La Capra Associates

HULL OFFSHORE WIND FINANCIAL ASSESSMENT

Technical Report

PREPARED FOR

The Town of Hull

PREPARED BY

La Capra Associates, Inc.

One Washington Mall, 9th Floor
Boston, MA 02108

February 4, 2010

TABLE OF CONTENTS

ATTACHMENTS

I. PROJECT OVERVIEW

The Town of Hull has significant experience developing wind resources, being the first coastal community on the east coast to develop a commercial-scale wind project—a 660 kW wind facility located onshore in the harbor area that came on-line in 2001 and is known as "Hull Wind I". The town further added to their renewable resource portfolio with the addition of "Hull Wind II", a 1.8 MW wind facility installed on a closed landfill that came on-line in 2006. Hull wishes to continue their development of wind resources and has set the ambitious goal of installing enough wind energy to fully cover the town's annual electricity consumption. The energy production of Hull I and II account for approximately 12% of current consumption. Depending on the particular assumptions concerning the production of wind at certain locations and under certain configurations, between 12 and 14 MW of additional nameplate capacity of wind will be required to meet this goal.

Hull has concluded that there is no suitable and available land onshore to site further wind facilities. As a result, Hull is examining different options for locating turbines offshore and has asked La Capra Associates to perform a financial assessment of pursuing an offshore wind strategy. Offshore wind facilities do have advantages over onshore sites, such as higher capacity factors and the ability to site large facilities closer to large populations (and load centers), but also feature some important disadvantages, such as higher capital, operating, and interconnection costs and more complex and costly installation, which has limited the expansion of offshore wind relative to onshore. Of the approximately 121 GW of installed wind capacity in place around the world at the end of 2008, only 1.5 GW is offshore, all of which is located in Europe. As a result, all of the installed project-specific data underlying the assumptions used in the financial analysis discussed herein necessarily come from the European experience, supplemented by our experience in and knowledge of proposed offshore installations for various locations in the Northeast United States.

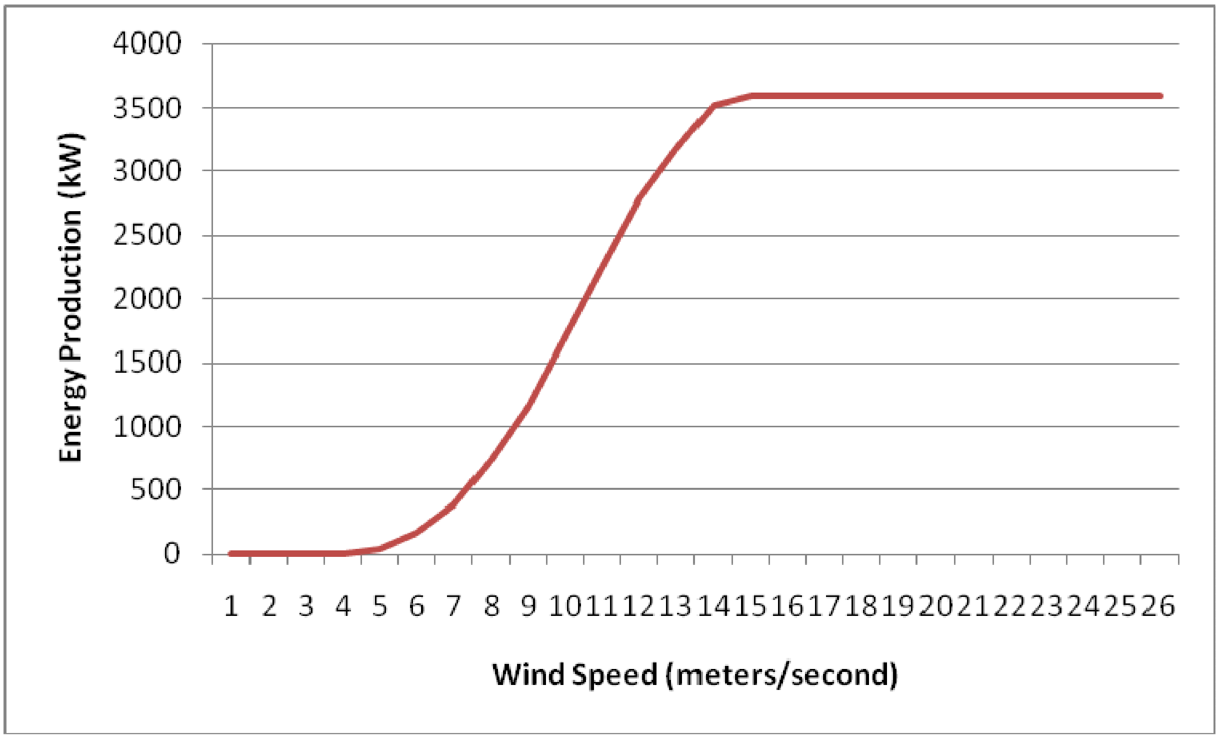
A. Available Configurations

The particular wind turbine configuration and site have not been established, but it will be selected on the basis of providing the maximum energy output while minimizing the environmental damage. Hull has indicated that a maximum of 4 wind turbines will be installed. Available offshore turbine sizes that either have been installed or will be available by the anticipated construction date of the fourth quarter of 2010 range from 3 MW to 5 MW.[1] We make no particular assumptions regarding the site and configuration of the turbines and their ultimate impact on energy production.

