Appendix F

Economic Model

Description of Economic Model

Draft Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet

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Introduction

The Economics Division of the Minerals Management Service evaluated the proposed Cape Wind Energy Project site and alternatives with the Offshore Wind Energy Project (OWEP) model, a Microsoft Excel cash flow spreadsheet created by the author. Evaluation parameters include economic and project finance assumptions, fiscal terms, power output, technical and physical constraints, capital and operating expenses, and decommissioning expenses. A capital account balance showing the after tax, discounted, cumulative net revenue was calculated for each site, and the alternatives were ranked according to relative economic performance, measured as the cost of energy. For this analysis, the cost of energy is defined as the 2007 electricity sales price, in dollars per kilowatthour (KWhr), which the project owners would need to meet or exceed a specified debt coverage ratio. Electricity prices were escalated annually at a flat rate of 1.5% for the life of the project. Debt payments and all cash flows are calculated on an annual basis.

Part *3.0 Alternatives* of the Cape Wind Energy Project draft environmental impact statement (EIS) contains discussion of the proposed site located on Horseshoe Shoal, nine alternative sites at various locations on the New England outer continental shelf (OCS), and three alternative configurations at the proposed site. Maps are included at the end of this report showing the site locations. Only the alternatives having a cost of energy that allows for reasonable comparison with the proposed site will be subjected to additional environmental analysis in the draft EIS.

Primary elements of the economic analysis are described in the following points.

- The economic analysis was carried out for the purpose of site comparison, and therefore, required results of lesser accuracy than analyses carried out for investment decisions. Economic performance was measured in terms of the cost of energy, which allows for relative comparison of the sites, although it precludes consideration of price uncertainty.

- Financial terms were modeled from information available to the wind energy and electrical utilities industries, thought to be representative of current conditions in the debt and equity markets for offshore projects.

- Assessment of the wind resource for each site was conducted with information obtained from a public wind map. Power output was predicted using the mean of a distribution of wind speeds, characteristic of an average year. MMS did not have access to multiple years of site specific wind speed data.

- Main elements of project design were based on the applicant's proposal and held uniform across all alternatives, eliminating uncertainty for most concept selection issues. Some differences were incorporated to account for foundation and cable system requirements. Wind turbine generator (WTG) foundation design varies by water depth. Monopile foundations would be installed in water depths of 20 meters or less. Oil and gas type platform substructures with three or four piles could be used in water depths greater than 20 meters and less than 45 meters. Locations in water depths greater than 45 meters would probably require the use of floating platform technology. Cable system design for electricity transmission is dependent on the distance of a site to a grid connection. Sites less than 30 miles from shore were modeled with alternating current (AC) cable systems, while more distant sites could be connected with direct current (DC) cable systems.

- Historical cost data was not available from a similar project to estimate capital and operating expenses. The applicant proposes to generate electricity from 130 wind turbine generators (WTGs) having a capacity of 3.6 megawatt (MW) each, for a total installed capacity of 468 MW. However, commercial offshore wind energy projects presently operating in European offshore locations are of a smaller scale, ranging in size from 30 to 80 WTGs having capacities varying from 2 to 3 MW each. Further, construction for most of the existing projects was complete, or was underway, before prices for materials such as steel and copper began to exceed historical levels in late 2003. As a substitute for actual cost data, proprietary capital cost estimates were obtained from a wind turbine manufacturer. These cost estimates account for the higher steel and copper prices. Operating expenses were estimated from information posted on an offshore wind energy internet site.

References to the information sources used for this analysis are provided in the next section.

Materials and Methods

The Cape Wind Energy Project was evaluated with the OWEP Excel spreadsheet by entering case specific values for each input variable. Some input cells are located in the header row of the cash flow table, other input cells are located in the space between the cash flow table and the table for loan and tax calculations. Assumptions, parameters and terms for spreadsheet variables are described later in this section under headings titled: Project Assumptions, Economic Parameters, Fiscal Terms, Term Debt Inputs, Debt Service Reserve, Construction Loan Interest, Tax Considerations, Miscellaneous and Cost Inputs.

When the spreadsheet was used to calculate the cost of energy for the proposed site and alternatives, attention was given to ensuring that the cost of energy estimates, designated as the *power purchase price* in the spreadsheet, were great enough to satisfy debt coverage ratio requirements (see *debt coverage ratio* under Term Debt Inputs). Lenders use debt coverage ratios to assess a borrower's ability to make loan payments on schedule. Debt terms are set at a level that would allow a borrower to maintain a positive net operating cash flow over the life of the loan. The minimum acceptable debt coverage ratio used for this analysis was 1.3, calculated annually. The numerator of the debt coverage ratio is the sum of annual income derived from electricity sales, renewable energy certificate sales, monetization of the production tax credit and debt service reserve interest, minus operating costs and any rental, royalty or operating fee payments owed to the lessor. The denominator of the debt coverage ratio is equal to the annual principal and interest payments owed to the lender. Annual debt coverage ratios are calculated automatically by the spreadsheet, starting on row 43 of column P.

Values for variables affecting the debt coverage ratio were not entered in any particular order, with the exception of the following sequence of steps. After the entry of the other project scenario inputs, changes to the *cost per megawatt (MW)* input were made. This enabled the completion of two manual adjustments before determining the cost of energy. First, the *decommissioning cost per MW* estimate for each case was revised to represent the appropriate value, as explained under Cost Inputs. Second, the *one-half annual payment* variable under Debt Service Reserve was iteratively adjusted until the ratio of *one-half annual payment* to *annual payment* was slightly greater than 0.5. At that point, it was possible to properly estimate the cost of energy, by making incremental changes to the *power purchase price* until the debt coverage ratio requirement was satisfied.

It is important to note that the cost of energy calculated for the proposed site and each alternative provided a rate of return that exceeded 12%, the maximum of a 10% to 12% range that the developer might set as a target. The rate of return for the proposed site and the alternatives were calculated by iteratively adjusting the discount rate in row 2 of column M, until the cumulative cash flow was reduced to a value close to $0. Rate of return values are reported on the worksheet tabs within the spreadsheet.

Project Assumptions

wind turbine generators [column B, row 2] - The applicant proposed,a generating facility with an installed capacity of 468 MW. A total of 130 wind turbine generators would be installed. Each wind turbine generator would be rated with a nameplate capacity of 3.6 MW. This aspect of the project was held constant across all sites.

capacity factor and electrical output [column B, row 31 and rows 1-28] - The MMS conducted independent resource estimates for all sites, utilizing a wind power model provided by the National Renewable Energy Laboratory (NREL), Office of Energy Efficiency & Renewable Energy, U. S. Department of Energy. Several input parameters are required to run the NREL model. Average wind speeds and Weibull distribution parameters for the sites were obtained from public information available on the AWS Truewind internet site at www.awstruewind.com. The applicant supplied a power curve for the offshore wind turbine generator identified in its development plan. Power values from the curve were used to calculate electrical output. At the request of the turbine manufacturer, the power curve information is held proprietary by MMS. Array and soiling losses used by MMS in the NREL model were provided by the applicant. MMS independently estimated turbine availability and approximate cable system power losses for each site, and entered these values in the NREL model to calculate resource estimates.

The MMS carried out an independent review of wave height measurements recorded at offshore buoys in the vicinity of each site, to estimate wind turbine generator accessibility and availability. Accessibility to the wind turbines for maintenance and repairs is dependant on the significant wave height, which MMS assumed to be 1.5 meters. Field work requiring the transfer of personnel from a boat to a wind turbine tower would be deferred when the significant wave height is exceeded. Accessibility was determined by calculating the fraction of 24 hour periods in a year when the wave height did not exceed 1.5 meters, for periods from 6 p.m. to 6 a.m., and also from 6 a.m. to 6 p.m. the next workday. These accessibility rates were converted to turbine availability with a function published in Figure 8 of a paper titled The DOWEC Offshore Reference Windfarm: Analysis of Transportation for Operation and Maintenance, by G. J. W. van Bussel and W. A. A. M. Bierbooms of the Delft University of Technology, Delft, The Netherlands. This paper can be found on the internet at www.ecn.nl/docs/dowec/2003-Wind-Engineering-Accessibility.pdf. Availability for each site was used as an input in the NREL model to approximate the frequency of turbine downtime.

In a paper written in 2003 for the applicant entitled Limitations of Long Transmission Cables for Offshore Wind Farms, ESS, Inc. estimated that alternating current (AC) cable system power losses from two of the offshore sites, Horseshoe Shoal and Nantucket Shoals, to the onshore interconnect would be 1.5 percent and 4.5 percent, respectively (this paper was included as Appendix 3-C to a draft environmental impact statement published by the Army Corps of Engineers and is available on the internet at http://www.nae.usace.army.mil/projects/ma/ccwf/app3c.pdf). Cable length is given as 17 miles for the Horseshoe Shoal site and 41 miles for the Nantucket Shoals site. The rate of cable system power losses increases with distance, and so, the power loss per mile for the Nantucket Shoals site was considered a maximum. Therefore, this rate was applied in the viability analysis to estimate power losses for sites utilizing AC cable systems. For example, a cable system of 30 miles length would have an estimated power loss of 3 percent, etc. Information presented in a paper titled Study on the Development of the Offshore Grid for Connection of the Round Two Wind Farms, by Econnect Ltd., found at www.dti.gov.uk/files/file30052.pdf?pubpdfdload=05%2F846, was used as a reference to determine when it may be to the applicant's advantage to install a direct current (DC) cable system rather than an AC cable system. Figure 5.3 of the study shows that AC cable lengths of 50 kilomters or less (<31 miles) would not require reactive compensation to maintain cable system power losses below an acceptable level. When cable systems of greater than 50 kilometers would be required, MMS assumed that DC cable systems would be installed. While DC systems include the additional cost of AC/DC converter stations, cable costs are lower and cable system power losses are generally less than 3 percent. DC cable systems with power losses of 3 percent were modeled for the sites at Nantucket Shoals and Phelps Bank.

A summary of the cost of energy, electricity generated, capacity factor, wind turbine generator availability, cable system power loss and cable length for each site evaluated in the viability analysis is shown in the Table 1. Deviations in the cable route, to avoid areas of hard bottom and endangered species, were a consideration in the submarine cable length estimates.

Table 1

	1	2	3	4	5	6	7	8	9	10
Site	Horseshoe Shoal	Block Island	South of Tuckernuck Island	Cape Ann	Monomoy Shoals	Boston Outer Harbor	Portland Outer Harbor	Nantucket Shoals	Phelps Bank	East of Nauset Beach
Cost of Energy ($/KWhr)	$0.122	$0.132	$0.143	$0.151	$0.205	$0.213	$0.224	$0.238	$0.287	$0.299
Electricity Generated (MWhr/year/ 130WTGs)	1,608,600	1,610,900	1,688,000	1,515,800	1,172,700	1,600,300	1,430,300	1,046,100	1,035,200	1,184,100
Capacity Factor	39.24%	39.29%	41.17%	36.97%	28.60%	39.04%	34.89%	25.52%	25.25%	28.88%
Wind Turbine Generator Availability	93%	92%	92%	88%	64%	91%	92%	56%	56%	64%
Cable System Power Losses	1.5%	1.0%	3.0%	0.9%	2.6%	3.0%	1.6%	3.0%	3.0%	2.7%
Cable Length (miles)	17	9	27	8	24	27	15	41	67	25

NREL model output for the proposed site at Horseshoe Shoal yielded a capacity factor of 39.2%, and an average output of 1,609 gigawatthours of electricity delivered to the grid for sales, per year. The EnergyBiz Insider reported that Cape Wind had released a comparable power output estimate of 1,594 gigawatthours for Horseshoe Shoals, in an article titled "Cape Wind's Prospects and Energy Output Get a Boost," published on December 13, 2006

Economic Parameters

cost of energy (power purchase price) [column C, row 2] - Each site was evaluated to calculate the cost of energy. For this analysis, the cost of energy is defined as the 2007 electricity sales price, in dollars per KWhr, which the project owners would need to meet or exceed a specified debt coverage ratio during the life of a loan. Prior to a loan approval for the Cape Wind Energy Project, it is likely a lender would require that the applicant obtain a long term power purchase agreement for electricity sales. An annual price escalation rate of 1.5% was assumed to be a provision of the power purchase agreement. The escalation rate is discussed further under *price growth factor.*

inflation factor [column P, row 2] - An annual inflation rate of 2.5% was assumed. The Energy Information Administration provided its inflation forecast from 2003 through 2030 in the Annual Energy Outlook (AEO) for 2006 (available at www.eia.doe.gov/oiaf/archive.html), which is based on the Gross Domestic Product Chain-Type Price Index. For the period of electricity generation, from July 2010 through June 2030, the average of the annual rate of inflation is about 2.2%.

price growth factor [column Q, row 2] - According to the AEO for 2006, electricity prices could decline slightly over the next 5 years, and remain relatively flat for the following 15 years. The product of the inflation rate and price growth was assumed to be 1.5% annually, to account for the lack of price growth in the forecast.

operating cost growth [column R, row 2] - Estimated costs in 2015 and 2030 for producing electricity from new advanced coal and advanced combined cycle plants are given in Table 16, page 83 of the AEO for 2007 (available at www.eia.doe.gov/oiaf/aeo/index.html). Fixed cost growth for both plant types is flat over the time period shown. The flat fixed cost growth rate does not include fuel costs, and may be a reasonable indicator of the operating cost growth rate to be expected for the proposed project, since the fuel, offshore wind, does not have a direct cost. The product of the inflation rate and operating cost growth was assumed to be 2.5% annually, to account for the flat operating cost growth rate in Table 16.

discount rate [column M, row 2] - MMS calculated the weighted average cost of capital for the project to determine a discount rate. To make the calculation, MMS utilized information obtained from an investment bank identified by the applicant. The interest rate on term debt was assumed to be 7%, derived as an approximation of the London Interbank Offer Rate (LIBOR), which changes over time, plus 1.5% to 2.5%. Further, information from the investment bank indicted that equity investors might assume a 10.5% after tax return. Therefore, nominal rates of 7.0% and 10.5% were used for the debt and equity portions, respectively, of the weighted average cost of capital calculation. The weighted average cost of capital may be calculated as $((1 + 0.07*0.75 + 0.105*0.25)/((1+0.025) -1))*100\% = 5.24\%$.

Ibbotson Associates, a well known financial consulting firm, reported that the nominal cost of capital for the electric services industry, comprised of 41 companies, was about 9.0% in the fall of 2005. This value was not used in the calculation because it is thought to represent a composite of electricity generators, transmission service providers and utilities.

In contrast to the project assumptions discussed above, the economic parameters – except for cost of energy – are invariant across all sites.

Fiscal Terms

rental and royalty rates [column F&G, row 2] - Prior to the generation of electricity, a rental rate of $7.50 per acre is assumed. After the project is placed in service, a royalty rate of 12.5% is assumed, to be charged on income from electricity and renewable energy certificate sales. These fiscal terms are used for illustrative purposes, and are not intended to imply or otherwise represent future fiscal term policy for the MMS alternative energy program. MMS has not set fiscal terms for any form of alternative energy authorization. Proposed fiscal terms will be discussed in the draft rule for 30 CFR 285, Alternative Energy and Alternate Uses of Existing Facilities in the Outer Continental Shelf, which MMS plans to publish in the fall of 2007.

As presented in this analysis, the fiscal terms are a proxy for adopting an opportunity cost approach, which assumes MMS would provide payment rates for a wind energy lease that are similar to payment rates for an oil and gas lease. Terms for deepwater oil and gas leases (400 meters water depth or greater) were chosen instead of terms for leases issued in shallower water, because technological challenges for the offshore wind industry are similar to those encountered by deepwater oil and gas operators in the 1990's. In both cases, the operators either are, or will be, among the first to acquire the capability to place their leases in a productive status.

Like most of the economic parameters above, the fiscal terms are the same for all sites.

Term Debt Inputs

debt-equity ratio [column F, row 30] - According to Principles of Project Finance by E. R. Yescombe, on p. 285, a debt:equity ratio of 85:15 may be appropriate for a standard power plant with an offtake contract, although lower ratios such as 50:50 would be required for nonstandard projects with higher risks, such as merchant power plants with no offtake contract or price hedging. Information obtained from an investment bank identified by the applicant indicates that typical debt-equity ratios for wind energy projects range from 65:35 to 75:25. A debt-equity ratio of 75:25 was assumed for the Cape Wind evaluations, given the certainty of the wind resource.

loan rate [column F, row 33] - The interest rate on term debt was assumed to be 7%, derived as an approximation of the LIBOR, which changes over time, plus 1.5% to 2.5%.

debt period [column F, row 34] - This project has a 20 year life. It was assumed that the bank would require re-payment of the term debt in 15 years.

annual payment [column F, row 35] - Uniform annual payments are automatically calculated, in the same manner as a home mortgage.

debt coverage ratio [column P, row 49-63] - A minimum annual debt coverage ratio was set at 1.3 for the evaluations. According to Principles of Project Finance by E. R. Yescombe, on p. 273 and 274, a ratio of 1.3 has been used for standard power plant projects with offtake contracts. A ratio of 1.5 could be applied for a natural resource project. Ratios as high as 2.0

have been required for nonstandard projects with higher risks, such as merchant power plants with no offtake contract or price hedging.

