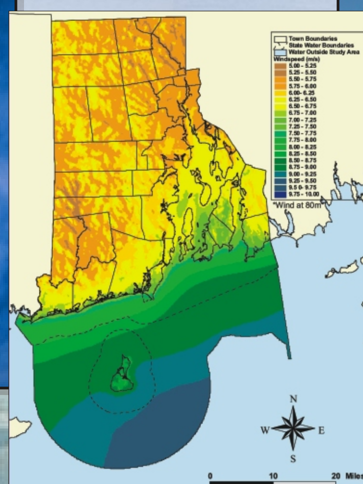
Final Report
RIWINDS Phase I: Wind Energy Siting Study



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ATM
APPLIED TECHNOLOGY & MANAGEMENT

APPLIED TECHNOLOGY AND MANAGEMENT, INC.

FINAL REPORT

RIWINDS
PHASE I: WIND ENERGY SITING STUDY

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EXECUTIVE SUMMARY

In January, 2006, the State of Rhode Island established the RIWINDS program to promote the development of wind energy in the State. The goal of the program is aggressive: to meet 15 percent of the State's 1000 MW annualized average electric demand, or 150 MW. This results in the demand of 1.3×10^6 MW-h per year. This requires approximately 450 MW of wind energy capacity due to the intermittent nature of wind energy generation.

The Phase I Siting Study was awarded to Applied Technology and Management (ATM) in June, 2006 by the Rhode Island Economic Development Corporation (RIEDC). The ATM team worked closely with the RIEDC and the Chief Advisor to the Governor on Energy to accomplish the RIWINDS goals. In addition to ATM, who provided environmental resource and technical feasibility assessment, the team included TRC Companies, Inc. for environmental review and electrical engineering, the Maguire Group, Inc. for civil/structural engineering, and Birch Tree Capital, LLC for financial analysis. Subcontractors for the team included Sustainable Energy Advantage, LLC and Deacon Harbor Financial, L.P. for financial analysis and market price projections and Loria Emerging Energy Consulting, LLC for project management service.

The scope of the study was to evaluate the entire State of Rhode Island, including offshore waters, to identify the most viable areas for wind energy development and assess the potential energy generation associated with these areas. The process screened and prioritized potential areas, both on land and offshore, taking into consideration technical, environmental, financial, and public acceptance issues. The study evaluated projects using utility scale wind turbines (1.5 MW and larger) for small customer-connected and community installations as well as for large, wholesale installations where all of the power is fed into the New England electric transmission system.

It should be noted that the study focused on the areas and types of projects that would most likely meet the significant goals of the RIWINDS program. There are possibly many unique situations for small wind projects which may be economical but were removed through the screening process as they would not make a significant contribution to the RIWINDS energy goal. The study did not consider potential projects that would use a turbine smaller than 1.5 MW for the same reason.

A detailed financial analysis was performed on the potential projects. The analysis included a projection of the wholesale and retail market prices for electricity in Rhode Island over the next 20 years. The analysis also evaluated alternate project financing arrangements.

The RIWINDS Phase I process was conducted by implementing a number of sequential and parallel activities as briefly described below.

1. A range of five different indicative classes of project were identified that could be used to reach the RIWINDS goal of 1.3 million MWh/yr. These indicative project classes are based on using utility scale turbines and covered the range from small, onshore, customer-connected projects to large, offshore, grid-connected projects
2. Selection criteria were developed for each type of indicative project to identify the areas of the state that would be appropriate for these projects. These criteria included minimum economic wind speed, area requirements, land use, electric load and environmental criteria.
3. A thorough and comprehensive screening analysis was performed using the selection criteria to determine the "technically viable" areas of the state where these projects could be implemented. To facilitate the analysis and the decision making process, the evaluation data and results were integrated into a comprehensive Geographic Information System (GIS) database.
4. Wind turbine generator (WTG) performance estimates were prepared to determine the average annual wind energy (in kWh) that would be generated from each type of indicative project in each of the viable areas. The analysis was based on regional, model predicted annual average wind speed from AWS Truewind prepared for the National Renewable Energy Lab and on historical data from the NOAA wind monitoring station located in Buzzards Bay, Massachusetts. This offshore data is believed to be the most representative wind data for offshore projects located south of Rhode Island.
5. An evaluation of the spatial distribution of annual average wind speeds at the standard WTG hub heights was performed to determine the preferred hub height. Evaluation of the 65m, 80m and 100m elevation wind speeds and land use mapping indicated that the 80m and 100m elevations both showed a significant improvement over the 65m results. The incremental improvement of the 100m over the 80m resources did not warrant the expected increased costs and construction challenges of the larger tower. In addition, a hub height of 80 meters is currently common practice for utility scale WTGs. The study therefore used 80m elevation wind speed predictions.

6. Feasibility level project capital and O&M cost estimates were prepared for each of the indicative projects in the viable areas. The project cost estimates were developed using design basis assumptions for each of the indicative projects and included allowances for project development costs.
7. A detailed financial analysis was performed to determine if wind generated electricity can compete with conventionally generated electricity in Rhode Island. The analysis included a projection of the wholesale and retail market prices for electricity in Rhode Island over the next 20 years.
8. The analysis also evaluated three alternate project financing arrangements to determine the effect of financing arrangements on the cost of energy.
    - Equity plus commercial debt financing. This scenario assumes that the project is financed with a combination of equity and commercial debt and is often referred to as limited or no-recourse project financing.
    - All-equity financing. This scenario assumes that the owner provides equity capital to cover the full project costs and is often referred to as balance sheet financing.
    - Bond financing. The third scenario envisions the full amount of the project costs being financed through long-term bonds issued by public sector entities.

The study analysis relied upon published documents, information from the ATM team in-house database, confidential information received from potential industrial project customers, and upon information derived from conversations with National Grid and offshore wind project developers. The results of the study are very encouraging and the program offers many positive opportunities for the State. While the results of the study are encouraging, it is important to note that there are many challenges to meeting the RIWINDS goal. The results, opportunities and challenges are summarized below.

The key results of the siting study are summarized below. In addition, the ATM team offers the following comments on the RIWINDS program based on what we learned during the performance of this study and on our collective knowledge and understanding of the industry.

Key Results of the Study

1. The RIWINDS program goal is achievable.
2. The cost of wind energy to meet this goal appears to be competitive with the projected cost of electricity in Rhode Island.
3. There are significant wind resources in the state of Rhode Island both onshore and offshore.
4. Eight towns or cities have expressed interest in developing small wind projects in their communities. They have formed the “Rhode Island Wind Alliance” to further wind power development in the state.
5. Only four sites were identified as potential industrial/institutional customer connected project sites using utility scale wind turbines.
6. Only one viable area for a wholesale onshore project has been identified.
7. Over 95 percent of the wind energy opportunity in Rhode Island is offshore. A total of 10 potential different offshore areas were identified with a total of 98 square miles which can produce over 6 million MWh of wind energy per year.
8. Approximately 75 percent of the offshore wind opportunity is in State waters. The remainder is in Federal waters.

Challenges to Implementation

1. This siting study is the first step in the development of the RIWINDS project. The results of this study need to be refined by a development entity as part of the project implementation. Unlike onshore wind energy projects, there are currently no offshore wind projects in operation in the US. There are a number of small offshore projects in Europe, but many of these are demonstration projects which have been funded by their respective governments. These projects are viewed as successful and there are plans to significantly increase the number of offshore projects in Europe. There are a number of offshore projects under development or being studied in the US in the Northeast, Southeast, Gulf of Mexico, and in the Great Lakes, but none have received final approval.
2. There is insufficient electric transmission system capacity in Rhode Island to distribute the power generated from large offshore projects to electric customers. The transmission lines are not located near the shore and the transmission lines closest to the shore do not have the capacity to transmit the electric generation to the electric loads in Rhode Island.

3. Financing capital-intensive projects, such as wind energy projects, in the restructured New England electric market will be difficult without long term power contracts from a power authority or some other entity to finance projects. The certainty of long term power contracts by a power authority or some other entity would make investors and financial institutions more willing to invest in these projects by reducing revenue risk. This, in-turn, reduces the cost of financing these projects.
4. Public acceptance of the offshore wind projects is critical to the success of the RIWINDS program. However, public perception of these wind projects is difficult to predict. For example, a recent study of the public perception to offshore wind in Delaware is generally positive, yet there has been a good deal of public resistance to the Cape Wind project off of Cape Cod, Massachusetts, in spite of the fact that the majority of public sentiment is in favor of wind energy generation.

Opportunities for Citizens and Electric Rate Payers

1. The cost of electricity from wind energy is stable and predictable unlike the cost of electricity from conventional fossil fuels. The predominant component for the cost of electricity from wind energy is the capital cost which is fixed after the plant has been constructed. The predominant cost component for conventional fossil fuel plants is the cost of the fuel which historically has varied significantly and this variability and uncertainty is expected to continue in the future. The certainty of future electricity prices also offers intrinsic economic benefits to large energy customers such as industry and institutions.
2. Electricity generated from wind energy offers significant environmental benefits compared to electricity produced by non-renewable energy sources. There are no air emissions from wind projects. There may be environmental disturbances during the construction of the project, but these are temporary and can be avoided by proper site selection. Concerns over avian impacts may overestimate actual impacts for modern wind turbines, according to new studies performed at European offshore sites, and can also be mitigated by proper site section and avoiding nesting areas. Other studies have also indicated that additional sub-surface structures provide enhanced fisheries habitat.
3. Rhode Island is well situated to take advantage of the significant opportunities for coastal industries and businesses supporting the construction, operation, and maintenance of offshore wind projects developed off of Rhode Island, Massachusetts, and New York. If a large scale project proceeds in Rhode Island, there is a strong

potential to lure wind turbine related industries to Quonset and/or Fields Point. Rhode Island has the opportunity to create a renewable energy center of excellence using this program as a base.

4. The availability of Federal, State, and regional financial incentives for clean, renewable energy will decrease the relative cost of wind energy to rate payers. Federal production tax credits (PTC) are currently available for projects that go into operation by the end of 2008 and the PTCs are expected to be extended beyond 2008. Renewable energy credits are available as financial incentives to qualified facilities that meet the State's renewable energy standard. The Regional Greenhouse Gas Initiative is expected to increase the cost of fossil fired (carbon dioxide emitting) generated electricity. These financial incentives help to balance the cost of renewable versus non-renewable energy generated electricity and take into account the positive environmental attributes of renewable energy and the externalities associated with non-renewable energy sources.
5. Development of offshore wind projects in State waters versus Federal waters could provide additional revenue for the State. The owner of wind projects typically provides a lease payment to the "property" owner for beneficial use of the property. If the projects are located on state owned property, potential lease payments could generate revenue for the State.
6. The cost of electricity from wind energy is stable and predictable unlike the cost of electricity from conventional fossil fuels. The certainty of future electricity prices also offers intrinsic economic benefits especially to large energy customers such as industry and institutions.
7. One of the concepts behind the RIWINDS program is that Rhode Island would invest some of its natural resources in the production of clean, affordable energy. The ability to keep the energy generated by this program within the state at least implies that title to that energy be held by an entity willing to do so. Within the current New England electricity market structure, electricity generated anywhere in the system is distributed throughout the system. Since Rhode Island comprises a very small portion of the overall system load (approximately 6 percent), Rhode Island ratepayers would only receive a small portion of the energy generated from wind projects in the state and the benefits derived there from. A state power authority could ensure that energy generated from in-state wind projects would serve Rhode Island first.
8. Another concept behind the RIWINDS program is to provide stable electricity prices. The price for electricity within the current New England electricity market is established

through a clearing price auction mechanism. Most often, the clearing price is set by power plants that operate on natural gas so the clearing price is a function of the price of natural gas. As recent history has demonstrated, the price of natural gas has increased dramatically and can fluctuate significantly. Within the construct of the current electricity market, the price of wind generated electricity would most often be established by clearing price, would fluctuate significantly, and most likely increase over time. A state power authority could take advantage of the inherently stable prices of wind energy and pass these stable prices directly on to the ratepayers of Rhode Island.

Recommendations

To continue the progress of the RIWINDS program, we offer the following independent recommendations.

1. It has been shown that there is a strong correlation between summer high wind speeds far offshore of New England and peak electricity demand/prices. If this is true for near shore locations, it would increase the value of the energy produced by offshore wind energy projects. A more detailed wind energy assessment should be performed for the offshore areas identified in this study to quantify how this correlation would improve the economic benefit of wind energy projects off of Rhode Island.
2. To encourage the development of community wind projects, a series of workshops should be conducted with representatives of interested municipalities around Rhode Island to carefully review the results of this Phase I Siting Study and what it means for these municipalities.
3. As this study had demonstrated, a large percentage of the wind resources to economically meet goals of the RIWINDS program are offshore. The success of the program will depend on the perception of the citizens of Rhode Island to offshore wind. To properly gauge pubic perception of offshore wind, a public opinion study should be conducted.
4. Several European countries have successfully adopted wind energy generation policies and installed offshore wind farms, including Germany, Denmark, Great Britain and the Netherlands. As in the fledgling U.S. market the offshore wind farms faced initial public scrutiny, objection and rejection. The counties mentioned were able to overcome those obstacles and eventually develop a series of successful offshore wind power facilities. Preliminary discussions with developers, engineers and government officials from those

countries indicated that many of the public concerns are similar to those facing the offshore industry her in the U.S. There are many lessons that may be learned from the European experience and implemented here in Rhode Island in a proactive manner. An investigation into the European experience should be conducted with a focus on what factors, policies and/or regulations contributed to acceptance of offshore wind projects.

The European experience indicates that community involvement in the development of wind projects must be fostered. A positive connection between any wind project development and the public (particularly local) should be made such that the public are beneficiaries of the project and it therefore becomes “our” project rather than “their” project.

1.0 INTRODUCTION

1.1 PROJECT OBJECTIVES AND APPROACH

The siting study was performed by executing specific tasks which focus on the various aspects needed to fully evaluate the energy generation potential and siting of wind energy projects. In order to facilitate the analysis and the decision making process, the evaluation data and results were integrated into a comprehensive GIS (Geographic Information System) database. The GIS database geo-referenced all of the component analyses to allow for both a visual and analytical (matrix database) comparison of the results. The parameters that were integrated not only include the available pertinent RIGIS (Rhode Island GIS) data, wind and wind power data, and electrical system data, but the calculated values such as site specific project cost, financial analyses, environmental and permitting issues and final site rankings.

The GIS database allows for iterative geospatial cost/benefit analyses and rankings to be performed on any combination of the evaluation parameters, so that many aspects of the analysis can be incorporated and varied. This facilitated the decision making process and will provide an invaluable tool for presentation purposes.

A key step in the siting process was to identify indicative projects and the characteristics of these projects to define the project criteria to apply in the screening process. Five different indicative project classes were identified and are described in detail in Section 2. These are not specific projects, but rather a construct of data necessary for financial analysis.

Once these project types were chosen, a two level screening and elimination process was applied to the entire state and nearby state and federal coastal waters. The first level analysis excluded inappropriate land/water use areas and clearly uneconomical wind areas depending on the type of project. The second level analysis excluded “difficult” development areas such as areas with environmental impacts, difficult regulatory requirements, likely public opposition and/or significant engineering requirements which would lead to excessive costs. The screening process is described in detail in Section 3 of the report.

A wind energy performance analysis was prepared for the indicative projects in the final study areas that remained after the screening process as described in Section 4. Section 5 discusses the capital and operating cost estimates as they were developed for the indicative projects in these study areas. Finally, a detailed financial analysis was performed using the wind energy performance estimates and cost estimates prepared for the indicative projects in the final study areas. The financial analysis is described in Section 6. Conclusions drawn from this study are addressed in Section 7.

2.0 ANALYTICAL APPROACH

2.1 INDICATIVE PROJECTS

In order to simplify the process of siting, five categories of wind generation project sites were specified. These categories of projects will be referred to from here on as indicative projects. Key steps in the siting process included the identification of these indicative projects and their defining characteristics as well as the development of the project criteria applied in the screening process. These indicative projects as they are defined below are considered the minimum practical size in each category of project.

Several factors were taken into consideration in defining the indicative projects including the size of wind turbine generators, location of projects, and the impact of the project on the overall energy goal. In considering the size of the wind turbine generators, it was decided that all projects would use modern, large scale, “utility” wind turbine generators (WTG). Onshore projects were therefore assumed to use 1.5 MW WTGs and offshore projects were assumed to use 3.6 MW WTGs as described later in the report.

The projects would also represent the different types of commercial projects that could be developed in Rhode Island, both onshore and offshore. Considering the scale of the overall energy goal; smaller, one unit projects would not make a significant impact on achieving the 15 percent energy goal, but they could be an important factor in the long term adoption of wind energy in Rhode Island. On this basis, the following five different indicative project types were identified.

Customer-Connected (Retail) Projects

1. 1.5 MW Industrial/Institutional Projects
2. 1.5 MW Community Projects

Grid -Connected (Wholesale) Projects

3. 10 MW Onshore Projects
4. 30 MW Offshore Projects
5. 200 MW Offshore Projects

Customer-connected projects are defined as those providing some amount of electricity directly to the owner to offset their own electric load such as an industrial or institutional facility or a municipality in the case of a community project. While the project size of these two customer-connected projects are the same, they were separated in to two different indicative projects because other aspects of the project (i.e. the amount of wind generated electricity used by the owner is different and the financing arrangement) are significantly different.

Grid-connected projects are larger scale projects where all of the wind generated electricity is sold “into the grid” – sold to the local utility or third party electric energy company at wholesale, market electricity rates. The 10 MW onshore project is considered the minimum practical/economic size for an onshore wind project under this category.

The minimum size for offshore wind energy projects is generally considered to be larger than onshore projects due to the high mobilization costs to construct offshore projects. In fact, the minimum size that appears to be economically viable based on proposed offshore projects in the Northeast is at least 200 MW, However, in recognition of the challenges that are being faced for the proposed large offshore wind energy projects in the New England area, and the potential for closer to shore opportunities in Rhode Island that could reduce costs for an offshore installation, a smaller 30 MW project size was also considered for the purposes of this study. Further, the smaller offshore project, was evaluated to test this assumption and identify a potential project that could be a “stepping stone” to a larger, 200 MW project. 30 MW was selected because it is the maximum size that can operate at the generator voltage of 35 kV and would not require an expensive offshore step-up transformer to transmit the power to shore.

2.2 SCREENING FACTORS

Identifying potential wind energy sites was performed through a technical screening process which was applied to the entire state of Rhode Island and nearby state and federal coastal waters. There were two levels of screening, each with multiple screening criteria which are described in detail later in this section. The screening data used in the evaluation included wind data, various land use and environmental data, offshore navigational data, bathymetry and engineering judgment.

The main tool used in the RIWINDS Siting Study was ArcView’s GIS software. GIS is used to perform spatial analysis on specified input data layers, or coverages, which contain georeferenced data that is either a result of analysis or field survey. The pertinent input data layers for this study were obtained and manipulated based on their characteristics. This process resulted in areas containing overlapping suitable characteristics for WTG siting (i.e. wind speed and land use) and the exclusion of areas of unsuitable characteristics. Each data type used in the site screening portion of this study is described in the following sections.

2.2.1 WIND DATA

Turbine site feasibility is dependent on the characteristics of the site, most importantly the wind characteristics. The screening process performed for RIWINDS was based on average annual wind speed. The follow on capacity analysis was a function of both the average annual wind speed and the frequency distribution of wind speeds throughout the year. The average annual wind data was purchased from AWS Truewind (AWS Truewind 2006). This data is the output of their mesoscale meteorological model and wind flow simulation model which are used in this case to produce the average annual wind speeds for the region. The model resolution is a 200m x 200m grid with an extent covering all of the New England states as well as state and federal waters. The AWS model predicted wind speeds were developed for both 50m and 100m elevations with an accuracy of ± 0.49 m/s.

For the proposed indicative project classes and WTG it is customary to use a tower with a turbine hub height of 65m, 80m or 100m. In order to determine the wind speed at elevations other than the 50m or 100m levels a vertical profile (vertical variation) of the wind speed must be developed. This is often accomplished using a power law profile (Patel 2006). The wind shear equation was first used to solve for surface roughness at each point based on values of velocity at different elevations as well as the values of the elevation. The wind shear equation is shown in Equation 2.1 where v is the velocity; h is the corresponding height and α is the roughness coefficient.

$$v_2 = v_1 * \left(\frac{h_2}{h_1} \right)^{\alpha}$$

Equation 2.1

Once surface roughness is known in addition to the wind speed at a specific elevation for a location, the wind speed at any height at that location can be estimated using the wind shear equation. This method was employed to determine the wind speed at the hub elevations of the candidate wind turbines. Turbine characteristics (output) are provided by vendors and are to be interpreted based on the wind characteristics at hub height.

An evaluation of the spatial distribution of annual average wind speeds at the standard WTG hub heights was performed to determine the optimal hub height. Preliminary evaluation of the 65m elevation wind speeds and land use mapping (to be discussed in more detail below) indicated that there were limited resources available at that height. Similar evaluations were also performed for the 80m and 100m elevations, both of which showed a significant improvement over the 65m results. In addition, it was determined that the incremental improvement of the 100m over the 80m resources, did not warrant the expected increased costs and construction challenges of the larger tower. Lastly, a hub height of 80 meters is currently common practice for utility scale WTGs. For the remainder of the study all wind speeds used in the evaluations are referenced to the 80m elevation predictions.

In addition to the average annual wind speed, the frequency distribution of wind speed was used in calculating site capacities. A frequency distribution curve shows the occurrence of various wind speeds expressed in percent of time (0 to 100 percent) expected at a site. Frequency distribution is site specific and is most accurate when derived from historical data; however, it can also be estimated assuming a statistical distribution. For this study the offshore wind site frequency distribution was calculated by correlation to a nearby station with a twenty year period of historical data while the onshore sites were calculated using a probability function. Historical data was available and analyzed for two onshore locations. However, due to the wide variability in wind speed and patterns from local topographical effects, it was concluded that this data was applicable only for areas in close proximity to the station where data was obtained and was therefore not used in the capacity analysis for any onshore sites in this study.

Onshore sites, both customer-connected and grid-connected, were assumed to exhibit wind speed variability fitting a Weibull distribution. Previous studies of wind data have shown that a Weibull distribution accurately describes wind speed variability (Patel 2006, Danish Wind Industry Association 2003). The Weibull function is a function of the shape factor *k* and a scale parameter *c* and is as shown below in Equation 2.2 (Patel 2006).

$$h(v) = \left(\frac{k}{c}\right)\left(\frac{v}{c}\right)^{(k-1)} e^{\left(\frac{v}{c}\right)^{k}} \qquad \text{Equation 2.2}$$

The shape factor, *k*, represents the skewness of the distribution and can vary from 1- 3, where 1 represents an exponential distribution, 2 represents a Raleigh distribution and 3 represents a normal distribution. For onshore sites, the average and most typically used value of k = 2 was assumed for the shape factor (Patel 2006, Hennessey 1977) and the value of c was calculated using Equation 2.3 (Patel 2006).

$$c = \left(\frac{V_{mean}}{.9} \right)$$

Equation 2.3

Customer-connected (retail) sites were evaluated based on an average annual wind speed of 6.5 m/s and grid-connected (wholesale) 10MW sites were evaluated based on an average annual wind speed of 7 m/s, which will be discussed in more detail in a later section. The calculated frequency distribution curves for onshore retail and onshore wholesale are shown in Figures 2-1 and 2-2 respectively. As can be seen in these figures the wind speed varies over a wide range however most times occurs within a smaller range. For example, the onshore retail distribution occurs over a range of 0-20 m/s. However almost half of the time the wind speed is between 4-8 m/s.

Historical data was used to determine the typical frequency distribution for the offshore sites. This was performed using data from NOAA's C-MAN (NOAA 2006) station BUZM3 located in Buzzards Bay, 4.25 miles southeast of the Rhode Island state nautical limit. Approximately 20 years of hourly data from 1985 to 2005 for this site was analyzed to determine the frequency distribution of wind speed. This distribution was used for all locations offshore, while the magnitudes applied to the distribution was varied by site. The magnitude variations of the velocity for each site were calculated based on the ratio of average annual wind speed between the site and Buzzards Bay. Figure 2-3 shows the location of the Buzzards Bay station BUZM3 and Figure 2.4 shows the frequency distribution of wind at the Buzzards Bay station at both the elevation at which the data was obtained (24.8m) and at the elevation of the turbine hub (80m), which was calculated using the wind shear equation based on a surface roughness of 0.10 over the ocean surface.

The correlation between AWS Truewind data to that of historical data was determined using the data available at BUZM3 station. The two sources exhibited good agreement with the average annual wind speeds within 0.15 percent of one another.

2.2.2 LAND USE AND ENVIRONMENTAL GEOSPATIAL DATA

Another important feature in determining site feasibility is the land/water use characteristics of the locations where turbine placement is feasible based on wind speed. Avoidance of environmentally sensitive areas can be used as screening criteria since siting of a wind project in these areas has the potential to cause opposition to a project from regulators, politicians, and the public. In addition, areas that are protected by a variety of laws and regulations can cause challenges and hurdles in obtaining the approvals necessary to allow construction and operation of a wind energy project. Such challenges and hurdles can increase project costs and delay, or in some cases prevent the start of construction and operation of the project. The locations of state boundaries, environmentally sensitive areas such as parks, wildlife refuges, wetlands, rare species habitats, airports, cemeteries, etc, offshore navigational features such as federal channels, anchorages, and lightering areas, and the like are publicly available in GIS layers which can be download through organizations such as RIGIS (RIGIS 2006) and NOAA (NOAA 2006). Table 2-1 shows a description of each land use and environmental screening criteria (GIS data layer) and the source of the data. These data were used in the study to assess the five indicative projects defined for this study.

2.2.3 BATHYMETRY DATA

For offshore wind energy installations, water depth is often an important consideration from both a design and cost basis and was therefore selected as a screening criterion. Water depth can have a large impact on the design and construction of foundations, which can represent a high percentage of overall project costs. Current foundation technology limits cost effective offshore wind energy installations to water depths shallower than about 75 feet. In addition, the design of the foundation takes into consideration water depth as it relates to stability and wave effects, with designs ranging from monopile to three or four leg foundations. The construction process gets more expensive with increasing water depth but also is not possible in extremely shallow waters (less than 8 ft) due to accessibility limitations of heavy equipment which must be transported by large barges in the marine environment. Bathymetric data was obtained from NOAA's Geophysical Data Center (NOAA 2006). This data was compiled from many bathymetric surveys performed over the years by NOAA and others within the study area off the coast of Rhode Island. This data was used to assess the offshore wholesale project category of project.

