STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

In re Review of Proposed Town of New Shoreham Project Pursuant to R.I. Gen. Laws § 39-26.1-7	)))))	**Docket No. 4185**

NATIONAL GRID AND DEEPWATER WIND BLOCK ISLAND, LLC'S
MOTION TO STRIKE TESTIMONY

Pursuant to Commission Rule 1.20(g), The Narragansett Electric Company d/b/a National Grid ("National Grid") and Deepwater Wind Block Island, LLC ("Deepwater Wind") (collectively, "Applicants") object to and move the Commission to strike testimony regarding renewed open solicitation, avoided costs, and rate effects, and specifically (1) lines 111-144 of the Direct Testimony of William P. Short III on behalf of the Patrick C. Lynch, Rhode Island Attorney General ("Attorney General"), and (2) lines 8:15-10:16 of the Direct Testimony of Robert McCullough on behalf of the Citizen Intervenor Group ("Citizen Group"). In support of this motion, the Applicants state as follows:

A. The Commission should exclude the testimony and disallow further testimony on renewed open solicitation because the topic is not relevant to this proceeding.

At the July 21, 2010 hearing on the motions to dismiss filed by various parties to this docket, the Attorney General argued for the first time that the Long-Term Contracting Standard for Renewable Energy, as amended (the "Amended LTC"), R.I. Gen. Laws §§ 39-26.1-1 through 39-26.1-8[1], requires National Grid to conduct another open solicitation prior to entering any amended power purchase agreement in connection with the Town of New Shoreham Project (the

[1] Unless otherwise stated, all statutory references are to the Rhode Island General Laws.

"Project"). The Attorney General claims that the present proceeding is "tainted" because National Grid did not undertake this renew this solicitation. In support of this claim, the Attorney General submitted the testimony of William P. Short III describing the selection process purportedly necessary in order to achieve a "commercially reasonable" power purchase agreement. *See* Short Direct at 111-144, attached hereto as Exhibit A. The Amended LTC, however, on its face, does not require National Grid to conduct another open solicitation. Therefore, Mr. Short's testimony on this issue should be stricken because it conflicts with the Amended LTC and is irrelevant to the issues actually before the Commission. The Commission additionally should disallow any further testimony, including cross-examination, regarding the issue of solicitation.

Far from requiring National Grid to conduct another solicitation in connection with the Project, the Amended LTC authorizes National Grid "to enter into an amended power purchase agreement with the developer of offshore wind . . . on terms that are consistent with the power purchase agreement that was filed with the commission on December 9, 2009 in Docket 4111." § 39-26.1-7(a). The Amended LTC plainly and unambiguously provides that Deepwater Wind is "the developer of offshore wind" within the meaning of the statute. If a statute is "clear and unambiguous," the task of interpretation is at an end and the Commission must apply the "plain, ordinary and usual meaning of the words used." *In re New England Gas Co.*, 2003 R.I. PUC LEXIS 21, *103 (R.I. PUC Aug. 1, 2003) (citing *Bristol County Water v. PUC*, 117 R.I. 89, 94 (1976)).

First, Deepwater Wind is "the developer of offshore wind" that was National Grid's counterparty in the power purchase agreement filed in Docket 4111. In now authorizing National Grid to enter into an "amended" power purchase agreement on terms that are

"consistent" with the power purchase agreement filed in Docket 4111, the General Assembly clearly contemplated that National Grid would enter into a power purchase agreement, if any, with Deepwater Wind – the only developer that submitted a bid during the original solicitation for the Project, and the only developer with which National Grid had a prior agreement that could be "amended." The Amended LTC specifies that the amended power purchase agreement must contain a substantially revised pricing structure to allow for modified "open book" pricing, but must otherwise be "consistent" with the prior agreement.[2] § 39-26.1-7(a). Nowhere in the Amended LTC does it provide, or even suggest, that the amended power purchase agreement might include a new developer or different counterparty. Nor did the General Assembly require National Grid to undertake any additional solicitation process similar to that which had been required in advance of the prior agreement.

Second, the Amended LTC provides that all the parties to Docket 4111 shall be allowed to appear and file testimony in this docket. § 39-26.1-7(b). This again demonstrates that the General Assembly intended the amended power purchase agreement to continue to be between National Grid and Deepwater Wind – the two parties who reached agreement on the original power purchase agreement. If the General Assembly contemplated a re-opening of the solicitation process and a new agreement with a different developer with, possibly, an entirely different approach to the Project, there would be no reason to automatically presume that all the parties to Docket 4111 would be sufficiently interested in the amended agreement to justify their intervening in these proceedings.

Third, the Amended LTC sets forth an expedited schedule according to which the Commission must hear and consider all testimony and argument and issue a written decision

[2] The statute allows other minor changes to the agreement, including revised dates, deadlines, and other minor changes necessary to conform to the amended statute.

accepting or rejecting the amended power purchase agreement *within 45 days* after the agreement is filed. § 39-26.1-7(b). This extraordinarily compressed schedule indicates that the General Assembly intended that the parties and the Commission complete this Project quickly. If the General Assembly intended that National Grid re-open the solicitation process, it would have established a similarly tasking time frame for that process, given the importance of swift action. Further, the General Assembly plainly believed there would be substantial similarities between the agreement in Docket 4111 and the agreement in this docket. Again, if there was a chance that the amended agreement would involve a different developer with a different approach, it would be unreasonable to expect the Commission to evaluate the agreement within only 45 days.

Fourth, the Amended LTC specifically references the prior agreement in establishing requirements for the amended agreement. For example, the Amended LTC provides that the maximum initial price contained in the amended agreement shall be the same as the initial fixed price contained in the prior agreement. § 39-26.1-7(e). This provision would make no sense whatsoever if the amended power purchase agreement involved a developer other than Deepwater Wind. That developer would find its maximum initial price to be limited by the initial fixed price agreed to by Deepwater Wind in connection with a different project design. The absurdity of this result underscores the General Assembly's intention to facilitate an amended agreement involving National Grid and Deepwater Wind, and not to provide a second bite at the apple for other developers who, for whatever reason, failed to bid on the Project when provided the opportunity to do so.

Because the Amended LTC clearly and unambiguously provides that National Grid is authorized to enter into an amended power purchase agreement with Deepwater Wind without

reopening a new solicitation, the Commission should strike lines 111-144 of Mr. Short's testimony, which set forth Mr. Short's opinion as to the minimally necessary solicitation process. Moreover, the Commission should disallow any further argument and testimony, including cross-examination and rebuttal, that concerns or relates to a contention or presumption that the Amended LTC required National Grid to conduct an open solicitation before signing the amended power purchase agreement.

B. The Commission should exclude the testimony and disallow further testimony on avoided costs and rate effects because that testimony is not relevant to this proceeding.

1. Mr. McCullough's comparison of the Project costs to National Grid's avoided costs is inappropriate in light of the Amended LTC's standard of review and express definition of "commercially reasonable."

In his direct testimony on behalf of the Citizen Group, Mr. McCullough claims that National Grid should have compared the Project costs to National Grid's avoided cost filings. *See* McCullough Direct at 8:15-10:16, attached hereto as Exhibit B. Only with such a comparison, he suggests, can it be determined whether the amended power purchase agreement is "commercially reasonable." *Id.* at 9:3-4. Mr. McCullough's approach contradicts the plain language of the Amended LTC which expressly defines "commercially reasonable" for purposes of this proceeding: "'[C]ommercially reasonable' shall mean terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see *for a project of a similar size, technology and location, and meeting the [Amended LTC's] policy goals . . . .*" § 39-26.1-7(c)(IV) (emphasis added). Under this clear mandate, the comparison suggested by Mr. McCullough is inappropriate, irrelevant, and uninformative. The amended agreement is to be evaluated not on how its terms and pricing compare with traditional energy

sources, but on whether its terms and pricing are consistent with what could be expected for a similar project that meets the General Assembly's policy goals.

The Commission should strike lines 8:15-10:16 of Mr. McCullough's direct testimony and disallow any further argument and testimony, including cross-examination and rebuttal, that involves a comparison of the Project costs and National Grid's avoided cost filings.

2. Mr. McCullough's testimony that the Commission should compare the Project's rate impacts with its benefits is improper and ignores the standard of review set forth by the Amended LTC.

Moreover, to the extent that Mr. McCullough's testimony seeks to impugn the amended agreement because the Project will produce energy at a cost higher than that incurred to produce energy from fossil fuels, that testimony is also irrelevant to the questions before the Commission. The General Assembly has *already* decided that the benefits of the Project justify its costs and the slightly higher electric rates that will result. That is why the General Assembly instructed the Commission to approve the amended agreement if the agreement is likely to provide those other benefits defined in the Amended LTC. § 39-26.1-7(c). In fact, the Commission in its Docket 4111 Order recognized that that this Project will produce higher than current market price energy. "The Commission is keenly aware that offshore wind resources are likely to be more expensive than electricity generated from fossil fuels, but the price premium does not automatically disqualify a project in the future, provided that the pricing is commercially reasonable." Order No. 19941 (Docket 4111) at 84. The standard of review Mr. McCullough seeks to employ is more akin to that found in § 39-26.1-8, which sets forth the standard of review applicable to applications for a utility-scale offshore wind project. Under that standard, the Commission is required to consider, among other things, "[t]he economic impact and potential risks, if any, of the proposal on rates to be charged by the electric distribution company." § 39-

26.1-8(b). That standard simply does not apply to this proceeding. What is relevant here is whether the amended agreement is "commercially reasonable" and will, among other things, facilitate new and existing business expansion and the creation of new renewable energy jobs, contribute to the further development of Quonset Business Park, and increase the preparedness of the Rhode Island workforce to support the renewable energy industry. *See* § 39-26.1-7(c).

The Commission should strike lines 8:15-10:16 of Mr. McCullough's direct testimony and disallow any further argument and testimony, including cross-examination and rebuttal, that involves a contention or presumption that higher electricity rates justify denial of the amended power purchase agreement.

WHEREFORE, The Narragansett Electric Company d/b/a National Grid and Deepwater Wind Block Island, LLC respectfully request that the Commission: (1) strike lines 111-144 of the Direct Testimony of William P. Short III on behalf of Patrick C. Lynch, Rhode Island Attorney General and lines 8:15-10:16 of the Direct Testimony of Robert McCullough on behalf of the Citizen Intervenor Group, and (2) disallow any further argument and testimony, including cross-examination and rebuttal, that (i) concerns or relates to a contention or presumption that the Amended LTC required National Grid to renew an open solicitation before signing the amended power purchase agreement, (ii) involves a comparison of the Project costs and National Grid's avoided cost filings, or (iii) concerns or relates to a contention or presumption that higher electric rates justify denial of the amended power purchase agreement.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID and DEEPWATER WIND BLOCK ISLAND, LLC

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DATED: July 23, 2010

CERTIFICATION

I hereby certify that an original and twelve copies of the within were hand-delivered to the Commission Clerk, Public Utilities Commission, 99 Jefferson Boulevard, Warwick, Rhode Island 02888. In addition, electronic copies were transmitted by e-mail to all persons on the below service list. I hereby certify that all of the foregoing was done on July 23, 2010.

National Grid – Review of Proposed Town of New Shoreham Project
Docket No. 4185 – Service List Updated 7/22/10

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EXHIBIT

A

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATION
PUBLIC UTILITIES COMMISSION

In Re: Docket No. 4185 - Review of Amended Purchase Power Purchase Agreement between Narragansett Electric d/b/a National Grid and Deepwater Wind Block Island, LLC Pursuant to R.I.G.L § 39-26.1-7	**:**	**Docket No. 4185**

Pre-Filed Testimony of Expert Witness
William P. Short III

Michael Rubin, Esq.
State Of Rhode Island &
Providence Plantation
Department of Attorney General
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(401) 274-4400, x-2116

July 20, 2010

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

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

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

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

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

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

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

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

[1] The NEPOOL GIS is the tracking and trading system that was established for, among other things, the verification of compliance with the various New England state RPS programs. It also provides a data base of public reports on generator production.
[2] "New" RECs may be defined collectively as Massachusetts Class I, Connecticut Class I, New Hampshire Class I, Maine Class I and Rhode Island New REC.

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

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

Q. **Please describe your education.**

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

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

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

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

Q. **Were you a participant in Docket No. 4111 - National Grid - Review of Proposed Town of New Shoreham Project Pursuant to R.I.G.L. § 39-26.1-7?**

A. Yes, I was retained by Maggie and Michael Delia (the "Delias") as their expert witness in that proceeding. I prepared written testimony and answered one set of questions from the Division.[4] Unfortunately, before I could answer additional questions and provide oral testimony, the Delias withdrew from the proceeding as an Intervenor and my testimony was changed to Public Comment.

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

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

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

A. I have been retained by the Department of Attorney General of the State of Rhode Island & Providence Plantations as its expert witness in this proceeding.

Q. **What have you done to prepare for this proceeding?**

4 My written testimony and answer can be found at http://www.ripuc.org/eventsactions/docket/4111page.html.

A. In order to prepare my testimony, I have reviewed the file for both Docket No. 4185 and No. 4111 as well as relevant industry literature.