[1] "Offshore wind turbines Design and availability." Garrad Hassan. http://www.all-energy.co.uk/userfiles/file/Colin_Morgan210508.pdf

B. Wind Plant Energy Production

Capacity factor is the key determinant of a wind project's economic or financial feasibility. For the Hull Offshore project, we utilized hourly wind data supplied by UMass and applied the following wind power curve for a Siemens 3.6 MW turbine[2]:



Power curves are unique to each wind turbine model and are used to translate wind speeds to energy production. As shown in the graph, at low wind speeds there is no energy production and maximum energy production is met at wind speeds between 13 and 14 meters/second. Though not shown in the graph, wind turbines will shut off at extremely high wind speeds (over 27 meters/second). Applying this power curve to the wind data provided results in a capacity factor of **31.1%.**

Offshore wind is generally assumed to have higher capacity factors than onshore facilities, but actual energy production will depend on the particulars of the final site selection and the actual operation of the wind turbines. Generally speaking, sites more distant from the shore will support the greatest energy output but will be more costly due to higher interconnection, construction, and maintenance costs associated with operating under more extreme weather and marine conditions. In addition, offshore wind turbines, especially those in sites distant from the shore, may face more outages due to maintenance difficulties. As a result, recent data indicate that onshore capacity factors have exceeded offshore capacity factors in the past, but

---

[2] The graph data are found in Appendix A.

improvements in wind-turbine technology have reversed this relationship.[3] In the case of Hull, there is the limitation that the site be contained within the town's boundaries. Based on preliminary wind estimates, the potential wind speeds at 70 meters range from 7.5 to 8.5 meters/second, depending on whether the site is to be located between 1 and 3 nautical miles from shore. Such wind speeds can support capacity factors higher than 30%, and the relatively close location of the turbines to shore should hold down maintenance costs and related outages.

II. ESTIMATED WIND PLANT COSTS

Assuming that adequate wind resources are available and offshore sites are feasible and within the planning scope, the next critical task is to estimate the costs of purchasing and installing the offshore wind plant. Though there are numerous components to an offshore wind facility, we concentrate on three major capital cost categories: the wind turbine themselves, the foundations and substructures, and the transmission grid to connect the turbines to shore. We have not included any development or pre-construction costs in the estimates. The general approach used in this report is to develop a range (high and low) for each cost category for input to the financial model, assuming the construction start date from above. We then compare the ranges for each cost category with total actual and estimated capital costs for installed and proposed projects.

There is significant uncertainty in total wind costs with a wide range of estimates, depending on the year of the estimate or installation. In addition, offshore wind costs in particular have increased significantly over the past few years and are expected to continue to face cost pressures due to limited capacity in the supply chain in terms of wind turbine manufacturing and installation.[4] Finally, much of the production infrastructure (e.g., vessels) and manufacturing capacity is in Europe, which further adds currency risks. For example, decreases in the value of the U.S. dollar compared to the Euro directly impacts the estimates of capital and installation costs if materials and services are imported from Europe, which will likely be the case for a good portion of capital expenditures.

Offshore capital costs are categorized into three major categories: the wind turbine, the foundation and sub-structures, and the interconnection facilities. The goal in breaking the costs into these three categories is not to provide detailed cost estimates for each component, but rather to discuss factors that can impact the overall cost assumptions we used. Decommissioning costs were assumed and we included a decommission fund reserve in our financial estimate. Another option may be repowering, which will entail a lower cost estimate. Appendix A has the base assumptions used in the financial analysis.

Overall, we estimate that the total project cost will be in the range of $45 to $53 million at the time of completion. Not surprisingly, there is a large amount of uncertainty concerning future capital costs. Capital expenditure ("CAPEX") estimates have increased significantly over the last few years. Offshore wind costs have always been higher than their onshore[5] variant, but the increase in offshore CAPEX estimates has been extreme and much higher than changes in

[3] The 2008 Digest of United Kingdom Energy Statistics shows that for 2007 (latest available data), total offshore wind capacity factor was 28.3% compared to 27.3% for on-shore wind, which was not the case for prior years.
[4] Though the recent credit crisis and deterioration in overall economic conditions has provided some slack in the supply chain, increased demand from China is expected to provide support to strong demand.
[5] Onshore CAPEX have increased since 2004 by about $650/kw to $1850/kW. Estimates for 2010 are about $2200/kW. Source: Mark Bolinger, May 5, 2009 Windpower 2009 Presentation.

consumer price indexes. Early offshore wind farms installed in 2003/4 were completed at approximately $2200/kW in 2004 dollars[6]. Those wind farms were closer in scope to the proposed Hull project in terms of size and distance from shore than the larger wind farms that have been recently proposed. Applying an annual increase of 10%, which is the estimated compounded annual growth rate since 2004 in onshore CAPEX costs, yields a 2010 CAPEX estimate of $3810/kW, which is slightly higher (about 4%) than the high estimate shown in Appendix A. However, as we discuss below, we have seen cost estimates higher than this for offshore installations.

A. Wind Turbine

Based on availability and the majority of operational offshore wind projects, the preferred turbine size is 3-3.6 MW. There continues to be research and development on larger turbines, because it is more cost-effective for offshore wind farms to install, as fewer turbines and foundations reduce costs.[7] In addition, larger turbines feature larger rotor diameter, which is more than linearly related to power potential. Unlike onshore installations, there are few transport-related concerns with moving large turbines from manufacturers to wind sites. On the other hand, the larger rotor diameter does raise additional environmental questions.

The current offshore wind market is dominated by two turbine manufacturers, Vestas and Siemens.[8] For the purposes of the financial analysis, only two types of turbines (at the sizes above) have proven to be adequate to operate under the harsher conditions found offshore: a 3 MW turbine by Vestas and a 3.6 MW turbine by Siemens. Vestas and Siemens control most of the market share and U.S. developers, such as Cape Wind, have announced preference for contracting turbines from one of these companies instead of GE, who has now focused solely on onshore wind.[9] Other proposed offshore wind projects in New England, such as Rhode Island Offshore Wind, will most likely have to make the same move from GE offshore turbines, which they used in their site analysis, to either Vestas or Siemens turbines.

Each power turbine has an associated power curve that will impact energy production based on the wind characteristics at the site. Based on the wind data discussed above, it is anticipated that both models would be suitable (in terms of potential wind energy production and the capacity factors assumed above) for the site area, but due to scale economies associated with the larger 3.6 MW turbine and its increasing popularity in recently proposed offshore installations, this was the only size used in the financial analysis.