It is conceivable that a lender for the Cape Wind project could require a debt coverage ratio of greater than 1.3. However, a higher debt coverage ratio would not change the ranking order of the alternatives, if the same debt:equity ratio is assumed for all sites, as in this analysis. The debt coverage ratio for a project like Cape Wind is uncertain, since few banks have loaned money for offshore wind projects, and none of these projects have been built on the OCS. Cash flows in the evaluations conducted for the viability analysis fluctuate annually, but the most pronounced changes are due to the timing of subsidies. Monetization of the production tax credit over the first 10 years of a project's life has a cliff effect on the debt coverage ratio, beginning in the 11th year. Further, renewable energy certificate income is fairly uncertain and may fluctuate, increasing the variance of the debt coverage ratio. Banks may give borrowers special consideration for these effects, at their discretion. Any judgment made by MMS in this regard would be subjective.

Term debt inputs were held constant for all sites.

<u>Debt Service Reserve (DSR)</u>
pre-debt service reserve loan amount [column F, row 31] - This figure is calculated by the spreadsheet and is equal to the term debt less the *debt service reserve*. In the analysis, project owners would borrow 75% of the construction capital, plus all construction loan interest, loan fees and equity fees, as well as funds for the decommissioning bond and *debt service reserve*. The *post-debt service reserve loan amount* includes the *debt service reserve*.

debt service reserve [column N, row 35] - As a condition of term debt, it is assumed that a lender will require that project owners maintain a *debt service reserve* fund equal to one-half of the annual term debt payment. Project owners would borrow the *debt service reserve* as part of the term debt. In the spreadsheet, *one-half annual payment* is the same as the *debt service reserve.* The relationship between *one-half annual payment* (entered into the spreadsheet manually by the user) and the *annual payment* (calculated by the spreadsheet from the *post-debt service reserve loan amount*) is a circular function. *One-half annual payment* is entered iteratively by the user until the ratio of *one-half annual payment* to *annual payment* is slightly greater than 0.5. The *debt service reserve* (equal to *one-half annual payment*) is automatically added by the spreadsheet to the *pre-debt service reserve loan amount*, to calculate the total term debt, called the *post-debt service reserve loan amount*. The *debt service reserve* is added to the loan amount and automatically entered under Equity Investment for the year 2010.

interest rate [column N, row 34] - A minimal interest rate of 2% is assumed for earnings on the *debt service reserve* fund.

annual interest earned [column N, row 36] - This amount is added to the Gross Value of Production column during the 15 year debt period. The *debt service reserve* is withdrawn upon final pay off of the term debt, and added to the Gross Value of Production column in 2025.

Construction Loan Interest
interest rate [column I, row 35] - Treasury securities maturing in 2 years are offered at interest rates of about 4.5%. A 5% rate was used as a proxy for construction loan interest. Pay off of the construction loan is expected at the term debt closing, assumed in June of 2010.

2009 and 2010 interest [column I, rows 36&37] - Interest for 2009 is 5% of the construction capital expenses (CAPEX). Interest for 2010 is 5% of the sum of the construction CAPEX plus the 2009 interest. Interest is not due until the term debt closing, assumed in June of 2010. The interest is added to the loan amount, and automatically entered under Equity Investment for 2010.

Tax Considerations
term debt interest deduction [column E, rows 49-63] - Interest paid on the term debt is deducted from taxable income in the site evaluations. Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter B, Part VI, Sec. 163(a) states in the General Rule that "There shall be allowed as a deduction all interest paid or accrued within the taxable year on indebtedness."

construction loan interest deduction [column E, row 48] - Part of the construction loan is spent in 2009, with the remainder spent in 2010. The interest due on the part of the loan that was not spent in 2009 was deducted for tax calculations. Since it was assumed that no interest would be paid to the lender until the closing of the term debt in 2010, the deduction of construction loan interest is entered in 2010. This feature was included to model the deduction allowed by Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter B, Part IX, Sec. 263(f).

depreciation [column K, rows 48-53] - It is likely that a wind energy project on the OCS will be classified as a "5 year property" by the IRS. References supporting this assumption are listed at Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter A, Part IV, Sec. 48(a)(3)(A)(i), and Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter B, Part VI, Sec. 168(e)(3)(B)(vi)(I) and Sec. 168(g)(1)(A). Capital expenses were deducted in the site evaluations using the depreciation schedule for a 5 year recovery period, half-year convention, shown in Table A-1 of Appendix A, IRS Publication 946, How to Depreciate Property. Depreciation rates for the recovery period are 20.00%, 32.00%, 19.20%, 11.52%, 11.52% and 5.76%.

amortizing loan fees [column G, rows 48-62] - Amortization of these fees is calculated automatically by the spreadsheet as 2% of the sum of the debt portion of the construction CAPEX plus the construction loan interest. The fees are paid at the term debt closing for services provided by lawyers and accountants, and other related costs such as commitment fees. The fees are included in the term debt amount, and are automatically entered under Loan Principal and Interest for 2010 to make cash flow calculations. Columns in the tax calculations for amortizing loan fees are also populated automatically. This method of approximating the effect of amortizing loan fees was identified in an unpublished NREL report. The deductions were included in the viability evaluations in an attempt to accurately model after tax cash flow.

amortizing equity fees [column H, rows 48-52] - Amortization of these fees is calculated automatically by the spreadsheet as 3% of the sum of the debt portion of the construction CAPEX plus the construction loan interest. The fees are paid for equity organizational costs and tax advice. No write-off was taken for 40% of the fees. Of the remainder, one-half was assumed to be for tax advice and expensed in one year. The other one-half was amortized over 5 years. The fees are included in the term debt amount, and are automatically entered under Loan Principal and Interest for 2010 to make cash flow calculations. Columns in the tax calculations for amortizing equity fees are also populated automatically. This method of approximating the effect of amortizing equity fees was identified in an unpublished NREL report. The deductions were included in the viability evaluations in an attempt to accurately model after tax cash flow.

tax rate [column L, row 44] - According to Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter A, Part II, Sec. 11, increasing corporate tax rates are imposed such that: a) a 15% rate applies to taxable income that does not exceed $50,000, b) a 25% rate applies to taxable income that exceeds $50,000 up to $75,000, c) a 34% rate applies to taxable income that exceeds $75,000 up to $10,000,000, and d) a 35% rate applies to taxable income that exceeds $10,000,000. To simplify tax calculations in the site evaluations, a 35% rate was applied to all taxable income.

production tax credit [column M, rows 48-58] - According to Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart D, Sec. 45(a), wind energy generators may claim the credit at a qualified facility during the 10 year period beginning on the date the facility was originally placed in service. The credit amount for 2006 was set at $0.019 per KWhr, by the IRS in Internal Revenue Bulletin 2006-25, Notice 2006-51 on June 19, 2006. Adjustments to the 2006 credit amount were made for the viability analysis by applying an annual inflation rate of 2.5%. Unused credits were carried forward as described in Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart D, Sec. 39.

net operating losses – After tax cash flow calculations in the MMS evaluations are carried out under the assumption that project developers can apply net operating losses from the wind energy project against income from other sources. Therefore, these losses are not carried over as described in Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter B, Part VI, Sec. 172. The reduced tax obligation allowed on income from other sources is applied to the wind energy project as a benefit, which increases the economic potential of the wind energy project. This accounting method was not intended to show how a tax payer would complete a tax return, but has been included for analytical purposes only.

state taxes – State taxes were not imposed on income derived from the wind energy project. Section 4(a)(2)(A) and (a)(3) of the Outer Continental Shelf Lands Act [43 USC Section 1333] refer to this restriction on state tax and jurisdiction. The last sentence in 4(a)(2)(A) explains that "State taxation laws shall not apply to the outer Continental Shelf." This provision should apply equally to oil and gas, minerals, and alternative energy.

<u>Miscellaneous</u>
2007 RPS alternative compliance payment [column N, row 31] - The value of renewable energy certificates sold by project owners during the first 5 years of production is calculated to be 90% of this figure. For 2007, the Massachusetts Division of Energy Resources, Office of Consumer Affairs and Business Regulation determined the payment would be $57.12 per MWhr. A lower value was used for later years. The MA Technology Collaborative has reported entering into forward contracts with renewable energy certificate values set at $25 per MWhr. This figure was used in the evaluations for years 6 through 20. Renewable energy certificate values were escalated at the rate of inflation.

EIS Costs [column N, row 30] - An estimate of $1.5 million is entered under Equity Investment for 2007, as the cost required to complete an environmental impact statement meeting requirements of the National Environmental Policy Act of 1969.

<u>Cost Inputs</u>
cost per megawatt (MW) [column B, row 32] - Wind energy developers commonly express capital expense estimates in terms of $ per unit of installed capacity. The factor includes the cost of all equipment and construction of the facility. Interest paid on the construction loan, debt and equity financing fees, the cost of establishing a debt service reserve fund and the cost of the decommissioning bond, are additional expenses not included in the cost per MW factor.

The cost factor for the proposed site located on Horseshoe Shoal was derived from confidential information obtained from the manufacturer of the wind turbine generator identified in the applicant's development plan. Before estimating costs for the alternative sites, corrections were made to the cost factor to adjust 1) foundation costs for differences in water depth, and 2) cable costs for differences in length. Foundation cost estimates are explained below. Cable cost estimates are explained in the next item.

The installation of monopile foundations was assumed for the sites at Horseshoe Shoals (average water depth: 6 meters), Monomoy Shoals (average water depth: 6 meters), Nantucket Shoals (average water depth: 9 meters), and for 37 of the 130 wind turbine generators to be installed at the site South of Tuckernuck Island (average water depth range: 5 to 30 meters). Monopile foundation cost estimates for Horseshoe Shoals were increased by 50% to estimate the foundation costs at the other sites. These sites are located in areas where water depths transition from relatively deep to relatively shallow, creating breaking wave conditions. Foundations at these sites would be engineered to a greater level of integrity than the foundations for the proposed site.

Oil and gas platform technology for 4 pile substructures was assumed for three of the other sites evaluated, Block Island (average water depth: 30 meters), Phelps Bank (average water depth: 33 meters), and Cape Ann (average water depth: 45 meters, as well as for 93 of the 130 wind turbine generators to be installed at the site South of Tuckernuck Island. The structural design of platforms used for wind turbines would differ from oil and gas applications, and is presently unproven. In the fall of 2006, a 5 MW wind turbine generator was installed on the first such structure, located in a water depth of over 40 meters in the Beatrice oil and gas field offshore of the United Kingdom. Costs for platform structures were estimated with off-the-shelf software available to the oil and gas industry. The license agreement between MMS and the software vendor stipulates that MMS must not share the software, output results or reports with persons outside the agency.

Floating platform substructures were assumed for the site east of Nauset Beach (average water depth: 200 meters), Boston Harbor (average water depth: 60 meters), and Portland Harbor (average water depth: 60 meters). MMS estimated the cost for a tension leg platform structure with off-the-shelf software available to the oil and gas industry, which was found to be prohibitive. A cost estimate provided by the applicant was lower by several magnitudes. The applicant's estimate was derived from information published for wind energy projects in deepwater, and was utilized to evaluate the sites.

cost per mile of submarine electrical cable [column B, row 33] - The edited version of the paper written in 2003 for the applicant by ESS, Inc., entitled Limitations of Long Transmission Cables for Offshore Wind Farms (this paper was included as Appendix 3-C to a draft environmental impact statement published by the Army Corps of Engineers and is available on the internet at http://www.nae.usace.army.mil/projects/ma/ccwf/app3c.pdf) gives cost estimates for AC and DC cable systems and electric service platforms. These costs were updated using confidential information obtained from the manufacturer of the wind turbine generators identified in the applicant's development plan, and information published in Figure 10.1 of the paper titled Study on the Development of the Offshore Grid for Connection of the Round Two Wind Farms, by Econnect Ltd., found at www.dti.gov.uk/files/file30052.pdf?pubpdfdload=05%2F846. Note that the cable costs are included in the cost per MW estimate. The spreadsheet uses the cable cost to schedule the timing and amount of investments which would occur over the 2 year construction period.

upland cable cost [column B, row 35] - This cost is an estimate taken from the 2003 paper by ESS, Inc., Limitations of Long Transmission Cables for Offshore Wind Farms (available on website cited above). The cable costs are included in the cost per MW estimate, but are backed-out by the spreadsheet to schedule the timing and amount of investments which will occur over the 2 year construction period.

operating expenses [column F, rows 38&39] - Operating expenses have fixed and variable components. Fixed costs are dependant on installed capacity, while variable costs are dependant on electricity generation and vary by site as a function of distance from shore. Base values for fixed and variable costs were obtained from information posted on the website at www.offshorewindenergy.org, and adjusted for inflation.

insurance costs [column F, row 40] - The applicant supplied a confidential annual premium quote that it obtained from a known wind energy insurer. The quote is entered as a percentage of the final project value, estimated to be equal to the construction CAPEX.

decommissioning cost per MW [column N, row 39] - Decommissioning estimates were inferred from information in Figure 2 of a paper titled Toward Selection of Concepts for Offshore Support Structures for Large Scale Wind Turbines by M.B. Zaaijer, W. van den Broek, and G.J.W. van Bussel. This paper can be found on the internet at www.ecn.nl/docs/dowec/2001-MAREC-Support-Structures.pdf. The figure shows a cost breakdown for an installed monopile structure adequate to support a 5 MW turbine in 15 meters water depth. Decommissioning represents about 10% of the monopile costs shown. Total decommissioning costs for the proposed site at Horseshoe Shoal may be less than 10% of the total CAPEX, partly because the cost of installed support structures (monopiles) may only be one-fourth of total CAPEX, the wind turbine generators may have some salvage value, and removing the support structures could account for a majority of the total decommissioning expense. Decommissioning may be considered the reverse of installation, with the exception being that decommissioning can be conducted with less care.

A breakdown of costs for offshore wind development showing installation costs is given in Figure 11, page 51 of a Study of the Costs of Offshore Wind Generation, prepared for the United Kingdom Renewables Advisory Board and Department of Trade and Industry by Offshore Design Engineering Limited, and posted on the internet at www.dti.gov.uk/files/file38125.pdf. The table gives estimates for the proportion of total costs attributed to installation as: WTGs – 2%, cables – 9%, and foundations – 6%. Neglecting cost variations due to water depth, if it is assumed that the cables would be left in place (to either minimize subsea disturbance or because the salvage value of the cable is less than the cost of removal), and the salvage value for the wind turbine generators is arbitrarily assumed to be equal to 1% of the total CAPEX, then total decommissioning costs for the proposed site could be approximately 7% of the CAPEX. Table 5 of the study provides a decommissioning cost estimate of £275,000 per WTG, which translates into factors of 8.6% and 3.4% of CAPEX for WTGs with capacities of 2.0 MW and 5.0 MW, respectively. The DTI study capital cost factor of £1,600,000 per MW was utilized for the calculations. The 7% of CAPEX factor is within the range, and was used to estimate decommissioning costs for the analysis.

decommissioning bond [column Q, rows 39&40] - Cost estimates for decommissioning were used to set the bond requirements assumed for each site. The decommissioning cost per MW is entered, and the spreadsheet calculates the cost for the project based on the installed capacity. Project decommissioning costs are inflated to 2031, the year the costs would be incurred. The inflated amount is used to determine the bond investment needed in 2009 to meet the decommissioning obligation in 2031, assuming the funds would be invested in Treasury securities at a rate of 4.75% over a 20 year period.

Results and Discussion

The purpose of the evaluations was to rank the proposed and alternative sites according to relative economic performance, adhering to a projected schedule for development. In this case, July of 2010 is the earliest time that the applicant and MMS anticipate electricity generation could commence. Capital investment for the facility would begin in 2008 with construction of the onshore control center and upland transmission cable support structures. Work to lay the upland transmission cable and to construct the offshore electrical service platform (ESP) would also begin in 2008 and carry over into 2009. In 2009, after the ESP is in place, submarine transmission cable would be laid. Installation of the monopiles, transition pieces and WTGs, and connection of the intra array cables, would begin in 2009 and continue until mid 2010.

Wind energy project development is often structured on a relationship between the design life of the generating equipment, equipment financing and power purchase agreement terms. A conservative approach was taken to model the operating life of the Cape Wind generating equipment, due to the corrosive nature of the offshore environment. This analysis was carried out under the assumption that the facility would generate electricity for 20 years. Financing terms would require debt repayment over 15 years, to reduce risk to the lender. The production term of the power purchase agreement was set at 20 years, a time period intended to cover the length of the debt term plus a few years to allow for the resolution of complications which could delay repayment of the debt in full. It is not uncommon for a power purchase agreement to include a provision allowing the seller an opportunity to extend the power purchase agreement for one or two additional terms of 5 years. Some power purchase agreements also provide project owners with the option to re-power the facility. The effects of exercising these types of options were not evaluated.