Q. Assume for the sake of this question the following legal conclusion: The most recent amendment to the LTC statute (chap. 31 of the 2010 PL of RI & chap. 32 of 2010 PL of RI) does not preclude the selection of developers other than Deepwater Wind Block Island, LLC ("Deepwater") as "the developer." With that assumption in mind, can you elaborate on the selection process that would be necessary to support a conclusion of commercial reasonableness?

A. Yes. The selection process of Deepwater as the developer of the Project was seriously flawed. Essentially, there was no competitive process held to select the developer of the Project and then negotiate the contract now before the Commission. With no competitive process, it is my opinion that the contract terms and conditions cannot be judged to be commercially reasonable.

National Grid is familiar with competitive bidding to obtain the lowest cost renewable energy contracts. Recently, the Massachusetts Department of Energy Resources and the Massachusetts electric distribution utilities, including National Grid, conducted a joint solicitation for long-term contracts to purchase Bundled Energy from Massachusetts renewable energy projects. In that case, there was a mass e-mailing of a notice of a request for proposals, a comment period with questions and answers, and then a bid period where offers were made using a form of standard contract. This was followed with a negotiating period where exceptions to the standard contract were finalized. Obviously, none of this happened here.

On a personal level, I, representing my renewable clients, regularly respond to offers from National Grid to purchase RECs for the various RPS programs that its distribution companies are subject to. These solicitations are made to a very broad group of renewable energy generators, REC brokers and REC traders. I generally make a non-conforming

bid. Having participated in this process for several years, the executed contracts are not the same as the ones initially proposed by National Grid. As previously mentioned, the final product of this competitive process is contracts that contain commercially reasonable terms and conditions.

In summary, given the form of solicitation that National Grid undertook with the Project, a sole source solicitation for a commodity product without competitive bidding, the contract before the Commission cannot contain commercially reasonable terms and conditions.

Q. **Do you have any opinions on the proposed power purchase agreement between Narragansett and Deepwater for the Project? If so, what are your opinions?**

A. Yes. To a reasonable degree of engineering and economic certainty, my opinions are that the Project's power purchase agreement between Narragansett Electric Company and Deepwater of up to 8 wind turbines, up to 30 MW wind farm (hereinafter the "Project"):

1. Does not contain terms and conditions that are commercially reasonable; the terms and conditions, such as the price, escalation rate and construction cost, are not commercially *reasonable* for a to-be-developed renewable energy resource (the Project) between a Rhode Island electric distribution company (Narragansett Electric Company) and a developer or sponsor (Deepwater Wind Block Island, LLC); and

2. Does contain arcane provisions that provide for a decrease in contract pricing but only if substantial savings can first be achieved in the construction cost of the Project that solely benefit the Project owner; and

3. Will create only a minimal number of jobs in the renewable energy sector in Rhode Island while costing Rhode Island many more jobs in other sectors of its economy and will not provide any net direct economic benefit to Rhode Island; and

4. Will, at best, only minimally provide environmental benefits to Rhode Island, including the reduction of carbon emissions and, at worst, may contribute to global warming by causing the electric generation network of New England to operate at sub-optimal levels.

Q. **Do you have an opinion whether certain provisions of the Project's contract are not commercially *reasonable* terms and conditions between Narragansett Electric Company and Deepwater Wind, LLC? If so, what is your opinion?**

A. Yes. The Project's contract contains provisions that are commercially *unreasonable* terms and conditions.

The commercially *unreasonable* terms and conditions of the contract can be divided into three general areas – unreasonable cost of the product (the combined price of energy, capacity and RECs or Bundled Energy), unreasonable cost of operations and unreasonable rates of return to the Project and its equity owners.

The unreasonable cost of the Project can be determined in several ways – the comparable cost to construct of-similar-size off-shore wind projects, the comparable price of the product from other projects, the comparable initial estimate of operating expenses and the comparable escalation in revenues and expenses. Fortunately, we have Great Lakes Wind Energy Center project[5] (the Cleveland project) and Delaware Bluewater Wind project[6] (the Bluewater project) to compare against the Project. On rates of return, we have utility rate cases to determine what should be appropriate returns on rate base and equity.

[5] See pages 324 to 377 of Great Lakes Wind Energy Center-- Final Feasibility Study. The full report can be viewed at http://blog.case.edu/case-news/2009/05/01/windfeasibilitystudy. The Great Lakes Wind Energy Center is a proposed 15-20 MW off-shore wind project to be constructed near downtown Cleveland, Ohio (hereinafter the Great Lakes Wind Energy Center is described as the "Cleveland project").

[6] The Delaware Bluewater Wind project is a proposed 450 MW off-shore wind project to be constructed 11 miles east of Rehoboth Beach, Delaware (hereinafter the Delaware Bluewater Wind project is described as the "Bluewater project"). Its executed contract with Delmarva Power & Light can be viewed at http://www.ceoe.udel.edu/windpower/DE-Os/Delmarva-Bluewater-PPA-10-December-07.pdf.

The construction cost of the Cleveland project, when adjusted from a 15-20 MW off-shore wind project to the same size as the Project, should range from $138 million for twelve 2.5 MW wind turbines to $159 million for six 5.0 MW wind turbines. Using the estimated construction cost of $220 million of the Project, the Project's construction costs are estimated to be between $61 million and $82 million more (41% to 59% higher, respectively) than the Cleveland project.

The operating cost of the Cleveland Project, adjusted for the size of the Project, should range between $6.1 million for twelve 2.5 MW wind turbines to $4.6 million for six 5.0 MW wind turbines. While the operating cost of the twelve 2.5 MW wind turbine project is similar to that of the Project, the operating cost of the six 5.0 MW wind turbine project is approximately 3/4 of the operating cost of the Project or 25% less than the Project's 2013 operating cost of $6.2 million.

In addition, the Cleveland project assumed a 2.5% rate of increase in its contract price versus 3.5% for the Project. This difference (the gap of a percentage point between project price escalators; that is to say, a 40% per cent higher rate of increase as compared to the other escalator clause) increases the unreasonableness of the Project dramatically over time.

The product cost of the Bluewater project also raises serious issues that the Project's contract prices are not commercially reasonable terms and conditions. With a 2013 cost of $140 per MWh to the Delaware ratepayers of Delmarva Power & Light versus $244 per MWh to Rhode Island ratepayers, the cost of the Bluewater project represents a $104 per MWh or 43% discount to the Project's cost. After adding an additional $21 to $35 per MWh to adjust the Project's small size relative to the Bluewater project,[7] the comparable

[7] The Great Lakes Wind Energy Center -- Final Feasibility Study assumed that large offshore wind facilities should have operating cost in the range of $25-40 per MWh. Interpolating between these costs and the assumed operating costs of the Cleveland project adjusted for a 30 MW facility, these adjustment factors were determined.

2013 contract price for the Project should range from $161 to $175 per MWh. Thus, the comparable cost of the Project is between $69 and $83 per MWh (39% to 52%, respectively) more than the 2013 contract price of the Bluewater project.

In addition, the contract for the Bluewater project has a 2.5% rate of annual increase in contract prices versus 3.5% for the Project. This difference (1% or 40% more the Project's escalation rate) over time increases dramatically the unreasonable cost of the Project.

Regarding the Project's economic returns, under the proposed terms and conditions contained in the contract, they are generous to the developer. In fact, the Project should earn for its owners commercially unreasonable rates of return. Using information supplied by the Project's owners in Docket No. 4111 and owners' estimates (which I deem to be unreasonably high) of construction cost ($220 million), operating expenses ($6.2 million) and contract prices ($244 per MWh in 2013) and, using my estimate of a 60/40% project debt/equity financing, I have arrived at the following. The Project's leveraged after-tax rate-of-return is 21.3% while the Project's unleveraged after-tax return is 9.1%. However, comparable utility rates of returns of 7.2%[8] for investment[9] and 9.0% for equity would be the norms. These costs-of-capital would produce to the Project owners just and reasonable returns.

Combining all of these observations together, it is my opinion that the commercially reasonable cost to construct the Project is in the vicinity of $160 million, the commercially reasonable cost of annual operations of the Project is in the vicinity of $5.35 million, the commercially reasonable rate of annual escalation of contract prices is 2.5% and the commercially reasonable return on investment and equity would be 7.2% and 9.0%, respectively. Using these parameters, the Project would need a 2012 contract price of

[8] A 60/40 debt equity ratio with a 6% cost of debt and 9% cost of equity has been assumed.
[9] For purposes of this analysis, the return on investment is analogous to return on rate base.

only $167.00 per MWh ($171.18 per MWh in 2013) and not the price of $235.70 per MWh ($243.95 per MWh in 2013) as specified in the contract.

At these commercially reasonable terms and conditions, the ratepayer would see a life-time reduction in the revenue requirements of the Project from $696.2 million to $441.3 million, for a decrease of $254.9 million or 36.1%. On a present value basis, the ratepayer savings would be worth $120.3 million.

In summary, it is my opinion that the Project contract ***explicitly*** contains the following commercially ***unreasonable*** terms and conditions:

1. A 2012 starting price of $235.70 per MWh; and
2. A cost to construct the Project of $220,403,512; and
3. An annual escalation rate of 3.5% of contract prices.

It is also my opinion that the Project contract ***implicitly*** contains the following commercially *unreasonable* terms and conditions:

1. Return on investment of 9.1%; and
2. Return on equity of 21.3%; and
3. A 2013 operating expense of $6.2 million.

Q. Do you have an opinion as to whether the power purchase agreement between Narragansett Electric Company and Deepwater Wind Block Island, LLC contain provisions that provide for a decrease in pricing if savings can be achieved in the actual cost of the Project. If so, what is your opinion?

A. Yes. From a narrow perspective, the answer is yes. In the larger context, the contract is a one-sided document that strongly favors Deepwater if any savings in construction costs are realized.

In general, there is one change in the proposed contract over the prior proposed contract that will definitely benefit Rhode Island ratepayers and one other change that may benefit Rhode Island ratepayers.

The former change is a minuscule reduction of the contract price for 2012 from $235.75 per MWh under the former proposed contract to $235.70 per MWh under the current proposed contract.[10] This reduction is just $0.05 per MWh, for percentage reduction of 0.021%. The escalation rate in the contract price of 3.5% remains the same. The impact of this price reduction is to reduce ratepayer requirements of the Project by approximately $5,096 in 2013 and $144,119 ($70,035 in discounted dollars) over the term of the contract.

Regarding the latter change, the current proposed power purchase agreement now provides for a reduction in the 2012 contract price from $235.70 per MWh if the Project cost less than $205,403,512, but more than $155,403,512, to construct. At the lower construction cost ($155,403,512), the 2012 contract price is equal to $189.70 per MWh for a price reduction of $46.00 per MWh or 19.5%. A $65 million or nearly a 30% reduction in construction cost leads only to a less than 20% reduction in the 2012 contract price. However, the first $15 million in cost reductions is solely for the benefit of the Project owners. Obviously, these constructions savings will be the first to be realized, the "low hanging fruit." In this sense, the reductions in Project cost may be simply illusory to Rhode Island ratepayers since the first benefit would fall solely to the Project owner. For example, if construction costs are reduced by $20 million from $220,403,512 to $200,403,512, the Rhode Island ratepayers will only realize 25% of the benefit. Instead of an $18.40 per MWh reduction in the 2012 contract price, Rhode Island ratepayers will see only a price reduction in the 2012 contract price of $4.60 per MWh.

[10] See page 4 of Appendix X of "Power Purchase Agreement between Narragansett Electric Company d/b/a National Grid and Deepwater Wind Block Island LLC, as of June 30, 2010."

The uneven allocation of potential savings to the Project owner does not stop here. The revised power purchase agreement does not provide for any reduction in the contract price if the operating costs of the Project are less or if the rate of escalation of 3.5% of the contract price is in excess of the rate of inflation.

In summary, it is my opinion that the proposed power purchase agreement:

1. Provides for a minuscule reduction in the 2012 contract price;
2. Provides the potential for additional reductions in the 2012 contract price if the cost to construct is less than $205,403,512, but only on a disproportionate basis in favor of the Project owner and on a somewhat illusory basis to Rhode Island ratepayers;
3. Does not provide for any reductions in the contract price if the cost of operations of the Project should decrease; and
4. Does not provide for any reductions in the contract price if the rate of inflation should be less than 3.5%.

Q. **Do you have an opinion whether the Project will create minimal jobs in Rhode Island in the renewable energy sector? If so, what is your opinion?**

A. Yes. Other than a few construction jobs, just one full-time job should be created in Rhode Island as a result of the Project.

The Project in and of itself is too small to build a renewable energy industry for off-shore wind for the Mid-Atlantic and New England states. In the direct testimony of Madison Milhous (who was a witness for National Grid in Docket #4111), the Project was called a "demonstration project."[11] These wind turbines should be assembled elsewhere. Only the site mobilization should occur on-shore. Basically, everything else should float in on barges or derricks. From those platforms, work should be performed and, once completed,

[11] See page 9, line 2 of the direct testimony of Madison Milhous in Docket No. 4111. Mr. Milhous pre-filed testimony and answers to questions can found at http://www.ripuc.org/eventsactions/docket/4111page.html.

then leave. During the construction period, there should only be a brief influx of a small number of construction workers and within a season they should be gone.