Table 2-1. Geospatial Data Source Summary

Wind Data	AWS Truewind
Rhode Island State Boundaries	RIGIS
Rhode Island Town Boundaries	RIGIS
Land Use	RIGIS
Protected Space (public)	RIGIS
Protected Space (public)	RIGIS
Audubon Protected Lands	RIGIS
Endangered & Threatened Species Habitat	RIGIS
Contaminated Land	RIGIS
Protected Water Supply/Watershed	RIGIS
Eel Grass	RIGIS
Ferry Routes	RIGIS
Navigational Features	NOAA
State Nautical Limits	NOAA
Water Depths	NOAA
Marine Sanctuary	NOAA
Cable Areas	NOAA

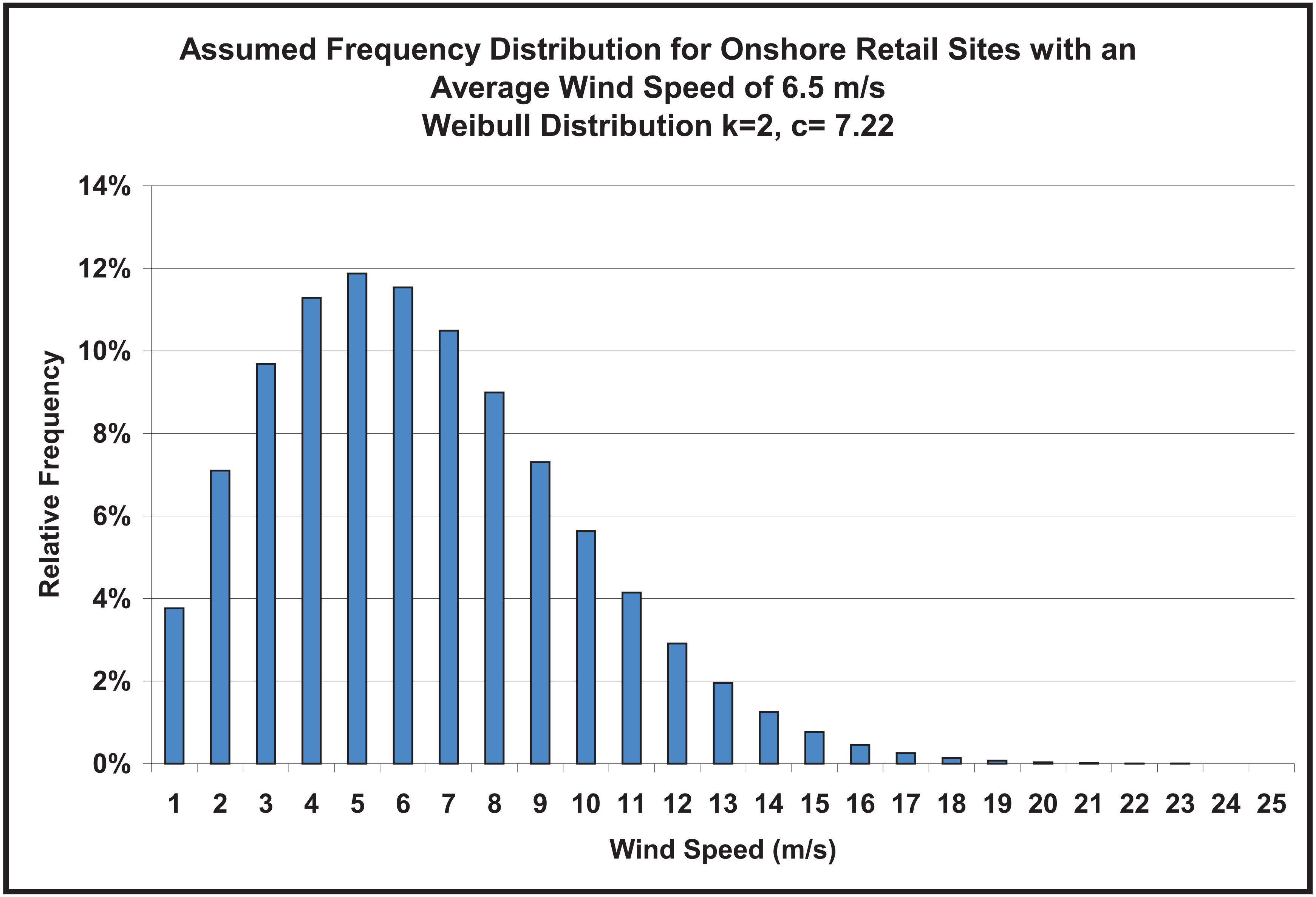

Figure 2-1

Assumed Frequency Distribution for Onshore Retail Sites with an Average Wind Speed of 6.5 m/s
Weibull Distribution k=2, c=7.22
RIWINDS Siting Study

ATM APPLIED TECHNOLOGY & MANAGEMENT

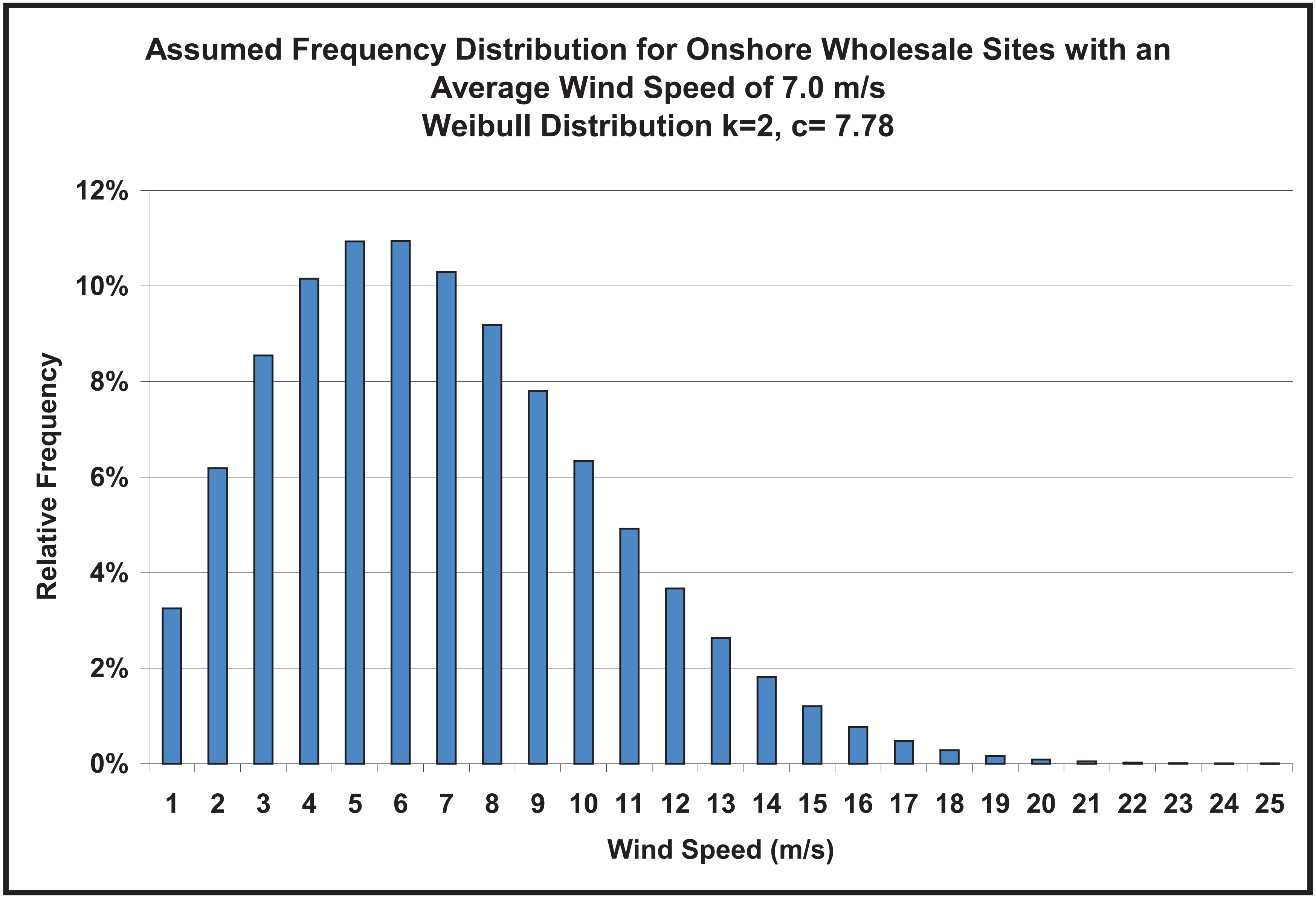

Figure 2-2

Assumed Frequency Distribution for Onshore Wholesale Sites with an Average Wind Speed of 7.0 m/s
Weibull Distribution k=2, c=7.78
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

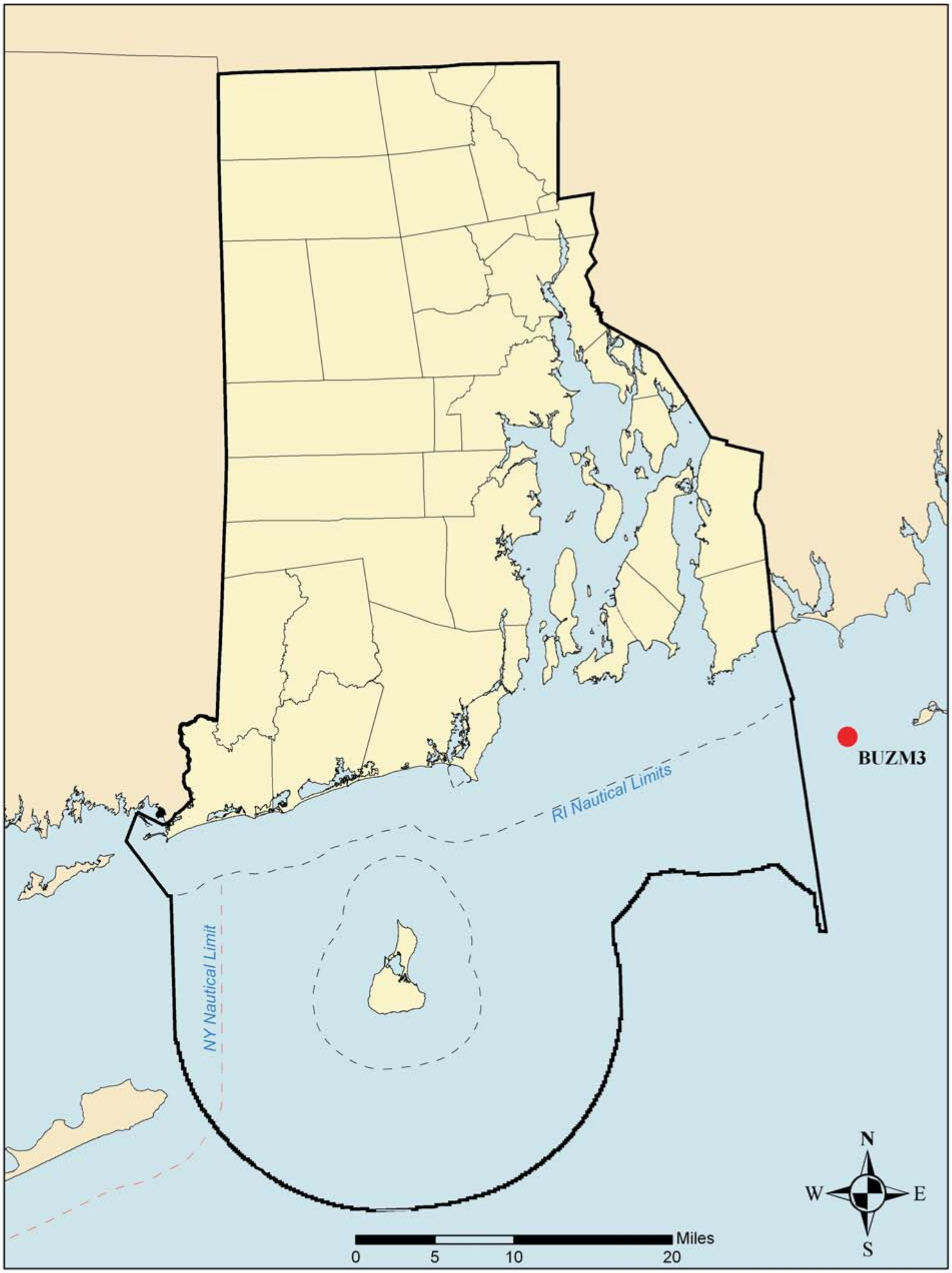

Figure 2-3

Map Showing the Location of Buzzard Bay C-MAN Station BUZM3 (Lower Right)
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

06-1296 2-3.cdr 04/10/07

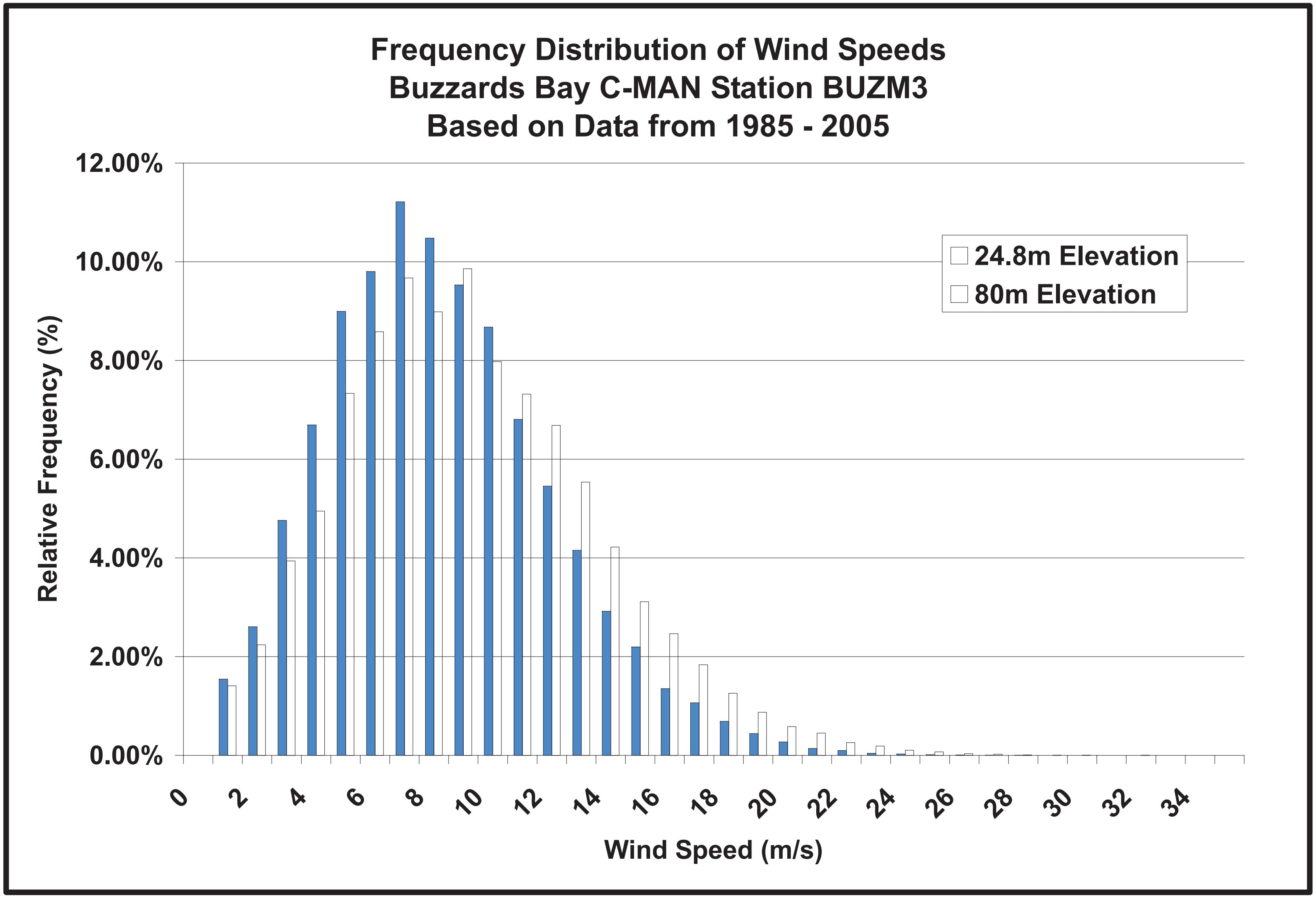

Figure 2-4
Frequency Distribution of Wind Speeds at Buzzard Bay C-MAN Station BUZM3 at Actual 24.8m Elevation and Estimated at 80m Elevation
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

3.0 SITE SCREENING

A central aspect of this study was concerned with determining the feasibility of implementing WTGs as an alternate source of energy through the identification of optimal sites. This was accomplished through a technical and environmental/regulatory screening process that was designed to determine areas with the most favorable characteristics for each of the indicative projects. This site screening processes has two levels. Level 1 provided a preliminary screening that determined which areas had the minimum characteristics to be technically feasible and economically viable. Level 2 screening was used to determine which areas would most likely avoid substantial difficulties and challenges in developing a site due to permitting, environmental resources, or public sensitivity. The screening process was applied to land areas within Rhode Island, and to state and federal waters abutting the Rhode Island coastline and islands. The extent of the study area is shown in Figure 3-1 and the wind speed at an elevation of 80m over the study area is shown in Figure 3-2.

3.1 LEVEL 1 SITE SCREENING

Each indicative project had a specific set of Level 1 site screening criteria, as outlined below:

3.1.1 GENERAL SCREENING CRITERIA

3.1.1.1. Minimum Average Wind Speed

One of the most important technical criteria in identifying suitable wind energy project areas is the wind energy resource. Fundamentally, this is an economic criterion because it indicates that there is sufficient wind energy to result in an economical project. The commonly used evaluation of the wind energy resource is the average wind speed. Therefore, the criterion of minimum average wind speed used in this analysis is a proxy for minimum economic wind resource.

The retail value of electricity delivered to the customer is considerably higher than the wholesale value of the electricity because it includes the transmission and distribution (T&D) charges and losses. The exact retail value will vary depending upon the customer’s load characteristics and the applicable utility rate tariff or the third party purchase program, but the retail value of electricity is generally on the order of two times the wholesale value. For customer-connected facilities, where a percentage of the electricity is assumed to be used on site to offset the purchase of electricity from the grid, the average value of the wind generated electricity depends on the portion of the wind electricity used onsite – the more used on site, the higher the value. For industrial/institutional projects, it was assumed that 75 percent of the wind electricity would be used onsite and 25 percent sold into the grid. For community wind projects, it was assumed that 25 percent of the wind electricity would be used onsite and 75 percent sold into the grid.

If the value of the wind generated electricity is higher, the project can afford a higher cost of production on a per unit of electrical energy basis (i.e. $/kWh). Therefore, customer-connected projects can be economical at a lower wind speed than is generally accepted as required for larger, grid-connected projects. If the wind generated electricity can be used to offset the purchase of electricity from the grid as for a customer connected facility the minimum average wind speed can be lower. The minimum wind speeds used for each of the indicative project classes in the feasibility analysis will be described under their respective categories in the following sections.

3.1.1.2. Suitable Area Use

Another important criterion for identifying potential sites is the existing or potential use of the siting area. WTG siting is not possible in all areas since some have inherent properties which restrict the development of such structures. Onshore sites must be developable areas with favor given to those free of any sensitive environmental resources or other significant encumbrances and offshore sites must remain outside certain existing navigation features.

3.1.1.3. Minimum Available Area

Although the footprint of a WTG is small (the base of the tower requires less than 500 sq. ft.), the area required for the project can be significant. Two key factors determine the required size of the project area.

1. Setback requirements for single WTG projects.
2. WTG separation for multiple WTG projects.

The setback requirements are defined by local building codes taking into consideration noise levels and fall zones. A setback distance of three (3) times the tower height (in this case 80 meters) is generally considered an appropriate distance to mitigate noise concerns. A circle with a radius of one times the WTG height (including the tower height and one blade length) defines the WTG fall zone.

The turbulence in the wake of the wind turbine blades can affect the performance of a nearby turbine. This is sometimes called the “wake affect” and can result in “array losses,” which are losses in output of the downwind turbine if the turbines are too close together. Obviously, increasing the WTG separation distance reduces the array losses, but also increases the land area required and the cost of the interconnecting electric cabling and roads. To balance these offsetting considerations, for multiple unit projects, the generally recommended WTG separation distance is ten (10) times the WTG blade diameter in line with the prevailing wind direction (downwind) and three (3) times the WTG blade diameter perpendicular to the blade diameter. These WTG separation guidelines were used to determine the potential project rated power density (power per area).

3.1.1.4. Sufficient Electrical Load (for Customer Connected Projects)

Short term wind resource is highly variable and difficult to predict. The electric loads of industrial and institutional facilities may also vary and are generally predictable, but are very different depending on the type of facility. Because of the probable mismatch in electrical supply and demand for customer connected projects, a detailed analysis of wind energy and the facility’s load must be undertaken to ensure that there is sufficient load to use the assumed amount of wind generated electricity at any given time. For purposes of this study, we only considered facilities that had a peak electric load of at least 1.5 MW, matching the peak wind generated electricity. A list of suitable facilities was developed from data maintained by the Rhode Island Office of Energy Resources (RIOER), confidential information provided by The Energy Council of Rhode Island (TEC-RI) and by National Grid. The RIOER provided a list of the facilities with electric consumption greater than the minimum peak, TEC-RI distributed a questionnaire from which five confidential responses were received, and National Grid produced a list of its largest customers which is filed with the Federal Energy Regulatory Commission (FERC) annually.

3.1.1.5. Suitable Water Depth

Similar to wind speed, there is an economical range of suitable water depths. This range reflects the depths at which construction is technically feasible as well as economical. A minimum water depth of 8 feet was selected based on the need to install the foundations and towers with barge mounted equipment. Maximum water depth was determined in part based on analysis of foundations that are suitable for the conditions off the coast of Rhode Island.

Foundation selection was discussed with engineers from Denmark who have experience designing offshore wind turbine foundations. Mono-tube foundations are the most suitable and preferred foundation solution for offshore applications. The mono-tube piles were considered suitable for areas similar to the conditions anticipated off the coast of Rhode Island due to favorable soil conditions. Mono-tube piles are cost effective due to being fairly efficient to install, eliminating the construction time offshore that is very expensive due to the high cost of the specialized equipment and the potential for down time due to bad weather. Fabrication of the large diameter piles could be performed at a plant that is equipped to work with large steel structures. This provides an excellent opportunity for established Rhode Island manufacturers with these skills to diversify into this market, or for spin-off companies to develop.

Design of the offshore turbine foundations must account for the lateral loads from wind and waves, moments imposed on the foundation from the movement of the turbines, and the axial loads from the weight of the turbine and towers. These loads are transferred from the foundation into the soil. The distance from where the lateral loads are applied to where the load is transferred into the soil creates a moment that increases based on this distance. Deeper water depths result in higher moments that must be absorbed by the foundation system.

Preliminary research indicates that the predominant soil conditions off the coast of Rhode Island consist of mainly sand with relatively deep bedrock elevations. These conditions were utilized to perform preliminary design of the foundation systems. It should be noted that final design of foundations would require soil sampling from each proposed turbine foundation location. No soil sampling was performed as part of this study. Preliminary wave analysis indicated that a 20 foot design wave be used for estimating lateral wave forces on the foundation.

An analysis was performed to determine a maximum water depth where industry standard mono-tube piles could be used. For the basis of this analysis we considered steel mono-tube piles up to 16 feet diameter to be the maximum size based on current capacity of equipment available in Europe to lift and drive the piles. The analysis showed that the maximum water depth was 75 feet. At this depth the total moments at the seabed, including wave and wind loads on the tower and turbine, would be approximately 65,000 ft-kips. Based on a geotechnical analysis, a 16 foot diameter pile would need to be driven approximately 90 feet into the anticipated medium dense sand to transfer these loads to the soil. The steel pile would need to have a two inch thick wall section to provide adequate structural capacity to resist the moments. While this evaluation was used as the basis of the financial analysis, any development that goes forward would need to perform detailed engineering analysis specific to the location chosen.

3.1.2 CUSTOMER-CONNECTED LEVEL 1 SCREENING

The following bulleted items reflect the Level 1 screening criteria used for the customer-connected project types.

- Minimum average wind speed of 6 m/s. For industrial/institutional projects, where most of the electricity is used to offset retail purchases of electricity, a minimum average wind speed 6.0 m/s at the hub height was assumed. This corresponds to the AWS Truewind suitability category of FAIR. For community wind projects, where most of wind generated electricity is sold at wholesale, a minimum average wind speed of 6.5 m/s was assumed.
- Suitable land use category. The land use categories used for this inclusive approach were those assumed to have potential for a sufficient electric load which could warrant the use of a wind turbine generator. In addition to the suitable load, a wind energy project is consistent with the following land use categories, but in certain other types (e.g. residential) is likely to be viewed negatively by the public and may not be approvable under zoning regulations, depending upon the town. The suitable land use categories are as follows.
    - Industrial
    - Institutional
    - Waste Disposal
    - Water & Sewage Treatment
    - Other Transportation
- Minimum land available. The minimum land area for a single WTG was assumed to be 11 acres. This is the approximate area of the “fall zone” of the WTG based on its overall height (For the 1.5 MW turbine assumed for this project - 118.5 meters including the 80 meter hub height and 38.5 meter blade radius).
- Sufficient electrical load. As described above, the minimum peak electric load for customer-connected industrial/institutional Projects was 1.5 MW. As portions of this

data were received under the expectations of confidentiality and therefore the information and results are presented in an ambiguous fashion. Locations have been omitted from the maps to maintain this confidentiality.