---

[6] This cost estimate is for the North Hoyle Wind Farm in the United Kingdom and assumes a currency conversion rate of 1.65. At the time of this project, there was a general consensus that offshore wind cost would actually fall due to scale economies in manufacturing and greater experience with technology and installation.

[7] "Study of the Costs of Offshore Wind Generation." Offshore Design Engineering (ODE) Limited. 2007.

[8] See this article, "Siemens Offshore Wind Farm Projects a Sign of Things to Come." http://www.glgroup.com/News/Siemens-Offshore-Wind-Farm-Projects-a-Sign-of-Things-to-Come-9869.html. However, GE has never fully left this segment of the wind turbine market and may seek to jump back in with a 3.6 MW model

[9] "Cape Wind Navigates Shifts in Market." http://greeninc.blogs.nytimes.com/2009/03/27/cape-wind-navigates-shifts-in-market/

Cost estimates for turbines were taken from recently announced orders for 3.6 MW offshore turbines at approximately $1950/kW. We then applied annual growth factors of approximately 3% and 10% (for two years) to arrive at the high and low ranges found in the assumptions table. The lower estimate assumes that there will be some slack in the turbine supply chain by 2011, and that Hull would be able to piggyback on purchases by other local offshore wind projects.

B. Foundations and Sub-Structures

There are four different types of offshore foundations out on the market currently. They include piled, gravity base, skirt and bucket, and floating structures with moored foundations. The piled and gravity base foundations can be further classified by structure into three configuration categories: monopiles, tripod and lattice.[10]

According to different technical studies and shown to be true with many operational offshore wind farms, piled foundations are most commonly used, with the monopile configuration being the most widely used design for this foundation type. Pile foundations are the easiest foundations to build incorporating large steel tubing and are also the most cost effective to manufacture compared to other types. Standard monopile foundations with no support should only be used for water depths up to 25 meters, which would be compatible with the site area currently being considered for Hull. Monopile foundations that have some form of support structure are more suitable for water depths from 20-40 meters in non-homogenous soil preferably.

Gravity base foundations can incorporate multiple support structures like a tripod and are more suitable for homogenous soils in water depths up to 25 meters. These foundations tend to be expensive because of its heavy weight and increased exposure to waves and currents due to the foundation being above the seafloor elevation at certain times. However, it may be possible to construct a concrete gravity based structure locally and save on transport costs, thus making this foundation type a viable alternative to steel monopile foundations.

The skirt and bucket foundation, otherwise known as suction caissons, are similar to gravity base but use steel skirts and buckets as its primary from of stability. There have not been many real world applications of skirt and bucket foundations and therefore it would be necessary to undergo a thorough installation analysis before designing a site specific structure. The use of floating structure and tripod fixed bottom foundations for offshore wind are still in early stages of testing.

Water depth is an important consideration when developing an offshore wind farm because that will determine which type of foundation could be used. In order to be the most cost effective, the foundation technology most commonly used presently limits water depth to between 8 to 76 feet. The shallower the water, the more stable the foundation will be to withstand waves and in turn the construction cost will be lower. The efficiency of installing mono-tube piles (or

[10] Much of this discussion is based on "Geotechnical Considerations for Offshore Wind Turbines." Westgate and DeJong. 2005.

"monopile") makes this type of foundation the most cost effective because construction time is greatly reduced.[11] According to the National Renewable Energy Lab (NREL), for water depths less than 30 meters, monopile foundations can be installed for an offshore wind farm without a large amount of research and development because it has become the most well established type of foundation in the market.[12]

The town of Hull commissioned a preliminary foundation design study by Garrad Hassan to assess the feasibility of different foundation types and to provide an initial cost estimate for the most feasibility design. Based on Hassan's analysis of soil and other geophysical conditions and wave height factors, steel monopile foundations were found to be most appropriate for the Hull project.[13]

With few exceptions, most of the cost data we have seen (and that were used to develop the cost assumptions in this analysis) are based on monopile construction. Unfortunately, estimation of foundation/sub-structure costs is extremely dependent on the specific site conditions and the future unknown availability of construction vessels. The Hull project would likely require piggybacking on other offshore wind (such as Cape Wind or the RIWind projects) or other type of installations that could utilize the same vessels. Hence, there tends to be a large range for these costs among different projects, based on a number of existing and proposed installations and the relationship between total project costs and the cost of the turbines shown above.

For this study, we utilized the cost estimates of $1.0 million/MW and $1.05 million/MW (if additional drilling would be necessary). Even with the benefit of a preliminary foundation design study and an examination of actual conditions at the site (rather than simply a review of past installations), Garrad Hassan cautions that there is a "high level of uncertainty" in these cost estimates due to a number of factors, including vessel availability and costs, uncertainty in material and steel costs, possible variability in ground conditions and use of a preliminary design methodology, and currency risk due to the probable use of foreign-supplied products.

C. Interturbine Power Grid and Submarine Cable to Shore

Though the costs to interconnect the turbines to the Hull electric distribution system will be small compared to the other capital cost components, there are a number of different options for interconnection. As a result, we provide a wide range of cost estimates based on interconnections of wind farms that are similar in scale (though a little larger) than Hull. The estimates did not include any costs related to onshore distribution system costs in the financial analysis.

[11] "Final Report RIWINDS Phase 1: Wind Energy Siting Study." Applied Technology and Management. 2007.
[12] "Future for Offshore Wind Energy in the United States." NREL. 2004.
[13] Garrad Hassan also investigate concrete monopile, jacket, and concrete gravity base foundations.