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

In summary, it is my opinion that the Project will result in a few construction jobs for a brief period of time in Rhode Island and followed by only one semi-skilled permanent job on Block Island after the completion of the Project.

Q. **Do you have an opinion whether the Project will provide any net economic benefit to Rhode Island? If so, what is your opinion?**

A. Yes. The simple answer is no.

While the Project does provide some direct economic benefits to Rhode Island, its above-market costs to the ratepayers of Rhode Island far exceed that benefit. Even using the economic benefit cited by Dave Nickerson,[12] the lifetime, non-discounted benefit of the Project is only $48 million. Assuming that the National Grid above-market analysis is correct, the above-market cost of the Project is nearly $400 million on a non-discounted basis and $185 million on a discounted basis. The negative benefit on a non-discounted basis would be the $352 million ($400 million less the $48 million). The benefits of the Project are only 1/8th of its costs. In summary, the Project should produce minimal

[12] See Dave Nickerson answer to Division's Question 2-4 in Docket No. 4111. Mr. Nickerson pre-filed testimony and answers to questions can found at http://www.ripuc.org/eventsactions/docket/4111page.html.

economic benefits to Rhode Island and, when its above-market costs are included, negative net benefits to the ratepayers of Rhode Island.

Q. Do you have an opinion whether the Project could actually cost the Rhode Island economy jobs, producing an overall net job loss? If so, what is your opinion?

A. Yes. The simple answer it that the Project, once completed, would cost the Rhode Island economy more jobs than the six jobs that Deepwater Wind estimates to be created. *Per force,* the project, once completed would cost the Rhode Island economy more than the one job that I estimate to be created.

In a summary report of the economic analysis[13] of the Bluewater project prepared by Professor Edward C. Ratledge of the Univeristy of Delaware, it was estimated that:

> "... the negative impact of higher electricity prices would cause an average [job] loss between 237 and 785 over a 25-year term.[14] In addition, he estimated a total loss of disposable income in the State of between $430 million and $1.5 billion due to the above-market prices. This premium for the Bluewater Wind power purchase depresses the economy in the same way as a tax increase on Delaware's citizens.
>
> "... the net effect of the Bluewater Wind power purchase agreement ("BWW PPA"), calculating both the increase in jobs from the wind farm and the decrease created by higher electricity prices. Depending on which consultants' results he used, his analysis shows a net loss of at least 90 jobs and as many 639 lost as a consequence of the BWW PPA. Professor Ratledge computed the net dollars lost to Delaware from the proposed BWW PPA, as well, assuming that Bluewater Wind pays operations and maintenance personnel an average annual salary of $60,000 (which the Committee considers a high estimate) and pays all applicable State taxes. Even with these conservative assumptions, the State can expect a net

[13] See pages 103 to 108 of Delaware Senate and Energy Transmit Committee, "Comprehensive Report on Affordable, Environmentally Friendly Energy with a Detailed Analysis of the Proposed Bluewater Power Purchase Agreement." The full report with its summary of Professor Ratledge's analysis of the Bluewater Wind project may be found at http://www.ceoe.udel.edu/windpower/DE-Qs/senatemajorityrpt042308.pdf

[14] The study used Regional Economic Models Inc. (REMI), of Amherst, Massachusetts, to perform its economic analysis. REMI was founded in 1980 for the purpose of developing regional forecasting and policy analysis models. REMI is often used to analyze public policy decisions in economic development, the environment, energy, transportation, taxation, and others. Additional information on REMI can be found at http://www.remi.com/.

> loss of between $165 million and $1.2 billion over the 25 years that customers will pay for the BWW PPA.
>
> "The proposed BWW PPA impacts Delaware's economy in two distinct but opposing respects.
>
> "First, BWW offers the prospect of a jobs influx for the State, initially during construction of the offshore facility and during its 25 years of operations. BWW has also suggested that Delaware could become **a hub for development of wind-based industry that would supply equipment and related services along the East coast, but these potential benefits are highly speculative and certainly unquantifiable.** (Emphasis added).
>
> "Second – and cutting decidedly in the opposite direction – because Delawareans will pay above-market electricity prices for most or all of its 25-year term, the BWW PPA will act as a drain on the economy, reducing disposable income and eliminating jobs as businesses suffer the effects of higher electric costs. Based on the evidence presented to the Committee, these negative economic effects attributable to the proposed BWW PPA will overwhelm any potential benefits, and **the net impact of the offshore wind project will likely be significant financial detriment for customers and the State as a whole.**" (Emphasis added).

Apples-to-apples comparisons between the Bluewater project and the Project are hard to make. Nevertheless, a linear interpolation can be made. Accordingly, the Project should cost Rhode Island between 6 and 42 net full-time jobs and Rhode Island's economy between $8 million and $65 million. The economic impact of the Project may be understated since the Bluewater project has a greater workforce (80 versus an allegedly 6 full-time jobs), a substantially lower 2013 contract price ($140 per MWh versus $244 per MWh in 2013) and a lower annual escalation rate (2.5% versus 3.5%).

A recent economic study has been published on the job destruction caused by Spain's efforts to develop "green jobs."[15] That report found the job loss from making uneconomical investment in renewable energy was 2.2 private sector jobs for every "green job" created. On an annual productive basis, the report arrived at the same private sector job loss per "green job." However, a detailed review of the Spanish report indicates a

[15] See pages 28 to 29 of "Study of the Effects in Employment of Public Aid to Renewable Energy Sources." A copy of this study may be found at http://www.juandemariana.org/pdf/090327-employment-public-aid-renewable.pdf.

potential far greater job loss in Rhode Island than Spain's experience. Unless the cost to create the average new private sector job in Rhode Island is $16.7[16] million and the annual productivity of that worker is $0.9 million,[17] Rhode Island should suffer a similar job loss as Spain arising from developing the Project. As shown below, the cost to create a new private sector job and the annual productivity of a new private sector job in Rhode Island are significantly less than these numbers; thus, the job loss from the Project may be far higher.

For 2008 (the latest year that economic statistics are available for Rhode Island) the average job productivity was $77,360.[18] (As of the time of this filing, a source of the average capital cost to create a private sector in Rhode Island has not been located. Once that number is located, I will supplement my filing). Thus, the Project should cost the Rhode Island economy a net loss of approximately 25 jobs in 2013. Given that the Project has an annual escalation rate in the Project's contract price (3.5%) greater than the forecasted rate of inflation (2.5%), I expect that this job loss should increase over time.

In 2009, the Vermont Department of Public Service commissioned a study on the economic impacts of its recently-enacted feed-in tariff, titled "The Economic Impacts of Vermont Feed in Tariffs."[19] The study looks at the economic impact[20] on Vermont arising from the installation of 47.8 MW of solar, wind, biomass (including landfill and farm

[16] For the Project, the capital cost per job is equal to $220 million (the cost of the Project) divided by 6 full-time jobs or $36.7 million per job. Thus, in order for the Project to have the same negative job impact as observed in Spain, the capital cost of a private sector job in Rhode Island must be at least $16.7 million ($36.7 million divided by 2.2 lost jobs).

[17] The Project, using as an above-market 2013 cost of the Project's Bundled Energy of $118 per MWh, produces a total above-market cost of $12 million for the Project or $2.0 million per job. Thus, in order for the Project to have the same negative job impact as observed in Spain, the annual productivity of a private sector job in Rhode Island must be at least $.9 million ($2.0 million divided by 2.2 lost jobs).

[18] For 2008, Rhode Island had gross state product of $47.364 billion, total state employment of 612,258 and, thus, an average worker productivity of $77,360. Although private sector gross state product for Rhode Island for 2008 was found $41.269 billion), private sector employment for Rhode Island could not be located.

[19] A copy of the study can be found at
http://publicservice.vermont.gov/planning/DPS%20White%20Paper%20Feed%20in%20Tariff.pdf

[20] The study also used Regional Economic Models Inc. (REMI), of Amherst, Massachusetts, to perform its economic analysis.

methane) and small hydro generation with an estimated capital cost of $228 million. Among some of the study's findings were:

> "Certainly the population most directly affected by the Standard Offer is utility **ratepayers who will pay a significant premium for a portion of their electricity** for up to 25 years. (Emphasis added).
>
> "Above-market energy costs had **the deleterious effects of reshuffling consumer spending and increasing the cost of production for Vermont businesses.** Increased costs for households and employers reduced the positive employment impacts of renewable energy capital investment and the annual repair and maintenance activities. (Emphasis added).
>
> "the smaller sized resources supported under this program suffer from diseconomies of scale within each renewable type. 50 MW of renewable electricity can be procured for Vermont ratepayers on a long-term basis at a much lower cost if the program dictated that the least cost renewable should be chosen. Put another way **Vermont consumers are paying a higher price for a portion of their renewable energy with no discernable benefit."** (Emphasis added).

In summary, it is my opinion that only a few construction jobs in Rhode Island should be created by the Project and then for only a brief period of time. This should be followed up with only one semi-skilled permanent job on Block Island after the completion of the Project. For the balance of the Rhode Island economy, between 6 and 42 net full-time jobs should be lost with a net negative economic impact ranging from the low tens of millions of dollars to several hundred millions of dollars over the life of the Project.

Q. **Do you have an opinion whether the Project will only minimally enhance environmental quality as opposed to other renewable energy technologies? If so, what is your opinion?**

A. Yes. The project utilizes wind energy. Wind at this project scale is an unreliable, intermittent energy source; thus, its ability to reduce or retire fossil generation is limited. As a small generator, the Project's rapid changes in output would cause its capacity to be largely ignored by ISO-NE.

A power pool such ISO-NE cannot rely on wind generation to be there at critical times. This is particularly true during the afternoon summer hours when peak loads are the highest. Since the production from a wind resource of this size cannot be reliably forecasted, ISO-NE does not require wind resources to schedule any of their production in the ISO-NE Day-Ahead energy market.[21] Instead, wind resources are permitted to operate exclusively in the Real-Time energy market.[22]

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

Looking at the dispatch of generation resources over a five-minute time period, although the electric grid does respond quickly to changes in the generation of all intermittent units, it does not respond immediately but, rather, with a small time delay. Within five minutes or less ISO-NE will re-dispatch the system based upon the then-prevailing level of load and generation resources in operation. Thus, the grid immediately absorbs the unexpected wind production when excesses are produced but does not change the order of generation

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

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

dispatch until the next dispatch period. The same thing happens when wind resources quickly reduce their output.

Looking at wind generation in isolation, and not considering the time of day and time of year of the generation, or the other power facilities on the grid at the time the wind was blowing, presents an overly-simplistic and inaccurate description of how the grid operates. While wind generation may offset fossil fuel use, which here in New England is likely natural gas, any emission reduction would need to be evaluated in the context of New England's power pool of over 30,000 megawatts. The premise that one MWh of wind generation will lead to one less MWh of fossil-fired generation is not correct. For these reasons, I believe that the Project will have a lower impact on reducing the air emissions than the supposed displacement of 30 MW of fossil-fired generation. Correspondingly, the carbon benefit of the Project will not be equal to the estimates offered by Dave Nickerson.[23]

This conclusion has been observed by others. Professor Jay Apt of Carnegie Mellon University has estimated CO_2 and NOx emissions reductions to gas generators operating in conjunction with wind.[24] The salient points of his conclusions are as follows:

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

Professor Apt's observation in his last sentence is alarming. Wind-power can abruptly force off-line very efficient generation facilities (which occurred recently in Colorado and

[23] See Dave Nickerson response to Division's Question 2.7 in Docket No. 4111. Mr. Nickerson pre-filed testimony and answers to questions can found at http://www.ripuc.org/eventsactions/docket/4111page.html.
[24] See "Air Emissions Due To Wind And Solar Power," Warren Katzenstein and Jay Apt. http://pubs.acs.org/doi/pdfplus/10.1021/es801437t.

Texas[25]), such as combined cycle facilities (in Texas) or steam plants (in Colorado), causing air emissions to soar. When the wind disappears quickly, these units cannot return to their prior levels of production without raising their overall emissions rates as they ramp back up. In two cases studies, it was found that:

> "... the surprising conclusion that the use of wind energy in the Public Service of Colorado ("PSCO") and Electric Reliability Council of Texas ("ERCOT") context results in increased SO_2 and NO_x and, in the case of PSCO, CO_2. (Emphasis Added). The mechanism driving increased emissions is the need to cycle coal facilities in order to accommodate wind, which is considered a "must-take" resource due to the respective states' RPS mandates. When wind generation comes online, generation from coal (and natural gas-fired) plants is curtailed until the wind subsides, then their generation is once again ramped up to meet demand. Cycling coal units in this manner drives their heat rate up and their operating efficiency down, resulting in higher emissions of SO_2, NO_x and CO_2 than would have been the case if the units had not been cycled."

In the case of ISO-NE, a project of this size will most likely back-off (substitute for) combined cycle natural gas to correct for the excess generation conditions and then call on oil-fired, simple cycle combustion turbines to fill the void when the wind disappears. However, these latter facilities are relatively inefficient with heat rates greater than 10,500 BTU/KWh (approximately 30% or less efficient) versus combined cycle heat rates of less than 7,000 BTU/KWh (approximately 50% or more efficient). In addition, simple cycle combustion facilities produce several times the levels of N_2O, a serious greenhouse gas with a 310 times multiplier over that of CO_2,[26] over that of combined cycle power plants. Thus, wind generation of this scale may force a 50% increase of CO_2 emissions due to differences in generation efficiency and, when one includes the CO_2 effect of N_2O emissions, the Project may actually contribute to global warming rather than cure it.