Figure 3-3 shows all of the area with wind speed over 6 m/s, Figure 3-4 shows all area with wind speed over 6 m/s that has suitable land use, and Figure 3-5 shows all areas with suitable wind speed, land use and available area.

As can be seen in Figure 3-3, more than half of Rhode Island has an average annual wind speed over 6 m/s at an elevation of 80m. The amount of this area that is categorized appropriately to be considered for customer connected projects is much less, and less than half of that area has a large enough contiguous area to be considered for a customer project. Of the possible areas, eleven contain a facility with a known electrical load large enough to be offset by WTG; five governmental and six private institutions. Table 3-1 shows a summary of the area associated with each level of the screening process.

Table 3-1. Summary of Level 1 Screening for Customer-Connected Projects

Onshore Areas	Area (Acres)	Percent of Rhode Island Land Mass (%)
State of Rhode Island	690056	100
Land with Wind Over 6 m/s at 80m	410699	59
Land with Suitable Wind and Land Use	11246	1.63
Suitable Wind, Land Use and Project Size	8615	1.25

3.1.3 GRID-CONNECTED LEVEL 1 SCREENING

- Minimum average wind speed of 7 m/s. This is the generally industry accepted minimum wind speed for a larger scale, grid-connected project. This wind speed also corresponds to the AWS Truewind suitability category of GOOD.
- Suitable land use category. All land use categories were considered for grid connected projects with the exception of the following categories.
    - Airports (Tall structures in proximity to airports have the potential to interfere with radar as well as presenting an obstruction to aviation within the airspace around an airport.)
    - Cemeteries (A single large, 1.5 MW, turbine requires a foundation area of roughly 50 feet by 50 feet, plus workspace, and relocating grave sites is unlikely

to be approved or publicly acceptable. An industrial facility within a cemetery is not consistent with the intended purposes of cemeteries.)

  - Developed recreation (An industrial facility within an area designated for recreation is not consistent with the intended purposes of developed recreational areas and may not be an approved use or a publicly acceptable use.)
  - Residential (An industrial facility within a residential neighborhood is not consistent with the intended purposes of such areas, is unlikely to get zoning approval, and is likely to receive considerable local public opposition.)
  - Railroads (Railroads have very restricted deeds and titles to their lands, and it is unlikely that a wind energy project would be granted a right to construct and operate on most railroad properties.)
  - Roads (A wind energy project within a road or road easement is not consistent with the intended purposes of roads, may cause a safety concern, and as with railroads, alternative uses are generally not granted approval to occupy the road easement.)
  - Transitional areas (Areas which are transitioning to a new land use for an ongoing project.)
  - Power lines (A wind energy project within a power line easement is not consistent with the intended purposes of the easement, may cause a safety concern, and as with railroads and roads, alternative uses are generally not granted approval to occupy the power line easement.)
- The minimum area for a 10 MW grid-connected onshore project is approximately 300 acres based on the recommended turbine separation distance discussed above.

Figure 3-6 shows all of the area with wind speed over 7m/s, Figure 3-7 shows all areas with wind speed over 7 m/s that has the suitable land use category and Figure 3-8 shows all areas with suitable wind speed, land use and available area.

It can been seen in Figure 3-6 that only a small portion of Rhode Island has an average annual wind speed over 7 m/s, and almost all of that is in near the coast. A good portion of the area does have a land use category conducive to grid connected project siting as well as contiguous area over 300 acres. Table 3-2 shows a summary of the area associated with each level of the screening process.

Table 3-2. Summary of Level 1 Screening for Onshore Grid-Connected Projects

Onshore Areas	Area (Acres)	Percent of Rhode Island Land Mass (%)
State of Rhode Island	690056	100.00
Land with Wind Over 7 m/s at 80m	17948	2.60
Land with Suitable Wind and Land Use	13522	1.96
Suitable Wind, Land Use and Project Size	3203	0.46

3.1.4 GRID-CONNECTED OFFSHORE LEVEL 1 SCREENING

- Minimum wind speed of 7 m/s. This is the same value used for all Grid Connected Projects.
- Suitable water depth from 8 to 75 ft. This range reflects the minimum depth needed to allow for operation of the equipment required to construct the foundations, allow access by maintenance vessels as well as the maximum depth economical to construct foundations with technologies anticipated by the year 2010.
- Suitable water use. Certain areas of Narragansett Bay and the ocean area within approximately 10 miles of the Rhode Island shoreline are designated for a specific function or use. Areas for which the construction of wind turbines would be unreasonable, unacceptable or not permittable were ruled out for turbine siting, as follows.
    - Recommended tracks for vessel navigation (Based on the navigation charts, to assist in vessel traffic management and for vessel transit safety, certain linear tracks have been specified as recommended locations to travel. Placement of numerous turbines could be viewed unfavorably by the Coast Guard and other mariners, even if for only the perceived increase in risk of collision and obstruction of the recommended track(s).)
    - Traffic separation zones (The Coast Guard has designated traffic separation zones to increase the margin of safety for mariners transiting in and out of Narragansett Bay. Placement of numerous turbines could be viewed unfavorably by the Coast Guard and other mariners, even if for only the perceived increase in risk of collision and obstruction of the traffic separation zone(s), should a vessel migrate into or through the zone(s).)
    - Traffic separation scheme lanes (The Coast Guard has designated Traffic separation lanes to separate inbound and outboard mariners transiting in and out of Narragansett Bay. Placement of numerous turbines within the lanes would not

be approved by the Coast Guard because of the increase in risk of collision and obstruction of the traffic separation lanes.)

- Military areas (There is a military area designated offshore of the Rhode Island coastline, and depending upon the types of military activity and use, this area is unlikely to be available for the installation of wind turbines because of potential conflicts with the military use.)
- Ferry routes (half mile width applied to route path) (Based on the navigation charts, to assist in vessel traffic management and for vessel transit safety, certain linear tracks have been specified as recommended locations for ferry traffic. Placement of numerous turbines could be viewed unfavorably by the Coast Guard, the ferry operators and other mariners, even if for only the perceived increase in risk of collision and obstruction of the ferry route(s).)

3.1.4.1. Minimum Area

The minimum area required for offshore projects was based on the recommended WTG separation distance described above. This was confirmed by review of publicly available information on other offshore wind projects. This results in a power density of 20 MW/square mile or a required area of 1.5 sq. miles for a 30 MW offshore project, and 10 square miles for a 200 MW offshore project.

Figure 3-9 shows all of the area with wind speed over 7 m/s and Figure 3-10 shows all area with wind speed over 7 m/s with a water depth from 8 to 75 ft. Figure 3-11 shows the Level 1 screening navigation features which were ruled out and Figure 3-12 shows the resulting remaining areas that pass all of the criteria.

Most of the study area waters have an average annual wind speed over 7 m/s at an 80 m elevation, while only a fraction of that area has the suitable depth from 8 to 75 feet. Most of the area with suitable wind and depth passes through the Level 1 screening process, the results of which are summarized numerically in Table 3-3.

Table 3-3. Summary of Level 1 Screening for Offshore Grid-Connected Projects

Offshore Areas	Area (Acres)	Area (Sq. Miles)	Percent of Study Area Waters (%)
Study Area Waters	659234	1030	100.00
Water with Wind Over 7 m/s at 80m	609779	953	92.50
Water with Suitable Wind and Depth	149280	233	22.64
Water with Suitable Wind, Depth, and Water Use	130560	204	19.80
Suitable Wind, Depth, Water Use and Project Size	121440	189.75	17.60

3.2 LEVEL 2 SITE SCREENING

As indicated above, a Level 2 site screening process was employed to further refine the study area to meet the project goals of identifying feasible and potential target areas for future consideration of wind energy projects. Results of the Level 1 screening process, while eliminating large areas of the state, was not refined enough to provide useful guidance to potential interested developers in the construction and operation of wind energy projects in the state of Rhode Island.

Each project type had a specific set of Level 2 site screening criteria, as outlined below.

3.2.1 ONSHORE CUSTOMER-CONNECTED LEVEL 2 SCREENING

A number of additional screening criteria were evaluated for the Level 2 process. Each of the criteria is described in detail below.

- Proximity to airports. Federal regulations require application for construction of any structures greater than 200 feet above ground level (FAA 1965). Structures greater than 200 feet typically must file for application in order to ensure that they will be identified and lighted regardless of their proximity to an airport. Additionally, structures less than 200 feet above seal level within certain distance to runways must file for application as they may be considered an obstruction to flight navigation. While the turbines will be greater than 200 feet and all require filing, it is was assumed that projects sited close to airports would receive greater scrutiny and would be a higher risk of prolonged FAA regulatory issues and/or denial of an FAA permit than areas outside these zones. Therefore sites that were located within the following FAA threshold zones of potential aeronautical concern were screened out.
    - 10,000 feet from airports with runways less than 3,200 feet in length

- 20,000 feet from airports with runways greater than 3,200 feet in length

- Contaminated land sites. Sites with known contamination are subject to additional construction considerations which may preclude them from being suitable sites or require additional expenditures to minimize negative environmental impacts, perhaps including remediation of the site. Therefore, locations that encompassed contaminated sites were screened out. However, the revenue generation opportunity may be considered a beneficial use of the site and directed towards remediation of the property.
- Endangered and threatened species habitat. Sites which contain habitats for endangered and threatened species may require filing for additional permits or have constraints that would limit and or prevent construction on site. Sites encompassing these areas were screened out.
- Public water supply/ watershed protection areas. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. In particular, land clearing and road construction, construction of facilities with oil or lubricant storage, or facilities with the potential to intercept groundwater or alter surface water runoff characteristics require additional levels of analysis, regulatory scrutiny, and public perception hurdles, that at a minimum could increase project costs, and in a worse case could prevent the project from being approved. Sites encompassing these areas were screened out.
- Protected public lands. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Generally, protected public lands have restrictions placed on them as to how the land can be used in the future, and depending on the reason for protection, may provide resources and uses that are in conflict with building and operating a wind energy project. Sites encompassing these areas were screened out.
- Protected lands (private, non-profit). Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Generally, protected lands, regardless of ownership, have a restriction placed on them as to how the land can be used in the future, and depending on the reason for protection, may provide resources and uses that are in conflict with building and operating a wind energy project. Sites encompassing these areas were screened out.
- Audubon protected lands. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Sites encompassing these areas were screened out.

- Conservation lands. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Generally, Conservation lands, regardless of ownership, have a restriction placed on them as to how the land can be used in the future, and depending on the reason for protection, may provide resources and uses that are in conflict with building and operating a wind energy project. Sites encompassing these areas were screened out.

Figure 3-13 shows all of the Level 2 screening areas overlaid on areas which were remaining after Level 1 screening for onshore retail sites and Figure 3-14 shows the remaining areas which pass through Level 2 screening unaffected.

Table 3-4 shows a summary of the areas prior to and after the Level 2 screening process for onshore customer connected suitable sites. Approximately two-thirds of the area which had passed through Level 1 screened out of the consideration process due to the Level 2 screening criteria. Of the 11 potential customer connected sites with known loads, three were located on areas that got screened out during this Level 2 screening process. There are 8 potential onshore customer connected sites; 4 governmental and 4 private institutions.

Table 3-4. Summary of Level 2 Screening for Onshore Customer-Connected Areas

Onshore Areas	Area (Acres)	Percent of L1 Area (%)
Area Remaining after Level 1 Screening	8615	100
Area Remaining after Level 2 Screening	3203	37.18

3.2.2 ONSHORE GRID-CONNECTED LEVEL 2 SCREENING

The onshore grid connected Level 2 criteria are similar to the Level 2 customer connected criteria and may be described as follows.

- Proximity to airports. Federal regulations require application for construction of any structures greater than 200 feet above ground level (FAA 1965). Structures greater than 200 feet typically must file in order to ensure that they will be identified and lighted regardless of their proximity to an airport. Additionally, structures less than 200 feet above seal level within certain distance to runways must file for application as they may be considered an obstruction to flight navigation. While the turbines will be greater than 200 feet and all require filing, it is was assumed that projects sited close to airports would receive greater scrutiny and would be a higher risk of prolonged FAA regulatory issues and/or denial of an FAA permit than areas outside these zones. Therefore sites were screened out that were located within the following FAA threshold zones of potential aeronautical concern.

  - 10,000 feet from airports with runways less than 3,200 feet in length
  - 20,000 feet from airports with runways greater than 3,200 feet in length

- Contaminated land sites. Sites with known contamination are subject to additional construction considerations which may preclude them from being suitable sites or require additional expenditures to minimize negative environmental impacts, perhaps including remediation of the site. Therefore, locations that encompassed contaminated sites were screened out. However, the revenue generation opportunity may be considered a beneficial use of the site and directed towards remediation of the property.
- Endangered and threatened species habitat. Sites which contain habitats for endangered and threatened species may require filing for additional permits or have constraints that would limit and or prevent construction on site. Sites encompassing these areas were screened out.
- Public water supply/ watershed protection areas. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. In particular, land clearing and road construction, construction of facilities with oil or lubricant storage, or facilities with the potential to intercept groundwater or alter surface water runoff characteristics require additional levels of analysis, regulatory scrutiny, and public perception hurdles, that at a minimum could increase project costs, and in a worse case could prevent the project from being approved. Sites encompassing these areas were screened out.
- Protected public lands. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Generally, protected public lands have restrictions placed on them as to how the land can be used in the future, and depending on the reason for protection, may provide resources and uses that are in conflict with building and operating a wind energy project. Sites encompassing these areas were screened out.
- Protected lands (private, non-profit). Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Generally, protected lands, regardless of ownership, have a restriction placed on them as to how the land can be used in the future, and depending on the reason for

protection, may provide resources and uses that are in conflict with building and operating a wind energy project. Sites encompassing these areas were screened out.

- Audubon protected lands. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Sites encompassing these areas were screened out.
- Conservation lands. Sites within these areas may require filing for additional permits or have constraints that would limit and or prevent construction on site. Generally, Conservation lands, regardless of ownership, have a restriction placed on them as to how the land can be used in the future, and depending on the reason for protection, may provide resources and uses that are in conflict with building and operating a wind energy project. Sites encompassing these areas were screened out.

Figure 3-15 shows all of the Level 2 screening areas overlaid on areas which were remaining after Level 1 screening for onshore grid connected sites and Figure 3-16 shows the remaining areas which pass through Level 2 screening unaffected.

Table 3-5 shows a summary of the areas prior to and after the Level 2 screening process for offshore grid connected suitable sites. Approximately three quarters of the area passing through the Level 1 process is screened out during the Level 2 screening process. Of the remaining areas the two western sites (one near Point Judith and the other in Southern Newport) were also screened out based on further detail of the land use categories and public sensitivity concerns. The Easternmost area is located within Little Compton on mostly farm land and is the only area with potential wholesale project development characteristics.

Table 3-5. Summary of Level 2 Screening for Onshore Grid-Connected Areas

Onshore Areas	Area (Acres)	Percent of L1 Area (%)
Area Remaining after Level 1 Screening	13522	100
Area remaining after Level 2 Screening	3060	22.63

3.2.3 OFFSHORE WHOLESALE

The Level 2 screening criteria for the offshore are focused quite differently than the onshore criteria as the concerns are of a different nature. The offshore Level 2 criteria are described as follows.

- Proximity to airports. Federal regulations require application for construction of any structures greater than 200 feet above ground level (FAA 1975). Structures greater than 200 feet typically must file in order to ensure that they will be identified and lighted regardless of their proximity to an airport. Additionally, structures less than 200 feet above seal level within certain distance to runways must file for application as they may be considered an obstruction to flight navigation. While the turbines will be greater than 200 feet and all require filing, it is was assumed that projects sited close to airports would receive greater scrutiny and would be a higher risk of prolonged FAA regulatory issues and/or denial of an FAA permit than areas outside these zones. Therefore sites were screened out that were located within the following FAA threshold zones of potential aeronautical concern.
    - 10,000 feet from airports with runways less than 3,200 feet in length
    - 20,000 feet from airports with runways greater than 3,200 feet in length
- Traffic convergence zones. These are areas which may presently exhibit navigational challenges as traffic is converging from multiple directions. The addition of turbines may complicate these areas further and therefore were ruled out as possible sites.
- Cable areas. These are areas designated for running cables. Placing a turbine foundation within these areas could have added complications if the turbine location coincided with a cable or if the inner-array cables or the transmission cable to shore ran too close to an existing cable. Construction and maintenance of cables constructed across or in close proximity requires additional design, materials, and methods that add expense to the project. For these reasons, cable areas were ruled out for possible turbine placement.
- Presence of eel grass beds. Eel grass provides habitat for numerous species and plays an important role in ecologic systems. Many measures have been taken by resource and regulatory agencies to preserve eel grass beds which may make permitting a site which could cause destruction to beds more difficult. Sites encompassing these areas have been screened out due to the added regulatory review and potential for restrictions and or prohibitions on use of these areas.
- Marine sanctuaries. Marine sanctuaries are protected areas which would require special use permits to grant rights to development of wind turbine projects which could disturb their natural environment. In some instances, the law establishing the marine sanctuary may actually prohibit development of structures within the boundaries of the sanctuary.

Sites encompassing these areas have been screened out due to the added regulatory review and potential for restrictions and/or prohibitions on use of the areas.

- Local authorities' jurisdiction offshore. This study includes both state and federal waters. At this point in time there is more uncertainty in the process of permitting an offshore wind project in federal waters and it is likely to be a more difficult process. Sites located within Federal areas were still identified as part of this study, however it should be understood that the feasibility of developing these sites is unclear given the current legislation. We note that given the offshore topography in Rhode Island, many of these areas would be excluded anyway as a result of the water depth screening criteria.

Figure 3-17 shows the offshore restricted areas for Level 2 and Figure 3-18 shows the offshore areas remaining after removing these areas. Figure 3-19 shows the split between state and federal waters of the remaining areas which passed through Level 2 screening. Once split by the state/federal boundary, the areas were grouped by average annual wind speed. Any areas smaller than 1.5 square miles were removed since this is the minimum area for offshore projects as was established in the Level 1 screening process. Furthermore some high recreational traffic areas were removed. The remaining areas are shown in Figure 3-20; these are the final offshore areas for which financial analysis was performed.

Table 3-6 summarizes the Level 2 screening offshore results and Table 3-7 summarizes the split between state and federal area. Almost half of the resulting area is located off the southeastern coast offshore from Aquidneck Island and Little Compton. The remaining area is split between the area offshore of Block Island and scattered areas offshore of the Southwestern Rhode Island coastline.

Table 3-6. Summary of Level 2 Screening Results for Offshore Grid-Connected Areas

Offshore Areas	Area (Acres)	Area (Sq. Miles)	Percent of L1 Area (%)
Area Remaining after Level 1 Screening	121440	190	100
Areas Remaining After Level 2 Exclusionary Screening	80640	126	66.40
Areas Remaining After State/Federal Separation Applied to Offshore Areas	62720	98	51.49

Table 3-7. Summary of State/Federal Split of Offshore Grid-Connected Areas Post Level 2 Screening Process

Offshore Areas	Area (Acres)	Area (Sq. Miles)	Percent of Total Area (%)
Total Area Remaining After State/Federal Separation Applied to Offshore Areas	62534	98	100
Portion State Area	49274	77	78.79
Portion Federal Area	13261	21	21.21

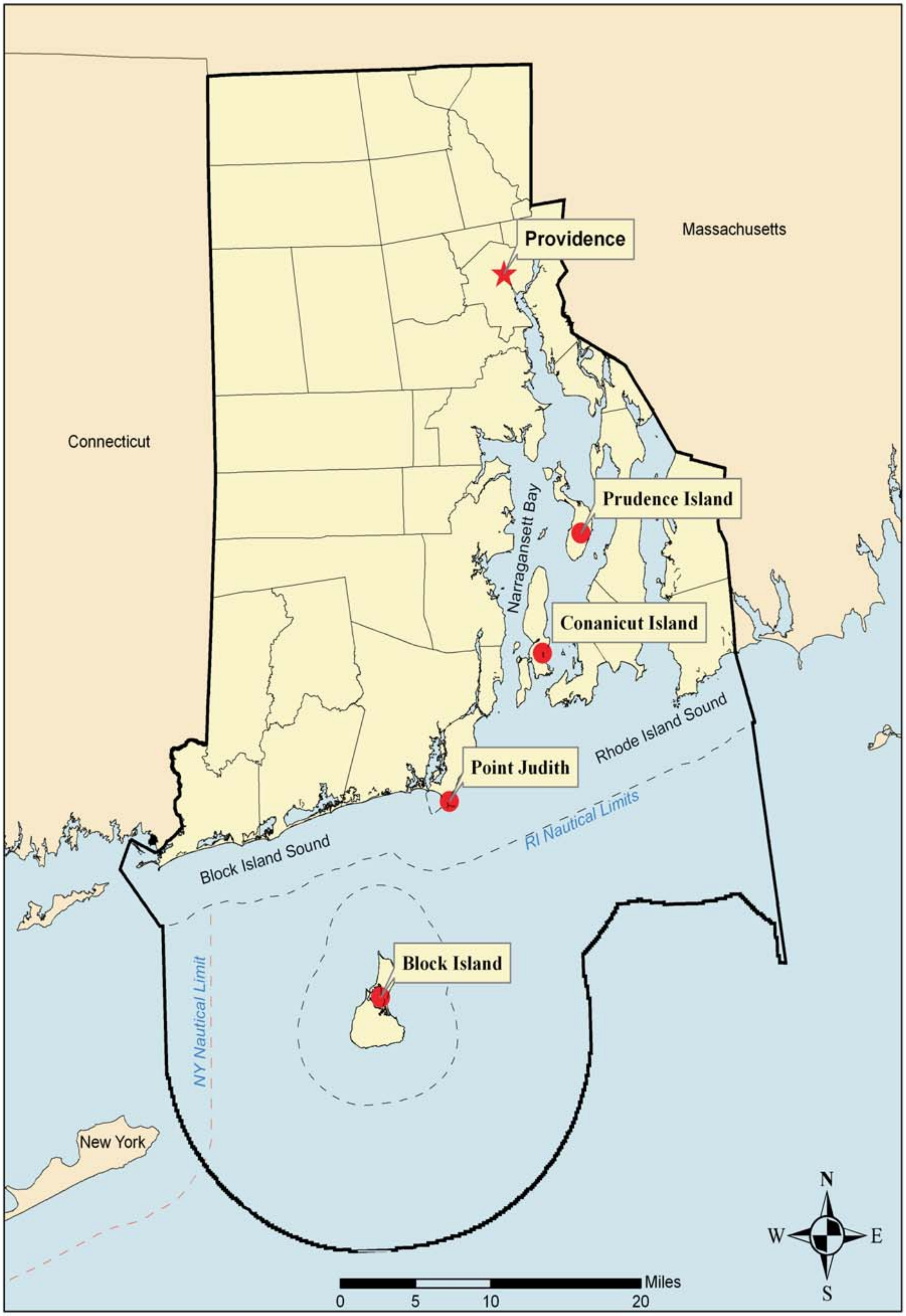

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Figure 3-1
Map Showing RIWINDS Study Area Extent
RIWINDS Siting Study

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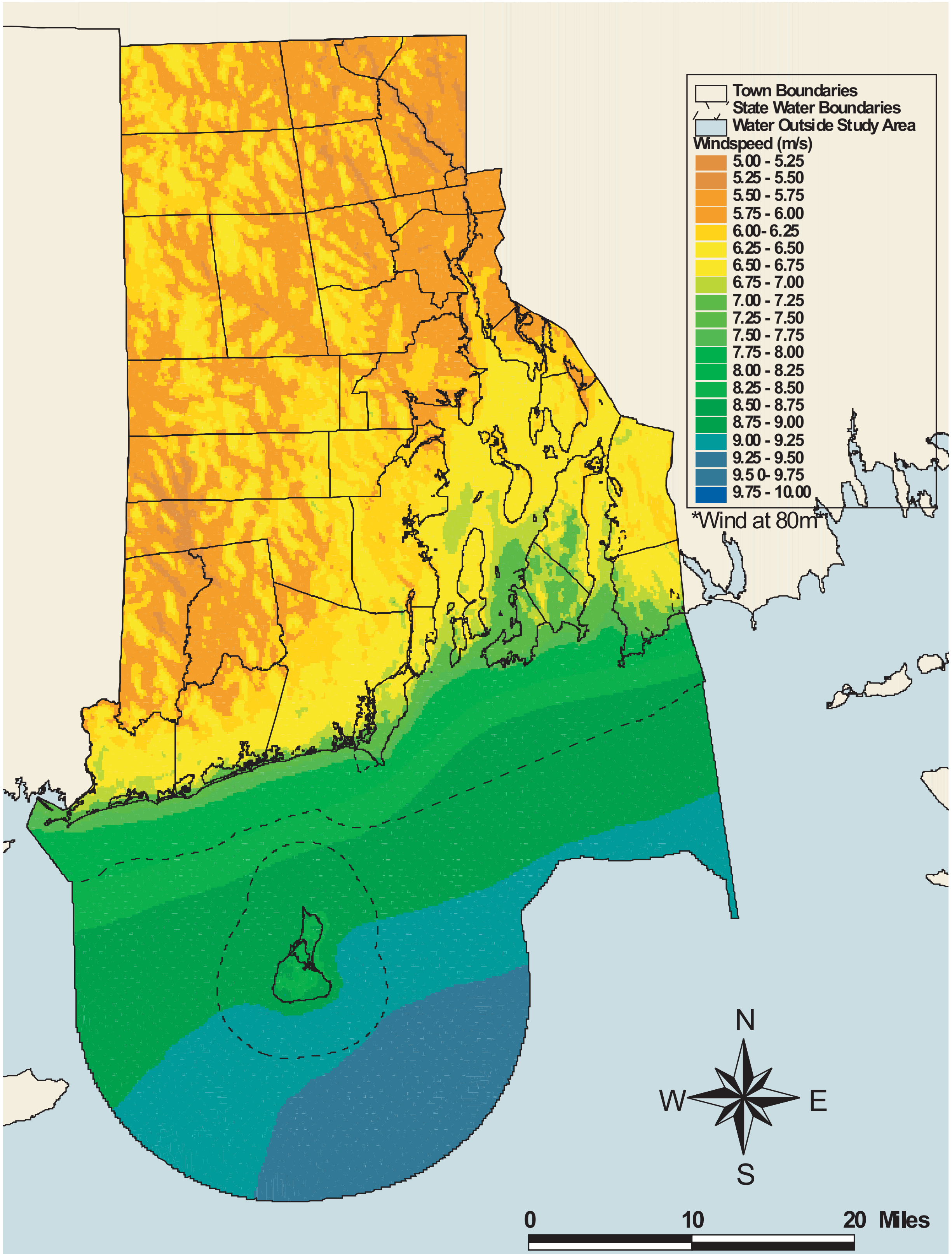