D. Cost Summary

Summing up the various costs above yields a range of $3150-$3650 per kW. Recent testimony sponsored by Deepwater Wind, LLC ("Deepwater") indicates that offshore wind facilities currently under construction are requiring greater expenditures than this level. Appendix B contains data from testimony sponsored by Deepwater, who is seeking regulatory approval to sign a purchase power agreement ("PPA") with National Grid in order to construct 8 turbines off the shore of Block Island in Rhode Island. The offshore wind statistics shown in Appendix B were taken from a pre-release draft for a study paid for by the New York State Energy Research and Development Authority ("NYSERDA") that was used by Deepwater's witness to show the increasing costs of offshore wind in order to justify the relatively high price—24.4 cents/kWh[14]—of the PPA they are seeking. Though we believe this price to be rather high and will be filing testimony to that effect, the table shows that the cost per kW to be $3440 for pre-2008 projects currently in operation and $4450 for projects under construction or with financing secured. It is important to note that many of the projects shown in the table have different characteristics than the proposed project at Hull, such as a greater number of turbines, greater water depth and greater distance from shore, thus the data are not completely comparable. The important point remains that there is great uncertainty and variability in cost estimates, and costs may be higher than those assumed for the financial analysis.

III. COST OF FINANCING

Financing costs represent an important cost component and specific financing arrangements influence both the cost of financing and cash flow necessary to service any debt. For this financial analysis, we did not attempt to analyze a particular or the best financing mechanism for the Town of Hull. Rather, we examined two major cases: (a) town-owned and financed and (b) privately owned and financed. In the latter case, the town would sign a long-term PPA with a developer/investor and thus would have access to the renewable energy, but all revenue streams would flow to the investor/developer. There are a number of hybrid approaches when involving a private investor that may be available, but these were not examined due to the uncertainty concerning the legal and tax ramifications of a private/public financing partnership between Hull and a private investor.

A. Town-only Financing

The most straightforward and controllable approach to financing the project is for Hull to issue its own bonds. Municipal bonds are tax-free and thus usually carry more favorable terms than those available to a corporate or private investor. Municipalities, as with other government agencies, are also eligible to use Clean Renewable Energy Bonds ("CREBs").

[14] This figure supports a relatively high capital cost of $6960 per kW as well an implicit high internal rate of return (as estimated by La Capra Associates).

i. Municipal Bond Financing

Assuming a total project cost of between $45 million and $53 million yields a size for the potential bond offering in the range of $33 million to $50 million, depending on the particular assumptions about project costs and sources of other financing. A bond offering of this magnitude would be challenging for a community the size of Hull if it elected to seek financing on its own. As an alternative, Hull could partner with other municipal light districts and sell off pieces of the project in the form of PPAs.

ii. CREBs

CREBs have been in existence since 2005 in order to help finance renewable energy projects in governmental entities and co-operatives and would be issued by Hull (or the Municipal Light Plant). Hull would first apply to the Internal Revenue Service for a CREBS allocation.[15] The American Recovery and Reinvestment Act of 2009 ("ARRA") added an additional $1.6 billion to the existing $800 million allocation that was established in the Energy and Improvement Extension Act of 2008. Hull would then issue bonds to a bondholder at 0%[16], with the bondholder receiving tax credits as interest payments. CREBs have typically been issued for small amounts. For example, the first round of CREBs had a maximum allocation of $3.2 million to a governmental borrower. Due to the limited award size, we assumed that a maximum of 15%, or about $9 million, of the capital costs would be financed through zero-interest bonds. It is conceivable that Hull would be able to receive approximately $12 million (or $3 million per turbine), which would represent approximately 20% of capital costs, and would serve to reduce costs further than we assumed. On the other hand, it is equally conceivable (and possibly more likely) that Hull would receive allocations at much lower amounts, such as $3 million, for the entire offshore wind facility.

B. Private Financing

The private financing option assumes that a private developer with a tax appetite (or a developer teamed with a tax investor) owns and operates the project. Hull would be able to meets its renewable energy goals[17] but would not control the project. This option would further permit use of the recent cash grant option included in the 2009 ARRA. In lieu of the production or investment tax credit ("ITC"), developers may receive a 30% cash grant to offset capital costs. This option allows even those private developers without income (and thus a tax liability) to receive an incentive payment. Wind projects that commence construction before 2011 and are placed in service before 2013 are eligible for this grant. For high-cost renewable projects, such as offshore wind, the ITC or the cash grant option proves more favorable than an incentive based on a certain amount per kWh.

---

[15] Total allocations are capped at certain levels by legislation—the ARRA of 2009 added an additional $1.6 billion to the existing $800 million allocation—thus Hull would be competing with other entities, including co-ops. The initial round of CREBs featured almost $3 billion in applications for the $800 million allocation.
[16] This case assumes that Hull would not need to offer a discount on these bonds to find a willing buyer.
[17] Under both municipal and private financing options, we assume the sale of the renewable energy certificates ("RECs"), which, technically, implies the sale of renewable energy claims. However, Hull can still take credit for the expansion of renewable energy capacity.

Private investors will have higher required project returns (if equity is involved) and will generally feature higher debt costs. Hence, the benefit of the cash grant will be somewhat mitigated by these two factors.

IV. OPERATIONS AND MAINTENANCE COSTS

We distinguish between three types of operating costs: maintenance and operations, insurance, and other costs, which include administrative and general and other operating costs, such as income taxes for the private ownership model. The first two categories have proven to be a distinguishing feature for offshore wind facilities compared to onshore wind facilities and important factors in calculating the overall financial feasibility for offshore projects. Estimates for these costs are found in Appendix A and are shown in $/MWh but were modeled as fixed costs. In reality, most of these costs are fixed in nature and will not change based on the output of the wind facility.

A. Maintenance and Operations

Operations and maintenance ("O&M") costs largely consist of maintenance costs. Despite forecasts to the contrary, existing offshore wind farms in Europe have struggled with maintenance costs due to the specialized equipment and crew involved in maintaining offshore wind turbines and the negative effects of harsh operating conditions on the turbines. For example, O&M costs in La Capra Associates' electricity market modeling tool, AURORAxmp (discussed below) are based on EIA's Annual Energy Outlook 2009 and total about $33 per MWh.[18] The estimates used for this report feature a wide range and consider both the small scale of the Hull project relative to the wind farms from which cost estimates were taken as well as the potential for lower costs due to location in relatively shallow water and close to shore.