[25] See "How Less Became More: Wind, Power and Unintended Consequences of the Colorado Power Market" http://www.bentekenergy.com/documents/bentek_how_less_became_more_100420-319.pdf.

[26] For example, three pounds of N_2O emissions are the Greenhouse Gas equivalent of 930 pounds of CO_2 emissions. Information on the relative weighting of greenhouse gases may be found at http://www.epa.gov/cleanrgy/energy-resources/calculator.html.

Looking out over a longer operating period, if wind resources of this scale were reliable generating resources that could consistently follow a dispatch schedule like a biomass plant or landfill facility, the marginal air emissions analysis of Dave Nickerson would be accurate.[27] Then, wind resources would provide another feature that reliable renewable resources provide -- permanently back-out the need for fossil generation since they can consistently be relied upon to operate. For example, a 30 MW biomass power plant can force the retirement of 30 MW of fossil-fired generation while a 30 MW wind farm will be lucky if it leads to the retirement of any fossil-fired generation. For wind, the truth appears to be that projects of this size fail to produce their claimed air emissions reductions for either brief or long-term periods of time.

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

Q. **Do you have an opinion whether the Project will decrease the nation's energy independence from foreign sources of fossil fuels? If so, what is your opinion?**

A. Yes, I have such an opinion. If you are referring to foreign sources of oil, the answer is no.

Although fossil fuels are used to generate a majority of New England's electricity, oil in only a small fraction of that total. In 2009, New England derived 35.0%, 12.1% and 5.3% of its electrical energy from natural gas, coal and oil, respectively. Of the first two fuels, the overwhelming percentage is from domestic sources, inexpensive and plentiful. Regarding natural gas, approximately 15% of the nation's supply is from foreign sources,

[27] See Dave Nickerson response to Division's Question 2.7 in Docket No. 4111. Mr. Nickerson pre-filed testimony and answers to questions can found at http://www.ripuc.org/eventsactions/docket/4111page.html.

with Canada making up about 70% of the supply. The balance, 4%, is from other foreign countries.

Although 70% America's oil is from imported sources, oil represents a small and shrinking source of New England's fuel used for electric generation. In 2009, all forms of oil-fired generation generated only 5.3% of New England's electricity. This percentage is down from 11.6% six years ago. Of the current number, 3.7% is burned in generating facilities used primarily for reliability or voltage stability purposes while the balance, 1.6%, is burned in oil-fired steam plants. Oil is rarely the fuel for the marginal power plant. In 2009, oil fueled these power plants less than 2% of the time.

Given the generation characteristics of small wind facilities, building wind facilities in the hope of reducing or eliminating the use of imported oil will achieve limited success. What has led to the recent drop in the use of oil in power plants in New England has been the construction and operation of very efficient combined cycle power plants, fired with relatively inexpensive and plentiful natural gas. Until wind facilities of this magnitude are capable of following dispatch or required to build storage to hold their production for high demand periods, wind energy will not be a factor in reducing or eliminating this use of oil in New England.

In summary, it is my opinion that there will be no material reduction caused by wind facilities, including the Project, in New England's use of imported oil as a boiler fuel for electric generation.

In conclusion, along with all of my other comments, it is my opinion that the contract between Narragansett Electric Company and Deepwater Wind Block Island, LLC for the Project should not be approved by the Commission.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT B

BEFORE THE

RHODE ISLAND PUBLIC UTILITY COMMISSION

DOCKET NO. 4185

REVIEW OF THE AMENDED POWER PURCHASE AGREEMENT BETWEEN NARRAGANSETT ELECTRIC D/B/A NATIONAL GRID AND DEEPWATER WIND BLOCK ISLAND, LLC PURSUANT TO R.I.G.L § 39-26.1-7

DIRECT TESTIMONY

OF

ROBERT McCULLOUGH

ON BEHALF OF THE CITIZEN INTERVENERS GROUP

July 20, 2010

1 **Q. Please identify yourself for the record.**

2 A. My name is Robert McCullough. I am the Managing Partner of McCullough Research, 6123 S.E.
3 Reed College Place, Portland, Oregon 97202.

4 **Q. On whose behalf are you testifying?**

5 A. The Citizen Interveners Group.

6 **Q. Can you summarize your experience and qualifications?**

7 A. Yes. I have been active in the electricity business for the past thirty years. I started as a
8 manager for rates in 1979 at Portland General Electric. Over the next decade I was steadily
9 promoted until I reached the rank of Vice President in PGE's power marketing subsidiary. In
10 1991 I left PGE to found McCullough Research, a consulting firm concentrating on bulk power
11 issues. Over the last twenty years I have advised energy buyers, utilities, governments, and
12 regulators on energy contracting issues from Quebec to California. My testimony at the U.S.
13 Senate concerning Enron's energy trading in 2002 initiated the investigation of its trading
14 practices by FERC, the CFTC, and the U.S. Department of Justice. We worked for the DOJ in the
15 course of the Enron prosecutions. We also worked for the state attorney generals of California,
16 Oregon, and Montana on related issues.

17 **Q. What is your background on energy contracts and procurement?**

18 A. Extensive. I have advised utilities, companies, and governments about power supply issues in
19 jurisdictions across the U.S. and Canada. My detailed curriculum vita is attached as Exhibit RM-1
20 to this testimony.

21 **Q. What is the purpose of your testimony in this proceeding?**

22 A. The Citizen Interveners Group asked me to review the National Grid Deepwater Wind
23 transaction for consistency with the "commercially reasonable" standard as set out in R.I.G.L §
24 39-26.1-7.

25 Q. What does the recently enacted statute say about "commercially reasonable"?

26 A. The statute states:

27 (c) The commission shall review the amended power purchase agreement taking
28 into account the state's policy intention to facilitate the development of a small
29 offshore wind project in Rhode Island waters, while at the same time
30 interconnecting Block Island to the mainland. The commission shall review the
31 amended power purchase agreement and shall approve it if:

> (i) The amended agreement contains terms and conditions that are commercially reasonable;

The statute further clarifies the definition of "commercially reasonable" in Section (c)(iv):

> Notwithstanding any other provisions of the general laws to the contrary, for the purposes of this section, "commercially reasonable" shall mean terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see for a project of a similar size, technology and location, and meeting the policy goals in subsection (a) of this section.

Q. How did you approach this evaluation?

A. I approached this as a standard business review. I asked how reasonable the pricing was, how well documented the product was, and how well the transaction was written down.

Q. Can you characterize your conclusions?

A. If I had been retained to evaluate the transaction for either Deepwater Wind or National Grid I would recommend substantial changes. The price for Deepwater Wind is high – significantly higher than similar projects recently completed or currently underway in Europe.[1] Our knowledge of what we are actually purchasing is limited.[2] The cost figures give the appearance of being reverse engineered from a required rate of return rather than derived from basic engineering estimates.[3] The rate of return seems high with any reasonable level of leverage and due diligence by the purchaser was lacking. Finally, the proposed contract's pricing sections are poorly written and several other sections may contain drafting errors.

Q. Why do you characterize the contract price as high?

A. The electric industry in the U.S. has three different standards for evaluating resource acquisitions. These are:

1. Fully allocated cost;
2. Avoided cost;
3. Competitive market pricing.

[1] See, for example, Figure 7 in Support schemes for renewable electricity in the EU, European Commission Economic papers 408, April 2010, reproduced below.

[2] See, for example, Deepwater Wind's Response 1-13 to DPU's first request in Docket 4111.

[3] See, for example, Deepwater Wind's Response 1-4 to DPU's first request in Docket 4185. The reduction of $14 million from Docket 4111 expected cost has apparently had no impact on the pricing in Docket 4185.

The Deepwater Wind acquisition meets none of these standards. All parties agreed in Docket 4111 that the price is higher than cost, avoided cost, or market. I can think of no simpler test of whether the price is high compared to standard commercial standards.

Q. How does the price Deepwater Wind compare against similar projects?

A. Very poorly. In fact, the price received by Deepwater Wind is considerably above even the comparable project recommended by Deepwater Wind, itself.

Q. Why do you characterize the purchaser's due diligence as lacking?

A. The purchaser's responses to interrogatories in this docket speak for themselves:

> While National Grid does not have Deepwater Wind's current financial model, National Grid has reviewed that model with a representative of Deepwater Wind. This review included the cost estimates provided by Deepwater Wind, the projected returns for the project, and the bundled energy price ($/MWh) included in the Amended PPA, to determine that the calculations, including the table in Appendix X, are correct. In that table, the bundled energy price in the December 9, 2009 PPA corresponds to the price if the Total Facility Cost is greater than or equal to the Base Amount; additional costs above the Base Amount do not increase the bundled price; and incremental savings below the Base Amount reduce the bundled price. National Grid is not is [sic] a position to review and confirm the elements of cost that are contained in the financial model.[4]

National Grid, the purchaser of the resource, is "not is [sic] a position to review and confirm the elements of cost that are contained in the financial model." In any reasonable commercial transaction it is appropriate to conduct due diligence on the product being purchased.

A concern that an "experienced power market analyst" might raise is that the payment that National Grid will receive as part of this transaction has given the wrong incentive – rewarding National Grid for the purchase without exposing National Grid to sufficient risk if the transaction's price is excessive.[5]

Q. Are there problems with the contract drafting?

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[4] Response to Division Data Requests – Set 1, Issued July 6, 2010, response to Request 1-3.

[5] R.I.G.L. 39-26.1-4, and State of Rhode Island and Providence Plantations Public Utilities Commission Docket No. 411 Errata Order

> Deepwater Indisputably has a great deal at stake, and Grid stands to receive approximately $19 million in statutorily-authorized "remuneration" payments just for signing the PPA, assuming the Project produces

A. Yes. The pricing language is opaque and difficult to interpret. In addition, there appears to be several substantive errors in the version proposed for approval in the instant hearing. In addition, there are minor errors which simply give the impression that the contract has not been sufficiently proofed.

This is an expensive project. Deepwater Wind is new to offshore wind projects. Capitalization and financing is unknown. All these are reasons to make the contract as iron clad as possible.

Q. Overall, how would you characterize this contract?

A. This contract is not commercially reasonable. The prices are high, the due diligence has not been completed (perhaps more accurately, even initiated), and the contract has a number of serious flaws. If I had been retained by either of the counterparties I would have recommended significant changes.

The scenario is akin to a purchaser buying a house through a real estate agent. The price is higher than comparable transactions, the agent is receiving a commission on the transaction, no inspection of the house has been undertaken, the creditworthiness of the seller is suspect, and the real estate contract is poorly written with a number of obvious errors.

Contract Price

Q. Why do we need to review the cost of this project?

A. If National Grid planned to purchase the project and resell it into the market, we would not have to review the pricing. National Grid would be taking the risk that the pricing was inappropriate. The situation here is very different. As an electric distributor, National Grid is acting as an agent for ratepayers and receiving a substantial payment for providing this service. Discovery indicates that National Grid has not exercised extensive due diligence in this matter, so it is incumbent upon the Commission to protect ratepayers by checking whether this is a commercially reasonable – one might even say "prudent" transaction.

Q. Is there anything new about this situation?

A. No. This review is built into the very fabric of the traditional utility model. The utility has an incentive to build the best possible system since it is remunerated on formulas based on investment and expense. Over time we have evolved three different cost standards: fully allocated cost, avoided cost, and market pricing.

1 **Fully Allocated Costs**

2 **Q. How did you evaluate this project on a fully allocated cost basis?**

3 A. I would follow the same basic steps as those presented by the Commission staff in Docket 4111.
4 Their approach was to question whether the project generated unreasonable rates of return for
5 the sponsor. Given the relatively small amount of information on the ownership structure and
6 financing, this is not an easy job.

7 **Q. Who actually owns this project?**

8 A. Based on the limited information available as of May 14, 2010 approximately three quarters of
9 Deep Water Wind Holdings, LLC. was beneficially owned by a hedge fund named D. E. Shaw. A
10 minority of the project is owned by First Wind Holdings, LLC.[6] D. E. Shaw also has a major
11 ownership position in First Wind Holdings.[7]

12 **Q. How does this affect the economics of the project?**

13 A. Projects like Deep Water Wind are often financed through a framework of special purpose
14 entities (SPEs) designed to capture tax benefits and take advantage of leverage. There has been
15 some discussion in Docket 4111 concerning whether Deepwater Wind would have the capability
16 to take advantage of these opportunities. Clearly, its ownership by a major hedge fund with $21
17 billion in investments and committed capital indicates that the benefits of structured finance are
18 readily available. This is not a small company with limited abilities to approach markets for tax
19 monetizations. Since Deepwater Wind Block Island LLC is a tax pass-through entity, any and all
20 of its tax loses and other tax assets are available to its parent, Deepwater Wind Holdings and
21 other tax pass-through affiliates. While this may or may not be the case, Deepwater's parent
22 company, its affiliates, and/or its beneficial owners will be able to do so due to the tax
23 passthrough status of its contract party under the Amended PPA.