Cost of energy was chosen as the economic measure for site comparison and is defined as the 2007 electricity sales price, in dollars per KWhr, needed to meet or exceed a specified debt coverage ratio of 1.3. Electricity sales prices were assumed to increase annually at a constant rate of 1.5%, under an escalation provision of the power purchase agreement. Debt coverage ratios were calculated as the future annual operating cash flow divided by the principal and interest payment for a given year. The rate of return for the proposed site located on Horseshoe Shoal and the alternative sites were calculated, and it was found that all exceeded 14%, which is greater than the 10% to 12% range that might be required by the offshore wind developer.

Evaluation results in Table 2 show that the proposed site appears to have the greatest economic potential.

Table 2

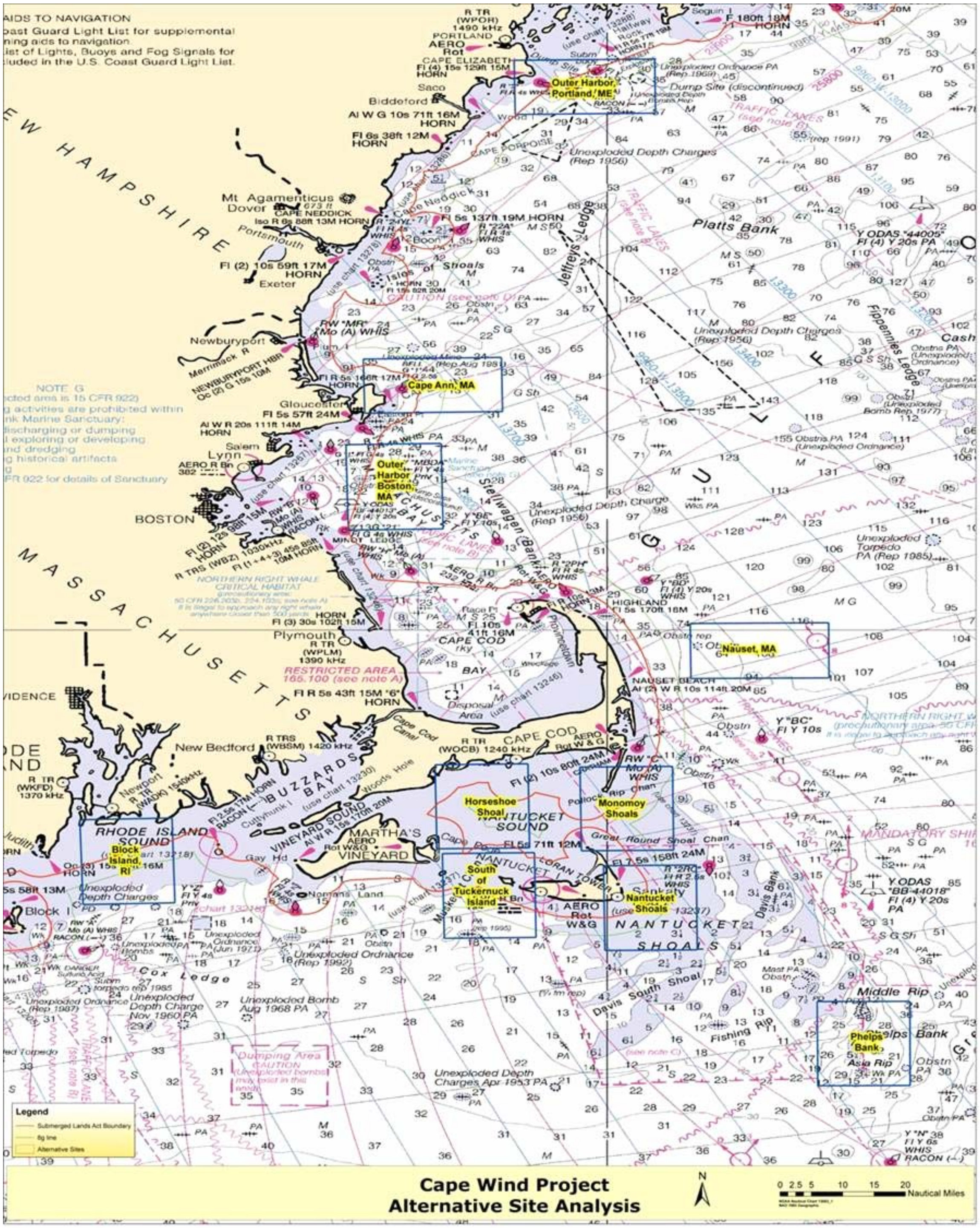
	1	2	3	4	5	6	7	8	9	10
Site	Horseshoe Shoal	Block Island	South of Tuckernuck Island	Cape Ann	Monomoy Shoals	Boston Outer Harbor	Portland Outer Harbor	Nantucket Shoals	Phelps Bank	East of Nauset Beach
cost of energy ($/kwh)	$0.122	$0.132	$0.143	$0.151	$0.205	$0.213	$0.224	$0.238	$0.287	$0.299
Energy capture (MWh/year/ 130WTGs)	1,608,600	1,610,900	1,688,000	1,515,800	1,172,700	1,600,300	1,430,300	1,046,100	1,035,200	1,184,100
Capacity Factor	39.24%	39.29%	41.17%	36.97%	28.60%	39.04%	34.89%	25.52%	25.25%	28.88%

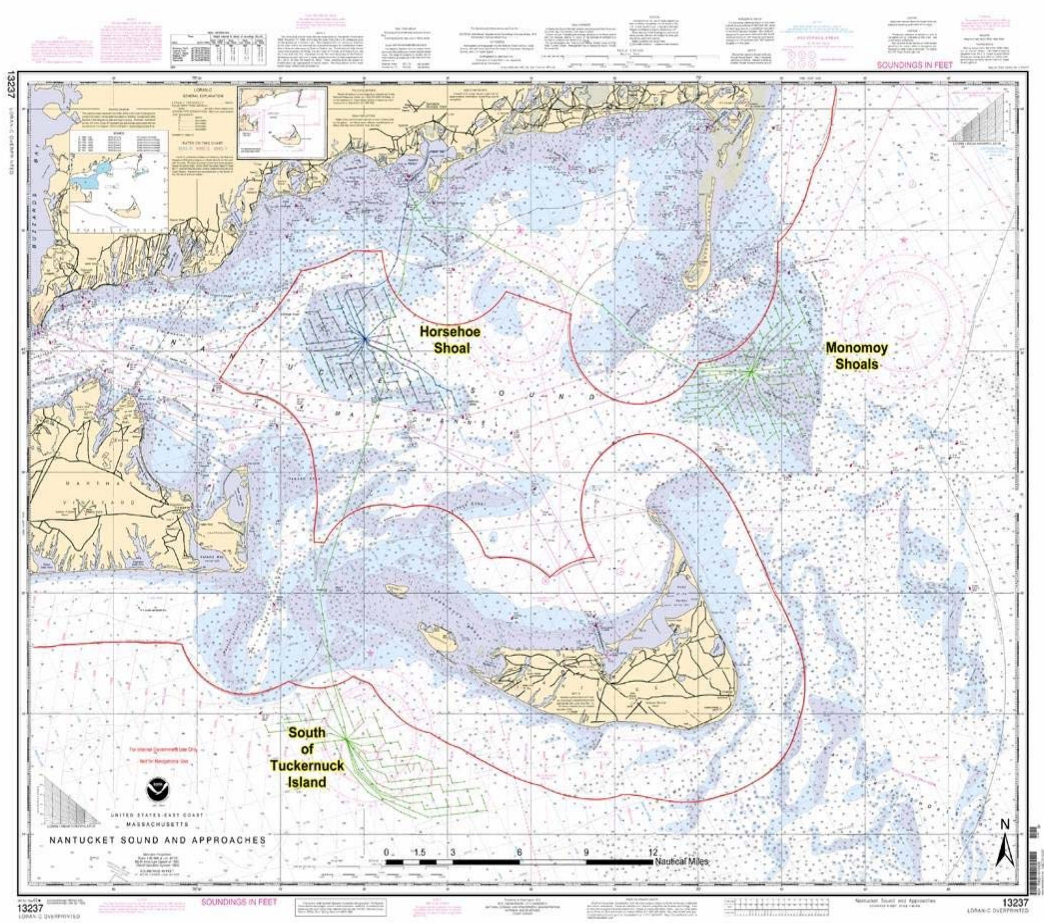
The proposed site at Horseshoe Shoal has the lowest estimated cost of energy, equal to $0.122/KWhr, or $122/MWhr, while none of the sites appear to be profitable at today's electricity prices. The average locational marginal price for southeast Massachusetts, reported by ISO New England, Inc. for the real-time market, was $65.97/MWhr over the 2 year period from February 2005 through January 2007. For January 2007, the average price was $58.77/MWhr. Standard measures of profitability such as net present value and rate of return were not used to rank these sites, because measures of project benefits are less meaningful under these conditions.

MMS has received information through the applicant showing that at least one lender may be willing to offer a debt:equity ratio equal to 75:25 to finance the project at the proposed site. The applicant could accept this ratio, or may find that it needs a debt:equity ratio of less than 75:25 to generate electricity for a more competitive price, or cost of energy. In explanation, it is clear that if a lower proportion of the sales revenue is required to make a principal and interest payment, the electricity price needed for profitable operations would be less. However, a lower debt:equity ratio and corresponding lower electricity price necessarily results in a lower rate of return. It would be in the interest of both the borrower and the lender to agree upon financing terms that allow each party to bear an acceptable level of risk. Determination of an "optimal" debt:equity ratio would involve a greater level of subjectivity than is required for site comparison, and so, a detailed analysis of project leverage was not carried out for the site comparison.

To demonstrate this point, a debt:equity ratio was determined for the proposed site that would correspond to a marginal rate of return equal to 10%. It was found that a debt:equity ratio of 60:40 could yield a project with a 10% return, if electricity could be sold for $0.102 per KWhr. This information is interesting but has limited use for this analysis, because MMS does not have knowledge of the applicant's ability to raise the additional equity, or if the applicant would be willing to accept the risk associated with the longer time period needed to achieve payout of a higher level of equity.

In conclusion, MMS recognizes that material costs for wind turbine generators and cables have risen significantly since the applicant initially proposed the project several years ago. Capital expenses used in the MMS economic analysis are based on cost estimates that account for the rise in steel and copper prices from 2003 through 2006. Results from the MMS analysis, which were calculated with cost estimates that wind energy developers might rely upon today, should not be construed as a profitability forecast intended to either endorse or condemn the action proposed by the applicant. Economic conditions will continue to evolve over time, changing the outlook for the project.


AIDS TO NAVIGATION
Outer Harbor, Portland, ME
Cape Ann, MA
Outer Harbor Boston, MA
Nauset, MA
Horseshoe Shoal
Monomoy Shoals
Block Island, RI
South of Tuckernuck Island
Nantucket Shoals
Phelps Bank
NEW HAMPSHIRE
MASSACHUSETTS
BOSTON
Legend
Submerged Lands Act Boundary
6g line
Alternative Sites
Cape Wind Project
Alternative Site Analysis
Nautical Miles



13237
Horsehoe
Shoal
Monomoy
Shoals
South
of
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NANTUCKET SOUND AND APPROACHES
SOUNDINGS IN FEET
0 1.5 3 6 9 12
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Small Project Alternative

MMS evaluated the effect of reducing the size of the applicant's proposed, full scale project of 130 WTGs to a small project of 65 WTGs. If the estimated cost of energy for the small project is within a range that allows for reasonable comparison with the full scale project, the impact of a small project alternative at the proposed site would be studied in the EIS.

Evaluation of a small project involved adjusting the capital costs for the full scale project to account for differences in procurement and construction requirements. To begin, a cost breakdown was analyzed for the full scale project by attributing fractions of the capital cost factor, given in $ per MW of installed capacity, to cost categories for WTGs, foundations, cable, electrical service platform, installation and engineering/other. Several sources of information were used to derive the breakdown given in the table that follows. The most current source, the Study of the Costs of Offshore Wind Generation, prepared for the United Kingdom Renewables Advisory Board and Department of Trade and Industry (DTI) by Offshore Design Engineering Limited, posted on the internet at www.dti.gov.uk/files/file38125.pdf, was published in April of 2007 and includes applicable information on page 51. Cost breakdown information from other sources was examined but not referenced, because the DTI study was viewed as a compilation of the industry's offshore wind energy experience in Europe. The cost breakdown from the DTI study included a category for consenting, i.e., lease costs, resource surveys, environmental studies, construction approvals, etc., which is estimated to account for about 7 % of total costs. Some of these costs do not apply to this application, are sunk, or are accounted for separately. Therefore, the capital cost factor for the proposed site does not include the equivalent of consenting charges, and so, the consenting cost was backed out by dividing each cost category a factor of 0.93.

Cost Category	Horseshoe Shoal Cost Breakdown	UK DTI 2007	Small Project Cost Breakdown
WTGs	38.00%	35.48%	35.43%
Foundations	19.00%	20.43%	17.71%
Cable	12.00%	10.75%	11.19%
ESP	3.00%	5.38%	4.86%
Install	20.00%	20.43%	17.83%
Eng./Other	8.00%	7.53%	12.98%
Total	100.00%	100.00%	100.00%

The capital cost factor for full scale development of the proposed site was derived from confidential information, which MMS obtained from the WTG manufacturer identified by the applicant in its development plan. It was possible for MMS to attribute fractions of the capital cost factor to the foundation, cable and electrical service platform categories from this information. Separation of the remaining fraction into cost categories for WTGs, installation and engineering/other, was inferred partly from information in the DTI study.

Several factors were considered when creating the cost breakdown for the small project. First, the number of WTGs and foundations would be reduced by one-half, and the length of cable would be less by about one-half. Clearly, installing fewer turbines would result in lower equipment costs, but it is anticipated that the cost per installed WTG would be higher due to a loss of economies of scale. With respect to the cable, it is likely that approximately one-half the length of 33 kilovolt inter array cable would be required to connect one-half as many turbines. Further, two 115 kilovolt cables would be installed to transmit power from the full scale project. A project of only one-half the size would only need a single 115 kilovolt cable. Adjustment of the cost categories for WTGs, foundations and cable was made by reducing the full scale cost estimates by 50%, and then applying a cost increase of 15% to the resulting amounts for these categories. The increase is intended to represent the fact that fixed costs for the manufacture of equipment would be spread over fewer units of production.

No change in the electrical service platform cost estimate was made. It is recognized that some savings would be accrued under the small project scenario by not purchasing and installing equipment that would only be needed for a full scale project. However, information was not readily available to make an adjustment. Likewise, no adjustment was made to the engineering/other category of costs. It is unlikely that costs in this category would change significantly by reducing the size of the project by one-half.

Installation costs would be lower for a small project. Costs related to mobilization and demobilization, as well as reduced time to install fewer WTGs, were considered to estimate potential savings to the applicant. There are presently no vessels operating on the OCS that were designed to install WTG systems. Consequently, it was assumed that the applicant would contract a purpose built vessel presently employed offshore of northern Europe, for a substantial mobilization and demobilization charge. This cost would not change whether the vessel installed 130 WTGs or 65 WTGs. Adjustment of the capital cost factor fraction attributed to installation costs was made by reducing the time period for actual WTG installation by one-half, but holding the mobilization and demobilization costs constant.

MMS determined that the capital cost per MW of installed capacity for the small project could be higher than the full scale project by a factor of about 1.25. Substitution of the higher cost resulted in a cost of energy estimate of $0.159 per KWhr.

Peer Review Comments

Frank A. Felder, Ph.D.
35 Ridge Road
Ridgewood, NJ 07450

Ms. Paula Barksdale
Minerals Management Service
381 Eden Street, MS 2101
Herndon, VA 20170

Dear Ms. Barksdale,

Via Purchase Order M07PX13326, the Minerals Management Service (MMS), U.S. Department of the Interior, has asked me to write a peer review letter report of Mr. Robert S. D. Mense's document entitled: "Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet" (OWEP Report) dated May 25, 2007. The OWEP Report consists of a twenty-page document and an accompanying Excel workbook with multiple spreadsheets.

The purpose of the OWEP Report is to determine whether alternative sites to the proposed Cape Wind Energy Project (Cape Wind), based upon costs of energy, should be subject to additional environmental analysis in the draft Environmental Impact Statement (EIS).

Summary of Key Findings

My two key findings are the following:

1. The OWEP Report does not provide the criteria by which one would decide whether alternative sites to the proposed site are sufficiently similar from an economic standpoint to warrant additional environmental analysis in the draft EIS. Thus, even if the results of the OWEP Report and model are accurate and credible, the original question of which alternative sites should be studied further is left unanswered.