B. Insurance

Costs to insure offshore wind facilities are higher than onshore wind for many of the same reasons that O&M costs are higher. The recent credit crisis impacts on the insurance industry have also exacerbated insurance costs and the overall availability of offshore wind insurance. The impact is so severe that costs have posed to be a barrier for several proposed European installations and insurance costs are now the highest single operating cost for offshore wind facilities[19].

[18] The variable O&M assumed for offshore wind resources is to be $0.00/MWh as EIA assumes that O&M must be performed on a fixed schedule regardless of wind performance and the fixed O&M is assumed to be $1,850/MW/week, which translates to roughly $11/MWh at 100% CF or $32.64/MWh at 34% CF. For purposes of the financial analysis, distinguishing between fixed and variable O&M is not relevant, but the greater level of fixed costs, the higher cost per MWh for a relatively small project such as Hull Offshore.
[19] See "Insurance Costs Hinder Development of Renewables," *Strategic Risk*, April 14, 2009.

Unlike other cost categories, publicly available estimates for insurance coverage are not readily available, thus the figures provided in Appendix A are based on fewer estimates than the other costs. We used confidential estimates of onshore wind facilities to develop the $5-$10/MWh range, which may be low given current concerns found with insurance of European offshore installations. However, without knowing the actual site conditions, we assumed the close proximity to shore would tend to temper insurance costs to some degree.

C. Administrative and General

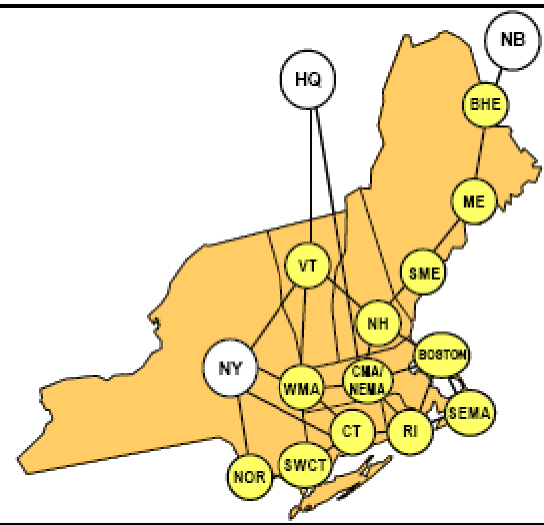
The final cost category is relatively minor in size and includes funds for staff to manage the project and other costs, such as tax (local and federal) payments. Hull may be able to avoid these costs if existing staff (at the municipal light plan, for example) were utilized.

V. REVENUES

We consider four revenue streams to fund the costs or revenue requirements developed above: (1) Energy market, which assumes that the Hull plant would participate in the day-ahead market up to their capacity value as well as self-schedule their output above this level in the real-time market. The energy market is the largest source of revenues for this wind farm. We did not utilize an avoided cost metric, since we assume that the municipal light district would continue to purchase and deliver energy in the same manner as in the past; (2) renewable energy certificates ("RECs")—we make certain assumptions concerning future RPS levels and requirements in New England as discussed below. Our forecast for REC prices are conservative, especially given the increasing focus on promotion of renewable energy; (3) Capacity market—this stream does not represent a large amount of revenue, given the capacity value that is normally assumed for wind plants, but it still represents a reliable revenue stream that should be included; and (4) State and federal incentives—we surveyed federal and state programs and laws to see which incentives (other than those discussed in the financing section above) that could be considered as additional revenue streams. We discuss each of these in turn.

A. Energy

We utilized the proprietary AURORAxmp production-cost dispatch modeling platform to perform the 20-year simulation for this study. The proposed offshore wind project would be sited in the Boston reliability zone and be eligible for energy revenues from this zone or an internal similarly priced system node. The graphic below, which was reproduced from the annual Regional System Plan produced by ISO-New England, depicts the New England zones modeled by La Capra for this study including the adjacent pools in Canada and New York.



Subarea Designation	Region or State	Subarea or Balancing Authority Area Designation	Region or State
BHE	Northeastern Maine	WMA	Western Massachusetts
ME	Western and central Maine/ Saco Valley, New Hampshire	SEMA	Southeastern Massachusetts/ Newport, Rhode Island
SME	Southeastern Maine	RI	Rhode Island/bordering MA
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine	CT	Northern and eastern Connecticut
VT	Vermont/southwestern New Hampshire	SWCT	Southwestern Connecticut
BOSTON (all capitalized)	Greater Boston, including the North Shore	NOR	Norwalk/Stamford, Connecticut
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts	NB, HQ, and NY	New Brunswick (Maritimes), Hydro-Québec, and New York external balancing authority areas

The AURORAxmp model is specifically designed to model wholesale electricity prices in a competitive energy market such as ISO-New England. In a competitive market, at any given time, prices should be based on the marginal cost of production. Prices will rise to the point of the variable cost of the last generating unit needed to meet demand. One of the principal functions of AURORAxmp is to estimate this hourly market-clearing price at various locations in North America, including New England zones.

We have assumed that the Hull project will have a commercial online date of July 1, 2011 and an installed capacity of 14.4 MW. The impact of a wind farm like the proposed project on a power pool and its electricity prices creates downward pressure on prices in all operations, since it acts a price-taker in the market as due to having no or negligible variable costs that provide the basis for marginal production costs (and power bids). Wind plants in general displace existing higher variable cost generating units, such as natural gas-fueled generators, thus effectively lowering the zonal energy prices.

AURORAxmp uses a fundamentals approach in estimating prices, reflecting the economics and physical characteristics of regional and zonal demand and supply side resources. AURORAxmp estimates prices by using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch formulaic approach. The operation of resources within the electric market is modeled to determine which resources are on the margin for each New England and neighboring zones in any given hour.

Existing supply-side generating units are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints such ramp up and minimum run times. Demand-side resources and price-induced curtailment functions are also defined, allowing the model to balance use of generating supply stations against alternatives to reducing customer demand.