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Figure 3-2

Map Showing Wind Speed at 80m Elevation over RIWINDS Study Area Extent, Derived from ASW Truewind 50m & 100m Data
RIWINDS Siting Study

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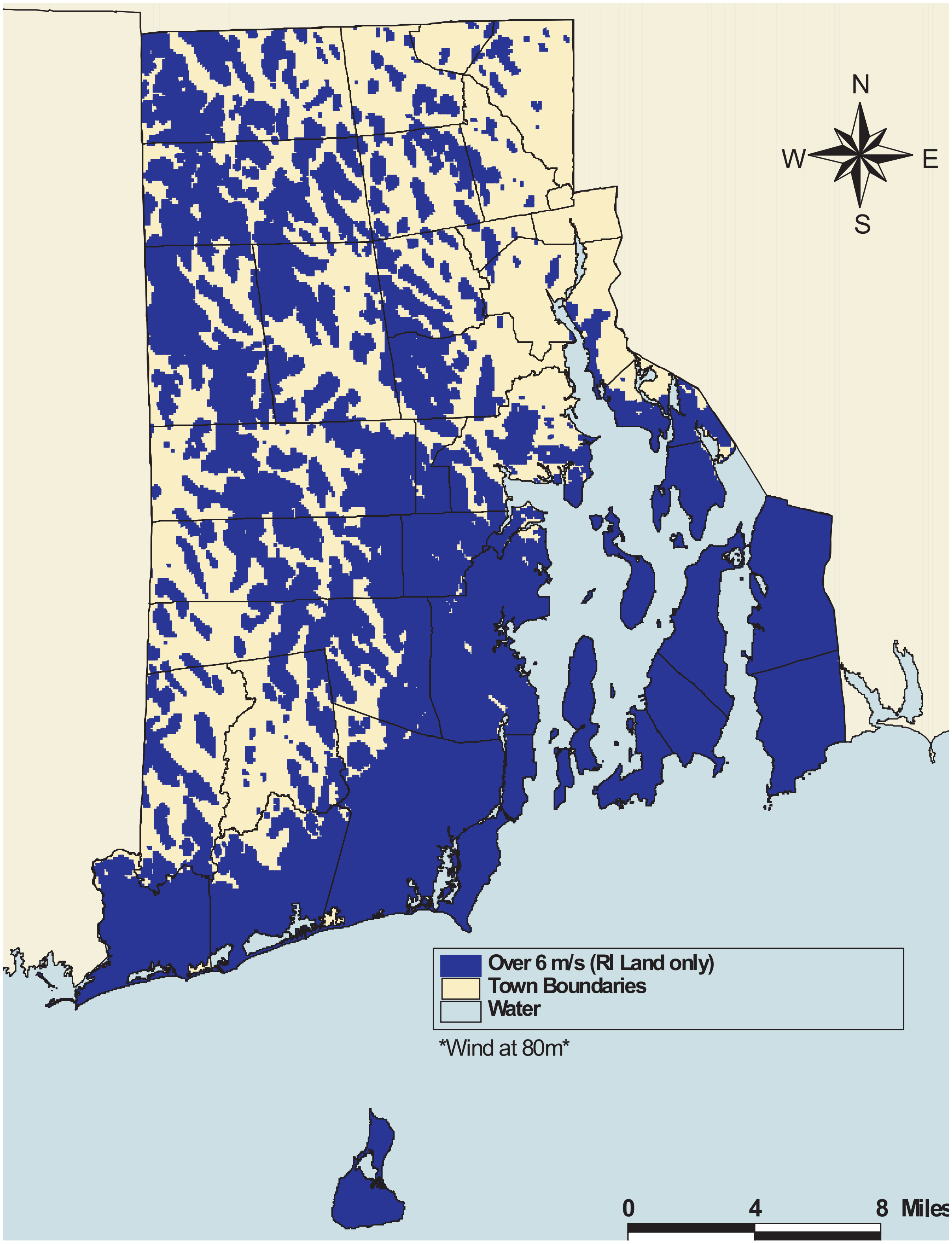

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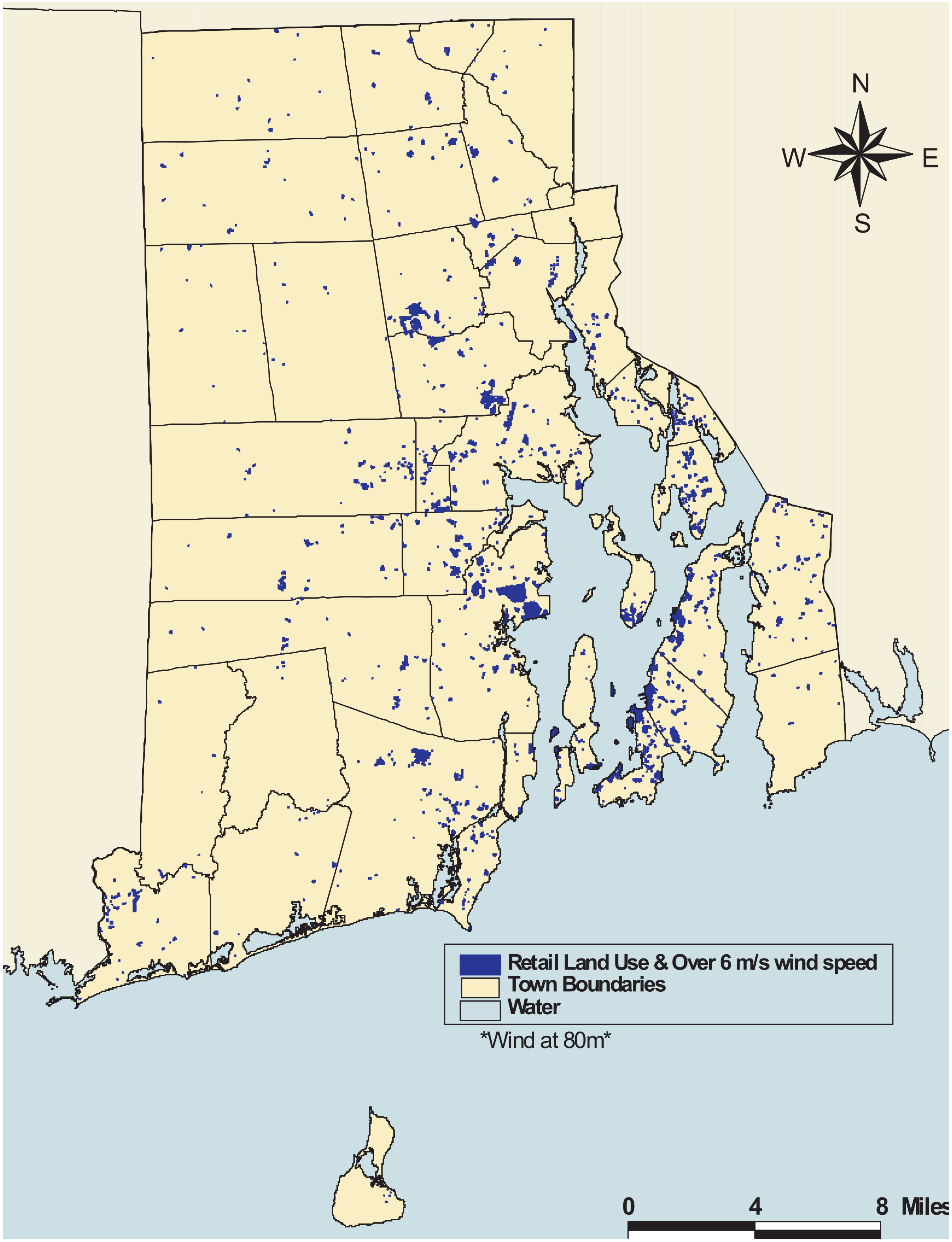
Figure 3-3

Map Showing Areas with Wind Speeds over 6m/s at 80m Elevation Onshore

RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT



06-1296 3-4 04/10/07

Figure 3-4
Map Showing Retail Suitable Areas with Wind Speeds over 6 m/s at 80m Elevation Onshore
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

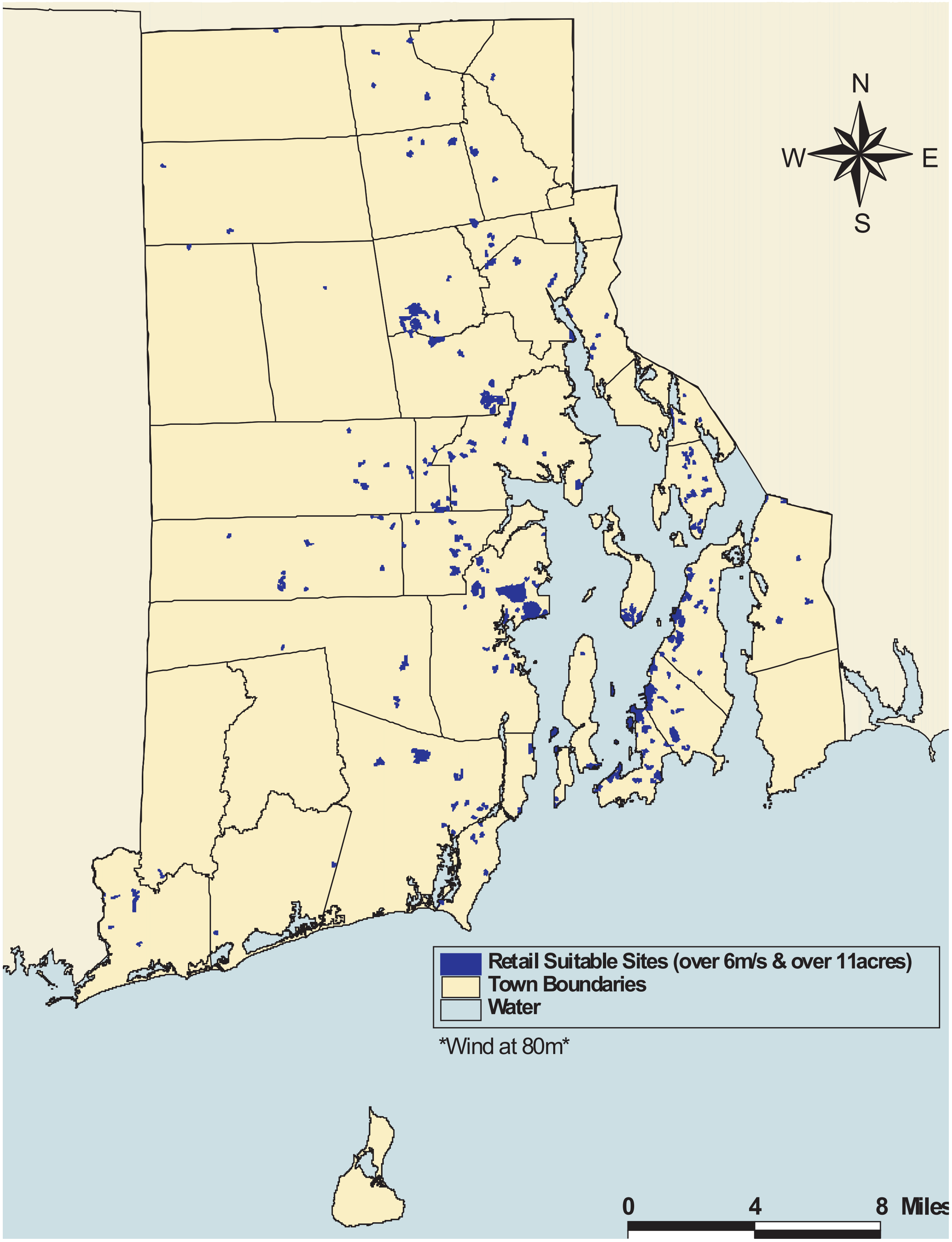


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Figure 3-5
Map Showing Areas Suitable after Onshore Retail Level 1 Screening
RIWINDS Siting Study

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APPLIED TECHNOLOGY & MANAGEMENT

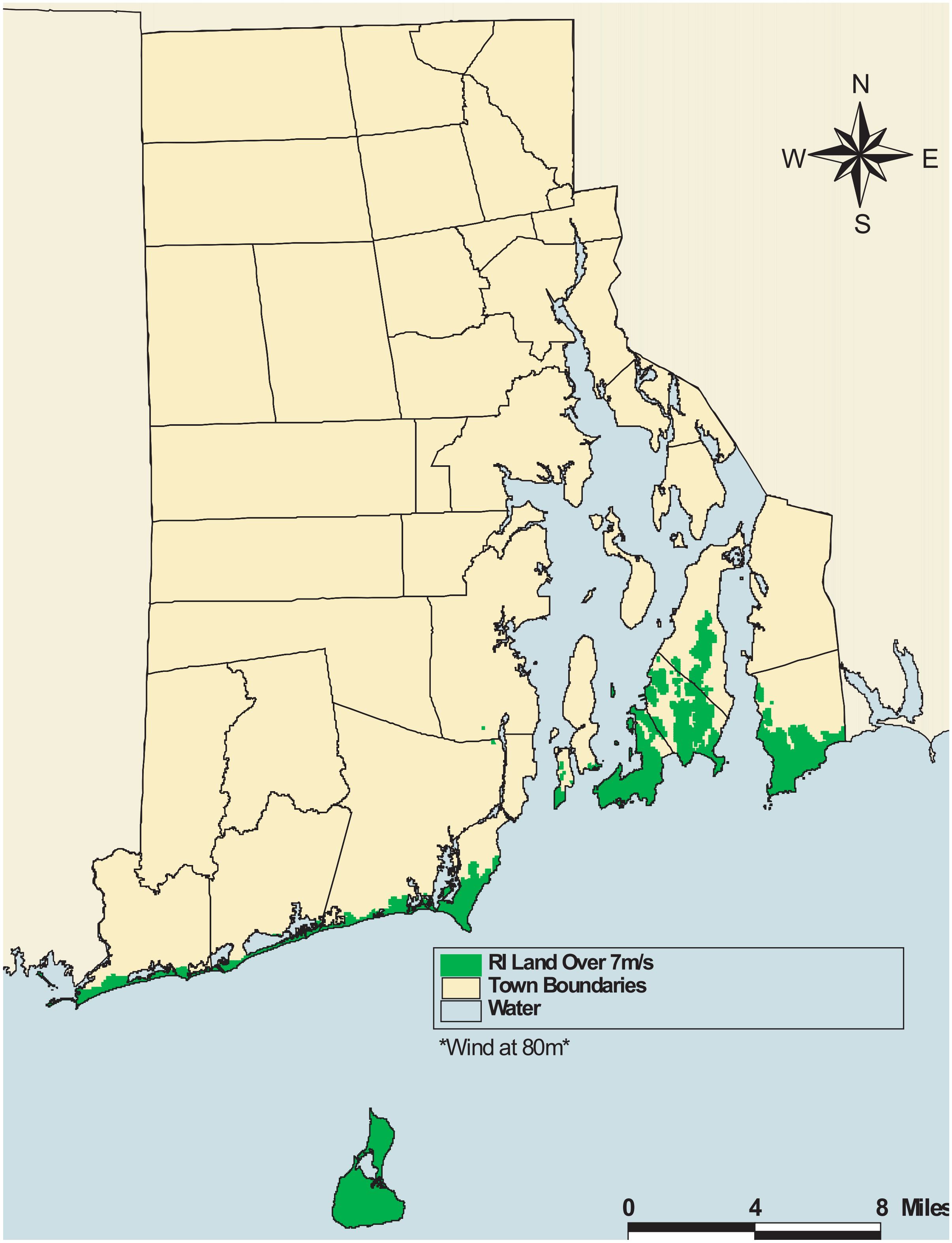

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Figure 3-6

Map Showing Areas with Wind Speeds over 7 m/s at 80m Elevation Onshore

RIWINDS Siting Study

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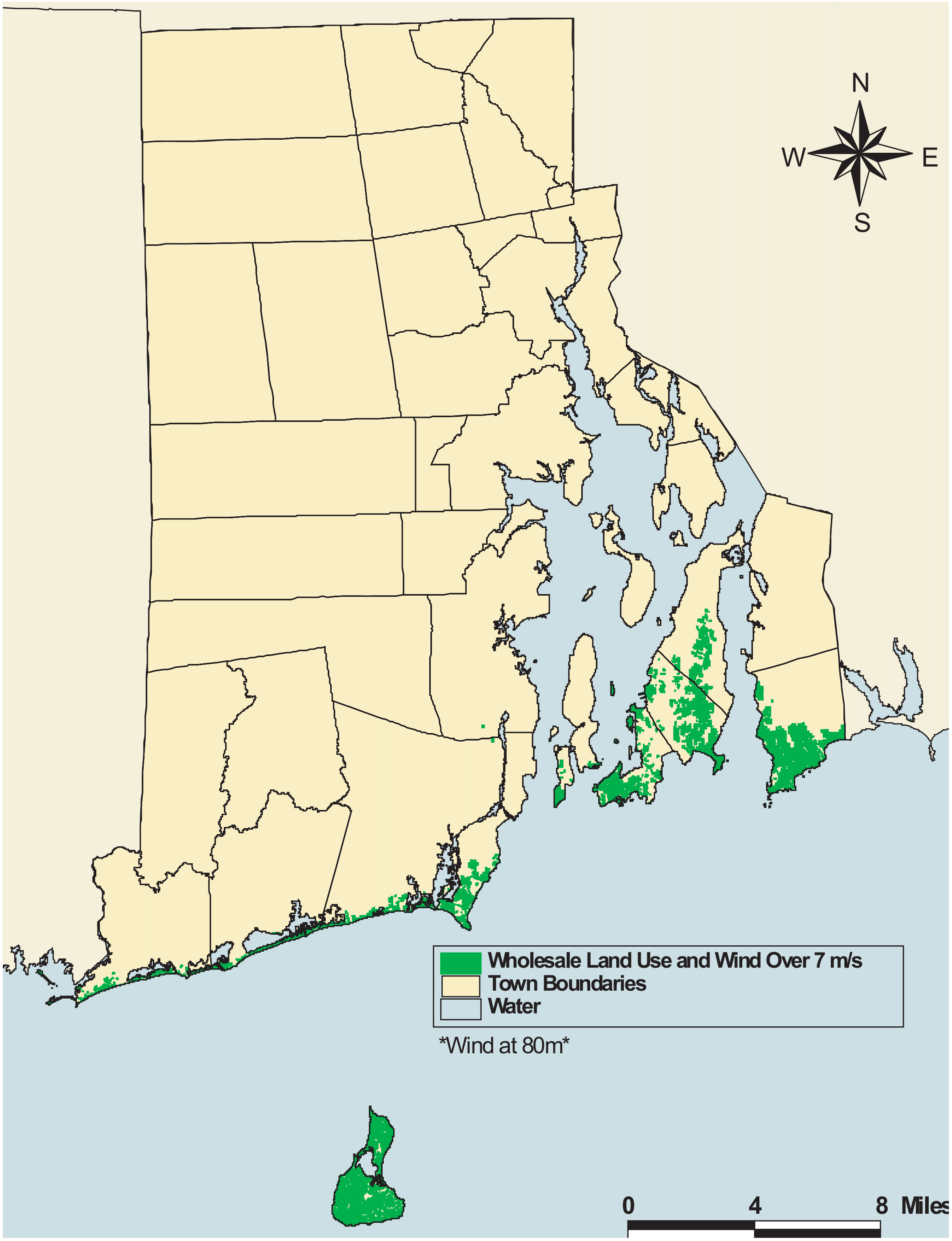

06-1296 3-7.cdr 04/10/07

Figure 3-7

Map Showing Wholesale Suitable Areas with Wind Speeds over 7 m/s at 80m Elevation Onshore

RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

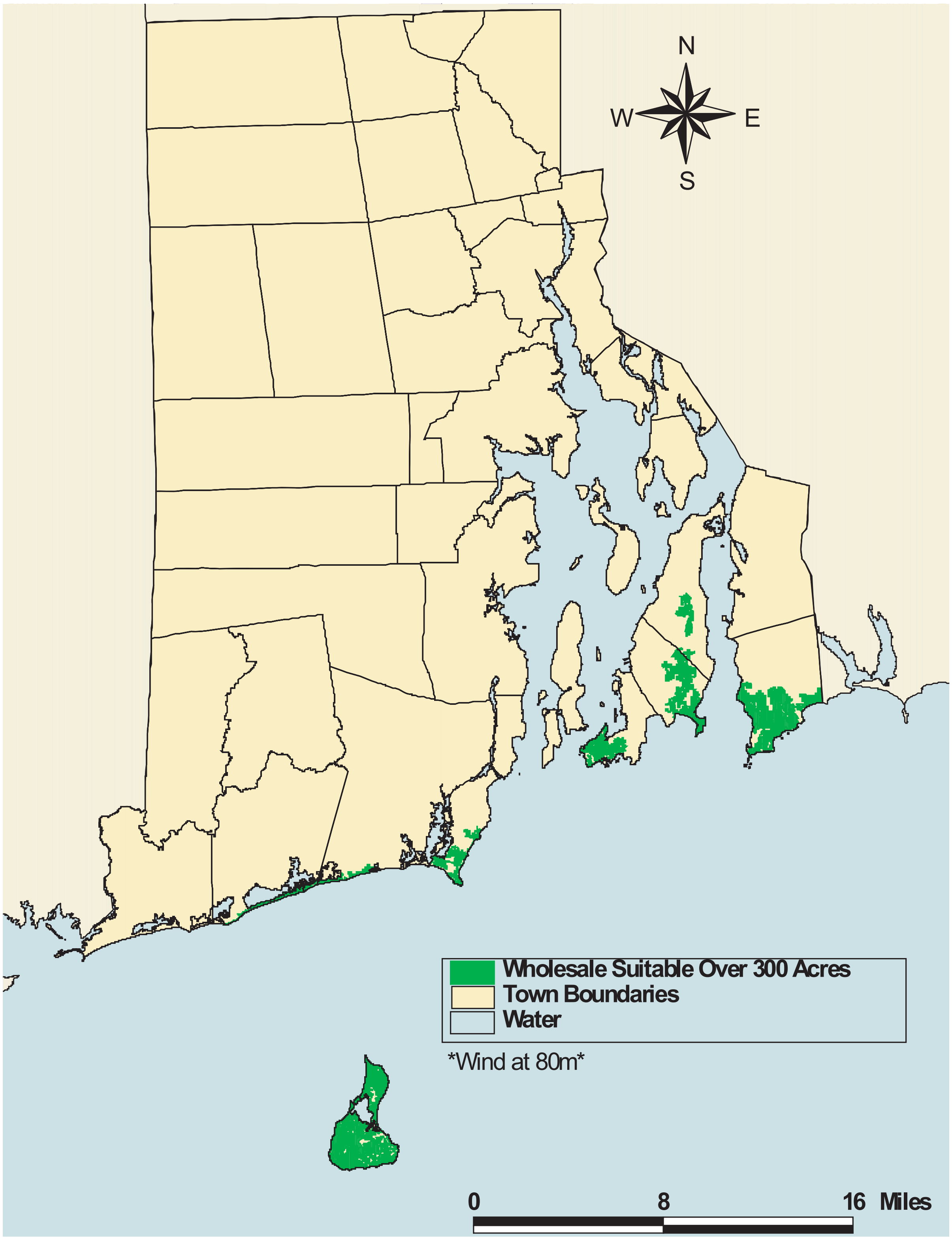

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Figure 3-8
Map Showing Areas Suitable after Onshore Wholesale Level 1 Screening
RIWINDS Siting Study

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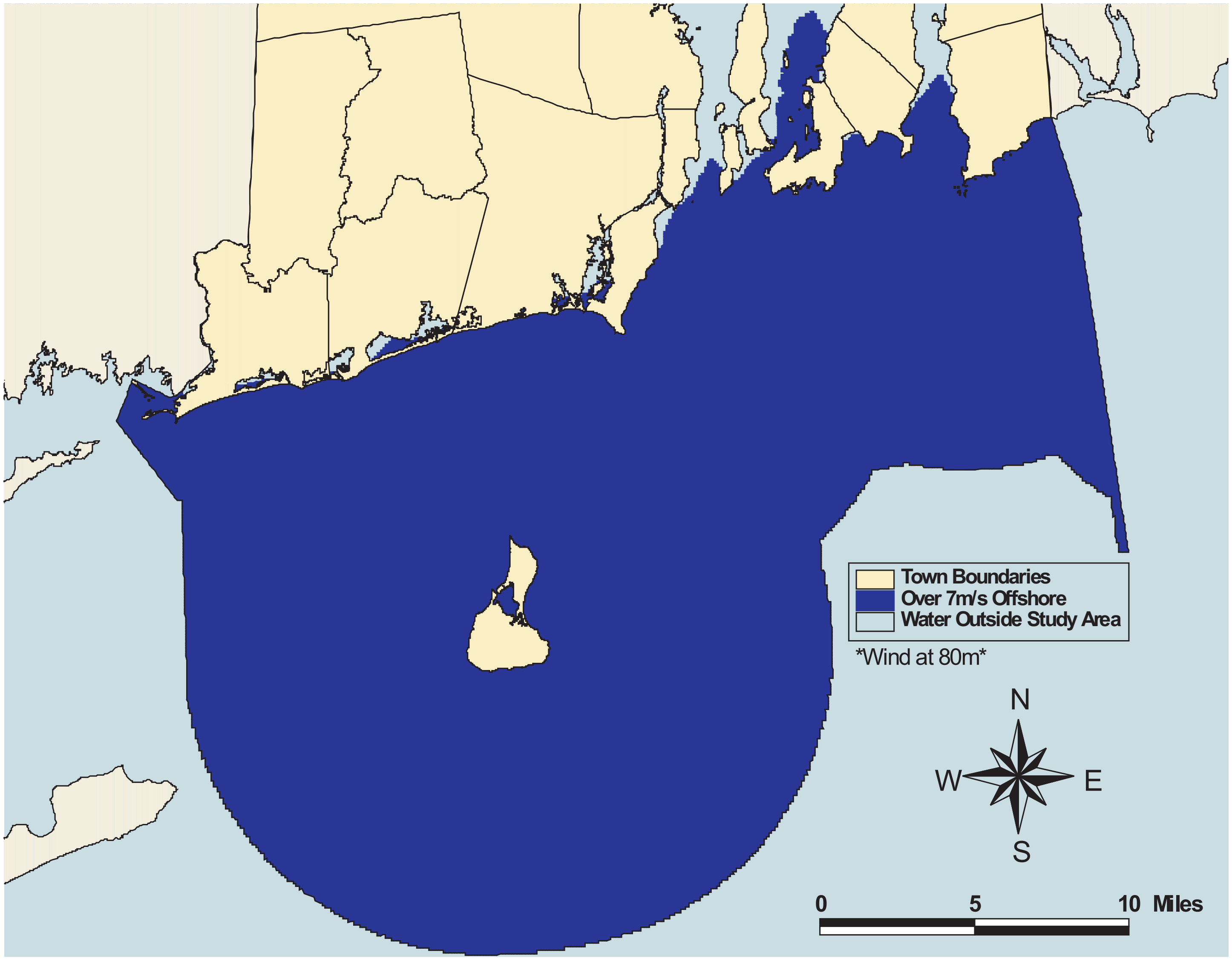