2. Although the OWEP Report calculates the difference in the costs of producing energy (megaWatt-hours or MWh) at the different sites, it does not account for the potential differences in the price of energy and capacity that these different sites may be able to obtain. New England's wholesale electricity market has locational marginal prices (LMPs) that result in varying energy prices by time and location. Moreover, New England is transitioning towards a locational capacity market.

Introduction

Cape Wind is a proposed offshore wind farm with a proposed site on Horseshoe Shoal, south of Cape Code, Massachusetts. The Economic Division of MMS has evaluated the proposed Cape Wind site and nine alternatives using the OWEP model. The OWEP model is being used to inform the MMS which additional sites are sufficiently economical to be subject to additional environmental analysis as part of Cape Wind's environmental impact statement (EIS).

I have been specifically asked to address the following five questions provided in the work statement:

1. Is the model an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities and ranking the cost of energy from facilities at various sites?

2. Are there any significant oversights, omissions or inconsistencies in the model and its application?

3. Is the application of the model to the sites as described in the documentation logical and adequately supported?

4. Are the conclusions reached logical and supported by the evidence and analysis provided?

5. Does the documentation include all necessary and pertinent citations to the literature to support the model's methodology, assumptions and conclusions?

I have been specifically asked <u>not</u> to provide policy advice.

My Background

I am the Director of the Center for Energy, Economic and Environmental Policy at the Edward J. Bloustein School of Planning and Public Policy, Rutgers, The State University of New Jersey. I am also a member of the School's faculty and teach a graduate seminar on energy policy and planning. My education, background and experience involve electric power systems as an engineer, economic consultant, and applied researcher. I currently direct energy policy studies involving renewable energy technologies, including wind resources. I have also worked on issues regarding New England's wholesale electricity markets and conducted economic and financial analyses of generation projects. My doctorate is from the Massachusetts Institute of Technology in Technology, Management and Policy, and I wrote my dissertation on the topic of the reliability of wholesale electricity markets.

Summary of the OWEP Report

The OWEP Report ranks the proposed site against nine other alternative sites by calculating the cost of energy for each site. The *cost of energy* is the 2007 electricity sales price in dollars per kilowatt-hours ($/kWh) that the project owners would need to meet or exceed a specific debt coverage ratio (p. 3).[1] The OWEP model solves for this cost of energy given all of the input assumptions. It finds that the proposed Horseshoe Shoal site has the lowest cost of energy among the 10 sites. Table 2 (p. 16) of the OWEP Report lists the ranking of the 10 sites and their costs of energy.

Given that the purpose of the OWEP Report is to compare the 10 sites, it rightly focuses on cost differences between the sites, although it does discuss at length assumptions that are uniform across the ten sites. It account for differences in wind speeds, foundation and cable system requirements that vary with water depth, distance from shore and other related factors. The OWEP Report does not forecast energy or capacity prices, the two most important products that wind production facilities can sell into New England's wholesale electricity market. These prices vary by location and therefore it is conceivable that different sites would have different revenues along with different costs.

Responses to Specific Questions I Have Been Asked to Address

1. Is the model an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities and ranking the cost of energy from facilities at various sites?

The OWEP model is an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities within its context of providing a screening tool to rank the costs of energy from various sites. By definition, a screening tool such as the OWEP model is not a detailed engineering cost estimate of each of the ten sites. Moreover, there is relatively little experience and associated data with offshore wind and not all of that data is publicly available. As a result, the OWEP Report must make due with limited data.

Table 1 (p. 7) of the OWEP Report summarizes the key differences among the ten sites that it considers. The differences in location of the sites drive the differences in the amount of production due to differences in wind (capacity factors), the availability of the wind turbines due to sea state, cable system power losses and therefore the amount of energy that can be delivered, and the length of the cables and therefore cable cost.

After making point estimates of the costs of the ten sites, the next issue that should be considered is the relative uncertainty of these point cost estimates. The OWEP model does not attempt this type of analysis, which is reasonable given the limited availability of data. Stated another way, the OWEP Report implicitly assumes that the relative uncertainty in costs for each site is about the same, making the use of point estimates appropriate. I find that this is a reasonable assumption within the context of the OWEP Report's charge.

[1] Page numbers refer to pages within the OWEP Report.

2. Are there any significant oversights, omissions or inconsistencies in the model and its application?

I find that there are two key omissions in the OWEP Report. First, it does not provide the criteria by which it would determine which sites are economically similar to the proposed site to warrant further investigation as part of the EIS. As a result, the OWEP Report leaves the original question unanswered. Table 2 of the OWEP Report (p. 16) ranks each site by the cost of energy. The proposed site is the lowest at $0.122/kWh; the most expensive site is East of Nauset Beach at $0.299/kWh. The OWEP Report does not identify which point on this continuum of costs that an alternative site's cost of energy is too expensive to warrant further study.

The second key omission is that the OWEP Report fails to consider the possibility that revenues as well as costs can vary by site.

The profitability of any investments, such as Cape Wind, is the difference between its revenues and its costs. Revenues are determined by the quantity sold and the price at which the quantities are sold. The OWEP model focuses on only comparing costs among the ten sites. It does not account for the fact that sites may have different revenues, either due to different energy prices, different capacity prices, or both. Thus, the OWEP Report omits a potential significant difference between the relative merits of the ten sites. Another way of characterizing this omission is that the OWEP Report implicitly assumes that the prices of electricity and capacity do not vary by site. The OWEP Report provides no basis for this assumption, and there is sufficient reason to believe that this assumption is not justified unless further investigation demonstrates otherwise.

In the New England wholesale electricity markets, there are two major products that Cape Wind can sell. The first and most important is energy ($/MWh). In New England, electric energy prices vary by location and by time. At the same time, the price of energy can be different even at nearby locations within a state, let alone between locations in different states. Just by looking at the Cape Wind Project Alternative Site Analysis map (p. 19), the ten locations would ship their power to locations on the wholesale power grid that are at different locations, and in some cases to different states. Thus, it is possible that although a site may have a higher cost, its revenues could more than make up for these additional costs. My point is not that this is the case, but that the OWEP Report did not verify that it is not the case.

Moreover, the amount of wind capacity delivered to a particular location on the New England wholesale electricity market can affect the price at the deliver point. As more and more energy is delivered, the locational price may decrease, particularly at points on the system that do not have much demand and may be transmission constrained.

The second major source of wholesale electricity revenue for Cape Wind is selling capacity. New England is transitioning to a locational capacity market. Although the number of different capacity prices is not near the number for energy, it is possible that capacity payments may vary by site. In addition, capacity payments depend on capacity factors, and to the extent that different sites result in the project having different capacity factors, this too would affect revenues and therefore profitability.

I find that the OWEP Report makes a significant omission by not considering the possibility that revenues may be different at the different locations. If it were the case that revenues varied substantially by location, then ranking the sites by only considering costs may result in an incorrect ranking because there could be sites that have higher costs but also higher revenues and therefore higher profits. The issue is not whether this is the case, but that there is reasonable belief that additional investigation and explanation is warranted.

3. Is the application of the model to the sites as described in the documentation logical and adequately supported?

The application of the model to the sites as describe in the documentation is logical and adequately supported. The OWEP Report lays out each of its assumptions and the supporting documentation.

4. Are the conclusions reached logical and supported by the evidence and analysis provided?

The conclusions of the OWEP Report are logical and supported by the evidence and the OWEP model with the exception of the two omissions in question #2.

5. Does the documentation include all necessary and pertinent citations to the literature to support the model's methodology, assumptions and conclusions?

The documentation includes all the relevant citations to the literature to support its methodology, assumptions and conclusions with the exception of the issues identified in question #2. It does not include reviewing and citing the appropriate literature related to wholesale electricity markets that have locational marginal prices and locational capacity markets in general or New England's market in particular. It does not consider the finance and investment literature that makes clear that both revenues and costs must be considered when evaluating a project's profitability.

This concludes my letter report.

Sincerely,

/s/

Frank A. Felder, Ph.D.

Comments of Lessly Goudarzi

CEO, Managing Director

OnLocation, Inc./Energy Systems Consulting

Regarding the

Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model;
A Microsoft Excel Cash Flow Spreadsheet
Dated May 25, 2007

SUMMARY

The Economics Division of the Minerals Management Service has prepared a MS Excel cash flow model for the purposes of evaluating the proposed Cape Wind Energy Project site and alternative sites.[1] The purpose of this brief report is to review the economic model (i.e., cash flow model), its application and the associated assumptions used in the assessment.

The analysis presents a simplified calculation of the minimal cost of energy required as a selling price to support a debt-equity structure of 75:25 and maintain at least a 1.3 debt service coverage ratio over the 15 year period of the assumed outstanding debt. The purpose of this calculation is to allow a comparison of the alternative sites for the offshore wind project. As discussed in more detail in the conclusions to this review, the evaluation by MMS using the model and its assumptions has deficiencies and should be revisited. As a minimum, fuller disclosure of the underlying data sources and a treatment of the relative risks associated with each site are recommended.

[1] Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet, By Robert S. D. Mense, May 25, 2007.

INTRODUCTION

The Economics Division of the Minerals Management Service has prepared a MS Excel cash flow model for the purposes of evaluating the proposed Cape Wind Energy Project site and alternative sites.[2] The purpose of this brief report is to review the economic model (i.e., cash flow model), its application and the associated assumptions used in the assessment. As a part of this review, a number of questions were posed to the reviewers:

Is the model an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities and ranking the cost of energy from facilities at various sites?

Is the application of the model to the sites as described in the documentation logical and adequately supported?

Are there any significant oversights, omissions or inconsistencies in the model or and its application?

Are the conclusions reached logical and supported by the evidence and analysis provided?

Does the documentation include all necessary and pertinent citations to the literature to support the model's methodology, assumptions and conclusions?

Each of these questions is directly addressed in the Summary section above. A detailed discussion is provided below of other issues that arose in the review and are organized in the order of the discussion in the paper itself.

Project Assumptions

Capacity Factor: The capacity factors for each site were derived from applying an NREL wind power model. Apparently three parameters are key to this model: average wind speeds, availability for each site and a power curve (i.e., the amount of power generated at varying levels of wind speed). Capacity factors are clearly key drivers of the economics of off-shore wind technology. While the analysis provides selected references to the NREL model and other literature as to the source of some of the inputs to this model, the sources were either proprietary or not generally available for verification. As such, it is impossible with the discussion provided to determine whether or not the resultant values are reasonable. Having said that, a review of capacity factors used for off-site wind in the NEMS modeling framework are in the same vicinity of values used in this economic assessment.

Loss factors: The reference sited for developing the loss factors used for direct current (DC) applications (>31 miles in this assessment) fails to point out a caveat in that reference which states that "HVDC is not commercially proven of offshore wind farms"[3]. While these losses are significant, the range of values used do not appear to be driving the ranking of the sites and therefore additional analysis or research into their reasonableness was not undertaken.

2 Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet, By Robert S. D. Mense, May 25, 2007.

3 Page 1 of Appendix 3-C referred to by the analysis.

However, it is not clear how these loss factors were entered into the analysis. It has been the author's experience that estimates of the "net" power available for sale has transmission losses layered such that the power for sale is reduced thereby. It is unclear from the write-up whether or not the capacity factor being used are at the busbar (or collecting substation in this case) or are intended to account for the losses transmitting the power to the grid delivery point. The spreadsheet shows a figure of 1,608,714,432 kwh for sale. This figure represents a direct application of the capacity factor and thereby implicitly assumes the losses are incorporated therein. This treatment seems at odds with the discussion of the NREL wind model and the subsequent discussion of the loss factors.

Economic Parameters

Cost of energy: Equally if not more than the technical project parameters, the economic assessment is driven by the economic parameters chosen in the analysis. One of the most critical positions taken in the evaluation is the statement that

> "Prior to loan approval for the Cape Wind Energy Project, it is likely that a lender would require that the applicant obtain a long term power purchase agreement for electricity sales." [Top of Page 8].

The analysis points out that the nearby delivery point LMP in recent times has been in the vicinity of $58-65 / Mwh. Given the estimated cost of energy is $122/Mwh, twice that of the current market and that this is after the full benefit of tax and RPS incentives, the prospects of entering a long-term purchase power contract would seem low. The analysis apparently purposely avoids observing this obstacle.

References to the Energy Information Administration's Annual Energy Outlook (AEO) are confusing. Why does the analysis refer to the AEO 2006 for both the inflation and price growth factors and to the AEO 2007 for the operating cost growth factor? One would expect that all the assumptions drawn from these forecasts should be from the same forecast and that the latest forecast would appear most relevant.

Inflation factor/Price growth factor/Operating cost growth: Energy prices for oil and natural gas are projected in the latest AEO 2007 to growth at about 1.1-1.2 percent in **real** dollar terms between 2015 and 2030, nominally around 3.75 percent per year. Given the analysis' s inflation assumption of 2.5 percent per year, the assumption that electricity prices will increase at only 1.5 percent nominally (i.e., decline in real terms) is difficult to accept. This is less than one half of the rate of increase of the oil and gas energy prices. Purchase power agreements for hydroelectric power imported from Canada have often been indexed to the cost of fossil generation in the Northeast or something similar. I would expect that any developer would want to negotiate similar terms.

Discount rate: There is much room for debate surrounding appropriate discount rates, particularly of projects that are a first of a kind as is the case here. However, a number of issues with the analysis' s assumptions (and calculations) need to be pointed out. First, the math as reported is confusing. How do you arrive at a weighted average cost of capital that is lower than either of the component costs (i.e., 5.24% compared to 7.0% and 10.5%)? [Note, it appears that the intent was to calculate a simple weighted cost of capital not an after-tax weighted cost of capital since there is no mention of a income tax rate.] The simple weighted cost of capital should be ((0.07 x .75) + (0.105 x .25)) or 0.079 (i.e., 7.9%). The reported calculation and result appears to be an estimate of the cost of capital in real terms, not nominal, yet the rest of the discussion is in nominal terms.

Second, the analysis points out that Ibbotson Associates reports a nominal cost of capital for the electric services industry of about 9.0 percent in the fall of 2005. Note, assuming a typical 50:50 debtequity ratio, and a nominal debt interest rate of about 6.5 percent, the implied return on equity is 11.5

percent.[4] The discussion then dismisses this point of reference because " it is thought to represent a composite of electricity generators, transmission service providers and utilities" [Page 8].

These industry sectors have partially or totally captive customers and are generally subject to cost-of-service regulation. They would typically be considered relatively lower risk investments. This is in contrast to the subject project that is deploying unproven technology (in the sense of the combination of a wind farm offshore with a need to collect and transmit the power some 15-30 miles to shore) in an unproven environment (offshore). The subject project is of considerably greater risk and would require a commensurate risk premium over that of the traditional electric services industry.

A key element in the cost of capital is the assumption of the Debt to Equity ratio. The analysis uses a 75:25 debt-equity ratio. The analysis cites an unnamed investment bank as indicating that wind energy projects range from 65:35 to 75:25 without providing any additional details as to the terms or other limitations associated therewith. What is missing from this discussion is a detailed review of the financial, security and other covenants that would be required to secure any level of debt for this kind of project. For example, it is assumed that the project is a stand-alone project financing with the only real collateral being the " assumed" power off-take agreement. When this is the case, the credit worthiness of the purchasing entity becomes of great concern. Where is this discussion? The entire setup of the " financing" of the project is seriously deficient in its level of detail and scope.

Loan rate: Without more details regarding the debt instrument covenants, it is not possible to fully address the reasonableness of the selected value of 7%. Suffice it to say that this very attractive rate would only be possible with a very tight off-take agreement and a strong credit position of the purchaser.

Debt period: This assumption is a bit on the long side but is not outside the range of reasonableness.

Annual payment: The assumption that the loan terms would amortize the loan with sinking fund levels seems aggressive. The backend loading of the repayment of principal associated with this " mortgage" type financing is better suited to a firm in a stable or growing industry. It is less applicable to a single, stand alone project like this.

Debt coverage ratio: Again, the target values appear on the low end for this type of project. However, under ideal conditions, these values could be negotiated with a bank. A great deal would depend on the ability to demonstrate to the lender that the variability in cash flows available to support the debt payments is sufficiently small that the implied 0.3 cushion is sufficient to insulate the lender from any material risks of default. The analysis explicitly put aside any assessment of the potential variability in the key performance parameters. The adequacy of the 0.3 cushion can not be evaluated without such an analysis. The discussion on the bottom of page 9 and top of page 10 try to address this concern but again, dismiss the issue by stating " Any judgment made by MMS in this regard would be subjective" . If the production tax credit or the income from the renewable energy certificates is uncertain, how can the economic efficacy of the project be assessed without some analysis of the sensitivity to these very parameters? Similarly, there is no consideration for the potential impact of a severe storm on the operations of the project over a 15 year debt repayment period. These types of stress tests are standard in any risk assessment of the project and would be

[4] In a recent FERC Press Release [February 7, 2007, Docket Nos: EL06-109-000, ER06-1549 -000 and 001], stated the following: " The Commission set for hearing Duquesne' s proposed base return on equity (ROE), in order to determine a range of reasonable returns for a public utility. With the proposed incentives, Duquesne is proposing a 13.81 percent ROE, and the Commission conditionally granted an incentive ROE in the upper range, up to one and one-half percentage points above a base-level ROE." Assuming the ROE approved is the 13.81 and subtracting 1.5 percent, the baselevel ROE could be construed to be 12.31. This is for a cost-of-service rate regulated firm with considerably less risk that that of the proposed Cape Wind Energy Projec.

expected of any lending institution with a risk management program. To not discuss these exposures and the potential differences across the sites leaves the assessment incomplete at best.