AURORAxmp also has the capability to simulate the addition of new-generation resources, including gas-fired and wind plants, and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology, including gas-fired CCs and CTs, and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable or when private investors can recover all-in costs with an acceptable return on investment.

Existing units that cannot generate enough revenue to cover their operating costs over time are identified as candidates for economic retirement. The rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years so that a unit cannot be retired based on a single or a couple of poor financial years, but for longer term sustained underperformance.

AURORAxmp uses the above information to build an economic dispatch for the markets of interest. Units are dispatched according to variable cost, subject to a variety of operating constraints until hourly demand is met in each area. Transmission constraints, losses, costs and unit start-up costs are all reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each New England area. All operating units in a given area of interest, regardless of their own variable costs, receive the hourly market-clearing price for the power they generate. For the current work, we differentiated between peak and off-peak energy prices and applied these prices to the hourly energy production that was calculated using the power curve and wind data discussed above. wind data, would have incorporated the facility's hourly production.

The resulting average market clearing prices received by the project from 2011-2030 are in the table below. Key drivers used in calculating the wholesale power prices include Henry Hub natural gas price and carbon emission prices. There are many other variables involved in the setting of the marginal price, and thus the energy revenues that will be received by Hull, but these two account for most of the future variability in energy prices.

Table 1 – Reference Energy Prices Received ($/MWh)

2011	63.53
2012	63.65
2013	72.26
2014	74.55
2015	78.23
2016	86.50
2017	90.08
2018	96.22
2019	102.03
2020	104.70
2021	108.37
2022	111.68
2023	115.66
2024	124.08
2025	131.62
2026	140.45
2027	146.91
2028	156.91
2029	164.14
2030	171.60

It is important to note that these prices assume that Hull will sell all of its production in the New England spot energy markets. Thus, we did not examine any options to use this power in the management of the municipal light plant's existing power portfolio.

B. Renewable Energy Credits (RECs)

To estimate future New England REC prices, we used La Capra Associates' proprietary, spreadsheet-based renewable energy market model. The model approach is based on the notion that market REC prices would be set by the cost of the marginal resource. To determine the marginal renewable energy resource in each year, we developed a renewable energy supply curve and used estimated New England renewable energy demand to "clear" the supply curve each year.

The supply curve is comprised of our estimates of future available renewable resources in New England and their associated costs. To develop the supply curve, resources are sorted by their required REC premium from lowest to highest. The required REC premium is the levelized cost for each resource type less the expected levelized energy, capacity and Production Tax Credit (PTC) revenues. The required REC premium of the marginal resource sets the market REC price in each year.

The model assumes a balance of supply and demand and is better suited to producing and estimate of where prices are headed in the longer term than in the next year or two. For this reason we assumed that REC prices would start at their current level of $34 per MWh in 2011 and remain at that level for 2012. After 2013 we assumed that the REC prices would approach the levels predicted by the model for the remaining study years.

As with the energy prices above, we make no assumptions concerning the enactment of national carbon legislation. Higher carbon prices will lead to higher energy prices, which will provide higher energy revenue streams to Hull. On the other hand, higher carbon prices would lead to lower REC prices because projects will be receiving higher energy revenues and therefore would require lower REC premiums, thereby bidding down final REC clearing prices.

The REC price forecasts are shown below in Table 2.

Table 2 – Renewable Energy Certificate Prices Assuming Reference Energy Prices ($/MWh)

2011	34.20
2012	34.20
2013	30.74
2014	27.29
2015	23.83
2016	20.37
2017	16.91
2018	13.46
2019	13.21
2020	13.55
2021	13.89
2022	14.24
2023	14.59
2024	14.96
2025	15.33
2026	15.71
2027	16.11
2028	16.51
2029	16.92
2030	17.35

C. Capacity

Capacity resources usually represent a small portion of the total revenue stream available to wind facilities. Offshore wind energy production, as opposed to onshore wind, generally is somewhat correlated with summer peak periods when energy demand is usually highest. Based on the wind data and the ISO market rules, we assumed a 31% capacity factor for the peak hours on which capacity performance is calculated. This factor, along with the advent of the forward capacity market ("FCM") in New England may allow Hull to capture higher capacity revenues than its onshore facilities.

ISO-NE, the system operator for the New England region, currently operates a capacity market that purchases capacity approximately 3 years in advance of the start of when the capacity needs to be in place, known as the capacity commitment period. As of now, ISO-NE has completed two forward capacity auctions ("FCA"), covering the periods June 2010-May 2011 and June 2011-May 2012. In October of 2009, there will be the third FCA which will procure resources for the June 2012 to May 2013 period. In order to be able to participate in the annual auctions, project sponsors must submit qualification packages with critical path schedules, interconnection plans, and capacity values, among other data, and the deadline for new qualification packages for FCA3 has passed. Given the initial stages of the Hull project, the earliest that Hull could receive capacity market revenues would be June 2013.

The other important component of calculating the capacity revenue stream is a forecast of forward capacity market prices. We used our in-house capacity market model for New England to provide a price forecast for Hull in the 2014-2030 capacity commitment periods (see Table 3 below). Capacity forecasts face different uncertainties than the energy forecasts given above. Rather than fuel and CO2 price forecasts, which are indirectly related to capacity prices, capacity prices are much more affected by the entry and exit (or retirement) of resources and the recent explosion in entry of low or zero-bid capacity resources, such as energy efficiency and renewable generators, who both generally have revenue streams supplemental to market sources, such as through public benefit charges and/or renewable portfolio standards. Near term (through 2018) capacity prices will continue to be low due to the entry of these resources and depending on the continued emphasis on energy efficiency in particular, may continue to be low over a longer time horizon. For capacity resources, we assumed a business as usual energy efficiency case along with existing renewable build outs. We also assume continued availability of capacity from these two resources in the 2020-2030 time period.