24 **Q. What capital structure is Deepwater Wind likely to use?**

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[6] Amendment No. 6 to FORM S-1 REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933 of First Wind Holdings Inc., May 14, 2010, page 159.

> On May 2, 2008, we received voting interests in Deepwater Wind Holdings, LLC, a wind energy development company focused on developing wind energy projects offshore the continental United States, in exchange for a contribution of $3.4 million in cash and other assets with a net book value of approximately $471,000. We and the D. E. Shaw Group currently own approximately 13.6% and 72.1%, respectively, of the outstanding voting interests in Deepwater Wind Holdings, LLC, with the balance of the membership interests held by third-party investors.

[7] Ibid., page 7.

A. Discovery indicates that the debt/equity ratio will be on the order of 80/20.[8]

Q. How does this affect the internal rate of return for the project?

A. If the unleveraged return is higher than the cost of debt, which it is in this case, the financial benefits for the developer are very significant. Let's take a simple example:

Unleveraged return on equity:	10.5%[9]
Cost of debt:	6.5%[10]
Leveraged return on equity:	26.5%[11]

Q. Please review Mr. Moore's statement:

> Deepwater Wind believes that the proper reference point for considering an appropriate projected rate of return is the project-level, or unlevered, rate of return, which does not take into account debt financing and associated tax consequences, such as tax benefits resulting from interest expenses, because to do so at this point in time would be a purely hypothetical exercise. The rationale is simple.[12]

Do you agree with this statement?

A. No, Mr. Moore's statement is particularly ironic since it is the timing of the Section 48 Investment Tax Credit grant which is apparently dictating the schedule for this project.[13]

Q. Have you reviewed the testimony of Mr. Pasqualini in his testimony in Docket 4185 that the long construction period envisaged for Deepwater Wind may make it impossible to find a tax equity investor?

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[8] Response to Division Data Requests – Set 1, Issued December 31, 2009, response to Request 1-18.

[9] Direct testimony of William H. Moore, Docket 4185, page 14.

[10] New York's Offshore Wind Energy Development Potential in the Great Lakes, NYSERDA, April 2010, page 158.

[11] Actual ROE = (Unleveraged ROE – 80% x Cost of debt))/20% Equity.

[12] William M. Moore Rebuttal Testimony, Docket 4111, Page 1.

[13] See for example, his comments on page 10:

> Under current rules, wind projects must make certain equipment purchases in 2010 in order to take advantage of the Section 1603 program through 2012. This is Deepwater Wind's current plan, and why it is important to have the PPA approved soon so it can take the next step of making financial commitments on equipment contracts. By doing so, Deepwater Wind will take a step in the direction of ensuring that the Block Island Wind Farm qualifies for this important Federal incentive.

A. Yes. In 2007 the Ernest Orlando Lawrence Berkeley National laboratory issued a useful monograph on this topic entitled "Wind Project Financing Structures: A Review & Comparative Analysis."[14] It provides a very cogent introduction for seven models of structured financing vehicles for wind power. The monograph has a variety of decision matrices (shown below) to guide prospective developers and their financial advisors through various options:[15]

Scenario	Developer can use Tax Benefits	Developer can fund project costs	Developer wants to retain stake in project ownership / ongoing cash flows	Developer wants early cash distributions	Project has low projected IRR	Project already exists (refinancing / acquisition)	Most suitable financing strategy or structure:
1	No	No	No	Yes	N/A	No	Sell project to a Strategic Investor
2	Yes	Yes	Yes	No	No	No	Corporate
3	No	Limited	Yes	No	No	No	Strategic Investor Flip
4	No	Limited	Yes	Yes	No	No	Institutional Investor Flip
5	No	Limited	Yes	No	Yes	No	Cash Leveraged or Cash & PTC Leveraged
6	No	Limited	Yes	Yes	No	Yes	Institutional Investor Flip
7	No	Yes	Yes	Yes	N/A	Yes	Pay-As-You-Go
8	No	Limited	Yes	Yes	Yes	No	Back Leveraged

The timing of construction does not appear in this matrix, nor has the timing of construction appeared in discussions I personally have been involved in other projects.

Q. Has Deepwater Wind or its owners explained their financing plan in any detail?

A. No.

Q. Can you describe your recommendation on the basis of fully allocated costs?

A. This is not a commercially reasonable transaction. Basic questions first asked in the RFP have not been answered. In the next section I note three areas where questions were answered, the answers themselves are in flux.

Avoided Costs

Q. Should the evaluation of this project have been subject to National Grid's avoided cost filings?

[14] Wind Project Financing Structures: A Review & Comparative Analysis, John P. Harper, Birch Tree Capital, LLC Matthew D. Karcher, Deacon Harbor Financial, L.P. Mark Bolinger, Lawrence Berkeley National Laboratory, September 2007.

[15] Ibid., page 37, for example.

A. Yes. This has been the standard for resource acquisition by utilities since 1979. The strongest argument for PURPA (Public Utility Regulatory Policies Act) pricing is that it is a level playing field. If National Grid actually felt that this was a commercially reasonable transaction, they would have allowed a variety of alternatives to be brought forward – not just one.

Q. How does this compare to National grid's filed avoided costs?

A. Deepwater Wind's price is very high compared to the avoided costs filed by National Grid in New York, New England, and Rhode Island:

(1) Rhode Island -- Narragansett Electric Company d/b/a National Grid:
"Company will pay rates equal to the payments received by the Company for the sale of such qualifying facilities' output into the ISO-NE administered markets for the hours in which the qualifying facility generated electricity in excess of its requirements."[16]

Effective Date: September 14, 2009

(2) New York -- Niagara Mohawk Power Corporation d/b/a National Grid:
Energy: NYISO Real-Time Generator Bus LBMP * Quantity - Incurred Costs ("NYISO Automatic Generation Control Penalties")

Energy + Capacity: (NYISO RT LBMP * Quantity - Incurred Costs) + (Monthly LBMCP * Monthly Capacity)[17]

Effective Date: April 27, 2009

(3) Massachusetts -- Massachusetts Electric Company d/b/a National Grid:
Company will pay "rates equal to the payments received by the Company from the ISO power exchange for such output for the hours in which the QF generated electricity in excess of its requirements."[18]

Effective Date: May 1, 2001

(4) Massachusetts -- Nantucket Electric Company d/b/a National Grid:
Company will pay "rates equal to the payments received by the Company from the ISO power exchange for such output for the hours in which the QF generated electricity in excess of its requirements."[19]

[16] Narragansett Electric Company Rates Tariff, R.I.P.U.C No. 2035.
[17] Niagara Mohawk Power Corporation Rates Tariff (PSC No: 220), Service Classification No. 6.
[18] Massachusetts Electric Company Rates Tariff, M.D.T.E. No. 1032-C.
[19] Nantucket Electric Company Rates Tariff, M.D.T.E. No. 1032-C.

Effective Date: May 1, 2001

(5) New Hampshire -- Granite State Electric Company d/b/a National Grid:

Energy Rates by Voltage Level (cents/kWh):[20]

Voltage Level	Peak Period	Off-Peak Period	Average
(1) Subtransmission	3.697	2.965	3.303
(2) Primary Distribution	3.971	3.111	3.508
(3) Secondary Distribution	4.111	3.184	3.612

Capacity Rates by Voltage Level:

Voltage Level	$/kW Year	$/kW Month
(1) Subtransmission	$27.80	$2.32
(2) Primary Distribution	$30.44	$2.54
(3) Secondary Distribution	$31.84	$2.65

Effective Date: January 1, 1998

Q. Are these close to the prices asked under this contract?

A. No. There is a large disparity between prices in this contract and the avoided costs filed by National Grid.

Market Pricing

Q. What are comparable market prices to this project?

A. This is a very interesting question. Unlike Western Europe, the United States and Canada occupy a vast continent with immense wind potential. Logically, the best locations would be developed first. Since off-shore wind costs over twice that of land based wind – and this project costs three to four times comparable land based projects – market forces have not rushed towards off-shore projects.

Q. Are there any comparable projects?

A. There are a number of comparable projects identified in the NYSERDA study published this spring.[21] A number of parties in Docket 4111 as well as the instant docket have cited Table 10.1 on page 153:

[20] Granite State Electric Company Rates Tariff, N.H.P.U.C. No. 17

Project Name	Country	Status	Operating Year	Project Cost ($M)	Project Capacity (MW)	Project Cost per MW ($M)	No. Turbines	Turbine Size (MW)	Turbine Model	Water Depth (m)	Distance from Shore (km)
Middelgrunden	Denmark	Commissioned	2001	$ 51	40	$ 1.28	20	2	Bonus 2 MW	5 to 10	2 to 3
Horns Rev	Denmark	Commissioned	2002	$ 295	160	$ 1.84	80	2	Vestas V80	6 to 14	14 to 17
North Hoyle	United Kingdom	Commissioned	2003	$ 138	60	$ 2.30	30	2	Vestas V80	5 to 12	7.5
Nysted	Denmark	Commissioned	2004	$ 316	165.6	$ 1.91	72	2.3	Siemens 2.3	6 to 10	6 to 10
Scroby Sands	United Kingdom	Commissioned	2004	$ 136	60	$ 2.27	30	2	Vestas V80	2 to 10	3
Kentish Flats	United Kingdom	Commissioned	2005	$ 179	90	$ 1.98	30	3	Vestas V90	5	8.5
Barrow	United Kingdom	Commissioned	2006	$ 172	90	$ 1.91	30	3	Vestas V90	15	7
Burbo Bank	United Kingdom	Commissioned	2007	$ 170	90	$ 1.89	25	3.6	Siemens 3.6	10	5.2
Egmond aan Zee	Netherlands	Commissioned	2007	$ 300	108	$ 2.77	36	3	Vestas V90	17 to 23	8 to 12
Inner Dowsing	United Kingdom	Commissioned	2008	$ 289	97.2	$ 2.97	27	3.6	Siemens 3.6	10	5.2
Lillgrund	Sweden	Commissioned	2008	$ 254	110.4	$ 2.30	48	2.3	Siemens 2.3	2.5 to 9	10
Princess Amalia	Netherlands	Commissioned	2008	$ 592	120	$ 4.65	60	2	Vestas V80	19 to 24	> 23
Alpha Ventus	Germany	Commissioned	2009	$ 350	60	$ 5.83	12	5	Multibrid & REpower	30	45
Gunfleet Sands I	United Kingdom	Commissioned	2009	$ 406	108	$ 3.76	30	3.6	Siemens 3.6	2 to 15	7
Horns Rev Expansion	Denmark	Commissioned	2009	$ 854	209.3	$ 4.08	91	2.3	Siemens 2.3	9 to 17	30
Rhyl Flats	United Kingdom	Commissioned	2009	$ 358	90	$ 3.98	25	3.6	Siemens 3.6	8	8
Robin Rigg	United Kingdom	Commissioned	2009	$ 651	180	$ 3.62	60	3	Vestas V90	>5	9.5
Sea Bridge	China	Under construction	2010	$ 345	102	$ 3.38	34	3	Sinovel 3 MW	8 to 10	8 to 14
Gunfleet Sands II	United Kingdom	Financing secured	2010	$ 275	64.8	$ 4.24	18	3.6	Siemens 3.6	2 to 15	7
Nordergrunde	Germany	Financing secured	2010	$ 440	90	$ 4.89	18	5	REpower 5M	4 to 20	30
Walney	United Kingdom	Financing secured	2010	$ 746	151.2	$ 4.93	42	3.6	Siemens 3.6	20	7
Belwind	Belgium	Financing secured	2011	$ 897	165	$ 5.44	55	3	Vestas V90	20 to 35	46
Thanet	United Kingdom	Financing secured	2011	$ 1,200	300	$ 4.00	100	3	Vestas V90	20 to 25	7 to 8.5
London Array	United Kingdom	Financing secured	2012	$ 3,095	630	$ 4.91	175	3.6	Siemens 3.6	23	>20
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

I have highlighted the project Mr. David Nickerson has argued is the most similar to Deepwater Wind:

> The most similar project in this group is a German project called Alpha Ventus that reached full commercial operation in April 2010. It is a demonstration project consisting of twelve, 5 MW wind turbines from two different turbine vendors. Six of the twelve turbine foundations are the jacket type that are likely to be used for the Block Island Wind Farm. I consider this to be similar in "technology", with one necessary adjustment, which is described later. The project is located in water 30 meters deep – effectively the same "location" as the Block Island Wind Farm. Only the "size" at 60 MW is different. However, it is the closest project in size in the data set.[22]

Q. Why has Mr. Nickerson singled out Alpha Ventus?

A. He states:

[21] New York's Offshore Wind Energy Development Potential in the Great Lakes: Feasibility Study, NYSERDA, April 2010.

[22] Direct testimony of David Nickerson, Docket 4185, July 15, 2010. Pages 5 and 6.

> The primary focus of my analysis is on installed cost, expressed in dollars per kilowatt ($/kW) of nameplate capacity. As I discussed in Docket 4111, a review of the key cost elements that impact the price and price structure in a long term PPA indicate whether the PPA pricing is reasonable and consistent with expectations. For offshore wind, the key cost elements are installed costs, ongoing operations and maintenance costs, and cost of capital (rate of return). If each of these underlying elements is reasonable, then it is consistent to conclude that the PPA pricing and the associated payment stream over time is reasonable, particularly in the context of the New PPA and its "open-book pricing" structure.[23]

Q. Is this a very common procedure?

A. No, it is very unusual indeed. In making a purchase I am most interested in the price, not the cost. When the salesman assures me that the vendor is losing his shirt on the transaction, I normally regard this as sales talk and nothing more. As with this transaction, I first look at the price, then check the performance, and finally review the purchase terms and conditions. This is particularly true in this situation where the "cost" of the project is somewhat hard to pin down.