Income Tax Impact: The assessment implies project type financing. An important assumption in the analysis is the immediate ability to use the early tax benefits without the project being required to roll them forward until it generates taxable income. Without knowing more about the project’s financial structure, this assumption is difficult to assess. However, it is clear that this assumption enhances the economic attractiveness of the projects.

Treatment of the RPS alternative compliance payment: The model assumes that the current forward contract value of $25 per Mwh can be used as an estimate of these sources of income going forward. However, the analysis assumes that this current forward contract value should be increased in future years to reflect inflation. In my limited experience, this is not consistent with the terms of most forward contracts (i.e., they are not indexed to some inflation measure but are stated in the nominal dollars at the time of delivery.)

Cost Inputs

Cost Inputs: This portion of the analysis is difficult to assess. Much of the information used is from confidential sources restricting their disclosure. The inability to review in depth the cost data requires that these costs be taken on faith as being accurate or reasonable.

The costs of the sites are not presented in a fashion to allow easy comparison but left to the reader to dig out of the underlying spreadsheet. The following table is extracted from the spreadsheet and summarizes selected key economic factors.

Capital Costs *B36*	Capacity Factor *B31*	Per Mw Cost *B32*	Miles to Shore *B34*	Decom Costs (apparently ~7% of Capital Costs) *N39*		Variable Per Mwh *F39*	COE Per Mwh *C2*	IRR *M2*
	39.2%		14		**Horseshoe DER=.75**	$7.50	$122	
	39.2%		14		**Horseshoe DER=.60**	$7.50	$102	
	41.2%		27		**S. Tuckernuck Isl.**	$11.00	$143	
	25.5%		41		**Nantucket Shoals**	$14.70	$238	
	28.6%		24		**Monomoy Shoals**	$10.20	$205	
	25.3%		67		**Phelps Bank**	$21.70	$287	
	28.9%		25		**Nauset Deepwater**	$10.40	$299	
	39.3%		9		**Block Island**	$6.20	$132	
	39.0%		27		**Boston Outer Harbor**	$11.00	$213	
	37.0%		8		**Cape Ann**	$5.90	$151	
	34.9%		15		**Portland Outer Harbor**	$7.80	$224	

The variation in capital costs is quite large due to the varying site conditions. Note that the IRR calculated in the spreadsheet at cell M2 is the “real” ROE, not nominal. Also, the reported COE is “net” of the 19$/Mwh federal PTC and 90 percent of the $55.13/Mwh RPS alternative compliance payment (initial, dropping to $25/Mwh in 2015). Both of these subsidies were assumed to escalate at the 2.5 general inflation rate used in the assessment. It is worth noting that all the sites have a total investment approaching $________, at least. The level of risks associated with this project at those investment levels should not be overlooked.

SUMMARY CONCLUSIONS

The Economics Division of the Minerals Management Service has prepared a MS Excel cash flow model for the purposes of evaluating the proposed Cape Wind Energy Project site and alternative sites.[5] The purpose of this brief report is to review the economic model (i.e., cash flow model), its application and the associated assumptions used in the assessment.

The analysis presents a simplified calculation of the minimal cost of energy required as a selling price to support a debt-equity structure of 75:25 and maintain at least a 1.3 debt service coverage ratio over the 15 year period of the assumed outstanding debt. The purpose of this calculation is to allow a comparison of the alternative sites for the offshore wind project. The review addresses the following questions posed by the MMS:

Is the model an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities and ranking the cost of energy from facilities at various sites? A broader reach of measures of economic merit would seem appropriate and prudent given the project circumstances described in the assessment. The model has a number of deficiencies that impact its adequacy for ranking the sites. For example, it fails to address any of the project risk differences across the sites. The wide range of estimated " availability" would suggest that the sites have considerably varying degrees of exposure to weather conditions (including but not addressed severe weather) that extend beyond the reduction in plant output. In addition, the resultant required price to support the debt service is materially outside the current market conditions, even when substantial subsidies are assumed. Additional factors to rank the sites would only seem prudent. These factors should focus on the risk exposure in terms of financial, weather, market, etc., factors.

Is the application of the model to the sites as described in the documentation logical and adequately supported? The assumptions regarding the capacity factors and the capital cost are central to the economic assessment. The sources of data and references used to estimate these two factors need greater disclosure and discussion in order to be evaluated. The necessary information is either embedded in the NREL wind power model (note there was no specific reference to a description of this model or how one could access it) or in the " confidential information obtained from the manufacturer of the wind turbine generator" . This approach does not allow for a conclusion that the model inputs are adequately supported.

Are there any significant oversights, omissions or inconsistencies in the model or and its application? There are a number of minor inconsistencies in the selection and application of the model assumptions regarding inflation. Frequently, the analysis discusses items in nominal terms (e.g., costs of capital) yet reports values that are computed in real terms. As stated above, a material omission is the failure to address any differences across the sites regarding financial, weather and market conditions, all of which will materially impact the economic efficacy of the project. Another key omission is a discussion of the financial controls that are likely to be imposed by a lender to allow the 75:25 debt-equity ratio to be assumed.

Are the conclusions reached logical and supported by the evidence and analysis provided? It is not clear what the conclusion of the analysis is supposed to be. Is the conclusion that the cost of energy is the appropriate measure of economic merit? There is insufficient discussion of why this is the appropriate measure, particularly given the uncertain nature of the cost estimates and variability of the weather and other site conditions. The MMS has taken into

[5] Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet, By Robert S. D. Mense, May 25, 2007.

consideration the recent run-up in material costs in its evaluation of the alternatives. Certainly the reliance on the wind turbine generator vendor for key cost inputs would suggest that is the case. Is the conclusion that "none of the sites appear to be profitable at today's electricity prices"? Certainly, the analysis supports that conclusion.

Does the documentation include all necessary and pertinent citations to the literature to support the model's methodology, assumptions and conclusions? Support for the selection of the financial assumptions appears to rely extensively on an unnamed investment bank. If this bank were to provide an irrevocable set of terms consistent with these assumptions, then perhaps this is adequate. Absent that, a greater investigation into the financing of these kinds of projects would seem a key improvement to the analysis.

Sustainable Energy Advantage, LLC

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July 5, 2007

David Downes
Alternative Energy and Alternate Use Program
Minerals Management Service
Department of the Interior
381 Elden Street MS 4010
Herndon VA 20170

Re: Peer Review of the Cape Wind Energy Project Economic Analysis and Model

Dear Mr. Downes:

Attached please find the requested written peer review comments on the **Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet**, dated May 25, 2007.

The cash flow spreadsheet model and associated documentation are clearly the result of a substantial and professional effort to estimate the cost of energy associated with the offshore wind energy facilities, for use in the Cape Wind Energy Project alternatives analysis and broader purposes of the MMS. I hope that you find the accompanying comments helpful in further improving the model methodology and accuracy of results.

Feel free to contact me with any clarifying questions by phone or e-mail.

Regards,

Robert C. Grace
President

cc: Rodney Cluck (MS 4042); Paula Barksdale (MS2101)

Peer Review Comments of
Robert C. Grace, Sustainable Energy Advantage, LLC
to the Minerals Management Service
of the United States Department of the Interior

MMS has requested peer review of both its offshore wind economic model, and its application to the Cape Wind Energy project and identified alternatives, as described in the document entitled **Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet**, by Robert S.D. Mense, dated May 25, 2007. The purpose of this peer review is to improve model methodology and the accuracy of its results. I have been asked to conduct an independent review of the technical and scientific merit of the model and its application to the alternative sites, but to not include advice on matters of policy. The following written comments constitute my peer review.

Reviewers were asked to address the following questions:

- Is the model an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities and ranking the cost of energy from facilities at various sites?
- Is the application of the model to the sites as described in the documentation logical and adequately supported?
- Are there any significant oversights, omissions or inconsistencies in the model and its application?
- Are the conclusions reached logical and supported by the evidence and analysis provided?
- Does the document include all necessary and pertinent citations to the literature to support the model's methodology, assumptions and conclusions?

Rather than providing comments directly in response to each of these questions, the majority of my comments below are organized by subject area to enable MMS to more readily follow and apply the comments.

General comments

For brevity, my comments focus on the potential shortcomings of the MMS model and approach. In general, items on which I offer no comment appear to be, at the least, reasonable given the data available and the objective of the analysis, and in many cases, as good as can be expected given the current state of knowledge. Of those issues identified, the majority pertain to the accuracy of the overall projection of the cost of energy (COE), as most of issues identified will not have a substantial affect on the relative ranking for comparison purposes (other than exceptions noted).

Is the model an accurate and adequate method for estimating the cost of energy associated with offshore wind energy facilities and ranking the cost of energy from facilities at various sites?

Generally speaking, a Cost of Energy (COE) analysis is a reasonable approach to estimating the cost of energy associated with offshore wind energy facilities, as well as ranking the relative COE from facilities at different sites. For reasons enumerated throughout my comments, MMS's model and its application appear to be better for the relative ranking of project economics (which is MMS's intent) than for estimating the COE accurately.

Methodology. In my experience, this type of analysis would typically determine the minimum COE that meets the minimum equity return subject to satisfying the minimum debt coverage ratio (DCR), <u>but</u> would adjust the debt-equity ratio to optimize (e.g. minimize) the COE. I have identified four issues with the methodology that may be problematic: the D/E ratio; the metric and calculation used for equity return; the calculation of DCR; and subtracting the REC revenue stream from cost in calculating COE.

- <u>Debt/Equity Ratio (D/E)</u>. By fixing the D/E ratio, the method compares the COE of different facilities which correspond to radically different equity returns. While it may not be possible to make the equity returns for all facilities being compared identical, the approach (keeping D/E static) magnifies the differences and erodes the ability to consider the analyses comparable. See also comments below regarding the specific D/E ratio chosen.
- <u>Equity Return, Discount Rate.</u> Several issues were identified relating to the discussion discount rate and weighted average cost of capital, and the calculation of equity rate of return.
  - *<u>Discount rate (p.8)</u>*. The calculation which references column M, row 2 is described as a weighted average cost of capital, to be used as a discount rate. Issues include:
    - The formula described on page 8 has an error; it does not equal 5.24% as stated in the example.
    - This formula is not the correct formula for calculating the weighted average cost of capital (WACC). The WACC cannot be lower than the cost of either source of capital alone. It appears that the formula is attempting to calculate a *real* WACC (e.g. backing out inflation), but the entire analysis is conducted on a nominal basis with nominal dollars, and therefore a real calculation does not appear appropriate.
    - The formula described on page 8 is a constant rate; the formula appearing in each sheet of the model differs for each project.
    - The formula described on page 8 is not the one used in the model in cell M2, as indicated.
    - The document describes an application of the same discount rate, at a constant WACC, to each project. In the model, however, cell M2 is not a calculation or the same discount rather a different discount rate imputed to yield a zero (or slightly positive) figure in cell N27. The model is discounting the cash flows (using what

appears to be a real rather than nominal formula) for every site by a different factor rather than using a constant discount rate. This is not what the write-up says it is, and if discount at different rates than result is not comparable.

- All of the above points appear to be immaterial because the discounting step is ultimately unnecessary and confusing. The model calculates the correct implied equity return elsewhere, in the internal rate of return (IRR) formula found in cell L29 of the model (but does not label it or mention it in the write-up). Having calculated the IRR, which is the nominal rate of return to equity, the discounting calculations in cells M1 through N28 may be deleted with no loss to the analysis, but avoiding substantial confusion. To put this another way, there is no need to discount, or calculate WACC, in this analysis. Rather, the COE must be set so that the IRR exceeds the minimum equity return assumed necessary to attract equity capital.[1]

- DCR. Traditionally lenders do not consider monetization of tax credits in calculating the DCR; rather, the DCR is based only on *operating* cash flows. As a result, the comparison of calculated DCR to lender's minimum acceptable DCR is thrown off… calculated DCR's are higher than a lender would attribute to such a project, because (as I understand it) tax credits are not reliable (bankable), because they are generated on a lagged basis, and because lenders stand behind the IRS in payment priority. On a related note, the minimum acceptable DCR appears low for a wind project, as discussed further below.

- Treatment of REC Revenues in Calculation of COE. A COE model should ignore REC revenue and instead define COE as the revenue needed from all sources necessary to meet minimum equity returns subject to minimum acceptable DCRs. The act of estimating a revenue stream appears contrary to the analytical framework and objectives of a COE analysis as well as the underlying financing and contracting assumptions. A more traditional and appropriate approach would be to simply calculate the COE independent of any revenue assumption. The COE would represent the revenue required from the sum of all revenue streams: sales of energy, capacity, RECs, perhaps some emission rights. It is not internally consistent, and is unnecessary for your comparison purposes, to bring in one revenue stream estimate and not others. In addition, many readers of the analysis will *assume* that the COE reflects the total revenue required. By having the COE dependent on an estimated revenue stream... basically being a net COE rather than a gross COE, many who read the ultimate study would be likely to misinterpret the results.

  This can be considered from a different perspective. In explaining the cost of energy (power purchase price) portion of the analysis, the write-up on pp. 7-8 explains that "the cost of energy is defined as the 2007 electricity sales price, in dollars per KWhr, which the project owners would need to meet or exceed a specified debt coverage ratio during the life of a loan. Prior to a loan approval for the Cape Wind Energy Project, it is likely a lender would require that the applicant obtain a long

[1] On a related note, the observation on page 17 that a 60:40 D/E ratio yields a 10% return at the stated COE is not accurate: the calculated nominal IRR is 13% (ignoring corrections discussed elsewhere in my comments).

term power purchase agreement for electricity sales." The same can be said for the REC revenue stream. No matter how reasonable a spot REC price forecast[2] may be, if a project proposed to finance based on an assumed REC revenue stream, debt lenders would discount the projected REC revenue dramatically due to the perceived risk of the future REC market. This would be reflected as either higher cost of debt or higher minimum DCR requirements. For the same reasons described in the write-up, the lender (if applying normal loan requirements) would require the applicant to obtain a long-term REC contract (or bundled REC and energy contract). As part of the long-term power contract (or portfolio of contracts), REC revenue would be folded in with contracts for electric energy, capacity or ancillary services for purposes of a COE analysis.

Adequacy for Estimating COE: Royalties. The assumed royalty rate is applied uniformly to all sites and is therefore unimportant for comparison purposes. However, the royalty rate used (12.5%) has the potential to distort perceptions of estimated cost of energy and economic viability. If the discussion did not get into drawing any observations or conclusions about viability at the calculated COEs, this might be OK. However, the write-up on page 17 discusses the implications of the calculated COE for the Horseshoe Shoal site at length. So while many of assumptions don't matter for comparison purposes between sites, if this model is also to be used for drawing any conclusions about the viability of specific sites, MMS may wish to consider revisiting or removing the royalty assumption. It might distort the analysis, or the perception of the results, to a lesser degree if royalties are set at zero for the purposes of the analysis and the results are described as COE at zero royalty.[3]

Is the application of the model to the sites as described in the documentation logical and adequately supported?

Generally, the model is applied to the different sites logically and adequately supported, particularly for comparative ranking purposes, with a few exceptions as noted below.

Wind Turbine Generator Availability and Operating Costs. The Wind Turbine Generator Availability estimates shown in Table 1 for some of the sites appear surprisingly low. While the approach to calculating availability is explained, the calculations are not shown. They may be accurate, but not

[2] Note that while the REC revenue assumption is not unreasonable, and regardless of the assumption would not affect the relative ranking of COE from the various sites evaluated, breaking out REC revenue this manner distorts the meaning of COE and the modeling of project financing.

[3] While not wanting to drift into discussion of what is primarily a policy issue, I wish to point out that (a) a 12.5% royalty rate appears very high – roughly 2.5 cents/kwh - well in excess of typical land-based wind royalties (in the 3-6% range of a figure of roughly half the magnitude), and (b) noting the COEs well in excess of current electricity prices, a royalty at a level well above comparable land-based plants is likely not sustainable (as the royalty itself at this level could make plants uneconomic, which is not an observation on the COE of the technology so much as on the royalty itself).

enough of the calculation is transparent to evaluate whether they are logical and reasonable. Unlike the potential for inaccuracy of cost item estimates, this factor has one of the largest influences in the whole COE calculation because of their influence on the net capacity factor, which is perhaps the biggest lever in the entire COE calculation. Therefore, this assumption deserves particularly careful consideration.