Table 3 – Forward Capacity Model Results
($/kw-month)

2014	$ 3.00
2015	$ 3.00
2016	$ 3.00
2017	$ 4.63
2018	$ 4.77
2019	$ 6.13
2020	$ 6.48
2021	$ 6.73
2022	$ 7.00
2023	$ 7.29
2024	$ 7.60
2025	$ 7.93
2026	$ 8.26
2027	$ 8.59
2028	$ 8.90
2029	$ 9.20
2030	$ 9.50
2031	$ 9.82

D. Production Credits and other Incentives

The primary incentives (at both the federal and state levels) have already been discussed above in the financing section. The ARRA of 2009 not only extended the availability of tax-related incentives but also provided a 30% cash grant option for investors who would otherwise also qualify for either the ITC or PTC. For municipalities, such as Hull, that have no tax appetite, these incentives are not available directly to help finance turbines. Rather, municipals currently have two federal incentives—CREBs financing discussed above and access to renewable energy production incentive ("REPI") funds, which Hull currently receives for their Hull I and Hull II onshore facilities. When the REPI program was initiated in 1992 it established a production incentive of 1.5 cents/kWh in 1993 dollars that was to be indexed to inflation. Unfortunately, even though the program continues to be funded, it has been oversubscribed for some time. As a result, Hull only received about 0.4 cents/kWh in 2007. Given the uncertainty of this program funding going forward, we assume that REPI payments will remain at this level (in nominal dollars) over the 2011-2030 study period. Aside from these programs, there is the additional possibility of receiving grant monies from the Department of Energy and other federal sources for use of the Hull facility for data collection and/or research and development of offshore wind facilities in the U.S.

We also surveyed the availability of state incentives and contacted state officials. Outside of participation in Massachusetts Renewable Energy Trust ("MRET") programs, there is no current form of state incentive that would be available for Hull's offshore wind project. Thus, we did not include any state-level incentives in our revenue projections.

VI. FINANCIAL MODEL RESULTS

Based on the cost assumptions detail in Appendix A and assuming a 5.5% discount rate, a summary of the results of the financial analysis are in the table below. The ranges provided in the table represent our best estimate of the costs at the current time and our forecasts of the revenues that Hull would receive starting in 2011. As can be seen in the extent of the ranges, we feel more comfortable with the estimates of revenues than costs. In addition, the given range for costs is not symmetric. Though we feel that there is the possibility for costs to be on the low end of the range, there is greater probability of costs ending up on the higher range of the cost estimates. In other words, while the average can be calculated as around $3400 the median could be higher depending on the success of Hull in acquiring turbines and contracting with installation companies.

Table 4 -- Financial Model Results Assuming Reference Energy Prices (Levelized 2011 $/MWh)

	Municipal Financing		Private Financing	
	Low Cost	**High Cost**	**Low Cost**	**High Cost**
Revenue Requirements (Levelized Cost of Energy)	$137.11	$177.12	$115.31	$135.63
Total Revenues	$129.86	$129.86	$125.86	$125.86
Difference	$7.25	$47.26	($10.55)	$9.78
20 Year NPV ($000)	(3,314)	(21,588)	4,818	(4,465)

The top row Table 4 contains the revenue requirements in levelized 2011 dollars and represents the amount that would be necessary from all revenue streams (including grants) to make the project breakeven from a financial analysis perspective. Subtracting the revenue streams from the revenue requirements (also in levelized 2011 dollars) thus yields a negative number in the difference row when there is a positive net present value ("NPV") or a positive number that represents the additional amount of revenues that would be necessary to make the project viable. As shown in the table, the project is only viable under the low cost, private financing scenario. Though not shown here, high carbon prices from future national carbon legislation may add additional potential revenue for the project and thus permit some increases in costs or decreases in energy production.

Given the importance of capacity factor in determining the financial feasibility of the project, we provide some sensitivity analysis results in Table 5 below. The table shows, for the low case of $3160/kW and assuming municipal financing, the effect of different capacity factors on the 20 year NPV figure. Assuming low-cost and reference energy price conditions, the Hull project appears viable (from a municipal financing perspective) if actual energy production is able to achieve capacity factors at about 33%. Of course, the caveats discussed above concerning the ultimate cost of the project still apply.

Table 5 -- Financial Model Results Assuming Reference Energy Prices and Low Costs

Capacity Factor	20 Year NPV ($000)
35%	$3,612
33%	$20
31.1%	($3,314)

VII. CONCLUSIONS

The financial analysis and summary results presented in this document represent a first cut at an economic assessment of the proposed Hull Offshore Wind Project. Since the time the project was first envisioned in 2003, interest in offshore wind has exploded as concerns with climate change have also increased. European countries have plans to greatly expand their installed capacity of offshore wind many fold, while offshore wind is increasingly seen as the only realistic option to provide large-scale renewable power to the load centers found in the Northeast U.S.

Unfortunately, along with this increased interest have come increased cost pressures. Wind turbine price increases have outpaced the materials and labor price pressures faced by non-renewable power plant developers due to increased demands on a limited pool of turbine manufacturers and offshore installation companies. Moreover, given the size of the proposed offshore facility, it may be difficult to contract with turbine manufacturers and/or foundation companies given the size and scope of competing worldwide demand. The results described in this report assume that such conditions will not significantly impact the prices that will have to be received from the output of the project; rather, the project size may require as a prerequisite that Hull be able to piggyback on other offshore efforts.

The financial estimates provided here necessarily feature a range due to uncertainty in a number of project assumptions as well as overall uncertainty in offshore wind costs. Nevertheless, taken together, the analysis provides a ballpark revenue requirement of approximately $157/MWh for the municipal financing option, with higher estimates possible assuming escalation in costs to levels higher than assumed here.