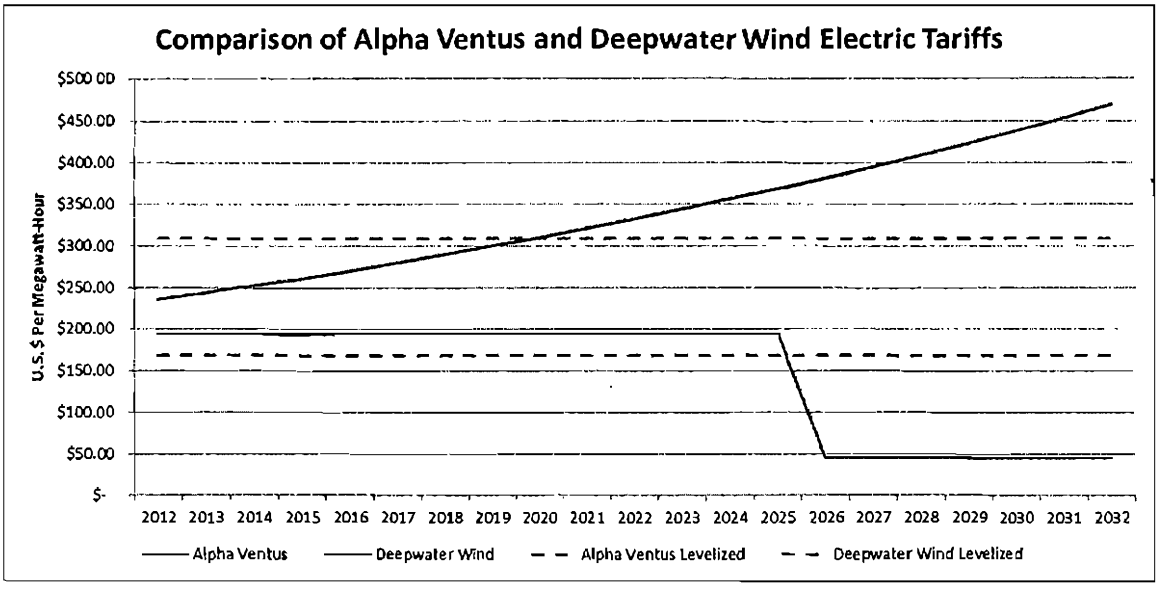
Q. Did Mr. Nickerson discuss the price Alpha Ventus is being paid?

A. Mr. Nickerson did not note that the price for energy for Alpha Ventus is considerably lower than the price being asked for Deepwater Wind in this docket.

Q. What is the levelized price for Alpha Ventus?

A. Using an 8% discount rate, the levelized price is $168.54. This compares to a levelized value of $309.04/MWh for Deepwater Wind. The following chart shows the prices for Alpha Ventus and Deepwater Wind:

[23] Ibid., page 6.



Q. How were the prices for Ventus Wind derived?

A. Germany, like many members of the European Economic Community sets a "Feed-In Tariff" or FIT for renewable energy projects. The Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz / EEG) regulates the feed-in power tariff in Germany. This law was adopted in 2000 and amended in 2004 and 2008.[24] The initial tariff for offshore wind energy is €13 per MWh for a period of 12 years (+ €2 per MWh for all turbines installed before year end 2015). The tariff period is extended before reduction to a base level for deeper waters and greater distances from the land.

Q. Is the German Renewable Energy Sources Act unusual?

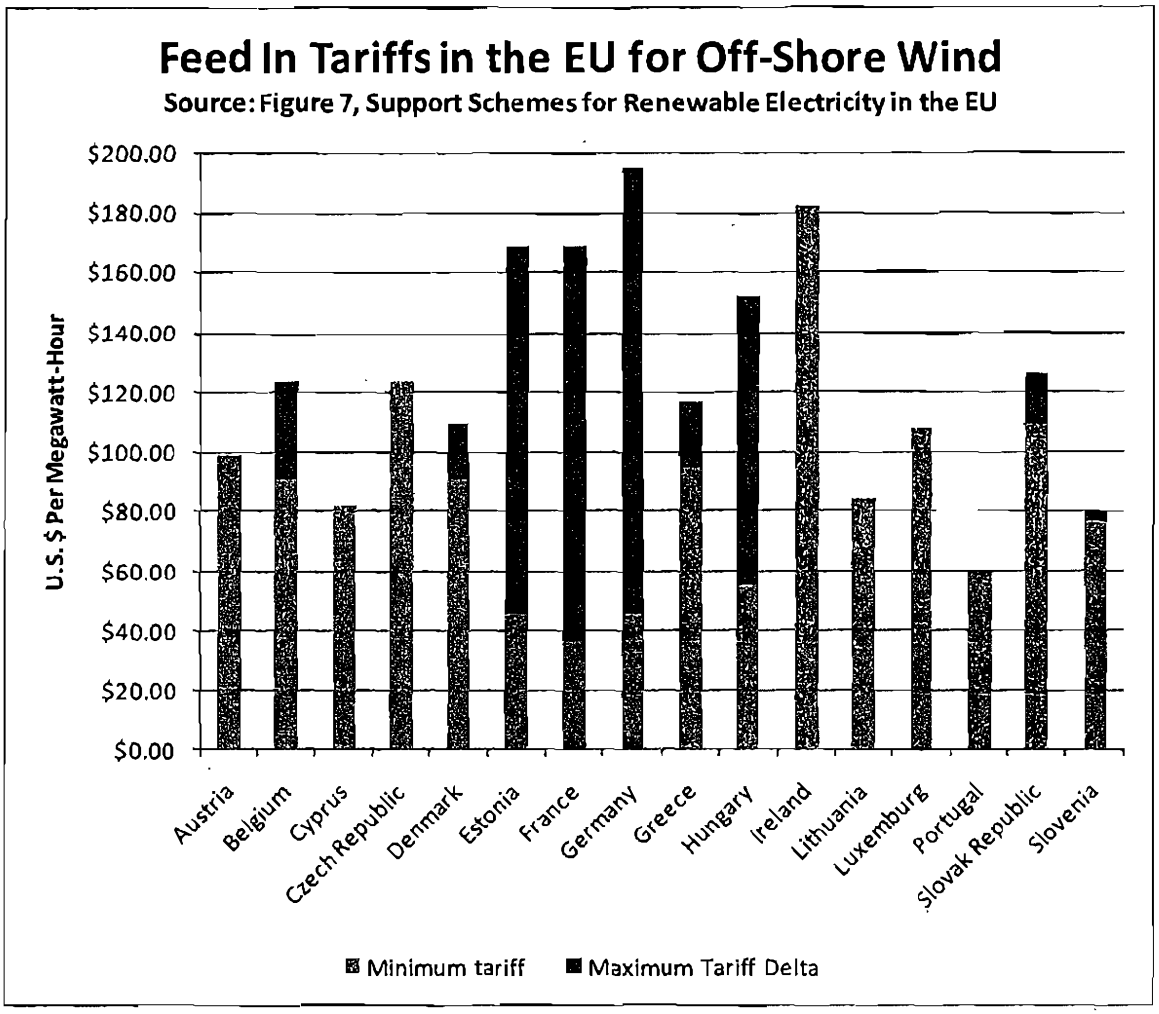
A. Not at all. Europe has adopted FITs in many different countries. Programs differ from nation to nation, however. A useful monograph has recently been released on the off-shore prices in the EEC named "Support schemes for renewable electricity in the EU."[25]

Q. Are European Feed In Tariff's lower than the proposed price for Deepwater Wind?

A. Yes. Figure 7 summarizes Feed In Tariffs by technology across the EU. I have reproduced their table here, using U.S. dollars per MWh for the convenience of the Commission:

[24] About Offshore Wind Energy in Germany, Frank B. Hawn, September 2008.

[25] Support schemes for renewable electricity in the EU, European Commission, Joan Canton and Åsa Johannesson Lindén, March 26, 2010.



Q. Is this the only source on European FITs?

A. No. There is an extensive literature on the subject. This monograph is significant because it is from an impartial source and was recently published. A second interesting monograph was published in 2007 by KPMG.[26]

[26] Offshore Wind Farms in Europe, KPMG, 2007. Their comparable table of FITs can be found on page 7:

Q. What proportion of the projects identified in Table 10.1 of the NYSERDA is from counties in the European Union?

A. The table has 25 entries. One project is from China. This means that 92% of the projects cited would be subject to tariffs set in the EU. The United Kingdom accounts for 14 of the projects. Great Britain has a complex system of its own, but has recently begun to adopt the Feed-In Tariff approach as well.

Q. How precisely has Deepwater Wind researched comparable projects?

A. They have apparently depended on the survey by NYSERDA cited above. While the survey is good, it is not as comprehensive as it could be. Within the time limits of Docket 4185, I have conducted a survey of 158 off-shore wind projects either now in service or currently under development. This survey is reproduced as Exhibit RM-2 to this testimony. Within this dataset, five projects meet the criteria of either having been recently placed in service or now being developed as well as having nameplate ratings between 20 and 60 megawatts.

Q. Why did you choose the range of 20 megawatts to 60 megawatts?

A. I followed Mr. Nickerson's selection of 60 megawatts in order to include his comparable wind farm, Alpha Ventus. The lower limit was chosen to be slightly lower than Deepwater Wind's projected capacity.

Overview of Feed-in tariff systems in Europe

Country	Current tariff ct/kWh	Duration	Subsidies	Grid connection	Tax relief
Denmark	6.95 (Horns Rev II)	50,000 full load hours	–	✓	–
Germany	9.1	12 years/20 years	–	✓	–
France	Initially 13.0 then 3.0 – 13.0	Both phases 10 years each	–	–	✓
Great Britain	13.49	Certificates up to 2027	✓	–	✓
The Netherlands	MEP tariff stopped	Not covered at present	Not covered at present	Not covered at present	Not covered at present
Sweden	6.19	Certificates 15 years/ bonus up to 2009	✓	–	–
Spain	12.03 (max. 16.4)	20 years	–	–	–

Q. **Which comparable plants have you identified in your survey?**

A. I have identified five offshore wind farms. The projects are in Belgium, Denmark, Germany, and the United Kingdom:

Plant	Capacity (MW)	Number of Turbines	Distance from Shore (km)	Depth (m) min	Depth max	In Service Date	Country	Feed-in Tariff Minimum $/MWh	Feed-in Tariff Maximum $/MWh	Addition To Market?
Alpha Ventus	60	12	56	28	30	2010	Germany	$ 45.50	$ 195.00	No
Baltic 1	48	21	16	16	19	2010	Germany	$ 45.50	$ 195.00	No
Geofree	25	5	19	20	21	2012	Germany	$ 45.50	$ 195.00	No
Sprogo	21	7	10.6	6	16	2009	Denmark	$ 91.00	$ 109.20	Yes
Thornton Bank I	30	6	27	13	19	2009	Belgium	$ 70.00	$ 123.50	Yes

Q. **How do we know what prices are paid for these projects?**

A. Our best estimates depend on finding projects with national tariffs in place. Germany, as described above, has a very straightforward tariff. Belgium and Demark also have FITs, although their tariffs are of a slightly different format where the FIT is in addition to spot prices.