A question that must be asked is whether a project in deeper water would take a different and more costly approach to operations and maintenance in order to increase availability, rather than the same approach as Cape Wind has proposed for Horseshoe Shoals and suffer such poor availability? The answer seems probable. Consider, that if (hypothetically) spending twice as much on variable operating expense at Nantucket Shoals could increase availability from 54% to 80%, its COE would be much lower. As the cited reference[4] states "In practice, there is a balance between the investment costs to increase the reliability and the recurrent cost of maintenance to achieve a certain availability level. Since offshore site accessibility is always less than 100%, it is first paramount to decrease the failure frequency of an offshore wind energy system". As modeled, the revenue loss from the projected availability is so extreme that quite a bit of money could be spent in alternative maintenance strategies that could increase availability at net increase to cash flow. Refining the approach taken to modeling availability and operating costs is somewhat analogous to the approach MMS took to estimate cable costs: at the point at which one approach become too expensive, a different approach was taken where the cost functions crossed.

Furthermore, it does not appear that the data in the reference is used quite as intended. By my quick review, the conclusion to be drawn from Figure 8 is that for a high availability, you would need to use an access system which, although more costly, would yield an acceptably high level of accessibility and therefore availability. As noted in Section 4.4 of the cited document, the curve simply suggests that to maintain a high availability rules out use of zodiacs as the access system.

I would suggest that a more realistic approach might be to model the farther-off-shore projects as a constant availability (perhaps around 90%) but with higher O&M cost to reflect the need for a costlier and more complex operations and maintenance access system and overall strategy. One might also increase the capital cost of such systems, for one could envision spending more on up-front capital to minimize the need for O&M in harsher environments. I suspect there is other data out there to work with, although probably quite inadequate for a very good understanding.

Debt/Equity Ratio and DCR. Because of the intermittence of wind projects, there is substantial risk in annual revenue variability which makes DCR higher than for conventional dispatchable plants. A typical figure for wind is 1.45, rather than the 1.3 minimum DCR used.[5] Furthermore, the 75:25 D/E appears

[4] The DOWEC Offshore Reference Windfarm: Analysis of Transportation for Operation and Maintenance, by G. J. W. van Bussel and W. A. A. M. Bierbooms of the Delft University of Technology, Delft, The Netherlands.

[5] Debt lenders typically require a level of conservatism in project cash flow pro formas. It is not transparent from the materials provided whether the capacity factors used represented a or middle of the range estimate (P-50, or 50% probability of being exceeded) or a P-90 (conservative estimate or production, 90% probability of being

too high. Wind projects being financed on a non-recourse project basis (as modeled by MMS) typically carry lower levels of debt, rarely much more than 50%, due to the tax and PTC issues. Higher levels of debt make the required revenues too high, for there is not enough cash to fulfill minimum DCRs at that level. While (as MMS points out on page 17, a lender may be willing to lend at a 75:25 D/E, they would be unlikely to do so without a more complex financing structure (for instance, refinancing after year to manage the year 11 cliff effect.

Are there any significant oversights, omissions or inconsistencies in the model and its application?

I found the MMS analysis to be generally comprehensive, with no obvious cost categories omitted. In addition to the DCR and D/E issues discussed earlier, I note here one minor issues which may be material in deriving a precise estimate of the COE, but which are not material in the relative ranking of sites that is the purpose of MMS's modeling exercise. Using an approximation, as has been done in the MMS model is fine, but the following description should be modified with respect to *depreciation* to clarify that it is assumed for modeling purposes that 100% of the wind energy project will be classified as 5 year ACRS property. In practice, some portions of the plant (perhaps on the order of 5%) are not likely to receive this accelerated depreciation treatment.

Are the conclusions reached logical and supported by the evidence and analysis provided?

The conclusions regarding the relative ranking and cost of the alternative project sites appears logical and supported by the evidence and analysis provided, with the exception of the discussion of availability and operating costs, which when addressed may cause the conclusions to be amended.

As noted above, the application of the analysis is less accurate with respect to the absolute level of COE for the alternative sites, and as a result its conclusions regarding the price level are not adequately supported and in my opinion should be trimmed back. In particular, on page 17 several comments over-reach what is supported by the analysis:

1. "**none of the sites appear to be profitable at today's electricity prices".** This statement is somewhat misleading with respect to COE for the reasons described earlier (DCR, D/E, method of incorporating REC revenues as netted from cost, royalty, and for some sites, availability and operating cost). Use of such a high D/E ratio and royalty rates so high above industry norms will result in COE's unrealistically high, which while not of paramount importance in a comparative analysis, may be taken out of context by various stakeholders to further their own agendas. I advise that MMS either use more realistic assumptions which yield somewhat lower and more representative COEs, or not include language suggesting that the project is uneconomic. In any

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exceeded) or some other basis. If a cash flow is based on a middle-of-the-range production estimate, a higher DCR will be required than if a P-90 estimate is used.

event, MMS should add language making it very clear that the COE metric is not representative of the actual revenue required by a project.[6]

The conclusion presented regarding profitability is also not supported by any rigorous assessment of revenue, which is unrelated to today's electricity prices. Future revenues, which dictate profitability, will be influenced by future electric energy prices, which are expected to have a increase to a modest degree over the life of the off shore wind project (which can be supported by the trend in NYMEX natural gas futures (the single most significant driver of NEPOOL energy prices). But they will also include capacity revenues in NEPOOL's forward capacity market which are not yet reflected in today's market. In addition, the implementation of the Regional Greenhouse Gas Initiative will cause an increase in regional electricity prices. Finally, the assumption regarding long-term REC prices is based on Massachusetts Technology Collaborative forward REC contracts entered into a few years ago, before the increases in steel and copper and wind turbine prices, and before the recent adoption of the New Hampshire Renewable Portfolio Standard or the substantial increase in Connecticut Class 1 Renewable Portfolio Standard targets, all of which will tend to drive up REC prices. While MMS has developed a tool which can (subject to earlier caveats) do a good job of comparing the relative price level of alternative sites, MMS has not presented a revenue analysis upon which to make statements of this sort regarding project profitability.

2. "**MMS has received information through the applicant showing that at least one lender may be willing to offer a debt:equity ratio equal to 75:25 to finance the project at the proposed site**:. As the MMS write-up of the modeling approach notes, at high D/E ratios the DCR becomes a challenging constraint. For this reason, if a lender were to offer D/E ratio in this range (as noted earlier, this would be highly unusual), it is likely the debt structure would differ from that modeled. Under such a scenario, any number of other more sophisticated debt financing approaches[7] may be applied to manage the "cliff" effect noted on page 10 of the MMS write-up. Use of such a high level of debt without the more sophisticated financing assumptions which would likely accompany it has caused the DCR to be a highly binding constraint in the MMS analysis, resulting in the modeling of COEs corresponding to far higher equity returns than demanded in the market.

[6] As an alternative approach, MMS might be better able to avoid creating any inaccurate perceptions that could be used out of context by adopting a different metric than COE. An alternative approach using the same model would be to hold price constant and use internal rate of return (IRR) as the comparative a metric, as follows: if we assume a project at Horseshoe Shoals is economic at a price necessary to meet its required minimum equity return, what is the IRR for other projects at the same per-kWh total (REC + energy + ancillary services + capacity) revenue?

[7] for example, a shorter initial debt term, multiple loans of different terms, refinancing after year 10, sweep of excess cash in the early years to accelerate debt paydown, or subordinated debt.

3. “”…. **a lower debt:equity ratio and corresponding lower electricity price necessarily results in a lower rate of return. It would be in the interest of both the borrower and the lender to agree upon financing terms that allow each party to bear an acceptable level of risk. Determination of an “optimal” debt:equity ratio would involve a greater level of subjectivity than is required for site comparison, and so, a detailed analysis of project leverage was not carried out for the site comparison**.” For analysis purposes, optimizing a D/E ratio to minimize the COE subject to objectives of meeting a minimum DCR and equity return is not subjective. Excel provides a “Solver” Add-in tool to accomplish such a task quickly and objectively.

4. “**To demonstrate this point, a debt:equity ratio was determined for the proposed site that would correspond to a marginal rate of return equal to 10%. It was found that a debt:equity ratio of 60:40 could yield a project with a 10% return, if electricity could be sold for $0.102 per KWhr. This information is interesting but has limited use for this analysis, because MMS does not have knowledge of the applicant’s ability to raise the additional equity, or if the applicant would be willing to accept the risk associated with the longer time period needed to achieve payout of a higher level of equity**.” First, as noted earlier, under the 60:40 D/E sheet, the IRR is not 10% but 13%, which meets the minimum equity return. This illustrates that modeling to minimize COE may be fruitful. Secondly, the comment regarding the ability to raise additional equity is unsupported and does not flow from any evidence presented. MMS has not made the case that it is more difficult to raise equity than debt, and in fact the experience in the wind industry supports lower D/E ratios (e.g. more equity) than assumed here. Therefore, in my opinion the second sentence of this quote should be deleted.

Does the document include all necessary and pertinent citations to the literature to support the model’s methodology, assumptions and conclusions?

In general, the document contains citations supportive of the MMS approach, subject to a few exceptions identified earlier. One area which was insufficiently referenced was the source of assumptions regarding operating expenses. The document indicates “Base values for fixed and variable costs were obtained from information posted on the website at www.offshorewindenergy.org, and adjusted for inflation”. This citation is insufficiently precise to identify the assumptions used and their basis – I tried to find the information used at this site and could not.

In addition, there were a few areas – turbine, foundation and cable costs - where pertinent citations were noted but portions of the data were referred to as confidential. As a result, some significant portions of the analysis are not sufficiently transparent for peer review, and I am unable to offer comment on the interpretation of the data and the execution of the analysis in these critical areas. For example, I was unable to assess whether AC and DC cable costs had been sufficiently updated for higher copper and steel prices to evaluate whether the relative economics of near-shore versus farther offshore installations had shifted, or whether the crossover point where DC became more economic than AC would be altered from the 31 mile assumption used.

I would also like to point MMS to an upcoming report to be published later this summer by Lawrence Berkeley National Laboratory's Environmental Energy Technologies Division, to be entitled "Wind Power Financing Structures: A review and Comparative Analysis", by John P. Harper, Matthew D. Karcher, and Mark Bolinger. I highly recommend that MMS get and review this DOE-funded report, as it will provide additional valuable guidance. Due to the timing of the tasks before MMS, I strongly urge that MMS contact authors Harper or Bolinger regarding the potential to review a pre-publication draft.[8]

[8] John Harper may be reached at jharper@birchtreecapital.net or (508) 665-5875; Mark Bolinger at MABolinger@lbl.gov, or (603) 795-4937.

Response to Peer Review Comments

Response to Peer Review Comments
Submitted for the Report Titled: "Evaluation of the Cape Wind Energy Project Proposed Site and Alternatives With the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet"
September 26, 2007

Comments and suggestions offered by the peer review participants have been considered and incorporated as a part of the record. Additional analysis was conducted in response to some issues. Other issues required further explanation or clarification. While input from the peer review participants helped to raise the quality of the economic analysis , the ranking of the proposed site and alternatives did not change.

Issues identified by the peer reviewers are listed, followed by responses from the report author.

1. The OWEP Report does not provide the criteria by which one could decide whether alternative sites to the proposed site are sufficiently similar from an economic standpoint to warrant additional environmental analysis in the draft environmental impact statement (EIS). Thus, even if the results of the OWEP Report and model are accurate and credible, the original question of which alternative sites should be studied further is left unanswered.

Response:
This observation is true. In fact, it was not the intent of the Minerals Management Service to provide the basis for the selection of alternatives in the report provided for peer review. Rather, the peer review was carried out to identify technical aspects of the OWEP economic model, and procedures used for the economic analysis, that could be improved upon.

As stated in the second paragraph of the report's "Introduction", the selection of alternative sites for detailed environmental review is addressed in part *3.0 Alternatives* of the Cape Wind Energy Project draft EIS. However, the second paragraph of the "Introduction" does not specifically state that the criteria for screening the alternatives in the draft EIS, and the results, would not be subject to the peer review. A sentence should have been added to the report's "Introduction" to clarify this point. The MMS plans to solicit comments on the alternative selection process from the public during the comment period for the draft EIS, and these comments will be considered during the preparation of the final EIS.

2. Although the OWEP Report calculates the cost of producing energy (megawatt-hours or MWh) at the different sites, it does not account for the potential differences in the price of energy and capacity that these different sites may be able to obtain. New England's wholesale electricity market has locational marginal prices (LMPs) that result in varying energy prices by time and location. Moreover, New England is transitioning towards a locational capacity market.

Response:
Historical electricity price data was downloaded from the ISO New England Inc. (ISO) website at http://www.iso-ne.com/markets/hstdata/znl_info/monthly/index.html by clicking on "Monthly Summary of Load, LMP and Weather Data Report". Electricity prices are reported for the ISO New England Control Area and the 8 load zones: southeast Massachusetts, west central Massachusetts, northeast Massachusetts/Boston, Rhode Island, Connecticut, Vermont, New Hampshire, and Maine. Average LMPs for the day-ahead and real-time markets are given on a monthly basis in $ per MWh for the period from March 2003 through May 2007. The report author estimated annual average prices, in $ per MWh, from the data and created the summary table below.

Year	Maine		New Hampshire		Vermont		Connecticut		Rhode Island		SE Mass.		WC Mass.		NE Mass./Boston	
	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP	Annual Average DALMP	Annual Average RTLMP
2003	44.87	44.16	47.83	47.32	49.61	48.71	50.45	50.18	48.06	47.66	47.69	47.51	48.94	48.64	48.80	48.05
2004	48.57	47.73	52.04	50.67	53.90	52.27	54.57	52.75	52.77	51.17	52.28	50.67	53.81	52.28	53.41	51.41
2005	70.66	70.18	75.12	74.26	78.60	77.26	82.95	79.92	76.02	74.34	75.91	74.24	78.55	76.85	79.65	76.76
2006	57.16	56.09	59.26	58.39	61.28	60.13	67.27	64.48	59.13	58.06	59.52	58.19	61.28	60.02	60.62	60.41
2007	65.45	64.00	68.34	66.71	71.28	69.55	73.33	73.39	67.84	65.98	69.04	66.76	70.87	68.84	68.08	66.27

Notes: DALMP - day ahead locational marginal price; electricity price includes the cost of generation, and the marginal price of transmission losses and congestion at every node on the system

RTLMP - real time locational marginal price; electricity price includes the cost of generation, and the marginal price of transmission losses and congestion at every node on the system

This information demonstrates that the price of electricity does vary among the load zones, and so the price received for electricity generated at one of the various alternative sites would also vary depending on where the offshore wind energy project is connected to the transmission grid. The southeast Massachusetts load zone provides the most direct grid access for the proposed site and alternatives in the Nantucket Sound area. The other alternatives could more easily obtain access to load zones within closer geographical proximity. Under this scenario, and assuming for a moment that investment and operating costs for the proposed and alternative sites are equivalent, a wind energy project located at one of the alternative sites could be more profitable than the proposed site, if the future LMP prices at an alternative load zone are greater than prices at the southeast Massachusetts load zone.

Publication of the draft EIS will show that the alternative sites selected for detailed environmental analysis are all located in the Nantucket Sound area. These sites, as well as the proposed site, would most likely serve the southeast Massachusetts load zone, although one of the selected alternatives could have a Rhode Island load zone interconnect. Analysis of the LMP price data indicates that for months in the study beginning in 2003 and through the end of 2005, prices for Rhode Island were slightly higher than southeast Massachusetts. Beginning in 2006 and until recently, LMP prices at the southeast Massachusetts load zone were a bit higher than the prices reported for the Rhode Island load zone. Further, in years prior to 2007, the difference in average price was less than $1 per MWh, or 0.1¢ per kilo-watthours (KWh). Only the day-ahead LMP average price differential for the first five months of 2007 was greater than 0.1¢ per

KWh. Therefore, at least three observations can be made. First, prices at a load zone will fluctuate over time, and as suggested by a peer review comment, could increase or decrease relative to other load zones as the amount of energy delivered varies. Second, because the historical price averages from the two load zones nearest the Cape Wind Energy Project proposed site and selected alternatives are very close, revenues from a project selling electricity into either would not be significantly different. And third, when evaluating the sites selected for detailed environmental analysis in the draft EIS, it is not necessary to incorporate the potential for higher revenue from sales at either the southeast Massachusetts load zone or the Rhode Island load zone, because the ranking of the sites would not be altered by the anticipated small differences in price.

The second point raised in issue 2 refers to the exclusion of revenue potential in the OWEP economic model from selling capacity under a program administered by the ISO. The omission was an oversight, but will be considered here.