Appendix A

La Capra Associates

WIND POWER CURVE AND DETAILED COST INPUTS ($2011 DOLLARS)

Exhibit A.1 Wind Power Curve

Wind Speeds (meters/second)	Energy Production
0	0
1	0
2	0
3	0
4	38.7
5	170.3
6	387.1
7	735.48
8	1161.29
9	1703.23
10	2245.16
11	2787.1
12	3174.19
13	3522.58
14	3600
15	3600
16	3600
17	3600
18	3600
19	3600
20	3600
21	3600
22	3600
23	3600
24	3600
25	3600
26	0
27	0
28	0

Exhibit A.2 Detailed Cost Assumptions

	Municipal Ownership	Private Ownership
Base		
Project Analysis	**20 years**	
Inflation Rate	**2.5%**	
Construction/Production		
# of Turbines	**4**	
Turbine Size	**3.6 MW**	
Capacity Factor	**31.1%**	
Degradation Factor	**0%**	
Availability Factor (excluding grid availability)	**100%**	
Construction Start Date	**Q4 2010**	
Operations Start Date	**Q2 2011**	
% Nameplate for Capacity	**25%**	
Capital Cost		
Turbine	**$2060/kW - $2350/kW**	
Foundation/Sub-Structure	**$$1000-$1050/kW**	
Transmission	**$100/kW - $250/kW**	
Total	**$3160kW- $3650/kW**	
Decommissioning?	**Yes**	
Financing		
Cost of Debt	**6.5%**	**9%**
Cost of Equity	**n/a**	**14%**
Private Financed %	**0%**	**100%**
30 % Cash Grant	**No**	**Yes**
Depreciation Schedule	**---**	**MACRS**
Depreciation Term	**---**	**6 years**
REPI	**Yes**	**No**
CREBS Financing %	**15%**	**0%**
O&M Costs		
Operations and Maintenance (Fixed and Variable)	**$10/MWh – $20/MWh**	
Insurance	**$5-$10/MWh**	
General and Administrative	**$1– $2/MWh**	

Appendix B

La Capra Associates

OFFSHORE WIND PROJECT STATISTICS

Project name	Country	Status	Operating Year	Project Cost ($M)	Project Capacity (MW)	Project Cost per MW	No. of Turbines	Turbine Size (MW)	Turbine Model	Water Depth (m)	Distance from Shore (km)
Middelgrunden	Denmark	Operating	2001	$51	40	$1.28	20	2	Bonus_2_MW	5 to 10	2 to 3
Horns_Rev	Denmark	Operating	2002	$295	160	$1.84	80	2	Vestas_V80	6 to 14	14 to 17
North_Hoyle	United Kingdom	Operating	2003	$138	60	$2.30	30	2	Vestas_V80	5 to 12	7.5
Nysted	Denmark	Operating	2004	$316	165.6	$1.91	72	2.3	Siemens_2.3	6 to 10	6 to 10
Scroby_Sands	United Kingdom	Operating	2004	$136	60	$2.27	30	2	Vestas_V80	2 to 10	3
Kentish_Flats	United Kingdom	Operating	2005	$179	90	$1.98	30	3	Vestas_V90	5	8.5
Barrow	United Kingdom	Operating	2006	$172	90	$1.91	30	3	Vestas_V90	15	7
Burbo_Bank	United Kingdom	Operating	2007	$170	90	$1.89	25	3.6	Siemens_3.6	10	5.2
Egmond_aan_Zee	Netherlands	Operating	2007	$300	108	$2.77	36	3	Vestas_V90	17 to 23	8 to 12
Inner_Dowsing	United Kingdom	Operating	2008	$289	97.2	$2.97	27	3.6	Siemens_3.6	10	5.2
Lillgrund	Sweden	Operating	2008	$254	110.4	$2.30	48	2.3	Siemens_2.3	2.5 to 9	10
Princess_Amalia	Netherlands	Operating	2008	$582	120	$4.85	60	2	Vestas_V80	19 to 24	>23
Alpha_Ventus	Germany	Under construction	2009	$350	60	$5.83	12	5	Multibrid& REpower	30	45
Gunfleet_Sands_I	United Kingdom	Under construction	2009	$406	108	$3.76	30	3.6	Siemens_3.6	2 to 15	7
Horns_Rev_Expansion	Denmark	Under construction	2009	$854	209.3	$4.08	91	2.3	Siemens_2.3	9 to 17	30
Rhyl_Flats	United Kingdom	Under construction	2009	$358	90	$3.98	25	3.6	Siemens_3.6	8	8
Robin_Rigg	United Kingdom	Under construction	2009	$651	180	$3.62	60	3	Vestas_V90	>5	9.5
Gunfleet_Sands_II	United Kingdom	Financing secured	2010	$275	64.8	$4.24	18	3.6	Siemens_3.6	2 to 15	7
Nordergrunde	Germany	Financing secured	2010	$440	90	$4.89	18	5	Repower_5M	4 to 20	30

Project name	Country	Status	Operating Year	Project Cost ($M)	Project Capacity (MW)	Project Cost per MW	No. of Turbines	Turbine Size (MW)	Turbine Model	Water Depth (m)	Distance from Shore (km)
Sea_Bridge	China	Under construction	2010	$345	102	$3.38	34	3	Sinovel_3_MW	8 to 10	8 to 14
Walney	United_Kingdom	Financing secured	2010	$746	151.2	$4.93	42	3.6	Siemens_3.6	20	7
Belwind	Belgium	Financing secured	2011	$897	165	$5.44	55	3	Vestas_V90	20 to 35	46
Thanet	United Kingdom	Financing secured	2011	$1,200	300	$4.00	100	3	Vestas_V90	20 to 25	7 to 8.5
London Array	United Kingdom	Financing secured	2012	$3,095	630	$4.91	175	3.6	Siemens_3.6	23	>20
Sheringham Shoal	United Kingdom	Financing secured	2012	$1,500	316.8	$4.73	88	3.6	Siemens_3.6	16 to 22	17 to 23
					Average all	**$3.44**					
					Average Non-Operating	**$4.45**					

Source: Exhibit B of Prefiled Testimony of David P. Nickerson for Deepwater Block Island, LLC, December 9, 2009.