Figure 3-9

Map Showing Areas with Wind Speeds over 7m/s at 80m Elevation Offshore
RIWINDS Siting Study

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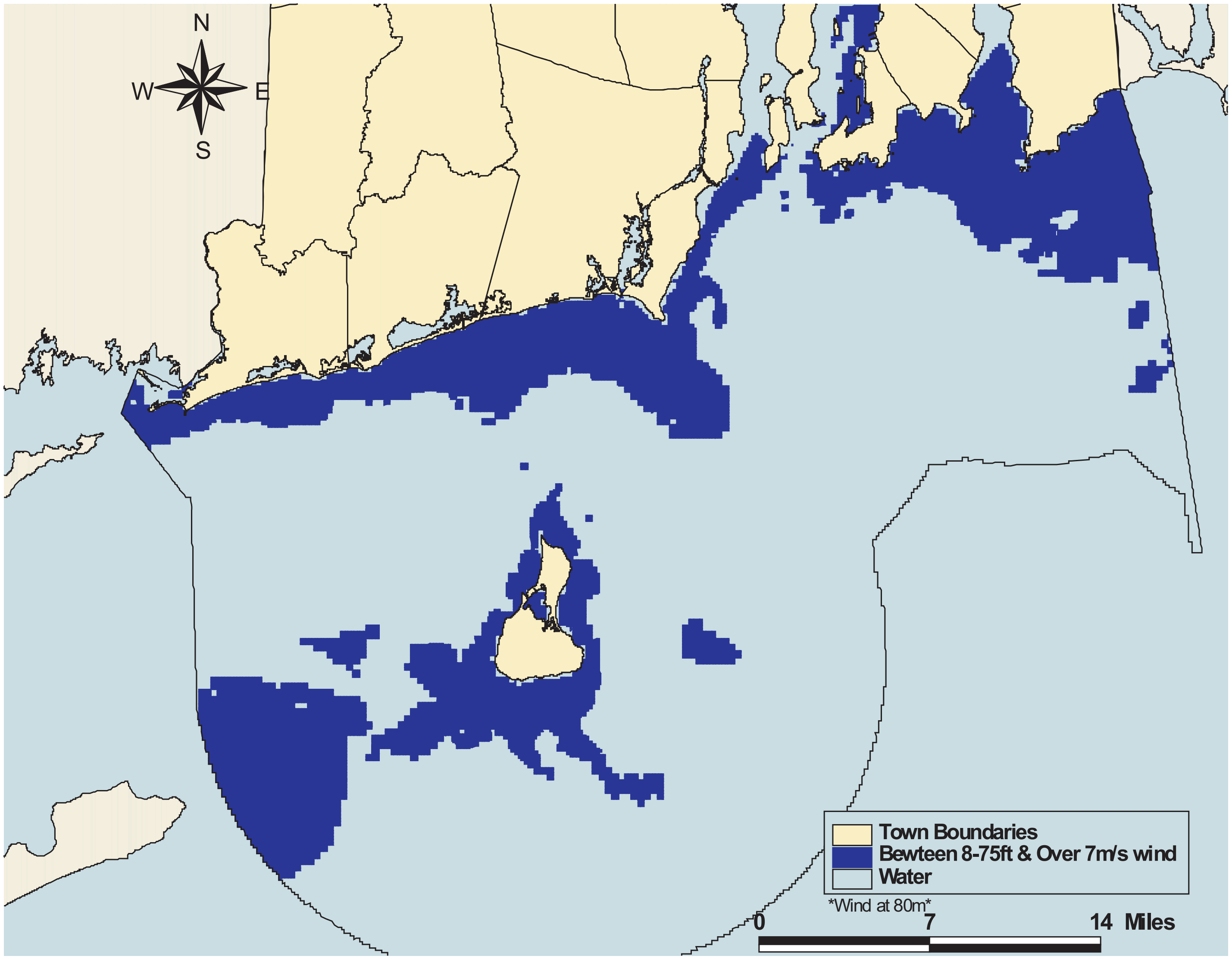

Figure 3-10
Map Showing Areas with Wind Speeds over 7m/s at 80m Elevation Offshore and Water Depth Between 8 and 75 Feet
RIWINDS Siting Study

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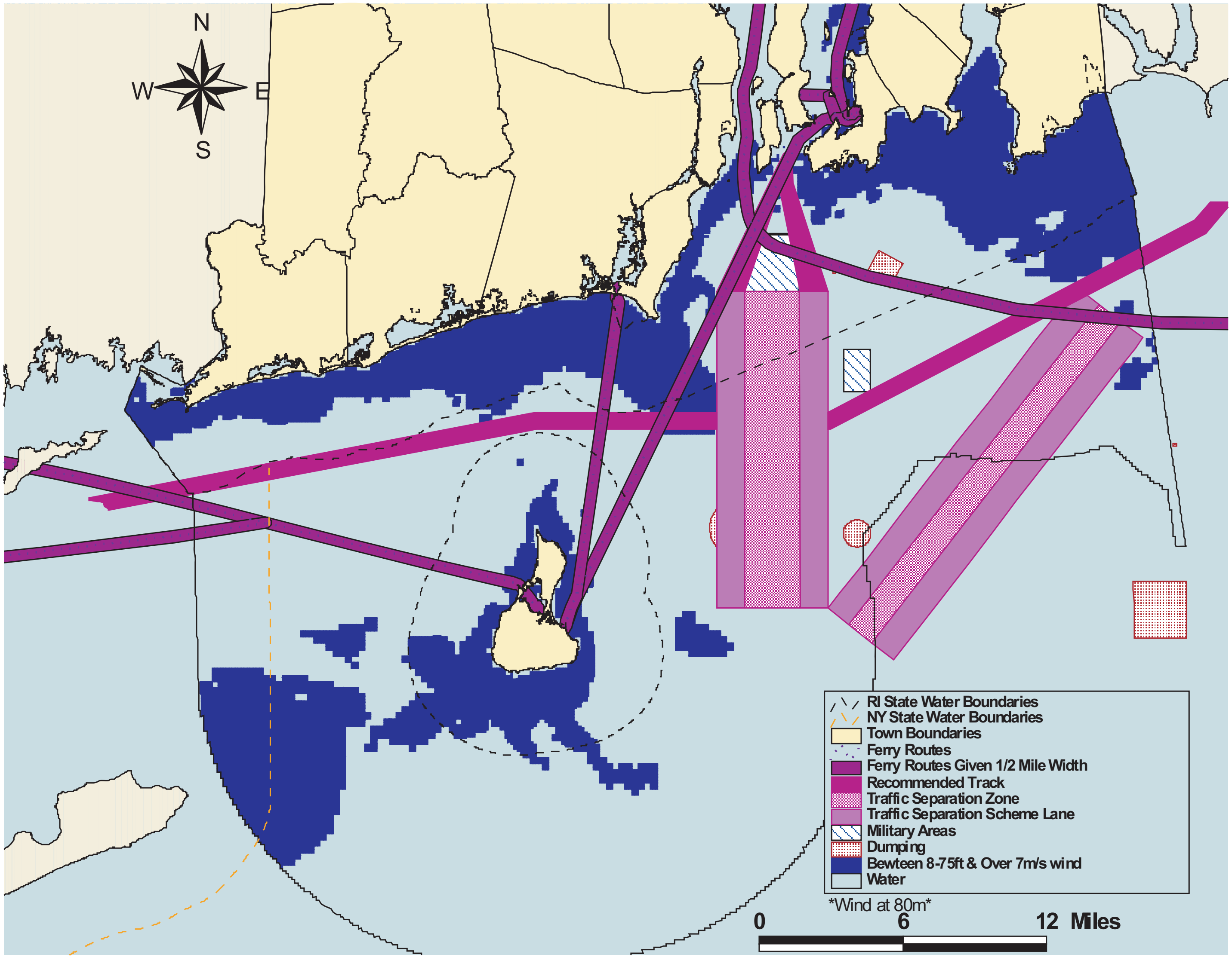

Figure 3-11

Map Showing Offshore Navigational Restrictions
RIWINDS Siting Study

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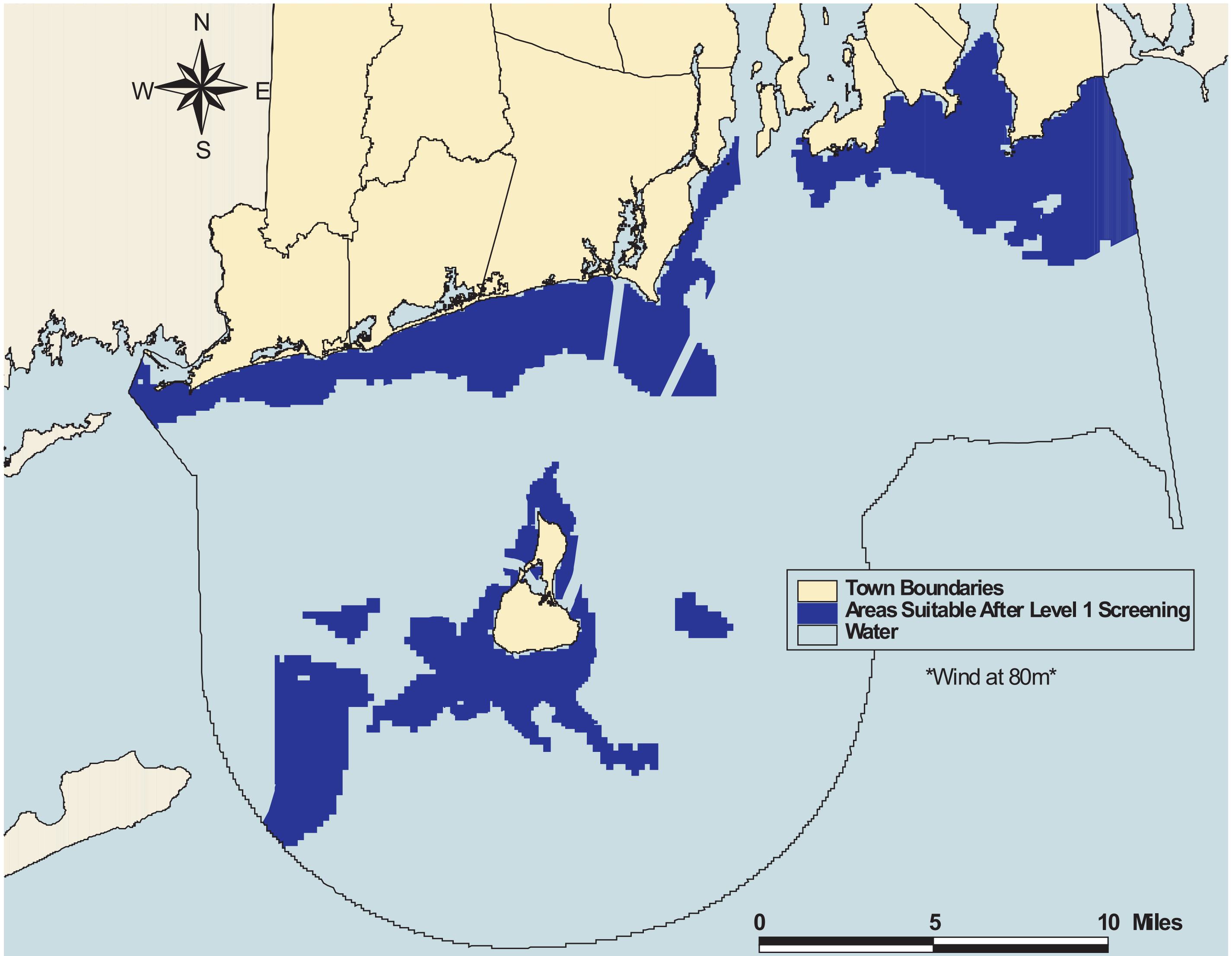

Figure 3-12
Map Showing Areas Suitable After Offshore Level 1 Screening
RIWINDS Siting Study

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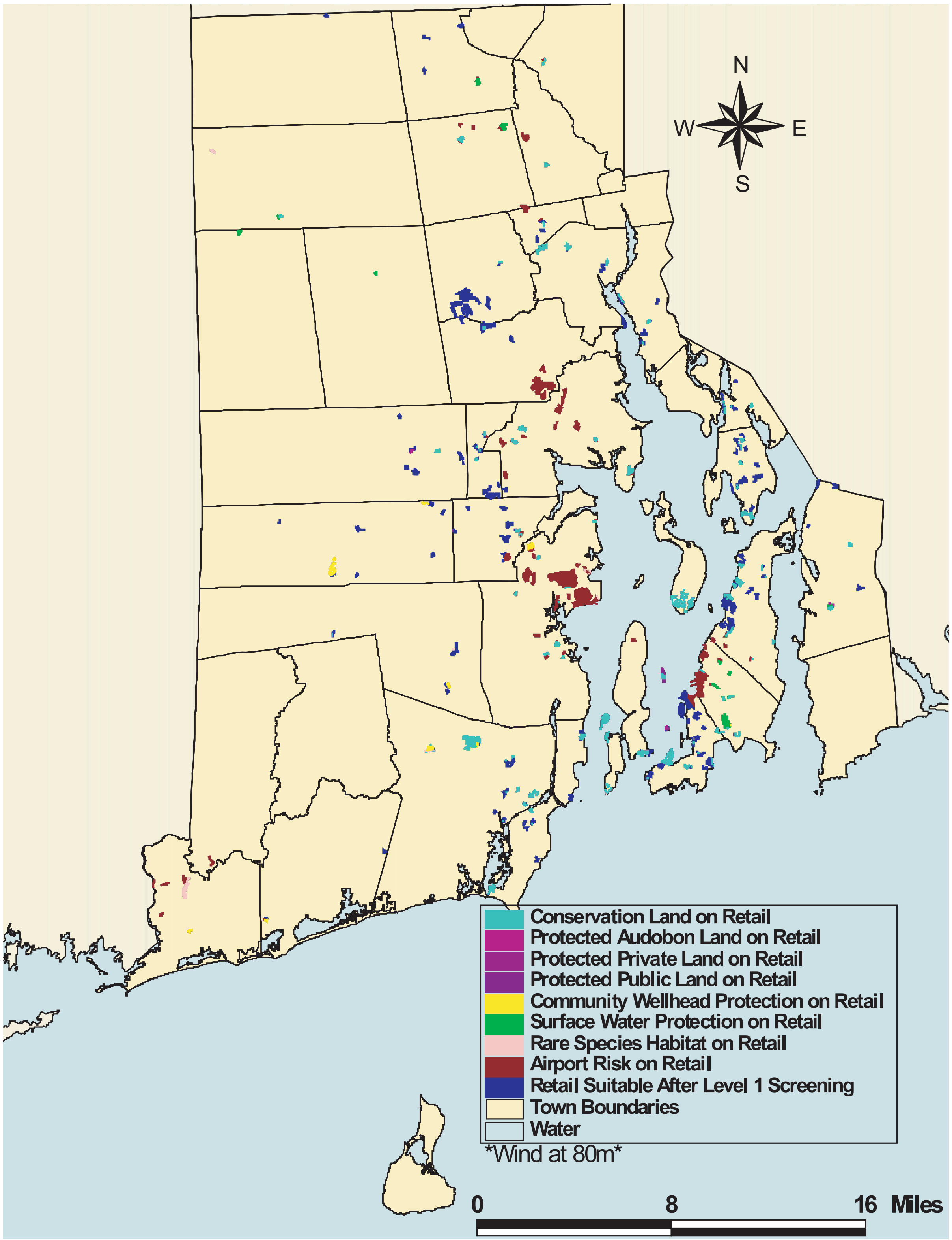

Figure 3-13

Map Showing Overlay of Level 2 Exclusionary Criteria on Areas Suitable After Onshore Retail Level 1 Screening
RIWINDS Siting Study

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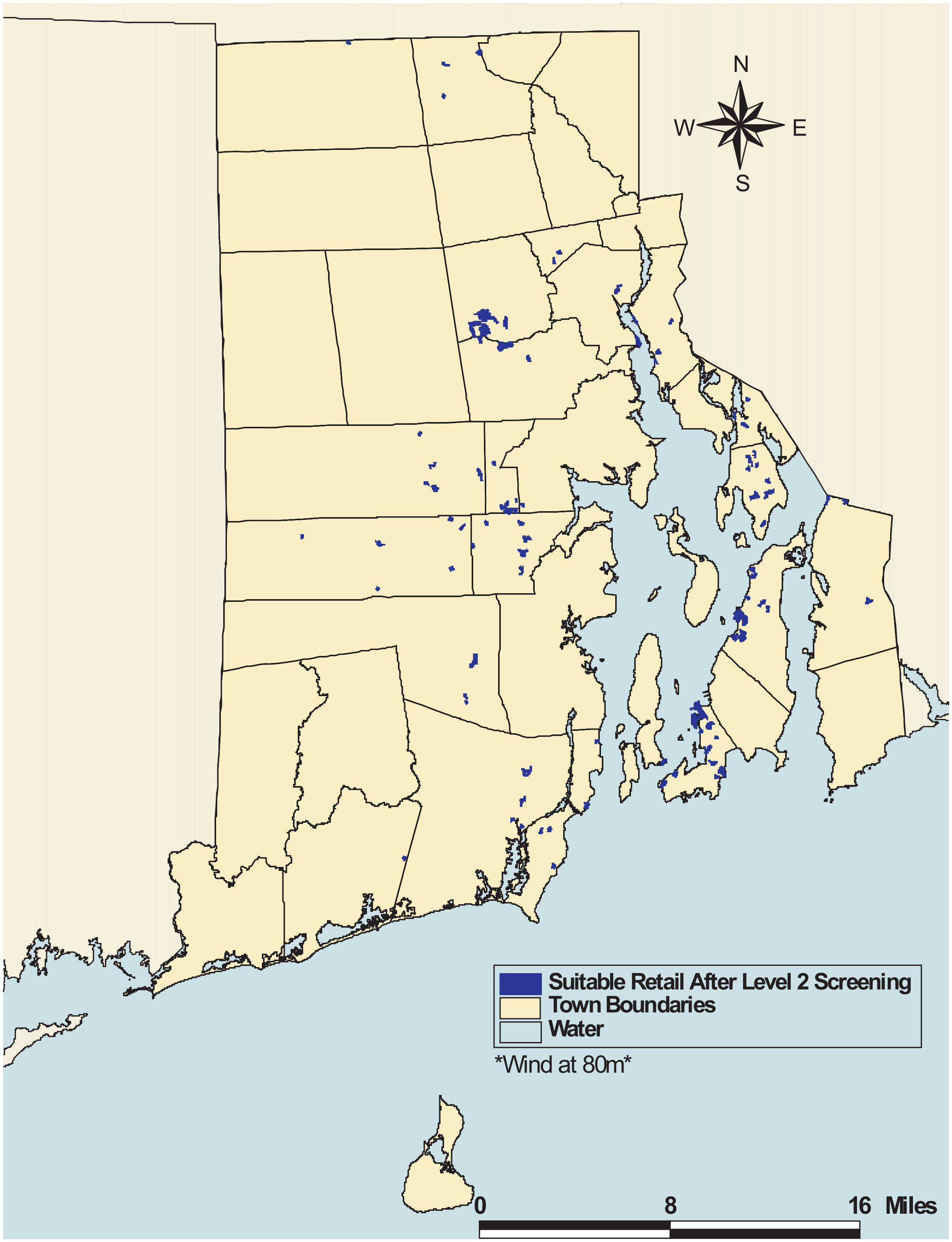

Figure 3-14
Map Showing Areas Suitable After Onshore Retail Level 2 Screening
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

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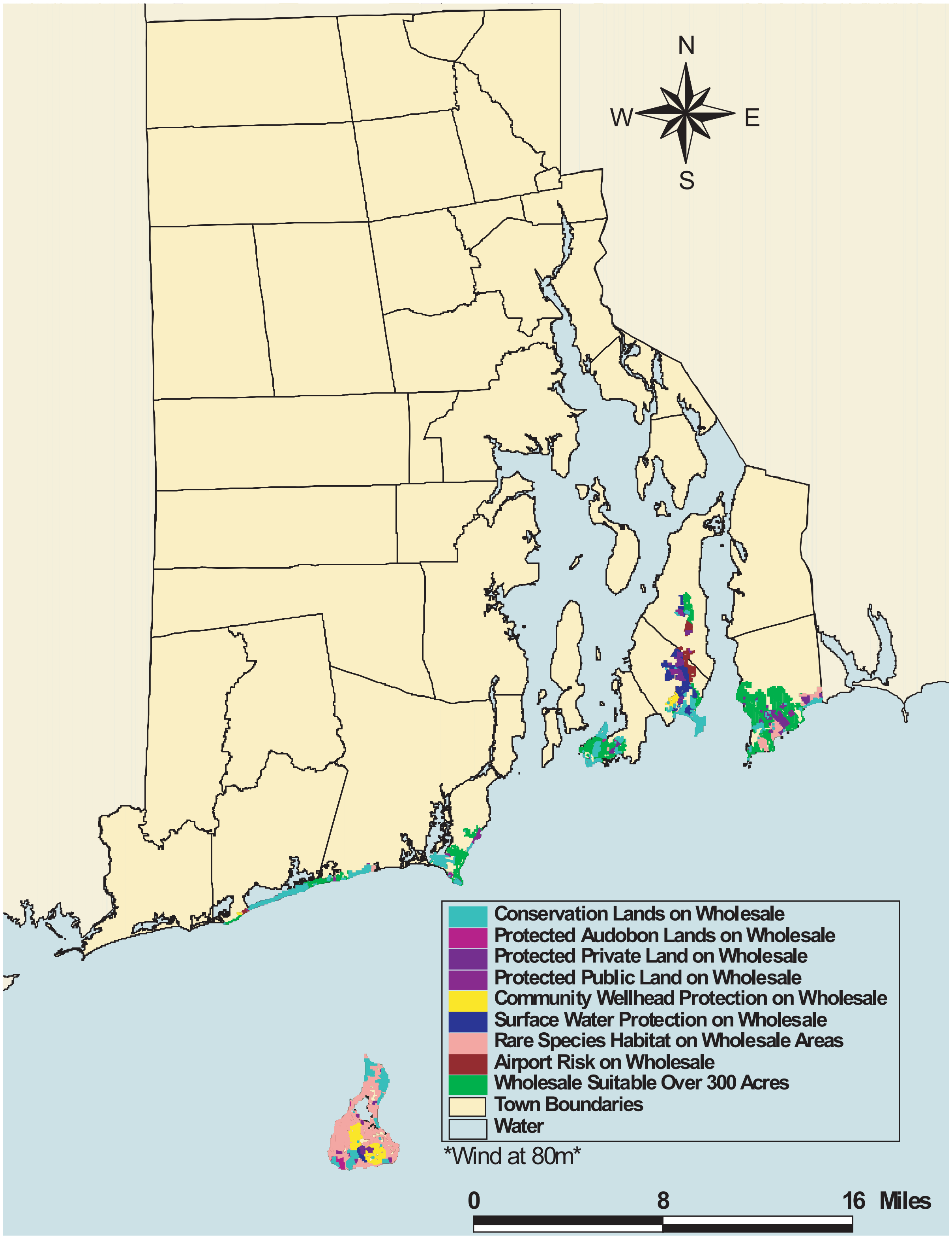

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Figure 3-15

Map Showing Overlay of Level 2 Exclusionary Criteria on Areas Suitable After Onshore Wholesale Level 1 Screening
RIWINDS Siting Study