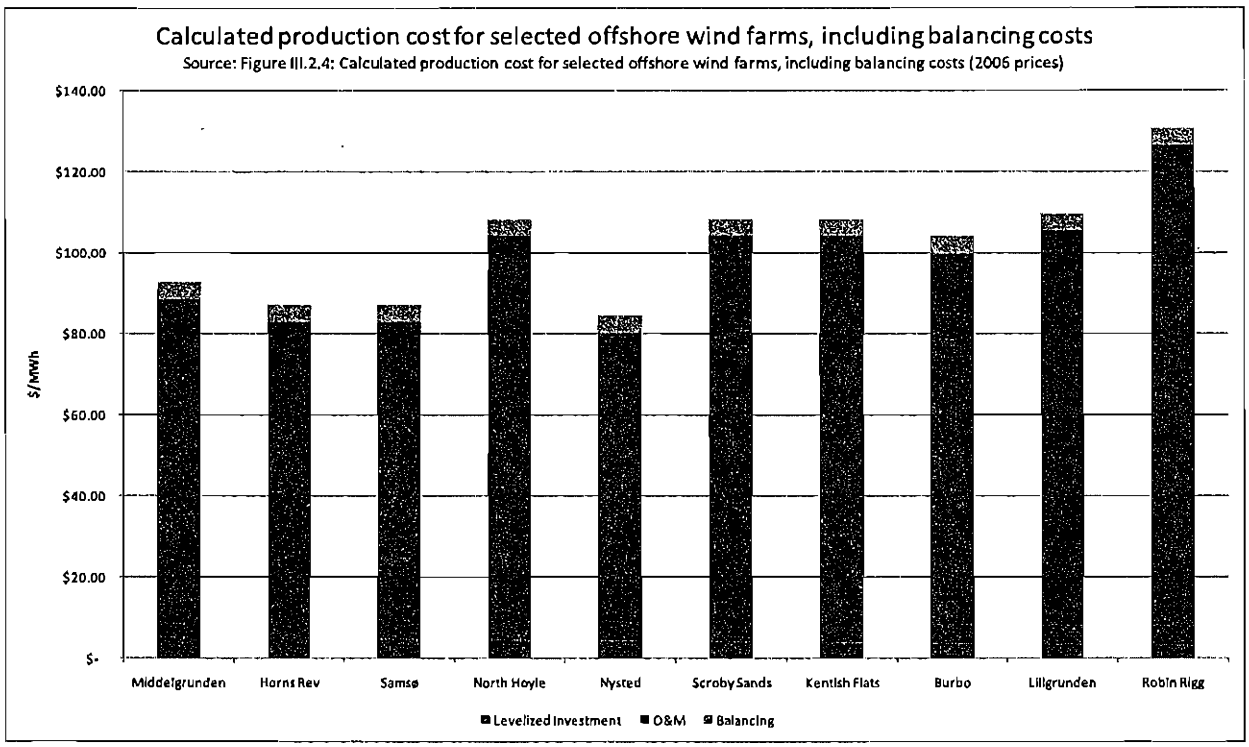
Q. **In Denmark and Belgium the FIT is in addition to market prices. What levels are these likely to be?**

A. Forecasting energy prices is challenging. Forecasting energy prices in several foreign countries is especially challenging. I have looked for current forecasts using models I have some familiarity with. Aurora forecasts indicate a range for base prices are in the range $65/MWh today through $120/MWh in 2030.[27] Given these forecasts, total prices paid to off-shore wind in Europe are still considerably less than the prices requested by Deepwater Wind.

Q. **Have you found any estimates of actual production costs?**

A. Yes. In a few rare cases we have estimates of their production costs. North Hoyle and Scroby Sands, for example, were analyzed as part of a study conducted in 2009.[28] These plants are of comparable size to our sample, but went into service some years ago. The following chart reproduces the conclusions of that study in 2010 dollars:

[27] See, for example, Modelling European Electricity Markets, Stephan Sharma, October 19, 2009.
[28] Wind Energy – The Facts, AWEA et al, February 2009, page 219.



Due Diligence

Q. What is "due diligence"?

A. This term describes the common sense review of the facts required before entering into a major transaction. A reasonable home owner has a home inspection conducted prior to completing the purchase. This is an everyday form of due diligence. The standards of due diligence increase as the price tag increases.

Q. What level of due diligence has been undertaken by National Grid?

A. A year ago it would have appeared that National Grid was proceeding in a normal fashion. The RFP issued included a number of "Bidder Response Forms" that would provide a description of the project under tender, its design, cost, maintenance, and financing. These submitted documents are now overtaken by events since the project has changed size, design, and ownership. As previously noted, National Grid states that it has done little in reviewing the costs of the project.

Q. How well is the project described in the proposed contract?

A. Without any exaggeration, Exhibit A, the description of the facility, is sketchy:

> EXHIBIT A
>
> DESCRIPTION OF FACILITY
>
> Facility: The Facility will be a wind generating facility to be located in the waters off the coast of Block Island, Rhode Island. The Facility will have no more than eight wind turbines, and the nameplate capacity of the Facility will be no more than thirty (30) MW.
>
> This Exhibit A will be supplemented with the Operational Limitations prior to Commercial Operation.

Q. Is this sufficient?

A. No. I would expect the equipment and its nameplate rating to be identified.

Q. What level of due diligence would you consider to be sufficient?

A. One would expect a utility to know the exact technology, equipment, and operational characteristics. Ownership and creditworthiness are also minimum standards. An excellent example of due diligence is the final report prepared for the Great Lakes Energy Development Task Force.[29] Contrary to assertions that financial structure should not be considered, the Final Feasibility Report has an extensive set of calculations showing the impact of leverage on economic feasibility.[30]

Q. Can you describe this document?

A. Yes. This pre-procurement document of 424 pages details the technology, industry, cost, contracting, financing, and market for off-shore wind on the Great Lakes. For example, Section 11 – fully 52 pages on project economics – contains vastly more information on the proposed Lake Erie project than anything from National Grid or Deepwater Wind in Docket 4185.

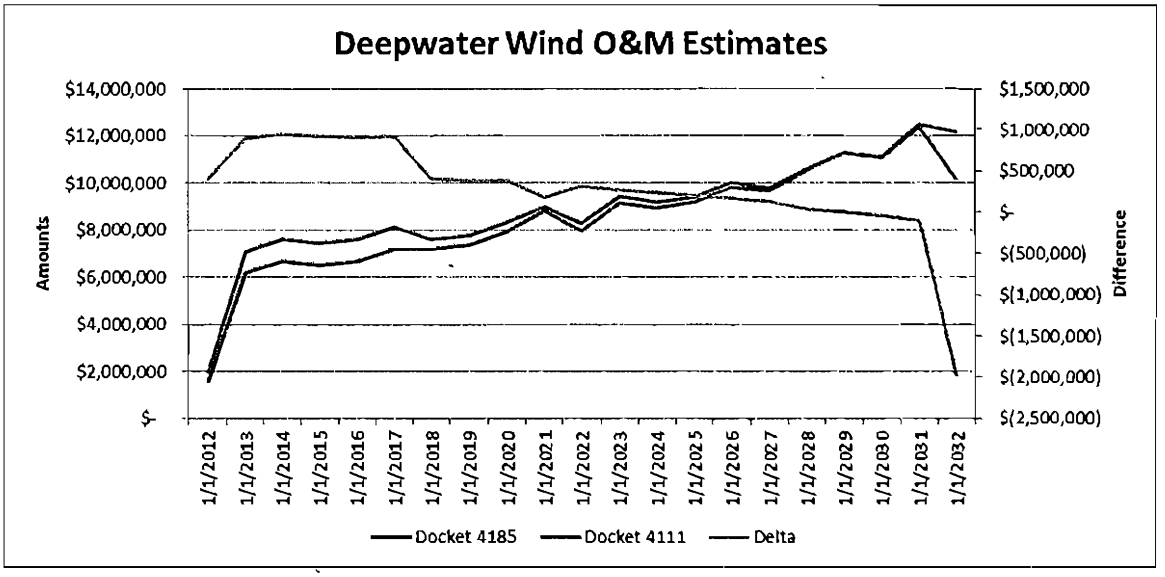
Q. How comfortable are we with the various numbers provided by Deepwater Wind?

A. It is difficult to be very comfortable with the materials they have provided so far. Two examples from the most recent pro forma make the shifting nature of their calculations apparent:

[29] Great Lakes Wind Energy Center Feasibility Study Final Feasibility Report, Barbi Driedger-Marshall et al, April 2009 at http://development.cuyahogacounty.us/pdf_development/en-US/GLWEC_Final%20Feasibility%20Report_4-28-09.pdf

[30] See, for example, Sections 11.2.7.3, 11.2.7.4, and 11.2.7.7.

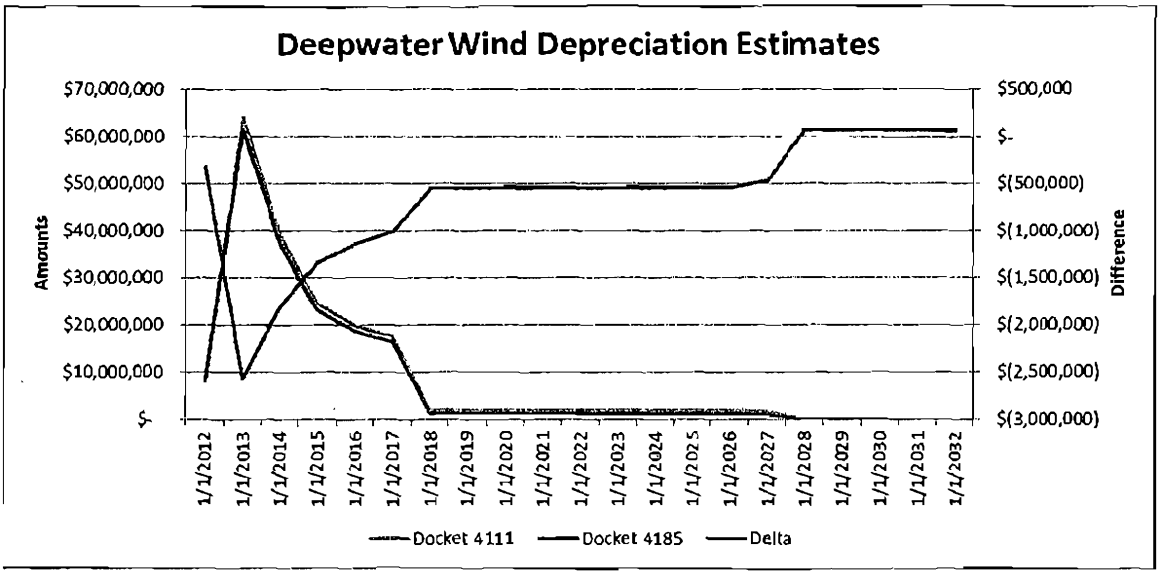
Docket 4111 contained testimony concerning the relatively high O&M values. Deepwater wind responded that these were solid estimates from a respected source.[31] Notwithstanding this response made only several months ago, the O&M numbers have increased significantly in the current pro forma:



Deepwater Wind's testimony did not address these changes. This undocumented increase in O&M would add .5% to the unleveraged return and over 1% to the leveraged return if eliminated from the calculations.

Similarly, the timing of depreciation has changed since Docket 4111:

[31] Rebuttal testimony of William H. Moore, Docket 4111, page 11.



Q. Are these changes legitimate?

A. It is impossible to know since the originals were undocumented and the new values are undocumented.

Q. What is the cost of Deepwater Wind?

A. This is an intriguing question. The cost in Docket 4111 was $219,311,412. The cost in Docket 4185 is $205,403,512. Deepwater Wind's response to a request to justify the difference was:

> The following differences reconcile the difference between the Docket 4111 Estimate and the Base Amount.
>
> (1) The contingency in the Docket 4111 Estimate has been reduced. This reduction results from a combination of factors. First, since the date of the development of the Docket 4111 Estimate last fall, Deepwater Wind has been engaged with various vendors and has done additional engineering of the facility. As a result, Deepwater Wind has removed various areas of uncertainty, and therefore Deepwater Wind's confidence in its estimates is greater than it was in the fall of 2009.
>
> (2) When Docket 4111 was pending, Deepwater Wind was still being considered for a Department of Energy Federal Loan Guarantee. Since the decision in Docket 4111, Deepwater Wind has been notified by the Department of Energy, that Deepwater Wind's application was not accepted. Accordingly, the financing

> costs of the facility that are in the Base Amount are higher than the financing costs in the Docket 4111 Estimate.[32]

Answer (1) indicated that the hitherto contingency amounts in the construction estimate have been reduced. Answer (2) indicates that the costs in Docket 4185 are larger than in Docket 4111 due to higher financing costs. The answer also contains a difficult to follow argument that the project cost is, in some fashion, dependent on the target unlevered return:

> The Base Amount, which is the measure against which realized savings are shared with the ratepayer, is approximately $14,000,000 less than the Docket 4111 Estimate. The Base Amount represents Deepwater Wind's estimate of a facility cost that Deepwater Wind projects will yield an acceptable unlevered return (approximately 10.5%) and a risk/return profile that will likely attract the financing necessary to construct the project.[33]

Q. Does this reassure you that we know the cost of this project?

A. No. Like Mr. Hahn, I am troubled that the cost of the project identified in the cost adjustment provision is now different than the cost used to develop the price of the project. It appears that the difference – approximately 10% of the total cost of the project has been reserved to increase profits from the project and may not represent costs at all.

Q. Is it necessary that the cost estimates be confused with the required rate of return for the project?

A. No. Deepwater Wind should provide a solid cost of the project and then justify a rate of return that would make it viable. These are separate issues and should be addressed as different parts of the analysis.

Q. Please characterize how commercially reasonable the current level of due diligence is on this project.

A. As previously stated, the due diligence has not been seriously undertaken by the buyer. Moreover, different estimates of the cost of the project have been changing without explanation or documentation. If I was advising the buyer in this transaction I would advise against going ahead without further verifiable information.

[32] Deepwater Wind Block Island, LLC Response to the Division of Public Utilities and Carriers' Data Request Div 1-4, page 2.
[33] Ibid., page 1.

Contract Language

Q. What is "contract failure"?

A. Contracts are an imperfect statement of the objectives of the counterparties at the time of signing. Any reasonably experienced businessperson is well-acquainted with just how imperfect even the best of intentions may be as a guide to the future. Contracts fail because the terms and conditions are not sufficient to deal with changing circumstances, changes in law or regulations, buyer's and seller's remorse, bankruptcy, and even issues of market manipulation.

In my review of the contract under discussion here, the standard of review – Section 19.5 – cited Morgan Stanley Capital Group Inc. v. Public Utility District Number 1 of Snohomish, Washington. This is a case that I have worked on for the past eight years, and is possibly the most famous example of contract failure in the history of the electricity industry.