Upon investigation of this comment, rates for installed capacity payments made to eligible generators were found in the ISO publication titled FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design, Section III.8 – Installed Capacity, dated September 1, 2006, and effective December 1, 2006. A schedule is given showing fixed rates in effect during what is termed the transition period: December 1, 2006 to May 31, 2008 - $3.05/KW-month; June 1, 2008 through May 31, 2009 - $3.75/KW-month; and June 1, 2009 through May 31, 2010 - $4.10/KW-month. After the end of the transition period, the ISO's capacity payment program will be administered through forward capacity auctions. Capacity payments determined through the auction process will first be paid for the 12 month period beginning June 1, 2010.

Guidelines for the forward capacity program are given in the publication titled FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design, Section III.13 – Forward Capacity Market, dated February 16, 2007. Information in the table given in part *III.13.1.10.Forward Capacity Auction Qualification Schedule* shows that the first day of the initial forward capacity auction will be February 4, 2008, for the capacity commitment period beginning June 1, 2010. The qualification deadline for New Generating Capacity Resources, those projects that had not received any capacity payments prior to the auction, was June 15, 2007. To our knowledge, Cape Wind Associates, LLC did not attempt to get their project qualified for the first auction.

According to the table in part *III.13.1.10.Forward Capacity Auction Qualification Schedule*, the next six auctions are scheduled at 10 month intervals, until the February 4, 2013 auction is held. After that, an auction is scheduled for February 3, 2014, with subsequent auctions to occur on the first Monday in February of following years. Nevertheless, capacity commitment periods for the auctions will always begin on June 1 of the corresponding years. For example, the first day of the second forward capacity auction will be December 1, 2008, for the capacity commitment period beginning June 1, 2011. The second forward capacity auction has a deadline for new capacity qualification of April 15, 2008. Under the most optimistic development schedule for the Cape Wind

Energy Project, the project owners would have an opportunity to qualify and participate in this auction.

Participation in the second forward capacity auction could be advantageous to Cape Wind Associates, LLC for at least two important reasons. One, sponsors of proposed projects will be allowed to bid on a capacity commitment of up to five years, instead of the standard one year commitment for existing generation facilities. The capacity supply obligation and capacity clearing price, indexed for inflation, would apply for the entire five year period. This provision would serve as an incentive for projects in the pre-construction phase, and is explained in *III.13.1.4.2.5.Capacity Commitment Period Election*. By reducing revenue uncertainty for proposals that are not fully financed, some developers may be able to obtain loan approval that otherwise could not qualify. Second, the potential for additional revenue is not insignificant, as will be explained in the next several paragraphs.

Winning bids offered in forward capacity auctions will be determined by the ISO commission, in sufficient number to procure one hundred percent of the installed capacity requirement approved for the capacity commitment period. A capacity clearing price is set using an aggregate supply curve, which shows the sum of generating capacity bid at each price. In general, the capacity clearing price is the highest price offered at the level of installed capacity approved by the ISO commission. Project sponsors may only bid for capacity in the load zone which covers the grid interconnect for their power plant. It is uncertain if Cape Wind Associates, LLC, the assumed project sponsor, could offer bids for the project's qualified capacity at or below the clearing price set for its load zone (also called a capacity zone), most likely the one in southeast Massachusetts, or in another such as the Rhode Island load zone. In the event that the Cape Wind Energy Project sponsor were to be successful in this regard, at the second and subsequent forward capacity auctions, revenues from capacity sales could be considered in the site evaluation cash flows, beginning in the second half of 2011.

An evaluator attempting to analyze the effect of this revenue stream on project economics must forecast the clearing prices for the applicable forward capacity auctions. Since there have not been any forward capacity auctions held, there is not any historical data to use for projections. Also, to our knowledge, the ISO has not published information indicating what the installed capacity requirement might be. However, the ISO guidelines do include bounds for maximum and minimum offers. In part *III.13.2.4. Starting Price and Determination of CONE,* the ISO has specified that the forward capacity starting price will be equal to twice the cost of new entry (CONE) assigned to that capacity zone, or 2*$7.50/KW-month = $15/KW-month, for the first auction. A provision in part *III.13.2.7.3. Capacity Clearing Price Collar,* (b), states that the capacity clearing price "shall not fall below 0.6 times CONE", and references a procedure for prorating offers to limit the amount of installed capacity procured to the amount approved by the ISO commission. So, for the first auction, the capacity clearing price can not be higher than the starting price of $15/KW-month, and can not be lower than 0.6 times the CONE, or about $4.50/KW-month.

Several factors will influence the level of participation in an auction, and the most important could be the willingness of project sponsors to take on the financial risk and obligations imposed by the ISO program, to include financial assurance requirements and penalties for not meeting supply obligations. Project sponsors offering winning bids must provide financial assurance by specified dates, or loose its capacity supply obligation. Penalties for shortage events in a year are capped at the annualized forward capacity auction payment. An example calculation of costs and benefits incurred by a project sponsor will give an illustration of the approximate magnitude of the program's value to a participant in the capacity market. Assume that the CONE of $7.50/KW is required for financial assurance purposes. If a project has a qualified capacity of 150 MW, then the amount of the financial assurance deposit would be (150MW)($7.50/KW)(1000KW/1MW) =$1,125,000. Monthly capacity payments are calculated by multiplying the qualified capacity times the capacity clearing price in the capacity zone. If the capacity clearing price was equal to the minimum of $4.50/KW-month, then the annual capacity payment would be equal to (150MW)($4.50/KW-month)(1000KW/MW)(12months/1year) =$8,100,000, or $6,975,000 more than the financial assurance deposit. Qualified capacity ratings approved by the ISO for new intermittent power resources, such as the proposed Cape Wind Energy Project, can be determined with wind speed and project engineering data as explained in *III.13.1.1.2.2.6(b), AdditionalRequirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.* The qualified capacity estimate of 150 MW is roughly equivalent to a capacity factor of 32%, and is used here as an example calculation only. The report author expects that a rate determined from actual wind speed data collected at the applicant's proposed site will vary from the figure in the example.

The potential for revenues from selling capacity was not included in the OWEP economic evaluations. Any attempt to forecast capacity clearing prices would be weighted more heavily on assumption than technical analysis. Additionally, of the proposed alternative sites, those selected for detailed environmental analysis in the draft EIS are located in the Nantucket Sound area. As stated earlier, electricity generated at these sites would probably be sold into the southeast Massachusetts or Rhode Island load zones, and therefore, a project at any of the selected sites would likely receive approximately the same capacity clearing price. Crediting each of the sites with the same amount of additional revenue from capacity payments would not change the ranking of the sites.

3. The capacity factors for each site were derived from an NREL wind power model. Apparently three parameters are key to this model: average wind speeds, availability for each site and a power curve (i.e., the amount of power generated at varying levels of wind speed). Capacity factors are clearly key drivers of the economics of offshore wind technology. While the analysis provides selected references to the NREL model and other literature as to the source of some of the inputs to this model, the sources were either proprietary or not generally available for verification. As such, it is impossible with the discussion provided to determine whether or not the resultant values are reasonable. Having said that, a review of capacity factors used for off-site wind in the

Response:
Persons submitting privileged or confidential information to MMS, to include trade secrets or commercial or financial information, may request that such information be withheld from public disclosure. The MMS will honor those requests to the extent allowed by law. The MMS does not plan to publicly disclose the confidential information referred to in the peer review report.

The MMS did not think it would be realistic to ask the peer reviewers to examine or verify the capacity factor determinations, nor did MMS expect to receive detailed comments on this topic, given that the determinations were made with confidential information. Nevertheless, the peer reviewers may find the following information useful. A version of the NREL wind power model was identified through an internet search, and can be accessed at http://www.nrel.gov/wind/docs/weibull_betz5_lswt_baseline.xls. This is not the same NREL model that MMS used to make independent resource estimates for the Cape Wind Energy Project proposed site and alternatives, but it is similar and available to the public. This model can be used to calculate a hypothetical power curve and capacity factor for a wind turbine generator (WTG) of the same specifications as the WTG identified in the draft EIS, using the same publicly available wind speed data that MMS obtained from the AWS Truewind internet site at http://www.awstruewind.com. Wave data measured at offshore buoys in the vicinity of the sites, and used by MMS to make the WTG accessibility estimates, is available to the public at http://seaboard.ndbc.noaa.gov/maps/Northeast.shtml. More discussion of how the wave data was used is given in the response to the next issue.

4. Operational risk factors for each site were not accounted for in the resource estimates and operating costs. There is no consideration for the potential impact of a severe storm on the operations of the project over a 15 year debt repayment period. Lending institutions with a risk management program would require this type of risk assessment. If the risk is assessed, the ranking of the sites might change. In another comment, it was stated that it was not possible to verify the operating costs assumptions with the internet reference or other information given in the peer review report.

Response:
Risk of component failure due to adverse weather conditions was incorporated into the calculation of the cost of energy (COE) for each site through adjustments made to power output and operating costs.

The conversion of WTG accessibility rates (to perform routine maintenance or the repair of random component failures) to WTG availability (for electricity generation) was made with a function published in Figure 8 of the paper titled The DOWEC Offshore Reference Windfarm: Analysis of Transportation for Operation and Maintenance, by G. J. W. van Bussel and W. A. A. M. Bierbooms of the Delft University of Technology, Delft, The Netherlands. This paper can be found on the internet at www.ecn.nl/docs/dowec/2003-

Wind-Engineering-Accessibility.pdf. Availability for each site was used as an input in the NREL model to approximate the frequency of turbine downtime. The DOWEC report authors derived the accessibility - availability function from a Monte Carlo simulation model that samples input distributions for wind and wave conditions, random wind turbine failures, maintenance crew deployment, and the availability of the maintenance equipment. The application of the DOWEC method to the OWEP evaluations is defensible in that it incorporates the statistical uncertainty anticipated for offshore wind energy project operations. Although the method is based on a theoretical project in the North Sea, wave data from each of the Cape Wind alternatives, in conjunction with a significant wave height of 1.5 meters for a rubber boat access system, was applied consistently to determine accessibility. Accessibility would increase at all sites if an access system could be built for a significant wave height of greater than 1.5 meters. Capacity factors for such a scenario were not calculated, because the report author is not aware of an access system which has been demonstrated to be reliable and safe for significant wave heights exceeding 1.5 meters.

Estimated operating cost factors applied to evaluate the proposed site are based on fixed and variable operating cost factor information for European offshore wind energy projects posted on the internet at http://www.offshorewindenergy.org, accessed by clicking on buttons labeled "CA-OWEE", "Resources_and_Economics", and "3 Economics". It was assumed that the operating cost factors were partly based on the use of access systems that can be used safely at wave heights of less than 1.5 meters. Cost factors from the website were converted from € to $ as follows: fixed cost factor - (€30/KW)($1.29/1€) = $38.70/KW, and variable cost factor - ($0.005/KW)($1.29/1€) = $0.0065/KWhr. Inflating these costs from 2001 to 2007 at an annual rate of 2.5% yields a fixed operating cost factor of $44.33/KW and a variable operating cost factor of $0.0075/KWhr. The € to $ currency exchange factor was obtained from http://www.xe.com on August 9, 2006. (If the currency conversion were updated, an exchange factor of closer to $1.35/1€, quoted on the xe.com website on August 22, 2007, might be used.)

Operating costs for the proposed site were adjusted to estimate the operating costs at the alternative sites by increasing or decreasing the variable operating cost factor as a function of distance from shore. Total operating costs for the sites evaluated were in the range of 3.3¢ to 6.9¢ per KWhr in real dollars, higher than the 2¢ per KWhr operating cost factor cited on page 5-9 of the RIWINDS (State of Rhode Island) study posted on the internet at http://www.energy.ri.gov/documents/independence1/RIWINDSReport.pdf, or the 2¢ per KWhr [(£10.02 per MWhr)($1.99/£1)(1000KW/1MW)] operating cost factor budgeted for the Scroby Sands project in the North Sea, as reported on page 10 of Scroby Sand Offshore Wind Farm: Annual Report 2005, posted on the internet at http://www.berr.gov.uk/files/file34791.pdf . The £ to $ currency exchange factor was obtained from http://www.xe,com on August 22, 2007.

5. Three issues were raised regarding the submarine power cable.
   (a) The referenced site for developing the loss factors used for direct current (DC) applications (>31 miles in this assessment) fails to point out a caveat in that reference

which states that high voltage direct current (HVDC) "...has not yet been proven to be a commercially available technology for offshore wind farms."

(b) It is unclear whether or not the capacity factor being used are at the busbar (or collecting substation in this case) or are intended to account for the losses transmitting the power to the grid delivery point.

(c) It is unclear whether or not AC or DC costs were updated for higher copper and steel prices, and whether the cross over point where DC became more economic than AC would be altered from the 31 mile assumption used.

Response:

(a) The quote appears at the end of part *9.0 Conclusion*, of the 2003 report posted at http://www.nae.usace.army.mil/projects/ma/ccwf/app3c.pdf), and incorporated as Report No. 3.1.2-1 in the Cape Wind Energy Project draft EIS. The report also states in part *8.0 Commercial Availability*, that HVDC technology is technically proven, and has been applied "for long distance submarine applications, such as 250 km crossings of the Baltic Sea, and most recently across the Long Island Sound." Information presented in the paper titled Study on the Development of the Offshore Grid for Connection of the Round Two Wind Farms, by Econnect Ltd., dated January 2005 and found at www.dti.gov.uk/files/file30052.pdf?pubpdfdload=05%2F846, which was also referenced in the peer review report, cites several other examples of offshore HVDC installations in parts *3.7.2* & *3.7.3*. The report specifies the use of HVDC cable for projects listed in the tables appearing in part *8 Individual Project Connection Cost Summary* and part *9 Joint Project Connection Cost Summary*. The report indicates that HVDC cables could become commercially proven within the time frame set for development of the Cape Wind Energy Project. However, sites that would utilize this technology were eliminated from consideration in the draft EIS because the technology is not commercially available, at present. Sites modeled with DC cable systems were evaluated to show how closely the COEs for those sites might compare to COEs for other sites, in the event that this information would be found useful in the future.

(b) The capacity factor was intended to account for cable system losses when transmitting power to the grid delivery point.

(c) As stated on page 14 of the peer review report, cable costs were updated to account for the increase in copper and steel prices, which occurred from 2003 through 2007, with information provided by a wind turbine generator manufacturer and with information found in Figure 10.1 of the paper titled Study on the Development of the Offshore Grid for Connection of the Round Two Wind Farms, by Econnect Ltd. The author determined that a DC cable system would cost less than an AC cable system for the sites at Nantucket Shoals and Phelps Bank, modeled to have cable lengths of 41 miles and 67 miles, respectively. Further, cable system power losses would be limited to about 3% for a DC cable system, but according to Report No. 3.1.2-1, could be 4.5% for an AC cable system from Nantucket Shoals. AC cable system power losses for the Phelps Bank site would be even greater. Both of these factors, cable system cost and power loss, would diminish the economics of development at these sites with an AC cable system.

On a unit of length basis, AC cable is more expensive than DC cable. Due to the high cost of DC converter stations, facilities for DC cable systems are more expensive than facilities for AC cable systems. Copper price increases since 2003 have had the effect of reducing the cross over point where it would be more cost effective to install a DC cable system rather than an AC cable system. Cost estimates made by the report author indicate that an investor for a site such as South of Tuckernuck Island, located approximately 27 miles from the preferred coastal interconnect identified for the proposed site at Horseshoe Shoal, may be indifferent to the use of either type of cable system, from an economic perspective. This possibility was not pursued in greater detail because the technology for DC cable systems is presently not commercially available.

6. Several issues were identified with regard to the way the weighted average cost of capital (WACC), discount rate and rate of return information was presented in the report.