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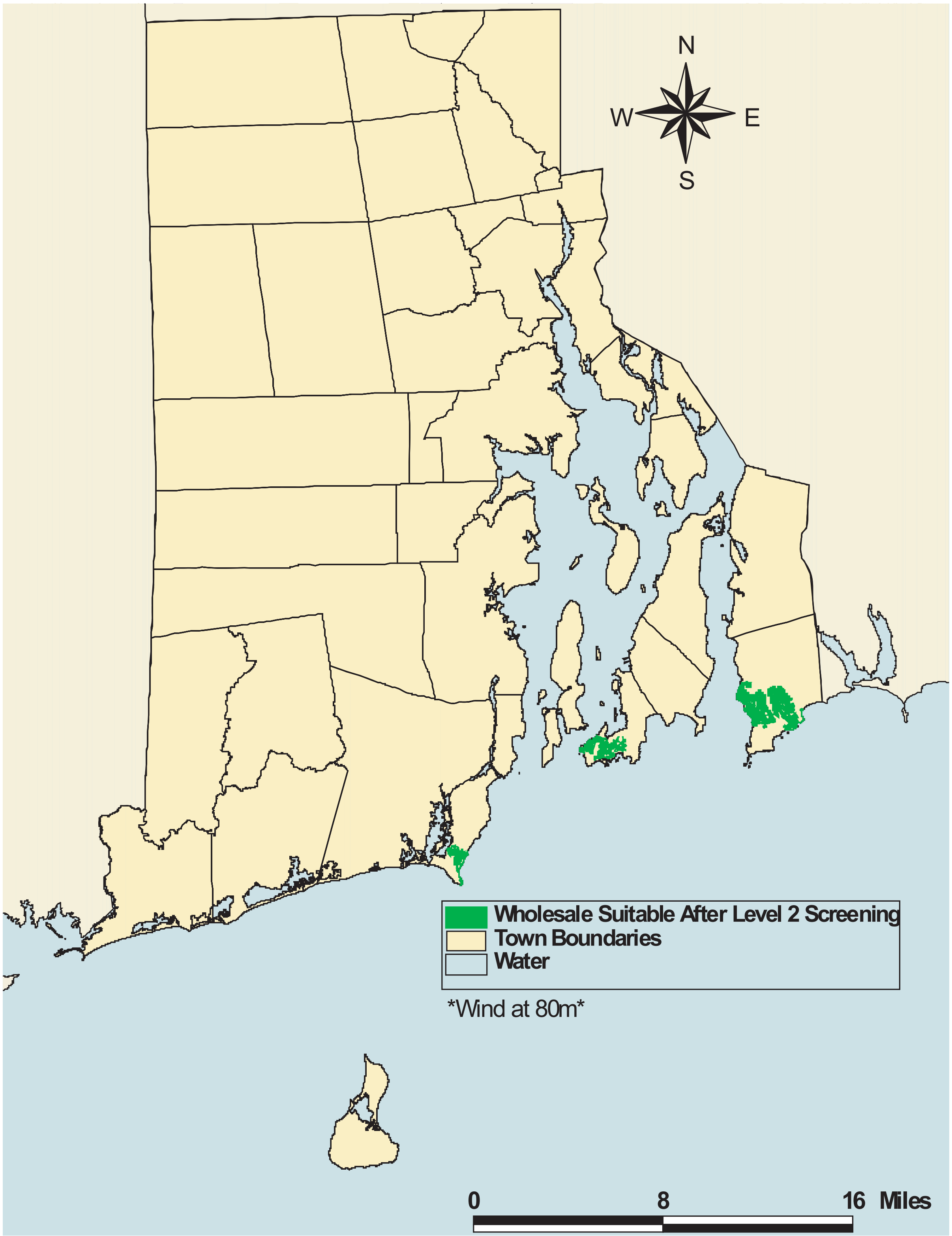

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Figure 3-16
Map Showing Areas Suitable After Onshore Wholesale Level 2 Screening
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

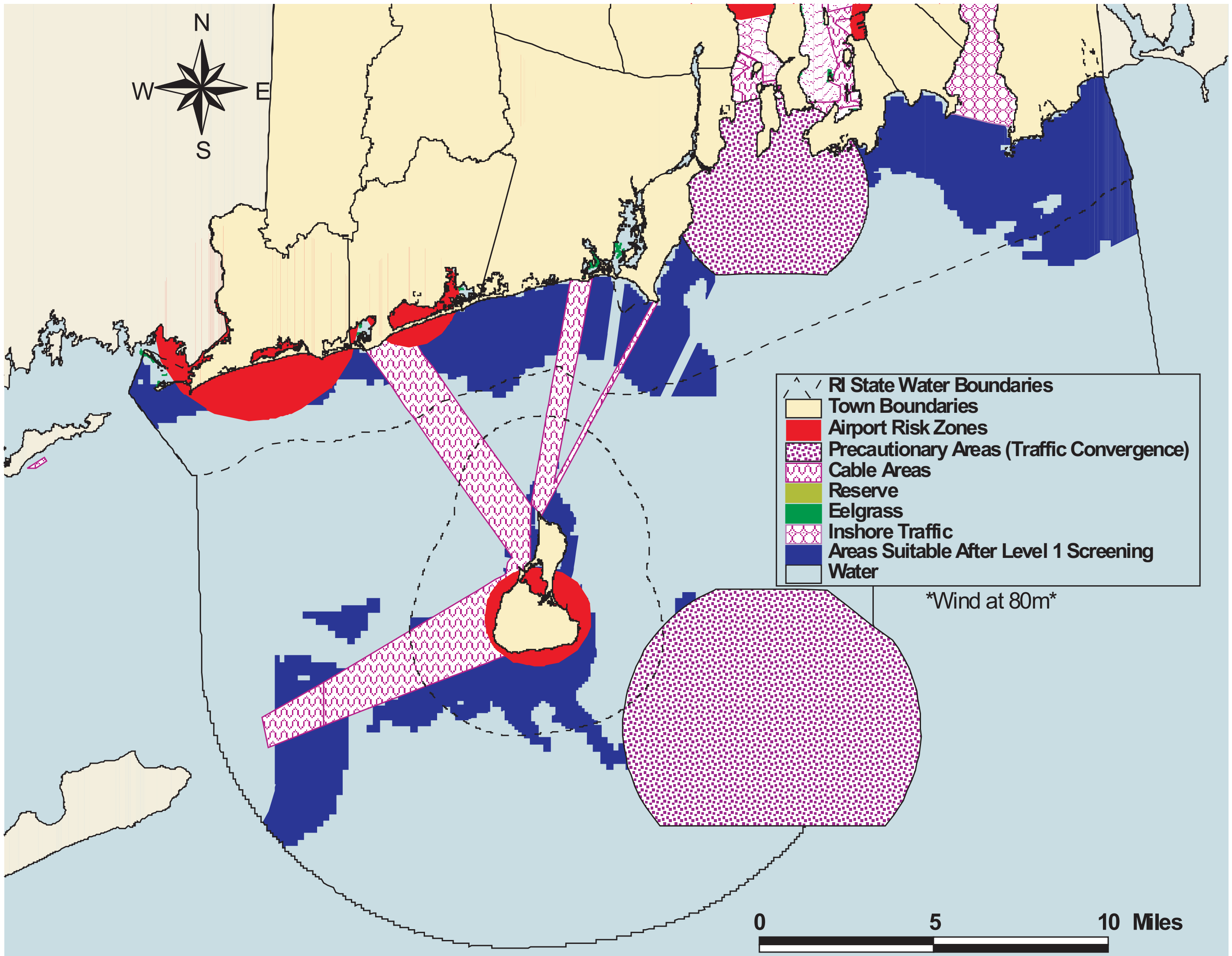

Figure 3-17
Map Showing Areas Offshore Level 2 Restricted Areas
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

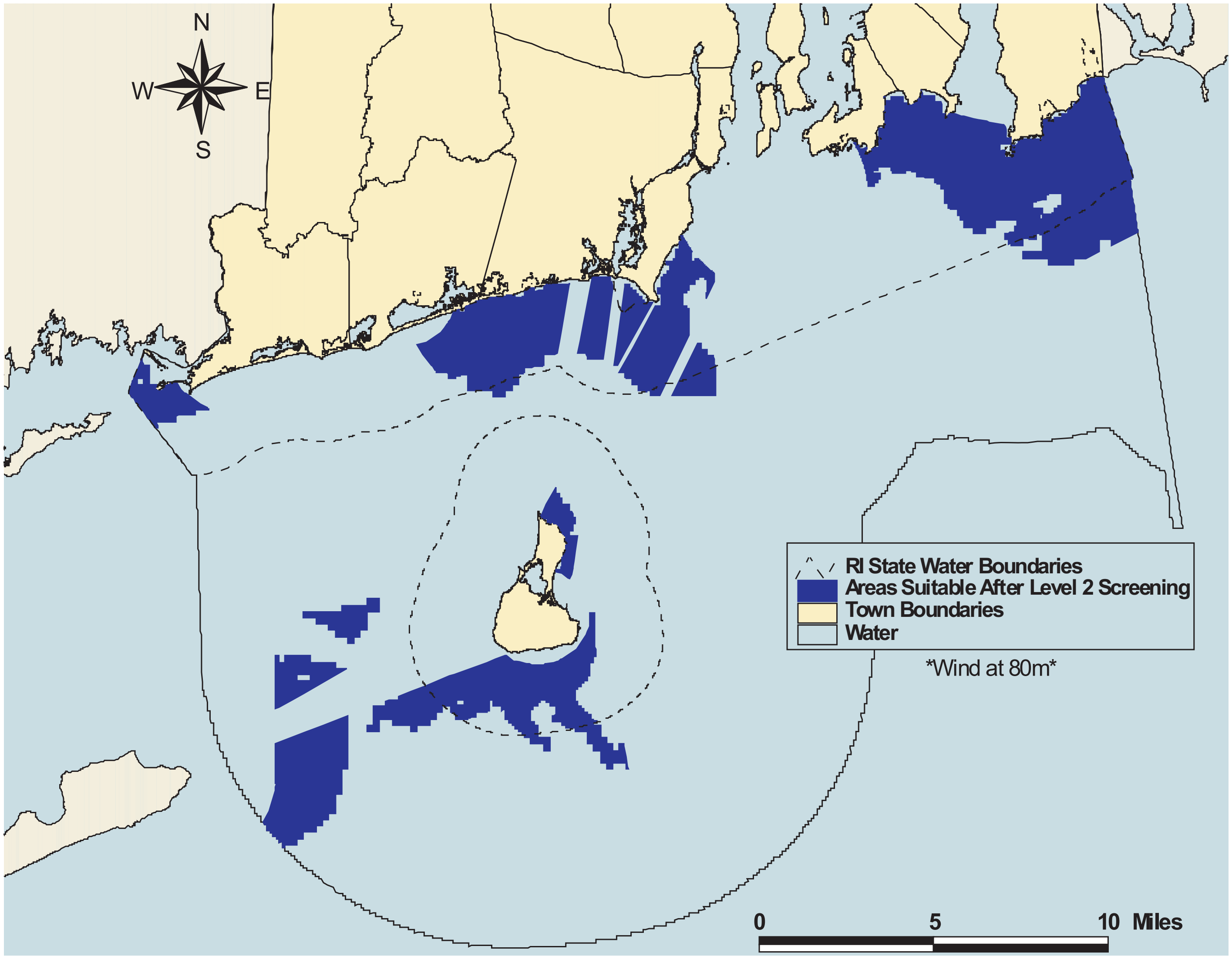

Figure 3-18
Map Showing Areas Suitable After Offshore Wholesale Level 2 Screening
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

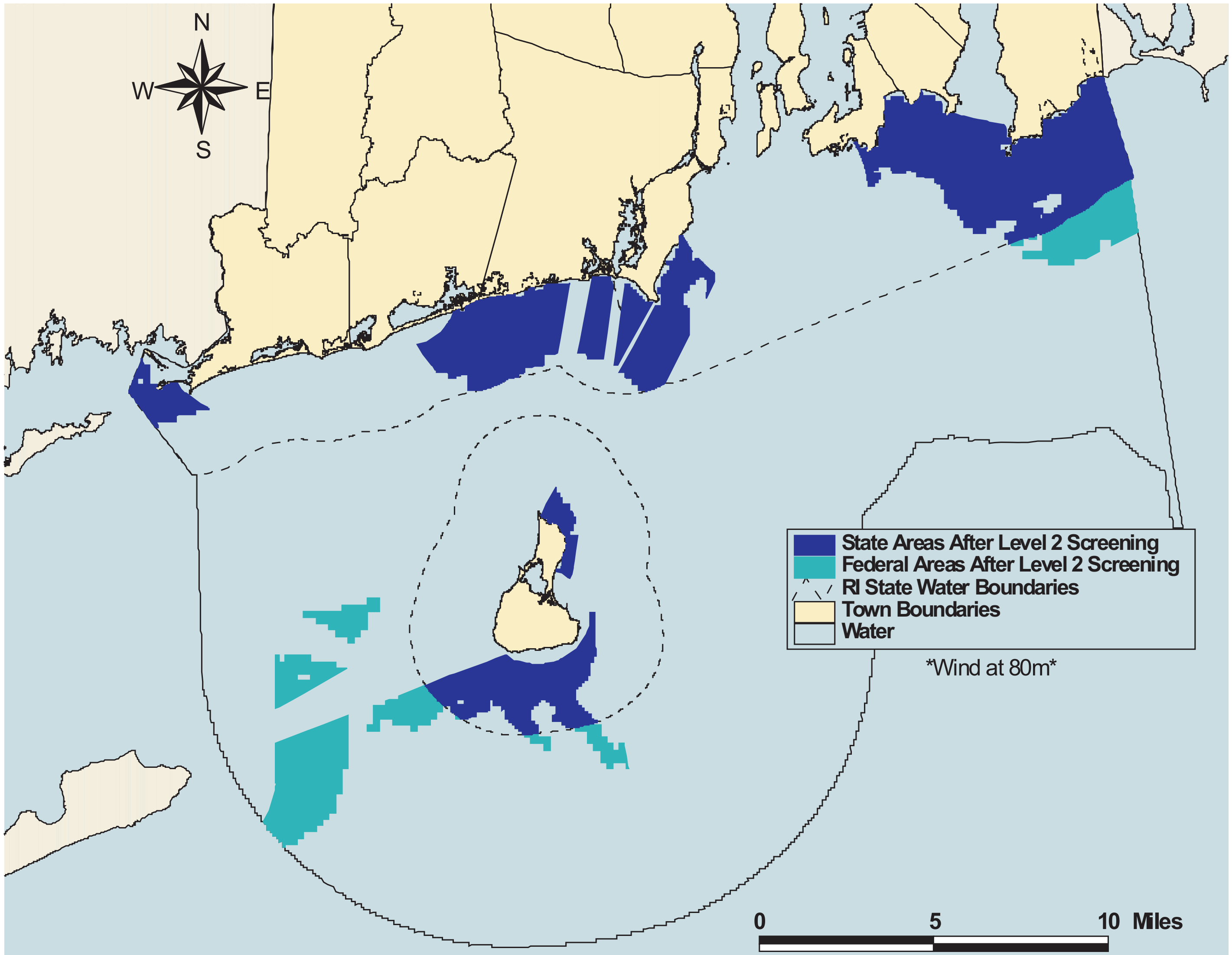

Figure 3-19
Map Showing Post Level 2 Screening Areas Separated into State and Federal Areas
RIWINDS Siting Study

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APPLIED TECHNOLOGY & MANAGEMENT

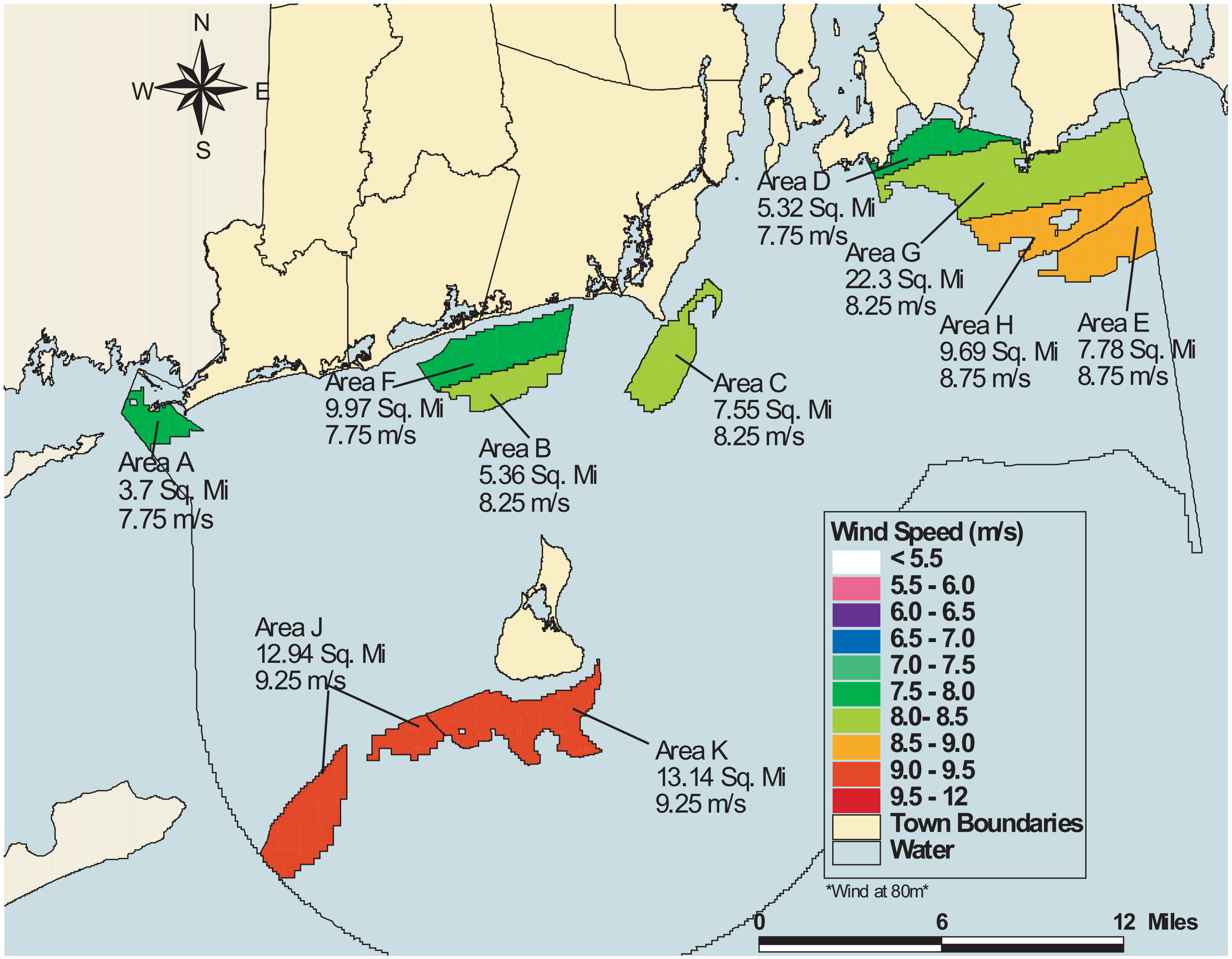

Figure 3-20

Map Showing Post Level 2 Screening Areas Separated by Wind Speed and Final Area Designation
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

4.0 SITE CAPACITY

4.1 TURBINE SELECTION

As stated in the goal of the RIWINDS program, the purpose of this study was to identify the most viable sites to reach the RIWINDS goal of 1.3×10^6 MW-h/year of wind generated electricity. To meet this ambitious goal, it was agreed to consider only utility scale WTGs. The 1.5 MW WTG is a very common machine and almost ubiquitous in the wind industry with literally thousands of units in operation around the world. The trend in the wind industry is towards larger WTGs to increase the economies of scale associated with larger WTGs. Larger turbines such as 2.0 MW and 2.5 MW are currently being installed on land, but for purposes of this study it was decided that the analyses be performed with the specifications of a well proven 1.5 MW WTG for onshore/land-based applications. For purposes of this study's performance and cost estimates, performance and cost data for the General Electric (GE) Model 1.5sle WTG were used. GE is the largest domestic manufacturer of WTGs and data for this WTG is widely available.

The economies of scale for WTGs are even more pronounced for offshore installations. Foundation costs and erection costs per WTG are significantly greater for offshore projects than for onshore projects. Therefore, larger WTG sizes will decrease these project costs components on a $/kW basis. In addition, WTG for offshore applications need to be constructed of improved materials to withstand the corrosive environment of offshore saltwater environment. Vestas currently manufactures a 3.0 MW wind turbine generator for the European offshore wind market, but this unit operates at 50 Hz and the US electric system operates at 60 Hz. GE is developing a 3.6 MW WTG for near-term offshore applications. GE is also designing a larger, 5 MW WTG for offshore applications under a research and development grant from the US Department of Energy. For purposes of this study, the technical specifications of the GE 3.6 MW WTG were used to take advantage of economies of scale that should be available in the timeframe for application in the RIWINDS program.

4.2 WIND TURBINE PERFORMANCE ESTIMATES

The performances of the two candidate wind turbine generators were evaluated against the characteristics of the different sites to estimate potential power output. The performance of a WTG is based on its power curve as well as the frequency distribution of wind speed. The power curve is a curve that shows the power output at various wind speeds. The approximate power curves for the GE 3.6MW and GE 1.5MW WTGs are shown in Figures 4-1 and 4-2 respectively.

The frequency curve shows the probability, as percent of the time, of the occurrence of various wind speeds. The curves for onshore retail and wholesale as well as an example offshore site were introduced in Section 2.2. The frequency distribution for each offshore site was calculated by scaling all BUZM3 data by the ratio of average annual wind speed between BUZM3 and the site. Table 4-1 shows the average annual wind speed for each of the offshore sites as well as its ratio to that at BUZM3, all at 80m elevation.

The expected gross output power from the WTG is the sum of the power generated at each wind speed multiplied by the percent of time that wind speed is expected (from the frequency distribution) over the range of operational wind speeds for the WTG, minus turbulence losses which were assumed to be 5 percent (DuPont 2006). The gross output energy is the sum of the average gross output power multiplied by the time in which the frequency distribution curve was generated (i.e. probability of various wind speeds over the course of a year). Tables 4-2 and 4-3 list the gross energy output for the 3.6 MW & 1.5 MW turbines, respectively, as a function of average annual wind speed.

The WTG performance curves are used to estimate the amount of electrical energy that can be produced by each WTG before losses, based on the available wind resource. This is generally referred to as the "gross" energy production under ideal conditions. The gross energy production needs to be reduced by "system losses" to determine the net energy produced by a wind turbine project over a long period of time. The primary system loss factors include the following.

- Electrical losses. This is the electrical line loss dependent upon the distance between the WTGs and the point of interconnection.
- Turbine availability. This is the loss in electrical production due to scheduled and unscheduled maintenance.
- Turbine interaction losses. This is the loss in WTG output due to the wind turbulence created by upstream turbines (This loss would be zero for single unit installations.) This loss can be reduced by increasing the distance between turbines, but increased separation increases electrical cable cost and loss, so some interaction loss is inevitable.

Other losses include turbine blade icing, blade soiling, high wind speed cutout.

Project specific loss calculations are site specific, dependent upon many varied factors and beyond the scope of this study. However, an estimate of losses must be included in any wind project performance estimates. For purposes of this study, the following system losses were assumed for each type of project.

Type of Project:	System Losses:	Comments:
Customer-Connected	11 %	Lowest because no interaction losses and minimum electrical losses.
Onshore Grid-Connected	15 %	Interaction losses.
Offshore Grid-Connected	18 %	Highest because of high availability loss due to difficult maintenance environment and greatest electrical losses due to distance from electrical grid.

The net energy production is equal to the gross production minus these external losses.

4.3 CAPACITY SUMMARY FOR AREAS

The capacity for each of the potential sites was calculated based on the project site characteristics (size and wind speed distribution) and turbine characteristics and estimation of losses. The summary for each site is shown in Table 4-4 and Figure 4-3 represents the distribution of the potential contribution from each of the different project types. Almost all of the potential energy is offshore with a total potential over 6 million MWh/yr.

