2: AESC RGGI Only Case		$/MWh	$ 2.89	$ 2.96	$ 3.03	$ 3.10	$ 3.18	$ 3.26	$ 3.34	$ 3.42	$ 3.50	$ 3.59
Case 3: AESC High CO2 Allowance Case		$/MWh	$ 43.18	$ 46.32	$ 49.67	$ 53.32	$ 57.23	$ 61.38	$ 65.86	$ 70.66	$ 75.81	$ 81.34
Case 4: EIA Forecast of Markey Waxman Climate Bill		$/MWh	$ 28.75	$ 31.57	$ 34.66	$ 38.07	$ 41.82	$ 45.90	$ 50.41	$ 55.35	$ 60.78	$ 66.75
Enter												
1 Case # and Carbon Allowance Cost Assumed		$/MWh	$ 32.01	$ 35.06	$ 38.38	$ 42.06	$ 46.08	$ 50.46	$ 55.27	$ 60.53	$ 66.30	$ 72.61
Adjusted Energy Market Value		$/MWh	$ 133.45	$ 140.03	$ 148.76	$ 159.28	$ 168.81	$ 179.29	$ 193.09	$ 208.04	$ 224.23	$ 241.77
Step 5: REC Value												
Case 1: ACP Case - $60.92 in 2009, esc @ CPI		$/MWh	$ 91.24	$ 93.46	$ 95.69	$ 98.09	$ 100.52	$ 102.96	$ 105.47	$ 108.05	$ 110.69	$ 113.40
Case 2: High Case - Shortage (ACP less transaction costs)		$/MWh	$ 88.62	$ 90.84	$ 93.07	$ 95.47	$ 97.90	$ 100.34	$ 102.85	$ 105.43	$ 108.07	$ 110.78
Case 3: Low Case - Surplus and Banking		$/MWh	$ 43.06	$ 44.11	$ 45.16	$ 46.29	$ 47.44	$ 48.59	$ 49.78	$ 50.99	$ 52.24	$ 53.52
Case 4: Current Futures		$/MWh	$ 53.54	$ 54.85	$ 56.15	$ 57.56	$ 58.99	$ 60.42	$ 61.89	$ 63.41	$ 64.96	$ 66.55
Case 5: Probability Weighted Average of Cases 2, 3, and 4		$/MWh	$ 68.46	$ 70.16	$ 71.86	$ 73.70	$ 75.56	$ 77.42	$ 79.34	$ 81.32	$ 83.34	$ 85.41
Case 3a: Low+PTC Phase-Out+Reference Carbon		$/MWh	$ 43.06	$ 41.74	$ 40.16	$ 38.32	$ 36.17	$ 33.67	$ 30.80	$ 27.52	$ 23.79	$ 19.55
Case 4a Futures +PTC Phase-Out+Reference Carbon		$/MWh	$ 53.54	$ 52.47	$ 51.15	$ 49.59	$ 47.72	$ 45.50	$ 42.92	$ 39.94	$ 36.51	$ 32.58
Case 5a: Prob-Wtd +PTC Phase-Out+Reference Carbon		$/MWh	$ 68.46	$ 68.97	$ 69.36	$ 69.71	$ 69.92	$ 69.96	$ 69.86	$ 69.58	$ 69.11	$ 68.42
Enter												
5a Case # and REC Value Assumed		$/MWh	$ 68.46	$ 68.97	$ 69.36	$ 69.71	$ 69.92	$ 69.96	$ 69.86	$ 69.58	$ 69.11	$ 68.42
Adjusted Energy Market Value		$/MWh	$ 201.91	$ 209.00	$ 218.12	$ 228.99	$ 238.73	$ 249.25	$ 262.95	$ 277.62	$ 293.34	$ 310.19
Aggregate Market Value at Delivery Point)		$/MWh	**$ 201.91**	**$ 209.00**	**$ 218.12**	**$ 228.99**	**$ 238.73**	**$ 249.25**	**$ 262.95**	**$ 277.62**	**$ 293.34**	**$ 310.19**
Total Above Market Value at Delivery Point)		$/MWh	**$ 152.29**	**$ 157.75**	**$ 161.63**	**$ 164.22**	**$ 168.39**	**$ 172.29**	**$ 173.52**	**$ 174.30**	**$ 192.17**	**$ 192.31**

Summary			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Contract Year			13	14	15	16	17	18	19	20	-	-
Energy Delivered		MWh	100,915	100,915	100,915	100,915	100,915	100,915	100,915	100,915	-	-
Effective PPA Rate		$/MWh	$ 354	$ 367	$ 380	$ 393	$ 407	$ 422	$ 436	$ 452	$ -	$ -
PPA Payments		$000	$ 35,744	$ 37,011	$ 38,323	$ 39,680	$ 41,085	$ 42,540	$ 44,046	$ 45,606	$ -	$ -
PV @ Narragansett Electric WACC from pending rate case	8.98%	$000										
Levelized Price as of 1/1/2013	**$306**	$/MWh										
Market Value of Products Delivered		$/MWh	$ 202	$ 209	$ 218	$ 229	$ 239	$ 249	$ 263	$ 278	$ -	$ -
Market Value of Products Delivered		$000	$ 20,376	$ 21,091	$ 22,012	$ 23,109	$ 24,091	$ 25,153	$ 26,536	$ 28,017	$ -	$ -
PV @ Narragansett Electric WACC from pending rate case	8.98%	$000										
Levelized Price as of 1/1/2013	**$166**	$/MWh										
Above Market Amount		$/MWh	$ 152	$ 158	$ 162	$ 164	$ 168	$ 172	$ 174	$ 174	$ -	$ -
Above Market Amount		$000	$ 15,368	$ 15,920	$ 16,311	$ 16,572	$ 16,994	$ 17,387	$ 17,511	$ 17,589	$ -	$ -
PV @ Narragansett Electric WACC from pending rate case	8.98%	$000										
Levelized Price as of 1/1/2013	**$139**	$/MWh										