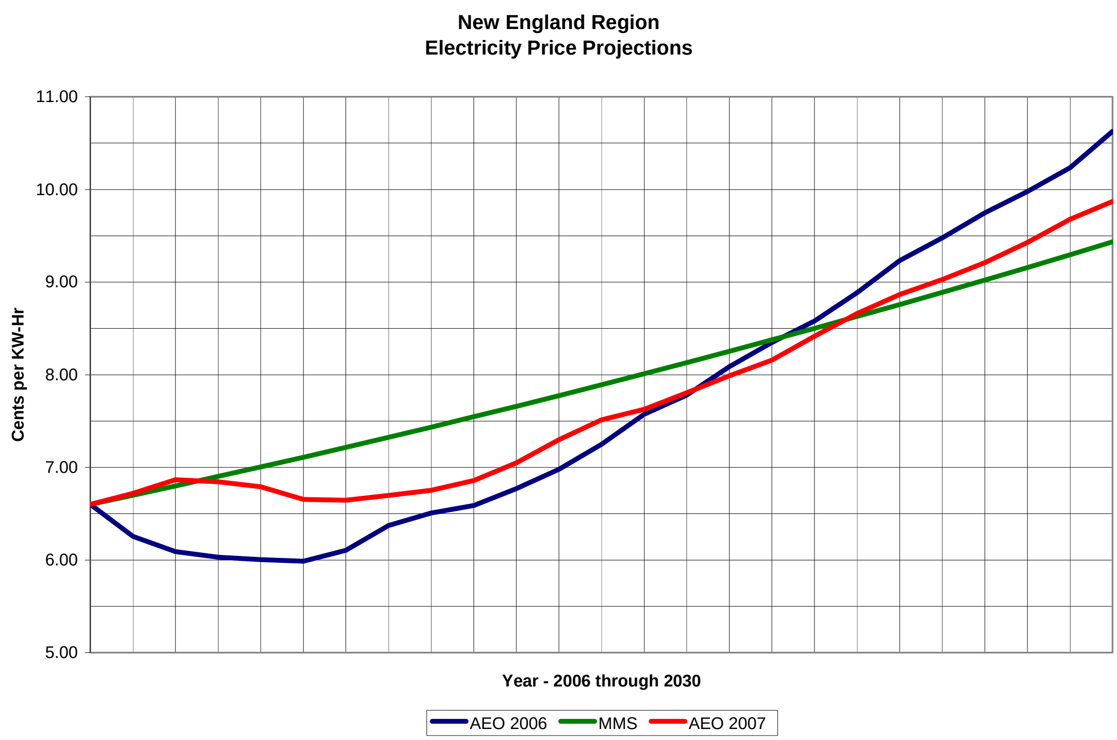
Response:
Prior to beginning the economic analysis, MMS considered the possibility that the project might not produce a positive net present value under existing economic conditions. Anecdotal cost information from offshore wind energy projects in Europe indicated that capital costs had risen significantly since the Cape Wind Energy Project was first proposed. To investigate, a preliminary evaluation of the proposed site was conducted, using a discount rate derived with the simplified WACC formula given in the peer review report. The formula calculates an approximation of the real, rather than nominal, WACC. The real WACC was calculated because nominal cash flows in the spreadsheet are deflated before discounting. The WACC formula did contain a typographical error in the peer review report; an extra set of parenthesis appeared in the denominator. The formula should have appeared as: $((1 + 0.07*0.75 + 0.105*0.25)/(1 + 0.025) – 1)*100\% = 5.24\%$.

A negative cumulative net present value was calculated for the preliminary evaluation. More attention was not given to the discount rate determination in the peer review report, because the net present value and internal rate of return values were not used to rank the projects.

An explanation of the values entered in cell M2 of the spreadsheet, in lieu of the discount rate described in the first paragraph of this response, was not given in the discount rate section on page 8 of the peer review report. Instead, the intended meaning of these values was explained in the last two sentences of the fourth paragraph in the narrative under “Materials and Methods” on page 5. It was explained that: “The rates of return for the proposed site and the alternatives were calculated by iteratively adjusting the discount rate in row 2 of column M, until the cumulative cash flow was reduced to a value close to $0. Rate of return values are reported on the worksheet tabs within the spreadsheet.” Attaching the generic label of “rate of return” to the value in M2 was not appropriate, and improperly implied that the real internal rate of return could be calculated from nominal cash flows that had been discounted and deflated. This calculation gives a false result and should be disregarded, because debt service is not subject to inflation and tax depreciation is based on the original cost, which is not inflated. More discussion of this topic appears on pages 183 and 184 of Principles of Project Finance by E. R. Yescombe, Academic Press, 2002. The correct calculation of the nominal internal rate of return was made in cell L29, although the cell was not labeled. The label “nominal internal rate of return” should have been added in cell K29 of the spreadsheet to clarify this point.

7. Electricity price and operating cost escalation rates were questioned. One comment stated that given the analysis's inflation assumption of 2.5% per year, the assumption that electricity prices will increase only 1.5% nominally (i.e., decline in real terms) is difficult to accept. A correlation or link between the EIA AEO oil and gas price forecast or NYMEX natural gas prices was suggested by more than one peer reviewer.

Response:
Before conducting the economic evaluations for the Cape Wind Energy Project draft EIS, locational marginal price data for the southeast Massachusetts load zone, as reported by the ISO for the real-time market, was downloaded from the internet site at http://www.iso-ne.com/markets/hstdata/znl_info/monthly/index.html. A starting electricity price of $65.97 per MWhr, or 6.60¢ per KWhr, was determined for the preliminary evaluation of the proposed site, as referred to in item 6 above, by calculating the average over the 2 year period from February 2005 through January 2007. (An updated calculation yielded an average price of $67.81/MWhr over the 2 year period from June 2005 through May 2007. For May 2007, the average price was $65.51/MWhr.) The average electricity price of 6.60¢ per KWhr was used as the starting price for each projection in the chart below. Price trends were projected by applying price escalation factors to the starting price.



The MMS projection was an approximation of the price projection determined from information published in the Annual Energy Outlook (AEO) for 2006, Tables 8 and 19, posted on the internet at http://www.eia.doe.gov/oiaf/archive/aeo06/aeoref_tab.html. As the chart shows, in addition to the MMS and AEO for 2006 projections, a projection is also displayed from information in the AEO for 2007 posted on the internet at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html. The MMS projection was based on the assumption that the product of the inflation rate and price growth would be 1.5% annually, and was made before the AEO for 2007 was published in February of 2007. The AEO price paths were projected by adjusting the starting price of 6.60¢ per KWhr with an annual price escalation factor calculated as the product of: a) growth – utilizing the "Prices by Service Category 9/Generation" forecast of electricity prices reported in Table 8, and b) inflation – utilizing the GDP Chain-type Price Index found in Table 19, from the respective AEO issues. The growth rate adjusts electricity prices to match the annual price changes in Table 8 of the AEO national electricity price forecasts. The inflation rate converts the electricity prices to nominal dollars. Substitution of the AEO for 2006 or 2007 national price projections for the MMS price projection would give slightly different COE results, but the difference is approximately five percent, too small to have had a significant effect on the magnitude of other economic performance measures or the ranking of the sites.

The report author agrees that the accuracy of the COE estimates could be improved by application of a regional or locational electricity price forecast, one that might be correlated with a NYMEX oil and gas price series or the AEO oil and gas price forecast, instead of the AEO national electricity price forecast. Clearly, a regional price forecast should be a major part of any revenue analysis carried out for investment decisions. Such a forecast was not used to rank the project sites reviewed in the draft EIS, because a) the MMS is not aware of a reliable source offering this information to the public at no charge, and b) it was not felt that the purchase of a proprietary forecast was justified or necessary, given the purpose of the economic analysis and because the sites passing the screen would be subject to similar market conditions. Interconnect points for these sites would be in either the southeast Massachusetts or Rhode Island load zones (see response to issue 2). Use of the same price forecast for the alternatives studied would not change the ranking of the alternatives.

8. One comment stated that it is misleading to include language suggesting that the project is uneconomic, without including a thorough assessment of the revenue streams. Another noted that the COE for the proposed site is much higher than the average LMP price calculated for the southeast Massachusetts load zone with the most recent 24 months of data, and the analysis purposely avoids addressing this obstacle.

Response:
On page 17 of the peer review report, it is stated that: "The proposed site at Horseshoe Shoal has the lowest estimated cost of energy, equal to $0.122/KWhr, or $122/MWhr, while none of the sites appear to be profitable at today's electricity prices." In addition to the revenue stream modeled from electricity sales, a forecast of renewable energy certificate (REC) sales was also made. The potential for the receipt of revenue through capacity payments and providing ancillary services was not considered when this statement was drafted. Given the uncertainty of the revenue potential from the proposal, and the fact that a rigorous analysis of the revenue streams was not conducted, it is acknowledged that the OWEP model does not give a precise estimate of the COE for the

sites evaluated. References to the apparent profitability of development at any of the sites could therefore be misleading, and will not be made in the draft EIS.

The last paragraph of the report prepared for the peer review states “In conclusion, MMS recognizes that material costs for WTGs and cables have risen significantly since the applicant initially proposed the project several years ago. Capital expenses used in the MMS economic analysis are based on cost estimates that account for the rise in steel and copper prices from 2003 through 2006. Results from the MMS analysis, which were calculated with cost estimates that wind energy developers might rely upon today, should not be construed as a profitability forecast intended to either endorse or condemn the action proposed by the applicant. Economic conditions will continue to evolve over time, changing the outlook for the project.”

The report author feels that entities that choose to pursue wind energy ventures on the OCS are cognizant of the technical challenges and economic uncertainty inherent with development. It appears likely that the Department of the Interior, and MMS, will give consideration to proposals that could be economic in the foreseeable future, either through the potential for significant cost reductions or other changes in economic conditions, to encourage advancement of the OCS alternative energy program and to create opportunities that could lead to a more reliable supply of electrical power for the public.

9. Several comments were made concerning the debt assumptions used to calculate the COE for the initial set of evaluations.

One set of comments stated that the debt-equity ratio (DER) assumption was not supported by a review of the financial, security, and other covenants or conditions that would be required to secure debt for this kind of project. “Support for the selection of the financial assumptions appears to rely extensively on an unnamed investment bank. If this bank were to provide an irrevocable set of terms consistent with these assumptions, then perhaps this is adequate. Absent that, a greater investigation into the financing of these kinds of projects would seem a key to the analysis.”

Another set of comments stated that the assumed DER of 75:25 is too high. Wind projects being financed on a non-recourse basis typically carry lower ratios of 50:50 or less. Use of a high DER, held constant for all sites, results in unrealistically high COEs that correspond to radically different equity returns. The approach erodes the evaluator’s ability to consider the evaluations comparable. An objective analysis could be carried out to optimize the DER and minimize the COE. It was observed that the royalty rate used may distort perceptions of the COE.

Other comments noted that the debt coverage ratio (DCR) of 1.3 is too low, but could be justified to a bank if it can be shown that the variability in cash flows is sufficiently small to protect the lender from the risk of default. Moreover, most banks do not include the monetization of production tax credits (PTC) when calculating the DCR. Such a difference should be explained before comparing the COE values to those that might be calculated by a bank.

Response:
These comments suggest that the debt assumptions currently available to onshore wind energy developers should be applied in the economic analysis instead of the debt assumptions contemplated by the applicant and their potential lender. The report author accepts these comments as having some merit, because of the uncertainty involved in projecting debt terms years in advance of an actual loan. With this in mind, a second set of evaluations were conducted to calculate the COE for the proposed site and alternatives which incorporated the advice of the peer reviewers, while acknowledging that debt assumptions made for the revised evaluations may or may not be more accurate than the assumptions made in the initial analysis. However, the procedures for the revised analysis should more closely follow a format thought to be common among investors analyzing wind projects in the regulatory permitting stage of planning, and are therefore less likely to be misinterpreted by people reading part *3.0 Alternatives* of the Cape Wind Energy Project draft EIS.

Economic evaluation results calculated in the second set of evaluations, for the proposed site and those alternatives passing the physical site screening criteria, will be presented in Table 3.1.2-1 of the Cape Wind Energy Project draft EIS. Sites that did not pass the physical site screening criteria and will not be given detailed environmental review were also evaluated. This is largely because initial phases of the economic analysis were conducted concurrently with the research carried out for defining the physical site screening criteria. Once information for the evaluation of each alternative site was assembled, it was determined that the results should be presented to form a baseline that could be used in the event further analysis of these alternatives is required. These COE results, for the first and second set of evaluations, are given in tables that appear in the peer review report, and later in this response, respectively. New, relevant information may be substituted for existing assumptions made in the evaluations, as it becomes available and is germane to future analyses conducted by MMS.

Several changes were made to the original analytical format before conducting the second set of evaluations.

a) The COE definition was revised. In the initial evaluations, two revenue streams were forecasted; electricity sales and renewable energy certificate sales. No attempt was made to forecast the individual revenue streams in the revised set of evaluations, although the total revenue stream was projected to escalate at a nominal rate of 1.5% annually. It was anticipated that revenue could be received from electricity sales, REC sales, capacity payments, and providing ancillary services. Therefore, the COE for the second set of evaluations is defined as the value of all revenue streams to be received by project owners, expressed in year 2007 $ per KWhr, needed to meet or exceed a debt coverage ratio of 1.5 during the life of the loan. This DCR was used instead of 1.3 to give the lender greater protection from the risk of default.

b) Monetization of the PTC was included in the calculation of the DCR for the original set of evaluations. This procedure was questioned by the peer reviewers. Upon review of the topic, a reference was found that supports the peer reviewer's comment. According to Principles of Project Finance by E. R. Yescombe, Academic Press, 2002, on p. 273, calculation of the DCR should be based on operating cash flow rather than accounting results. Therefore, monetization of the PTC was not considered when calculating the DCRs for the second set of evaluations.

c) An attempt was made to calculate an optimal or lowest COE for each site evaluated, by adjusting the DER subject to the conditions that the DCR would not fall below 1.5 and the internal rate of return would exceed 10%, a rate that might be considered marginal by an offshore wind energy developer. The numerator of the debt coverage ratio is the sum of annual income derived from electricity sales, renewable energy certificate sales, capacity payments, providing ancillary services and debt service reserve interest, minus operating costs and any rental, royalty or operating fee payments owed to the lessor. The denominator of the debt coverage ratio is equal to the annual principal and interest payments owed to the lender. Lower DER values were determined for the sites, and ranged from 49:51 to 55:45. Wind energy project developers may be more inclined to find an equity partner to share the risk of investment at lower DERs.

d) Cash flows were discounted at a real rate of 7% for the second set of evaluations. A revised estimate of the WACC for the project was made by assuming the interest rate on term debt would be 7%, derived as an approximation of the London Interbank Offer Rate (LIBOR), which changes over time, plus 1.5% to 2.5%. Further, information submitted by one of the peer reviewers indicated that a base return on equity might be approximately 12.5% for a public utility making onshore investments. Therefore, 12.5% was taken as a minimum return on equity for an offshore wind energy project of higher risk. Nominal rates of 7.0% and 12.5% were used for the debt and equity portions, respectively, of the real WACC calculation: $(1 + 0.07*0.5 + 0.125*0.5)/(1+0.025)-1 = 0.0707$, or 7%. The denominator term is included to convert the nominal WACC to a real WACC, assuming an annual rate of inflation equal to 2.5%.

e) For reasons explained in the peer review report, a royalty rate of 12.5% was used in the evaluations. It is acknowledged that this rate is higher than the rates charged by private landowners or other government agencies in the U.S. for onshore wind energy projects, and could have the effect of distorting COE estimates for the Cape Wind Energy Project. While the MMS will not propose fiscal term policy for alternative energy leases until regulations are published for review by industry and the public, a lower rate of 5% was adopted in the second set of evaluations, for illustrative purposes.

Results from the two sets of evaluations are shown in the following table.

#		1	2	3	4	5	6	7	8	9	10
Site		Horseshoe Shoal	Block Island	South of Tuckernuck Island	Cape Ann	Monomoy Shoals	Boston Outer Harbor	Portland Outer Harbor	Nantucket Shoals	Phelps Bank	East of Nauset Beach
Scenario 1	cost of energy ($/kwh)	$0.122	$0.132	$0.143	$0.151	$0.205	$0.213	$0.224	$0.238	$0.287	$0.299
Scenario 2	cost of energy ($/kwh)	$0.128	$0.137	$0.148	$0.155	$0.209	$0.217	$0.228	$0.240	$0.288	$0.301
	debt-equity ratio	49:51	49:51	50:50	50:50	53:47	53:47	53:47	54:46	54:46	55:45

Note: The debt-equity ratio for Scenario 1 was held constant at 75:25.

As presupposed in the peer review comments, the approach taken in the second set of evaluations did not change the order of the ranking, but may give a more accurate estimate of the COE. Results from Scenario 2 above will be given in the draft EIS, with an explanation of the basic assumptions applied to calculate the results.

In general, it was observed that exclusion of the PTC in the DCR calculation for the revised set of evaluations resulted in the higher COE values. The COE is less sensitive to the effects of the PTC at higher revenue levels. The minimum DCR occurred in year 11 of the Scenario 1 evaluations, and in year 1 of the Scenario 2 evaluations. On page 10 of the peer review report, it was noted that monetization of the PTC over the first 10 years of a project's life has a cliff effect on the DCR, beginning in the 11th year. This variability was eliminated when calculating DCR values for the revised set of evaluations, because monetization of the PTC was not included in the cash flow and the slope of the revenue stream was held constant. Calculation of the minimum DCR occurred in year 1 of the Scenario 2 evaluations, due to the value of revenue levels rising faster annually than the corresponding magnitude of royalty and operating costs.

10. In practice, some portions of a wind energy electrical power plant investment, on the order of 5%, may not be classified as 5 year ACRS property for Federal tax calculations.

Response:
The section of the peer review report discussing depreciation should have indicated that although 100% of the power plant was classified as 5 year ACRS property, in practice, a small part of the investment would not receive accelerated depreciation treatment.