Table 4-1 Summary of Average Annual Wind Speed of Offshore Sites

Site (Area #)	Average Annual Wind Speed at 80m Elevation (m/s)	Ratio to Buzzards Bay (BUZM3) (%)
A	7.75	86
B	8.25	92
C	8.25	92
D	7.75	86
E	8.75	97
F	7.75	86
G	8.25	92
H	8.75	97
J	9.25	103
K	9.25	103

Table 4-2 Summary of Estimated Gross Energy Output for the GE 3.6 WTG

	GE 3.6s WTG	
m/s	kW-h $*10^6$	MW-h
7.00	10.645	10645
7.25	11.401	11401
7.50	12.034	12034
7.75	12.720	12720
8.00	13.297	13297
8.25	13.882	13882
8.50	14.507	14507
8.75	15.050	15050
9.00	15.530	15530
9.25	16.105	16105
9.50	16.600	16600

Table 4-3 Summary of Estimated Gross Energy Output for the GE 1.5 WTG

GE 1.5sle WTG		
m/s	kWh $*10^6$	MWh
6.50	4.00	4000
6.75	4.25	4250
7.00	4.52	4520
7.25	4.80	4800
7.50	5.00	5000

Table 4-4 Capacity Summary for All Areas

Name	Project Type (MW)	Number of Turbines	Average Wind Speed (m/s)	Typology Gross Potential (MWh/yr)	Typology Predicted (MWh/yr)	Typology Net Energy Production (MWh/yr)	Net Potential Energy Production Based On Area Required/Available Area (MWh/yr)
Customer-Connected	1.5	1	6.5	13140	4000	3560	3560
Community	1.5	1	7	13140	4520	4023	4023
Onshore	10	7	7	91980	4520	26894	26894
Offshore Area A	30	9	7.75	283824	12720	93873	229049
Offshore Area B	30	9	8.25	283824	13882	102450	366088
Offshore Area C	30	9	8.25	283824	13882	102450	515665
Offshore Area D	30	9	7.75	283824	12720	93873	332935
Offshore Area E	30	9	8.75	283824	15050	111071	576087
Offshore Area F	200	56	7.75	1766016	12720	584096	582344
Offshore Area G	200	56	8.25	1766016	13882	637467	1421552
Offshore Area H	200	56	8.75	1766016	15050	691106	669682
Offshore Area J	200	56	9.25	1766016	16105	739561	956992
Offshore Area K	200	56	9.25	1766016	16105	739561	971783

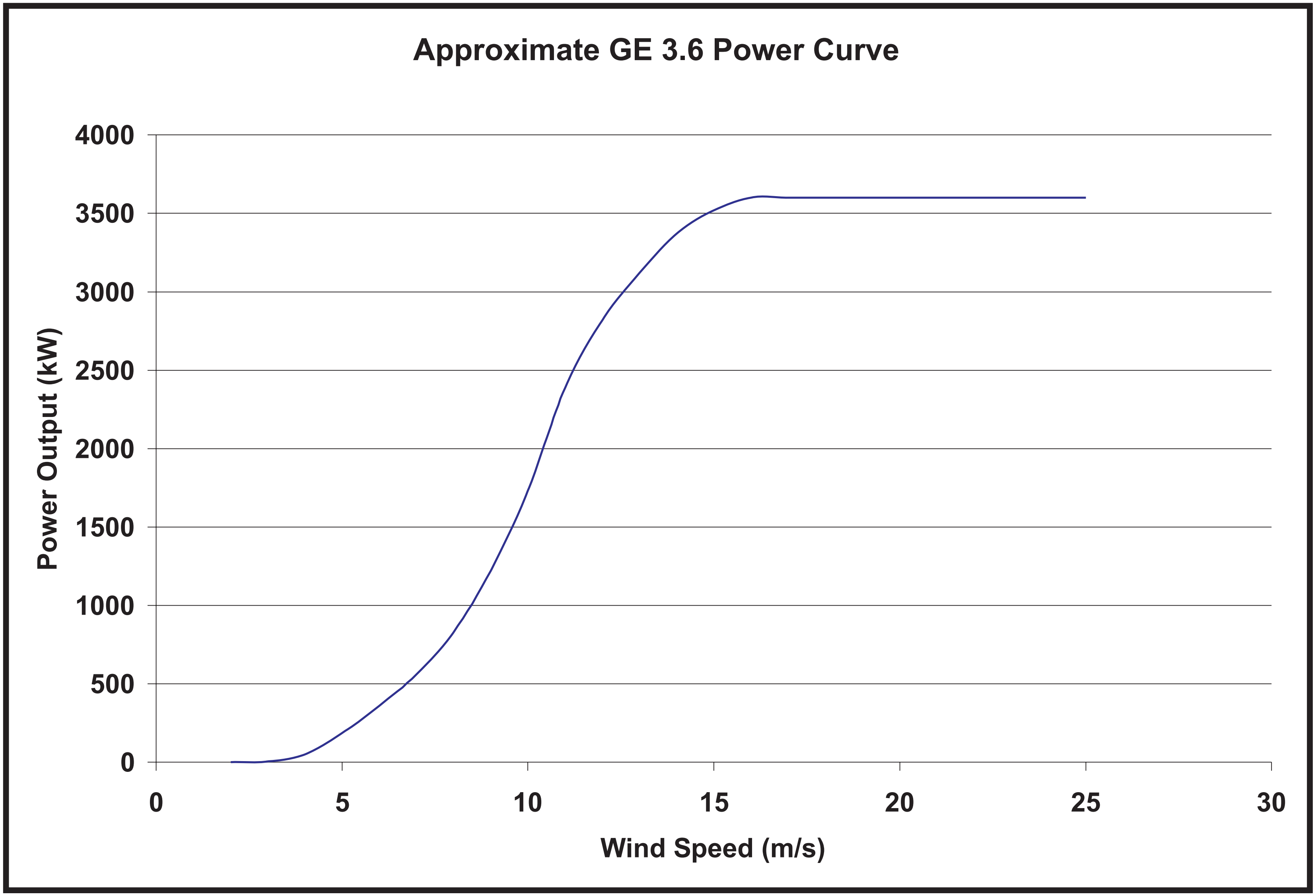

Figure 4-1
Approximate GE 3.6 WTG Power Curve
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

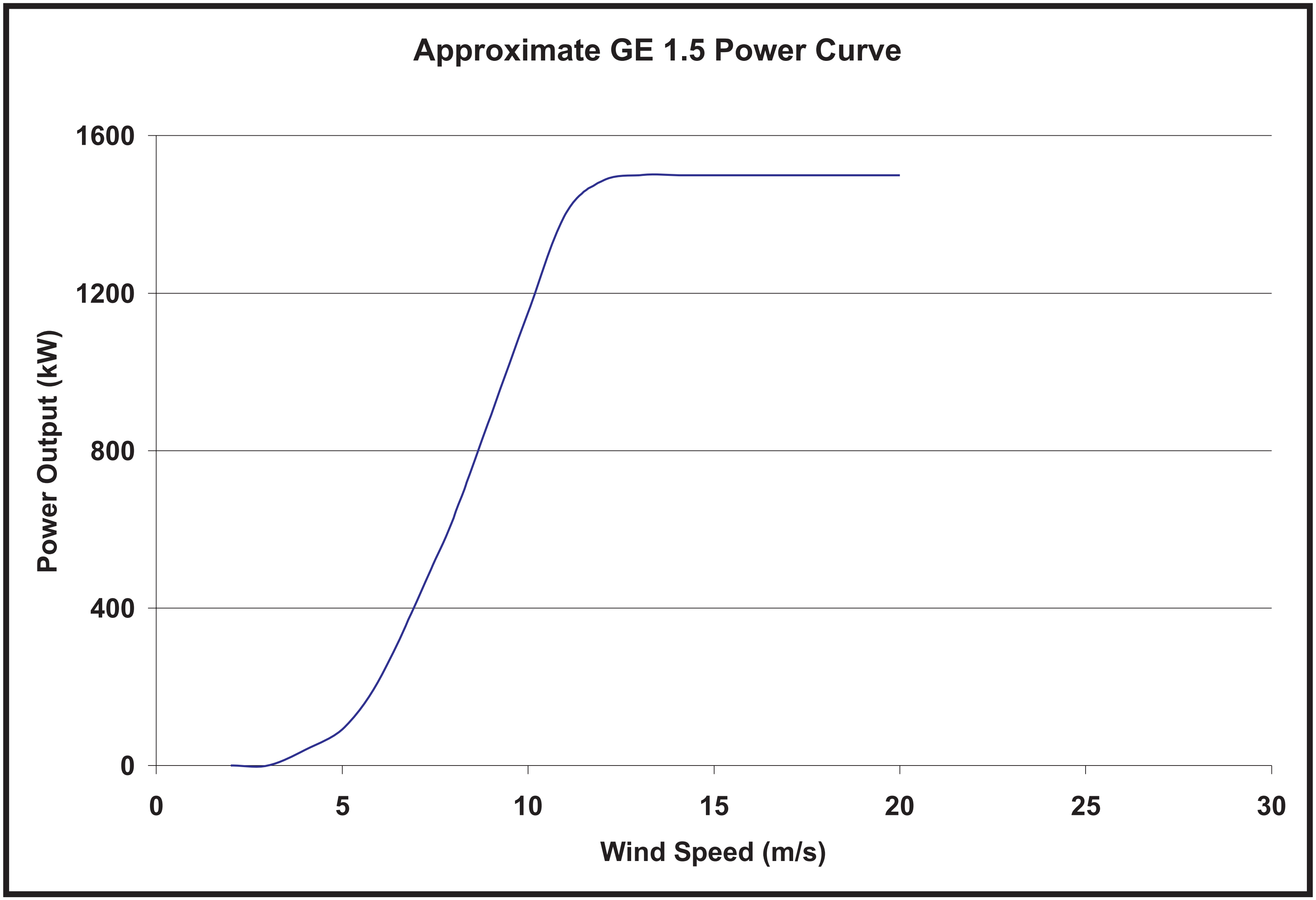

Figure 4-2
Approximate GE 1.5 WTG Power Curve
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

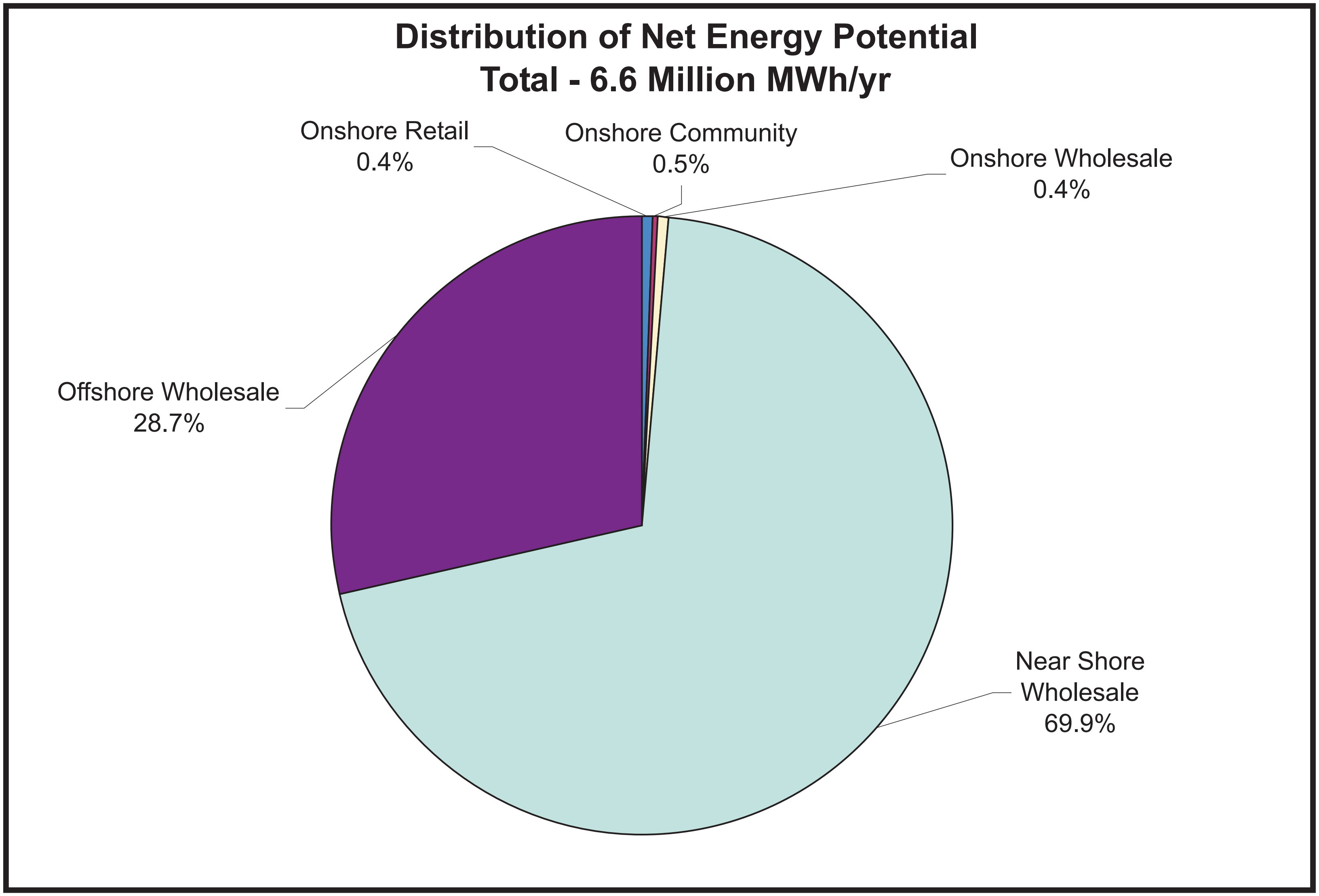

Figure 4-3
Distribution of Net Energy Potential
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

5.0 COST ESTIMATES

Project cost estimates and operation and maintenance (O&M) cost estimates were developed for each project type and study area identified in the previous sections. These cost estimates are based on preliminary design criteria, using fourth quarter 2006 costs, and without the benefit of performing detailed equipment layouts, engineering calculations, or detailed material lists or specifications. Good engineering judgment and the experience and knowledge of engineers working in the wind power sector were utilized to develop the estimated costs to construct and operate the indicative projects. The goal was to provide order of magnitude costs for each system configuration that would furnish our team with the infrastructure cost input information needed for the financial analysis.

5.1 CAPITAL COST ESTIMATES

The capital cost estimates were developed for the indicative projects by estimating the direct and indirect costs and the development costs for each project type. The estimates were adjusted to be consistent with publicly available project cost estimates for similar projects. The estimated interconnection cost and transmission improvements cost for the specific study area was added to develop a total project cost for each project type. O&M cost estimates were similarly developed for each project category (e.g. onshore versus offshore). This section describes the assumptions and methodology used to develop each of these cost components.

5.1.1 ONSITE CONSTRUCTION COSTS

5.1.1.1. Onshore Projects

The onsite cost items for the onshore projects include the wind turbine generator (WTG), construction contractor mobilization, site improvements including clearing, grading and building access roads foundations electrical connection, electrical interconnection, and WTG erection.

Turbine Costs

For purposes of this study, the General Electric (GE) Model 1.5sle WTG was selected for onshore applications. This unit has a rate of 1.5 MW. GE provided a budgetary cost estimate for the turbine generator and 80 meter tower which was used in the cost estimate.

Electrical Costs

The 1.5 MW projects (i.e. customer-connected and community) consist of one WTG generating at 4 kV. It was assumed to be located approximately 500 feet from a typical existing distribution feeder circuit. The WTG would be self contained with its own step up transformer, and control and instrumentation systems. An underground cable was assumed to be the method that would be used to interconnect with the local electric utility.

The 10 MW onshore projects consist of seven 1.5 MW units generating at 4 kV. Individual collection cables coming from each WTG would be routed to an onsite substation where these 7 cables would be bussed together and routed through a circuit breaker and connected to a dedicated 15 kV feeder circuit. This feeder would be overhead construction and would emanate from a substation owned by the local utility. A small control house would be required to house the generator control systems, relay system and batteries, and metering components, and other miscellaneous components.

Civil/Structural Costs

The onshore project civil/structural cost estimates include the cost of mobilization; site improvements including clearing, grading and building access roads; foundations, and WTG erection. We have assumed that the sites are forested and will need to be partially cleared to provide access to the turbine locations. Access roads, constructed of processed gravel, would be built to deliver foundation materials and the WTG components. Temporary crane pads would be constructed to allow for assembly of the turbines. Access roads would be designed and constructed to geometric standards directed by the WTG supplier to allow for delivery of the towers and turbines by over-sized truck loads. Additional site improvements include fencing and gates to restrict access to the site. We have not included the cost of improving local access roads to the site to allow for the delivery of the towers and turbines.

Foundations for the turbines were assumed to be constructed in areas with favorable soil conditions with medium dense sand and gravel. Unfavorable soil conditions including soft soils or high bedrock elevations may add cost to the foundations. Reinforced concrete spread footings were selected for estimating purposes.

5.1.2 OFFSHORE PROJECT COSTS

Turbine Costs

For purposes of this study, the GE Model 3.6sle WTG, with a rated capacity of 3.6 MW, was selected for offshore applications. This offshore turbine is still under development according to GE, but estimated performance is available. We assumed that this turbine would be available for commercial application in the next 3 to 5 years. We assumed that the unit price ($/kW) would be the same as the smaller 1.5 MW turbine because of the more rugged construction required for an ocean environment even though economies of scale should produce a lower unit costs than the smaller unit. An estimate for the cost of the transition section between the WTG foundation and 80 m tower was also included.

Electrical Costs

The 30 MW offshore project is based on the use of nine 3.6 MW WTGs operating at 35 kV. The onsite electrical equipment consists of the “collection system” electric cable which would be daisy-chained from turbine to turbine. The single 35 kV submarine cable would be run to shore and then to the transmission line as described under the Offsite construction costs section below.

The 200 MW offshore project is essentially a compilation of approximately seven of the 30 MW projects. The main difference is that this project will only have one utility interconnection at 115 kV. The onsite electrical collection system would include the 35 kV collection cables run to an offshore 35 kV to 115 kV substation, consisting of seven 35 kV circuit breakers, a step up power transformer, and a 115 kV circuit breaker. The 115 kV cable routed to shore and then to the transmission line is described below.

Civil/Structural Costs

The offshore project civil/structural cost estimates include the cost of fabricating and installing the mono-tube pile foundation, erecting the transition section, tower and WTG, installing scour protection at the base of the foundations and, for the 200 MW offshore project, the cost of constructing a platform to support the offshore substation described above. The estimate includes mobilization of a large jack-up barge with a high capacity crane to install the foundations, towers and turbines. Also included in the estimate are costs associated with operating an upland site with port access for fabricating and/or receiving equipment and loading materials onto barges for transport to the site.

Preliminary foundation engineering was performed for wind turbines to be constructed off the coast of Rhode Island. Water depth has a major impact on the design of foundations for offshore wind turbines; therefore, water depth was a critical factor for assessing offshore areas that are suitable wind energy production. A minimum water depth of 8 feet was selected based on the need to install the foundations and towers with barge mounted equipment.

As there are no offshore wind turbines in the US, European experience was relied upon for this study. Three types of foundations have been identified and used for offshore wind projects in Europe.

- Mono-tube piles that consist of a single large diameter, 14 to 16 feet, steel pipe pile driven 50 to 90 feet into the seabed.
- Multi-pod foundations which consist of a group of piles, generally three piles, approx. 36 inch diameter, driven into the seabed and connected by a rigid frame.
- Gravity foundations consisting of a large steel or concrete structure approximately 60 feet in diameter that resist moments due to their large mass.

Foundation selection was discussed with engineers from Denmark who have experience designing offshore wind turbine foundations. Mono-tube foundations are the lowest cost and therefore the preferred foundation solution for offshore applications. The mono-tube piles were considered suitable for areas similar to the conditions anticipated off the coast of Rhode Island due to favorable soil conditions and wave heights. Mono-tube piles are cost effective due to being fairly efficient to install, eliminating the construction time offshore that is very expensive due to the high cost of the specialized equipment and the potential for down time due to bad weather. Fabrication of the large diameter piles could be performed at a facility that is equipped to work with large steel structures.

Mono-tube piles have been installed in Denmark using large jack-up barges with high capacity cranes that can install the foundations, towers and turbines. Mammoet Van Oord of the Netherlands recently built a jack-up barge, the “Jumping Jack”, which is specifically designed for driving mono-tube piles and installing wind turbines. Mammoet was recently involved in a local project, moving the Providence River Bridge from its assembly site at Quonset Point to its final location on the Providence River.

Preliminary research indicates that the predominant soil conditions off the coast of Rhode Island consist mainly of sand with relatively deep bedrock elevations. These conditions were utilized to perform preliminary design of the foundation systems. It should be noted that final design of foundations would require soil sampling from each proposed turbine foundation location. No soil sampling was performed as part of this study. In addition preliminary wave analysis indicated that a 20 foot design wave could be used for estimating lateral wave forces on the foundation.

Preliminary engineering of the foundations was performed to determine a maximum water depth where industry standard mono-tube piles could be used. For the basis of this analysis we considered mono-tubes up to 16 feet diameter to be the maximum size based on current capacity of equipment available in Europe to lift and drive the piles.

Based on the expected soil conditions and wave heights off of Rhode Island, it was determined that mono-tube piles were appropriate for the study's estimating purposes. It was assumed that the foundations would be 16 foot diameter steel pipes with a wall thickness of two inches. The preliminary design anticipates favorable soil conditions consisting of medium dense sand with bedrock elevations below the estimated pile tip elevation of 165 feet below sea level. These mono-tube piles would be driven to a depth of 90 feet below the seabed. At this time, equipment to install these mono-tubes is not available in the US and would need to be mobilized from Europe resulting in high mobilization costs. For this study, it was assumed that this situation still exists at the time of construction. Note also, that because of the high mobilization cost, there are significant economies of scale to construct a larger project, such as the 200 MW offshore project.

5.1.3 OFFSITE CONSTRUCTION COSTS

5.1.3.1. <u>Electrical Interconnection</u>

For the 30 MW offshore project, the 35 kV submarine cable would run from the WTG area to shore. It was assumed that the electrical cable would be routed underground onshore to a suitable high voltage transmission line, even though it is more expensive than overhead lines, to facilitate the permitting and approval process in the highly populated areas near the coast. An interconnecting substation will be constructed where the cable comes ashore which would contain a 35 kV cable terminator and circuit breaker, a 35 kV to 115 kV step up transformer, and a 115 kV terminal and circuit breaker and associated structures to connect to the utility's 115 kV transmission system. Costs for the substation site, control building, instrumentation and controls, system protection, site work, metering, and associated balance of plant have been included.

For the 200 MW offshore project, a 115 kV submarine cable would run to shore. Similar to the 30 MW offshore project, it was assumed that the onshore cable would be routed underground onshore to the nearest suitable transmission line.

For projects connected to the 115 kV transmission line in southern Rhode Island, the length of the underground cable from the coast is approximately 5 miles. For projects connected to the 115 kV transmission line in Tiverton, the length of the underground cable from the coast would be approximately 13 miles.

The cost estimates also include the cost of equipment to connect to a second 115 kV circuit which exists along most rights-of-way in southern Rhode Island. This provides the flexibility to export the generation during scheduled and unscheduled outages of the transmission system.

5.1.3.2. Transmission Improvements

Our team met with senior level staff of National Grid's transmission department to discuss the interconnection requirements for all of these projects, but more specifically for the 200 MW size projects. Generation sources of this capacity require connection at voltages no less than 115 kV. Southern Rhode Island has limited 115 kV facilities with the closest lines located approximately five miles from the coast. On the eastern portion of Rhode Island, the nearest transmission line is in Tiverton, Rhode Island.

Developers and project owners are responsible to bear the cost for utility system improvements that are necessitated by the interconnection of their projects. The utility, upon a formal request for interconnection, will complete system impact studies (load flow; short circuit; stability studies, etc.) to determine what improvements will be required to maintain the integrity of the system with the new project on line. The applicant usually bears the cost of the studies as well, which have been included in our cost estimates.

National Grid's opinion was that projects in the 200 MW range would require substantial upgrades in capacity for the 115 kV lines. They estimated a cost of $1 million per mile for 25 miles as a reasonable estimated cost for these upgrades for large projects connecting to the 115 kV transmission line in Southern Rhode Island. Projects connected to eastern Rhode Island would require transmission improvements for the 9 miles from Tiverton to Fall River.

The lengths of the lines requiring improvements and the corresponding capital costs of the upgrades to the utility's transmission system are shown on the Technical and Cost Summary Sheet in this report.

5.2 DEVELOPMENT COSTS

An allowance for development costs including the cost of engineering and design, permitting, utility interconnection studies, and legal fees was included in each project cost estimate. The development costs will vary with the size, location, and complexity of the project, but are not proportional to the size of the project. For purposes of this study, it was assumed that the development costs would be 3 percent and 5 percent of the construction cost for the smaller onshore projects and the larger offshore projects, respectively.

5.3 TOTAL PROJECT COST ESTIMATES

Figure 5-1 illustrates the estimated cost breakdown and total estimated cost of each project type on a unit cost ($/kW) basis.

The project types are summarized in the figure as follows.

- "1.5MW" represents projects in the customer-connected and community study areas.
- "10MW" represents a project in a specific onshore study area.
- "A" through "E" represents the 30 MW offshore projects in specific offshore study areas.
- "F" through "K" represents the 200 MW offshore projects in the specific offshore study areas.

The estimate cost breakdown provides division of the project cost as follows.

- Turbine cost (erected WTG direct and indirect costs)
- Civil/Structural costs (onsite direct and indirect costs)
- Electrical costs (onsite direct and indirect costs)
- Other onsite costs (onsite soft costs – EPC construction and development costs)

- Interconnection costs (offsite costs - electrical submarine and underground Interconnection costs and transmission improvement costs)

It is important to remember that no offshore wind projects exist yet in the United States; accordingly, these estimated capital and operating costs have higher uncertainty than the onshore projects. The collection of actual data over time may cause the costs to vary significantly and the relative costs to change. In either case, it must be emphasized that a ranking based solely on expected capital cost per kW is not an accurate representation of project financial viability. The higher cost of offshore wind projects is expected to be offset by a higher average wind speed and the significantly greater energy production that comes with it. As a result, the rankings by cost of energy that will result from the financial analysis, described in the next section, is more representative of a potential project area's overall financial viability. Notwithstanding the above caveats, some relative observations might be made.

First, the capital costs per kW of capacity are generally higher for the offshore projects than the onshore projects. This is consistent with market expectations and preliminary information from the few European offshore wind projects for which data is available. The higher costs of offshore wind projects reflect the still-nascent status of offshore wind construction practices as well as the more demanding operating environment for offshore wind turbines. The generally lower capital costs per kW of capacity for the larger offshore projects reflects their ability to spread certain fixed capital costs over a larger installed base. Additional observations from analyzing the results represented in the figure are summarized below.

- The estimated installed cost of the WTG is approximately the same for all projects.
- The 10 MW onshore project estimated cost is higher than might be expected because of the high interconnection cost (i.e. the cost of running a 35 kV underground connection from Little Compton to the transmission line in Tiverton).
- The estimated project cost for the 30 MW offshore projects are the highest because of the highest onsite electrical and civil/structural costs.

Lastly, the project capital costs for each of the offshore projects also are higher as they conservatively assume that each project pays for all of the requisite capital costs for interconnecting such a project to the mainland. In effect, each offshore project is assumed to be the first project and forced to bear all of the costs. If this assumption is realized, then subsequent projects in the offshore study areas will have lower requisite costs of energy, as the connections to the mainland grid will already have been laid. The cost of energy for the offshore projects, conversely, will decline if an alternative means for financing or spreading the interconnection costs is developed to support offshore wind development.

5.4 OPERATIONS AND MAINTENACE

The O&M cost estimates included an allowance for the cost of long term service agreements (LTSA), property and liability insurance premiums, land lease cost, property taxes, road repair, and administration/asset management. The O&M cost estimates, expressed on a unit (i.e. $/kWh) basis, are estimated to be as follows for the different types of projects.

- Single unit, community and customer-connected projects - $0.015/kWh
- Multiple unit, onshore projects - $0.01/kWh
- Offshore (30 MW and 200 MW) projects- $0.02/kWh

On a relative basis, the single unit projects had higher capital cost because of the relatively low capacity factor/energy production (i.e. kWh) to spread the O&M costs over. The 10 MW projects have a higher capacity factor/energy production and economies of scale on which to reduce the unit O&M costs. The estimated O&M costs for on-shore projects were generally corroborated by publicly available information for similar projects. Although the offshore projects have the highest capacity factor and greatest economies of scale, maintenance is much more difficult due to the inaccessibility of the turbines. In addition, there is no long term operating history and no publicly available O&M cost data for this type of project. Therefore, we conservatively estimated that the O&M cost for offshore projects would be twice that of the onshore projects.