In this case the contract failed due to revelations concerning the widespread market manipulation during the period when the contract was signed and the possible involvement of the seller, Morgan Stanley.

The Morgan Stanley transaction was approximately the same size as that under discussion here. The case has passed through FERC (Federal Energy Regulatory Commission) the Ninth Circuit Court of Appeals, and the U.S. Supreme Court, and presently awaits rehearing at FERC.

Q. Is there any reason to fear problems with this In the contract between National Grid and Deepwater Wind?

A. One always considers future problems. As I have noted, the technology is new to the seller, the prices are high compared to market, and little, if any, due diligence has been exercised by the buyer. In addition, this transaction could easily have problems with bankruptcy, delay, or regulatory changes.

Q. How would you characterize the billing language contained in Exhibit E?

A. The language is difficult to follow and likely to cause disputes in later years.

Q. Please give an example.

A. Section 3 states:

> Adjustment to Bundled Price for Forward Capacity Market Payments. Beginning in the fourth Contract Year, each monthly payment due to Seller under this Exhibit E will be reduced by the amount that Seller is or would have been

> eligible to receive in the ISO-NE Forward Capacity Market or any replacement market for capacity in ISO-NE, without regard to whether the Facility has actually qualified as a Capacity Resource in the Forward Capacity Market or whether the Facility has received a Capacity Supply Obligation for the Capacity Commitment Period during which the applicable billing period occurred. If the Facility has not qualified as a Capacity Resource or received a Capacity Supply Obligation for the relevant Capacity Commitment Period, Buyer shall calculate the reduction due under this Section 3 assuming that the Facility had qualified as a Capacity Resource and received a Capacity Supply Obligation, based on information obtained from Seller and publicly available information from ISO-NE, which calculation shall be binding, absent manifest error. Seller shall use commercially reasonable efforts to cooperate with Buyer in calculating this reduction.

Q. How would you interpret this section?

A. The buyer deducted the deemed capacity revenues from his payments to the seller. The New England ISO capacity markets have been highly controversial and it would appear that the risks of the capacity market have been left with the seller.

Q. Might there be different interpretation of this section?

A. Easily. There are detailed calculations involved in the determination of "Capacity" as noted above. Even if the two parties agree on the calculation of "Capacity", it is common for administered capacity markets to have different bidding options. Presumably, National Grid could deem a more successful bidding strategy for Deepwater Wind than it actually employed.

Q. How would you interpret the last sentence?

A. I cannot. It is effectively meaningless. I would have advised a fallback provision to other data at the New England ISO or a different solution to this problem entirely. Asking counterparties to calculate hypothetical "what if" cases is likely to be contentious. A similar provision in the power contracts of the Bonneville Power Administration has been litigated for almost thirty years.[34]

Q. Can you point out any serious problems with this contract?

[34] Section 7(b)(2) of the 1980 Pacific Northwest Electric Power Planning and Conservation Act specifies a similar counterfactual calculation and has been the subject ever since.

A. Yes. I have identified two important problems. One is so unusual that I am tempted to describe it as a contract drafting error. The other constitutes an unusual feature that may eliminate seller's credit support after the onset of commercial operation.

Q. What is "credit support"?

A. Credit support is a common feature in energy contracts where the parties take precautions to ensure that the counterparty will be financially able to perform under the contract. In this case the provision is quite moderate: $10/kW of nameplate capacity during the period before commercial operation. As noted above, the contract is somewhat unclear about the nameplate capacity, since Exhibit A only specifies that the contract is less than 30 megawatts.

Q. How much money is involved?

A. There are 1,000 kilowatts in a megawatt, so the seller's per-commercial operation credit support is $10 x 1,000 x 30 megawatts at most, or $300,000. This is small compared to the estimated $205,403,512 million in projected program costs from Appendix X – approximately one day of the projected construction costs.

Q. Is this sufficient to protect National Grid and ratepayers against possible contingencies?

A, No. However, all contract negotiations are complex and the small degree of credit support may have been conceded by National Grid in return for some concession by Deepwater Wind.

Unfortunately, it appears that there either was a drafting error or a miscomprehension on behalf of National Grid in the next section that might well reduce seller's credit support to zero after commercial operation.

Q. What is the problem?

A. A close reading of the credit support language after commercial operation reveals a possible drafting error:

> (b) On or before the tenth (10th) day following the date on which Commercial Operation occurs, Seller shall provide Buyer with Credit Support to secure Seller's obligations under this Agreement ("Operating Period Security"). The Operating Period Security shall be $30 per installed kW of Capacity and shall be subject to replenishment from time to time, within five (5) Business Days after Buyer draws on the Operating Period Security, up to the amount required by this Section 6.1(b), but in any event, not to exceed $1,800,000 on an aggregate, cumulative basis, including all prior Credit Support provided as Operating Period Security. Buyer shall return any undrawn amount of the Operating Period

> Security to Seller within thirty (30) days after the expiration of the Services Term, or termination of the Agreement, but only after such Operating Period Security has been used to satisfy any outstanding obligations of Seller in existence at the time of such expiration or termination.

At first reading it appears that seller's credit support is intended to increase from $10/kW to $30/kW after commercial operation. The use of the term "Capacity" poses a problem, however, since "Capacity" is a defined term in this contract:

> "Capacity" shall mean on or as of any date of determination, the Facility's capability to generate a specific amount of electrical energy at any point in time, including without limitation, all capacity from the Facility as determined by ISO-NE's Seasonal Claimed Capability rating (or successor or replacement rating used to measure capability) as defined in the ISO-NE Rules that is obligated to deliver and receive payments in the Forward Capacity Market (or its successor market) as set forth in the ISO-NE Rules, including without limitation as both a "New" and an "Existing" Capacity Resource as those terms are used in the ISO-NE Rules.[35]

This sets the amount of credit support upon a determination by the New England Independent System Operator, which sets capacity for wind based on its Market Rule 1 which describes an extensive qualification process that is likely to change over time.

Q. What is the capacity associated with a wind resource?

A. There is extensive debate on this point throughout the U.S. and Canada. Traditionalists argue that wind resources often have zero capacity value since the wind might not be blowing at system peak. New England currently has a less rigorous standard that provides some capacity value depending on site-specific data.[36] It is not necessary for this debate to be recapitulated in this proceeding. It is important, however, to realize that the credit support will change by season and may well be zero if the New England ISO standards change or Deepwater Wind fails to meet the certification standards set out in the ISO New England tariffs.

Q. Can you describe the ISO-NE's Seasonal Claimed Capabilities protocol?

A. Yes. The Seasonal Claimed Capabilities for wind assets are determined by the process described in the Intermittent Power Resources section of the NE ISO's Market Rule 1 III.13.1.2.2.2, subsections 1 and 2.

[35] Amended PPA, page 2.

[36] See III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

> For Intermittent Power Resources, or Intermittent Settlement Only Resources, the first Forward Capacity Auction Qualified Capacity is determined by the median of the net output during the Summer or Winter Intermittent Reliability Hours. For all other Forward Capacity Auctions, the median of the first five years sets the quantity. Summer is defined as lasting from June through September, and winter is defined as October through May. Summer Intermittent Reliability hours are 2 pm through 6pm, while winter hours are 6pm through 7 pm. For Resources that have not yet achieved Commercial Operation the Qualified Capacity is equal to the capacity cleared from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.
>
> (a) With regard to the first Forward Capacity Auction, for each of the previous four summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours, as defined in Section III.13.1.2.2.2.1(c). With regard to any Forward Capacity Auction after the initial Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours, as defined in Section III.13.1.2.2.2.1(c).
>
> (c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and, after June 1, 2010, hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import constrained Capacity Zone, all Shortage Events in that Capacity Zone.[37]

Q. Did Mr. Nickerson conduct a calculation of Seasonal Claimed Capacity?

A. Yes. His calculations are:

> 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.[38]

[37] Market Rule 1 III.13.1.2.2.2.1 Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

[38] Docket No. 4111, Direct Testimony of David Nickerson, page 23.

Q. Can you describe the results of defining credit support in terms of the ISO-NE's Seasonal Claimed Capability protocol?

A. Yes. Using Mr. Nickerson's estimates, credit support would be equal to the nameplate capacity in kilowatts multiplied by the seasonal capacity factor, multiplied by $30. Winter credit support would be 28.8 MW x 1,000 x 50.0% x $30 = $432,000, and summer credit support would be 28.8 MW x 1,000 x 36.1% x $30 = $311,904.

Q. Is this a commercially reasonable provision for credit support?

A. No. It is not reasonable to calculate credit support based on a standard designed to qualify the project at a later date for inclusion in the ISO-NE capacity markets.

Q. Is this the only error in the contract?

A. No. A considerably more serious error occurs in Section 9.3. This section summarizes remedies – specifically termination payments if the contract fails. Section 9.3(b)(ii) states:

> (ii) Termination by Seller On or After Construction Financing. If Seller terminates this Agreement because of an Event of Default by Buyer occurring on or after the close of construction Financing for the Facility, the Termination Payment due to Seller shall be equal to the amount, if positive, calculated according to the following formula:
>
> $$\sum_{N}[(CV - MV) + P]$$
>
> where:
>
> "Σ" is the summation over the Services Term.
> N
>
> "CV" is the contract value of the Products for the remainder of the Services Term calculated with reference to the applicable Price and the Supply Forecast.
>
> "MV" is the market value of the Products for the remaining Services Term as determined with reference to the applicable Resale Price and the Supply Forecast.
>
> "P" is the amount of any applicable penalties and administrative costs incurred by Seller in selling the Products not accepted and paid for by Buyer as a result of the termination of this Agreement.

> All such amounts shall be determined by Seller in good faith and in a commercially reasonable manner, and Seller shall provide Buyer with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(ii), which calculation shall be binding upon Buyer, absent manifest error.[39]

Q. Can you describe the problem?

A. Yes. Both this section and Section 9.3(b)(v) omit calculating the present value of the future stream of payments. Since this is a twenty-year contract, the termination payment as calculated here will differ from the actual economic interests of the parties by a considerable degree. Citing the present value in termination provisions is the standard since the termination payment is intended to make the injured party whole, not confer a windfall profit or loss.

Q. Why does this matter?

A. If one of the parties has an incentive to make the contract fail, it will add to the probability that the contract will fail. This omission creates such an incentive.

Q. Why do you think that this is an omission?

A. The contemporaneous contract between Cape Wind and National Grid includes the language specifying present value in the termination payment calculation:

> "RV" is the replacement value of Buyer's Percentage Entitlement of the Products for the remainder of the Services Term, calculated with reference to the applicable Replacement Price and the Supply Forecast, using a discount factor of eight percent (8.0%).
>
> "CV" is the contract value of Buyer's Percentage Entitlement of the Products for the remainder of the Services Term calculated with reference to the applicable Price and the Supply Forecast, using a discount factor of eight percent (8.0%) (the "Contract Value").
>
> "P" is the amount of any applicable penalties and costs incurred by Buyer in replacing the Products not Delivered to Buyer as a result of the termination of this Agreement.[40]

[39] Amended PPA, page 31.

[40] POWER PURCHASE AGREEMENT BETWEEN MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY, D/B/A NATIONAL GRID, AS BUYER AND CAPE WIND ASSOCIATES, LLC, AS SELLER As of May 7, 2010, page 44.

Q. Are there other problematic issues in the contract?

A. Yes. As I mentioned above, the size of the project is not specified in the contract. Exhibit A sets the maximum nameplate capacity at 30 megawatts and limits the project to eight turbines. Appendix X reduces the bundled price as the project's cost falls below $205,403,512 without specifying the amount of equipment being purchased. Exhibit Y specifies – with a small mathematical error – the production target as a function of the as yet undetermined nameplate capacity. This gives Deepwater Wind an interesting incentive to increase the capacity of the project to 30 megawatts even if the purchaser might have gained a price reduction under Appendix Y at 28.8 megawatts.

Q. Is this a fruitful area for future litigation?

A. Conceivably. Nameplate capacity is just that – the capacity on the nameplate. It is not a defined term in the contract, nor is nameplate capacity always identical with actual capacity. Moreover, although Deepwater Wind's calculations have envisaged eight turbines at 3.6 megawatts, other configurations are certainly possible. Alpha Ventus, for example, is using the recently introduced 5 megawatt turbines.

Q. Can you describe the small error in Exhibit Y?

A. Yes. Exhibit Y omits to calculate the correct number of hours in leap years. Section 1.(a) sets the number of hours to 8,760 for every contract year regardless of the actual number. This is not a major issue, but it does go to the question of the level of review exercised in the preparation of the contract.

Q. Can you easily interpret the language in Exhibit Y?

A. No. While the language may not be in error, it lacks clarity. I presume that it is intended to match the interpretation but forward by Mr. Nickerson in Docket 4111:

> 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.[41]

Q. Would you change this?

A. Yes, or alternatively, directly include Mr. Nickerson's interpretation in the example.

Q. How "commercially reasonable" is this contract?

A. It is not a commercially reasonable document. As noted above there are possible errors, important sections are unclear and may lead to controversy, and it gives an overall sense of needing a thorough review before execution.

Q. Does this complete your testimony?

A. Yes.

[41] RIDPUC Docket No. 4111, Direct Testimony of Nickerson, page 22.