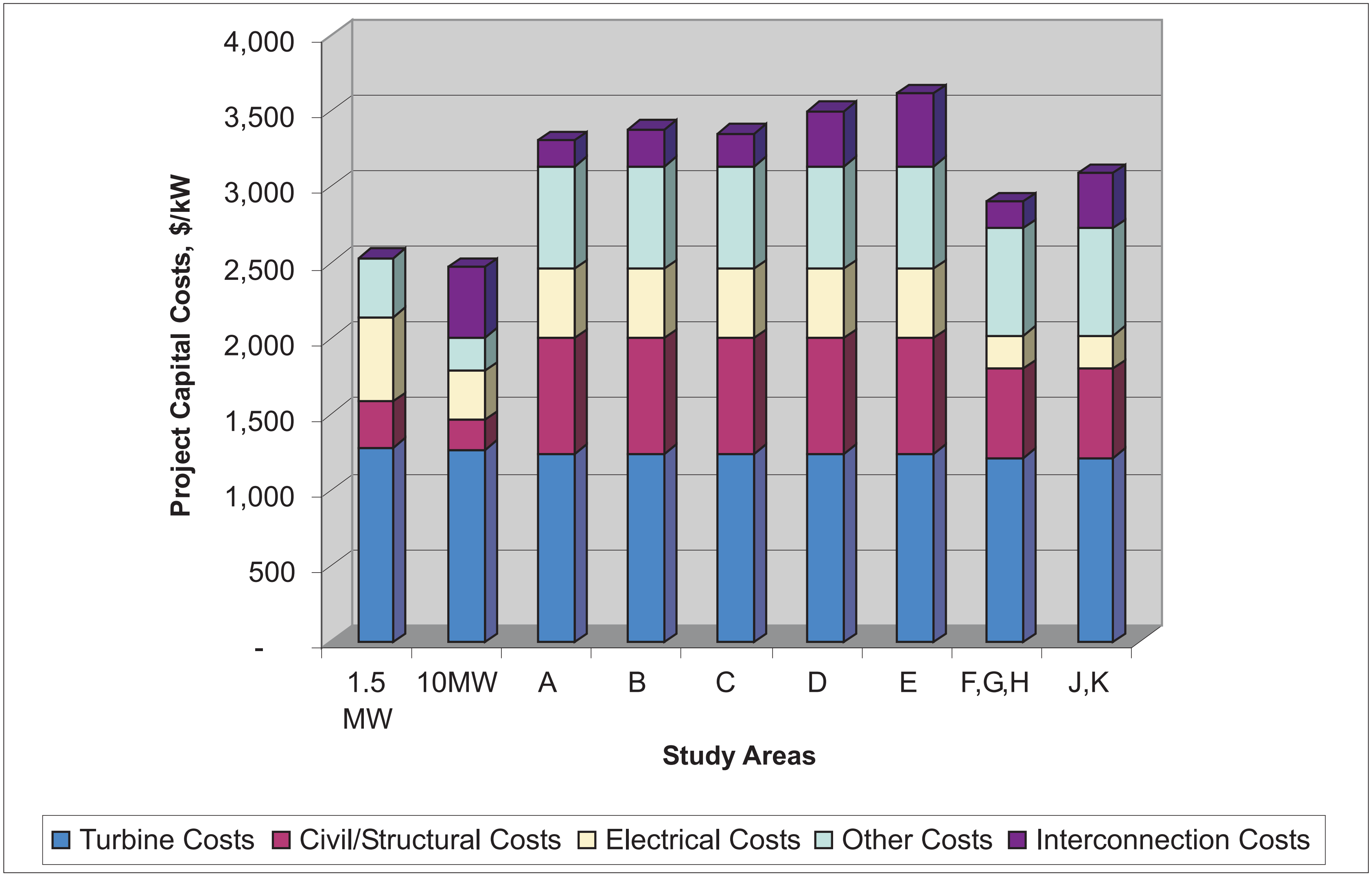

Figure 5-1

Estimated Project Capital Cost Breakdown
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

6.0 FINANCIAL ANALYSIS

6.1 APPROACH

This section describes how the selected project types for each study area are used to assess the relative financial feasibility of the final study areas.

The team has considered the economics of the wind projects on a stand-alone, i.e., project financing basis. Such financial analysis considers only the direct costs of constructing and operating a facility and the direct revenues stemming from sales of outputs from such facility. It does not factor in other potential secondary effects, e.g., the potential benefits to and effects on the State and local communities as a result of utilizing greater amounts of renewable power. Private sector entities, rather than public sector entities, are assumed to construct and operate the wind projects in two of the three financing scenarios and almost all of the study areas. Thus, these analyses include estimates for income and property taxes and offshore area lease payments projected to be paid by the projects. Projects built using the third financing scenario, the bond financing scenario, are assumed built by a public sector entity, so therefore are not subject to such payments. Separately, the wind project under the onshore community project is assumed built by ad hoc community electric cooperatives or similar groupings, rather than strictly private sector entities.

The financial feasibility rankings take into account estimates of several factors. These factors include estimates of the following aspects.

- Capital costs to construct each project type,
- Revenue flows from the sale of electricity produced by the projects,
- Other potential revenue flows such as renewable energy credits,
- Operating costs, and
- Potential Federal tax benefits potentially available to offset costs.

6.1.1 OWNERSHIP/FINANCING SCENARIOS

An assessment of the likely cost of developing wind power in Rhode Island needs to take in account how such capacity is likely to be owned and, more importantly, how the initial capital costs of constructing the wind project will be financed. As noted previously in this report, a major driver of the cost of energy for a wind project is the relative capital cost of the project. In contrast with thermal power projects where fuel costs represent a significant portion of the levelized costs, the initial capital costs of a wind project represent the principal factor in determining the levelized life-cycle cost of energy of a wind project. Strategies for financing such costs accordingly affect the levelized cost of wind energy. Even though offshore wind projects are still in the planning stages in the United States, early indications suggest that these financing considerations will affect offshore projects just as they do for on-shore projects.

Most wind power capacity in the United States installed to date has been undertaken by private sector entities, rather than public sector entities. These private sector entities vary significantly in their size. The American Wind Energy Association (AWEA) maintains a state-by-state database of existing and planned wind projects. The database identifies individual projects, their location, size, off-taker for the power, the owner, and the type of turbine utilized. The AWEA database is available at the organization's website: http://www.awea.org/projects/.

The AWEA database illustrates the variety of owners for wind power projects. In many cases, the owners were the original developers of the projects. Many wind projects, however, have been developed by third party entities who subsequently sold the project to the current owner. These pure developer entities have the development and sale of wind power projects as their principal business focus rather than the benefits from long-term ownership. The emergence of such developers reflects the tax-driven nature of industry incentives and such long-term nature of project benefits. Owners of wind power projects benefit from two significant Federal tax incentives for renewable power projects: (i) the ability to deduct the initial capital costs of the project on an accelerated basis over the first five years of the project, and (ii) the availability of the production tax credit (PTC) from the sale of project electricity to third parties during the first ten years of project operation under Section 45 of the Federal Tax Code. The value of these incentives lies in the ability of project owners to apply these incentives to reduce their taxable obligations stemming from other operations. Further detail on these and other Federal and state incentives for renewable power are outlined by a database maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council funded by the U.S. Department of Energy. The Database of State Incentives for Renewables & Efficiency (DSIRE) is available at http://www.dsireusa.org/. Over time, these tax-related financial benefits have come to represent approximately two-thirds of the total benefit streams accruing to owners of the projects. Net cash flows from project operations comprise the remaining one-third of the total benefits. Thus, ownership of most wind power projects in the United States has gravitated to entities able to make efficient usage of the tax benefits. Separately, those entities without the ability to make efficient use of the tax benefits either focus on realizing profits from the outright sale of the projects or use ownership/financing structures to share ownership with third party institutional investors that do have such tax capacity. Several law firms active in facilitating utility scale wind projects provide information on their websites on financing structures used to finance large-scale wind projects. For example, see publications by Stoel Rives, LLP (http://www.stoel.com/webfiles/LawOfWind_FINAL_6-19-06.pdf) or Chadbourne & Parke (http://www.chadbourne.com/publications/index.html).

In New England, there is growing interest in behind-the-meter wind projects where much of the power is consumed on-site rather than being sold to the grid (this study's "customer-connected project types"). Virtually all of these projects are financed with varying combinations of official grants and cash equity from the owner of the project. However, over time some of these projects may attract local bank debt and third party investor financing.

In both the New England region and nationally, community-based groups and cooperatives also are undertaking a small, but increasing, percentage of wind power projects. Not able to make use of the Federal tax incentives directly, some of these groups have pulled together alternative financing sources, e.g., Federal and state-level grants and guaranteed loans, to finance their projects. Others are adapting the financing mechanisms developed for larger projects to enter into partnerships with either larger developers or tax-oriented institutional investors. In the Midwest, a few wind projects have secured debt financing from local banks or farm credit institutions. More information on financing tools used by community-based wind power projects is available at www.windustry.com.

For this report, the team has developed three financing scenarios to illustrate the impact of financing costs on the cost of energy for wind power projects. While the scenarios are generic and simplified in nature, they are representative of the financing scenarios in use for almost all wind project development in the United States. Accordingly, they help to illustrate the varying impact of financing costs on the costs of wind power projects.

6.1.1.1. <u>Equity plus Commercial Debt Financing</u>

This scenario assumes that the project is financed with a combination of equity from the long-term owner and commercial debt financing. Such debt financing typically is provided on a limited recourse or "project" basis, i.e., where the lender provides the financing based on the quality of the project itself and of its projected net cash flow. Once construction is complete and the project is in operation, lenders typically have no recourse to the project sponsor or owner and look only to the cash flows and assets of the project itself for repayment of the loan. This is in contrast to corporate-style debt financing where the lending decision is based on the quality of the parent company's own financial strength and the parent company fully guarantees repayment of the loan.

Equity investors in wind projects utilizing debt look to benefit from the depreciation and production tax credit benefits and the residual cash flow after debt service obligations have been satisfied. Several leading wind project developers and owners are tapping project debt to finance portions of the costs of their wind project developments. These include Airtricity, (http://www.airtricity.com/america/), Invenergy (http://www.invenergyllc.com/), enXco (www.enxco.com), and UPC Wind Partners (http://www.upcwind.com/). Such entities typically have the financial strength to finance all or a portion of the equity component, but utilize third party project debt to reduce the required equity commitment and to boost the equity returns.

6.1.1.2. All-Equity Financing

The all-equity financing scenario assumes that equity capital from the owner(s) of the wind project covers the full amount of the capital costs. Versions of this scenario are used in the majority of new large-scale wind power project developments in the U.S. today. This is due in part to this being the principal financing strategy by the single company that is installing over half of all wind power project capacity currently. FPL Energy, LLC is the largest operator of wind power assets in the United States (http://www.fplenergy.com/). It owns and operates 47 wind farms in 15 states, comprising more than 3,600 MW of wind power capacity. FPL Energy also is one of the most prominent wind project developers considering offshore wind projects. The company is collaborating with the Long Island Power Authority on a 140 MW wind project being considered for a site south of Long Island in New York State (http://www.fplenergy.com/projects/contents/long_island_wind.shtml). FPL Energy is a subsidiary of FPL Group, Inc., which is in turn a major power utility holding company (http://www.fplgroup.com/).

In addition to FPL Energy, examples of other wind developers and owners opting for the all-equity financing approach include PPM Energy (http://www.ppmenergy.com/), MidAmerican Energy (http://www.midamericanenergy.com/wind/html/resource5.asp), Shell WindEnergy (www.shell.com), Babcock & Brown Wind Partners (http://www.bbwindpartners.com/), and JP Morgan Capital Corporation (www.jpmorganchase.com). Such entities opt for the all-equity approach to provide more flexibility and speed in closing transactions and control over ongoing projects. In effect, they finance their wind projects on a corporate-style basis using funds from other corporate operations or corporate-level financing. Not all of these companies have the ability to make efficient use of the tax incentives themselves, i.e., they do not generate sufficient recurring taxable obligations from other operations against which the tax benefits of the wind projects can be applied. Such entities typically partner with third party institutional investors in complex financing structures that allocate the tax and cash benefits of project ownerships to the partner(s) best able to use them. As such partnerships are versions of all-equity financing; they are not treated as a distinct financing scenario for this report.

Debt financing is sometimes used in conjunction with the all-equity financing structure. For example, some owners have arranged limited recourse debt financing to finance the construction costs of several wind projects, with the debt being replaced by equity upon the commencement of operations. The impetus for the investor is to delay investment until the project is demonstrated to be in full commercial operation, i.e., to avoid potential construction period risks. As such financing is used only for the short (less than one year) construction period, it has little impact on the long-run levelized cost of energy for a project. Construction period debt principally is used to allocate risk, rather than to lower all-in costs. Accordingly, such debt is not treated as a distinct scenario for this report.

Similarly, FPL Energy has secured long-term loans and placed long-term bonds to refinance portions of its existing portfolio of wind projects. The detailed terms of such debt facilities are not public information. However, press releases and rating agency reports suggest that the bonds have been limited in recourse principally to the cash flow from the projects, although FPL Energy appears to have extended certain key risk guarantees to the bond investors. The company appears to have undertaken such bond financing not to finance the original projects so much as to deepen overall financial market comfort with wind power and the prominence of wind power assets in the company's overall portfolio and to generate capital for other operations. The bond financings were undertaken after the contract prices for sales of power from the underlying project were set, i.e., the bond financing had no impact on the company's initial analyses of the cost of energy or viability of the projects. Accordingly, such bond financings are not treated as a distinct scenario for this report.

The all-equity financing scenario is also useful in assessing the 1.5 MW wind projects for the customer-connected and community study areas where these projects use cash equity capital to finance them.

6.1.1.3. Bond Financing

The third scenario envisions the full amount of the project costs being financed through long-term bonds. This scenario has been utilized by a few public sector entities to finance their wind projects. The Nebraska Public Power District (NPPD) issued just over $81 million in 20-year fixed rate bonds to finance a 60MW wind facility constructed in 2005. Earlier, two bond financings financed successive phases of a 63.7 MW onshore wind project constructed in southern Washington State in 2002 and 2004. Just under $92 million in non-recourse tax-exempt issued fixed-rate municipal bonds were issued by Energy Northwest to finance the project. Energy Northwest is a public power joint operating agency in Washington State, which generates power and provides other energy services on behalf of several member public utility districts. The Energy Northwest website has further information: http://www.energy-northwest.com/outreach/nine_canyon.php. For both the NPPD and Energy Northwest projects, the users of the power entered into long-term power purchase agreements with the project entities to support the bond financings. Most recently, at least one municipal bond underwriter, George K. Baum & Company, is structuring bond-based financing in support of community and other onshore wind projects (http://www.gkbaum.com/renewableEnergy/).

This report assumes that the bonds in the Bond Financing scenario are issued on a similar basis to the above projects, i.e., that the long-term bonds are issued by a public sector entity (in contrast to the other two scenarios which assume private sector ownership). The bonds are assumed supported by long-term purchase agreements for the output of the projects. They are assumed to be issued on a limited-recourse basis, i.e., that the bond holders principally look to the cash flows from the project for repayment of the bonds. The bond financing scenario assumes an interest rate that implies that the bonds are taxable (in contrast to the Energy Northwest bonds), as the status of such bonds is not clear at this early stage of analysis.

6.1.2 MARKET PRICE PROJECTIONS

The results of the financial analysis are put in the most useful context by comparing the projected cost of energy for the study areas to the projected cost of electricity in Rhode Island. We have developed an estimate of wholesale energy revenues available to wind generators located in Rhode Island from the sale of commodity electricity products. This estimate relies on publicly available data sources to the maximum extent possible.

It is important to recognize several aspects regarding these forecasts, including the following.

- These forecasts should not be taken or used out of context with the basic underlying assumptions. The sensitivity of results to variation of key parameters should be considered. This report considers sensitivity to the variable with perhaps the greatest uncertainty - the future price of renewable energy certificates (RECs).
- A given wind project's revenues will be site-specific and a function of a generator's production profile and capacity factor. The estimate described below utilizes confidential modeled production profile data for a southern New England land-based wind project as a proxy for a Rhode Island production profile, to estimate how a wind generator's actual production stream would differ in value from a flat block of generation equal in every hour. This proxy may be reasonably representative for many land-based sites in Rhode Island, particularly those away from the shore, but may be less applicable for shoreline and off-shore installations. Once seasonal and diurnal production profiles are available for a particular site, this methodology can be applied to estimating revenues for that site with greater precision.
- The wholesale market prices projected herein are applicable directly to a wholesale wind generator, that is, one interconnected to the NEPOOL transmission system, as measured at the busbar for the wind project. The relationship between long-term wholesale energy trends and *market-based* retail delivered electric generation service prices is fairly constant. The differentials between wholesale and retail reflect delivery losses, delivery voltage, load shaping and balancing, operating and capacity reserves and other ancillary services, Renewable Energy Standard compliance, transition charges, system benefit charges, and various uplift charges including reliability must-run costs. In addition, retail prices are extremely customer-specific due to load shape. However, the *trend* of the commodity portion of this forecast (not considering REC prices) over time can be used to estimate future retail avoided generation service cost for a customer-connected wind generator. By adjusting commodity market prices to reflect the components of retail generation service described above, and adding the components of retail rates which can be avoided through customer-connected generation, the future trend in retail rates can be approximated.
- This forecast represents a solid approximation of future market revenues under the stated assumptions. Certain additional drivers of future revenues were not considered here, as the precision was determined beyond the needs of this Report. These include site specific factors for generator seasonal and diurnal production profile, the projected retail load profile for wind projects in the customer-connected or community study areas,

and broader relationships of electric and fuel markets leading to shifts in ISO New England's system composition over time (since natural gas prices are not the only determinate of future ISO New England LMPs).

6.1.2.1. Wholesale Commodity Electricity Market Revenues

The forecast of wholesale electricity revenues available to a Rhode Island-based wind project is derived as follows.

- The most recent 12 months of historical locational marginal prices (LMPs) for the Rhode Island zone were examined, considering on-peak and off-peak, and averaging day-ahead and real time prices, inclusive of congestion. This data was not used directly in the forecast, but rather used to benchmark the reasonableness of the starting point for the approach described below.
- An all-hours average annual energy price forecast was generated by applying the forecast of delivered natural gas prices to the region to an average NEPOOL "market heat rate", the ratio relating delivered market natural gas prices to market electric energy prices. While a number of factors influence the wholesale market electricity prices in Rhode Island, the predominant driver of price trends has been (and is expected to continue to be) the price of natural gas, which is the fuel for the marginal (price-setting) generator in ISO New England in the majority of hours.
    - Through 2012, the natural gas price was projected using the December 20, 2006 NYMEX Henry Hub futures price (NYMEX 2006). From 2013 onward, the Henry Hub natural gas price forecast from the EIA's Annual Energy Outlook 2007(DOE 2006) reference case was used, adjusted upward to reflect the historical relationship between the AEO *forecast* and the NYMEX as derived by Lawrence Berkeley National Laboratory (Bolinger & Wiser 2007).
    - In each case, the Henry Hub gas price was increased to reflect a basis spread for power generators (representing transportation costs) to Southern New England based on 5 years of historical data (ICF Consulting 2005).
    - A market heat rate of 8200 Btu/kWh, which is representative of the current production mix in ISO New England, was assumed.
- To estimate the difference in value between an all-hours average price and the intermittent and heavily seasonal production stream of a wind generator located in Rhode Island, the following two adjustments were made.

- The all-hours average energy price derived above was adjusted to reflect the ratio of the market value of energy produced by a sample southern New England wind farm (derived using confidential data from a nearby site) to the market value of a 7x24 flat block of energy.
- In addition, a predictability adjustment was made to derate the market value of an intermittent production stream by an estimated $2.50 per MWh relative to a fixed firm block of energy.[1]

- Starting in 2009, the projected cost of a carbon allowance under the Regional Greenhouse Gas Initiative ("RGGI") regime was added to energy prices. RGGI allowances will be required from most fossil fuel generators in the region, and the cost of such allowances is likely to be added to bid prices in the energy market. The 2003 modeled NEPOOL marginal CO2 emission rate was first reduced by 10 percent to reflect the recent trend of improved conversion efficiency in marginal generation in the region (ISO New England 2004). This figure was used to convert the projected cost of carbon allowances from RGGI modeling to units of $/MWh.
- Capacity revenues available under ISO New England's Forward Capacity Market (FCM) were estimated, converted to $/MWh, and added to the forecast of energy revenues to derive the total commodity market revenues available to a Rhode Island wind generator. FCM revenues were projected as follows.
    - Price: During the transition period, prices are set by FERC-approved settlement. Thereafter, prices are allowed to float, being set by auction, between a $10.50 cap and a $4.50 floor. A figure of $7/kw-mo, slightly below the mid-point between cap and floor, was assumed for all years following the transition period.
    - Intermittent generators receive less than their nameplate capacity in installed capacity credit eligible for sale in the FCM market. While the mechanism for determining this treatment is not yet finalized, and is also very site-specific, an estimate of 20 percent of nameplate capacity was assumed.
    - A capacity factor of 30 percent was assumed to convert $/kW into $/MWh.

The results are summarized in Table 6-1.

[1] While the direction of this adjustment is certain, its magnitude is inexact. It was estimated based on conversations with various market participants over the past 2 years.

6.1.2.2. REC Revenues

In addition to commodity energy and capacity, a wind generator in Rhode Island is eligible to create and sell RECs which can be used for compliance with the Rhode Island Renewable Energy Standard (RES), as well as (for wholesale generators) similar Renewable Portfolio Standard policies in Massachusetts and Connecticut. The Rhode Island RES requirement starts in 2007, so there is no market data yet available. However, the major design characteristics and eligibility for the Rhode Island RES closely track the longer-running Massachusetts RPS, and therefore the prices for compliance RECs are expected to track closely.

Currently, Massachusetts RECs are trading quite near the Alternative Compliance Payment (ACP) rate under the Massachusetts RPS program (the Massachusetts Division of Energy Resources has more information on this program (http://www.mass.gov/doer/rps/index.htm)). In effect, the ACP rate functions as a price cap. This feature is identical to that to be used in Rhode Island, so the ACP rate in Rhode Island is treated as a price cap for purposes of this forecast. Broker-based market quotes are also available for the present and two to three years into the future, although these markets are very thinly traded. There are no public forward market quotes beyond the next few years, and no public basis for a forecast is available. Scenario analysis projections have been made by some market analysts, based on a number of assumptions and technical analysis. However, there remains considerable regulatory and political uncertainty in the still new REC markets. Rather than deriving a single point forecast of future REC prices, total market revenues have bounded by two REC price scenarios. These include the following.

- Case 1: REC prices are assumed to track the projected ACP rate (this represents the high end of the range of potential futures);
- Case 2: REC prices are assumed at a flat $20/MWh REC price throughout the analysis period (this represents the lower end of the range necessary on a sustained basis to attract market entry; in years of shortage, prices will exceed this level, and in years of surplus prices may drop below this level).

Table 6-2 combines these two case scenarios with the forecasted total market commodity values in the right-most column in the previous table to generate a range of future total wholesale energy market prices available to a Rhode Island wind generator. These two revenue forecasts are compared in Section 4.6.5 to the results of the cost of energy projections for the study areas.

These annual price forecasts can be levelized to enable comparison with levelized calculations of the annual projected costs of energy for the various study areas. Using a discount rate of 10 percent, the levelized total market value for Case 1 (assuming a low REC price) is $92/MWh, while the levelized total market value for Case 2 (assuming the ACP cap-based REC price) is $138/MWh.

6.1.2.3. Avoided Retail Electricity Price Forecast

Two of the study areas envision onsite consumption of portions of the wind project output by an on-site entity. As described earlier in this Report, such entities likely would have a significant sustained load profile. Locating a wind project behind-the-meter to meet all or part of such entity's load profile may make financial sense. To assess this relative benefit, it is necessary to compare the cost of energy for such a project to those components of retail generation, transmission and distribution service otherwise paid by such entity to acquire its electricity from the grid. We have also developed an estimate of the retail prices which can be avoided through locating a wind generator behind a large customer retail meter in Rhode Island.

The following approach and assumptions were used to derive a forecast of avoided retail electricity expenditures.

- Customer characteristics: The generator is assumed to be located on the premises of a large commercial retail customer taking service under National Grid's G-32 rate (peak demand over 200 kW), and being served by a competitive supplier licensed as a non-regulated power producer by the Public Utilities Commission.[2] For this report, the customer is assumed to have a class-average load profile and delivery loss factors.
- 75 percent of the annual production of a 1.5 MW turbine is assumed to be used by the host of the wind project for the customer-connected study area, whereas 25 percent of annual production is assumed to be consumed on-site for the 1.5 MW wind project in the community study area.

[2] Most G-32 customers are now served under market-based competitive supply options, which are usually lower in cost than the National Grid's Last Resort Service.

- Backup rates are assumed not to be applicable.[3] Two components of retail T&D rates are assumed not to be avoidable: the customer charge and the non-by-passable transition charge. In addition, the G-32 rate has a ratchet feature to the demand components of the T&D rates which severely limit the ability of intermittent wind generation to reduce demand charges. For purposes of this report, it is assumed that 40 percent of demand charges can be avoided for the wind project in the customer-connected study area, while only 5 percent of demand charges can be avoided as a result of wind production for the wind project in the community study area.
- Avoided generation service rates were projected by starting with the wholesale all-hours average energy price forecast discussed earlier, and adding to it the following.
    - An estimate of the cost of shaping/load balancing, ancillary services, reserves and other ISO costs (these cost components are necessary to supply retail load in addition to commodity energy);
    - The estimated carbon adder used in the wholesale price forecast;
    - FCM charges as derived for the wholesale forecast, including a 15 percent capacity reserve margin, and converted to a $/MWh value by spreading over annual energy usage;
    - REC pricing under the same two cases described above; and
    - Retail T&D losses.
- Avoided T&D charges are estimated by adding to the per-kWh distribution and transmission rate components (i) the proportion of annual T&D demand charges assumed to be avoided, converted to a per-kWh value, and (ii) the conservation charge. The T&D rate components are assumed to escalate with inflation (assumed 2.5 percent per year), while the conservation charge are assumed to continue at the constant statutory level indefinitely.

The resulting retail avoided costs are summarized in Tables 6-3 and 6-4 for the 1.5 MW project types for each of the customer-connected and community study project types, and using the two REC price forecast cases described earlier.

[3] Today, up to 3 MW in aggregate from customer-sited renewable energy generation facilities are exempted from National Grid's backup rates. The backup rate policy is due to be revisited in the near future. If the current policy is expanded beyond 3 MW, this assumption will hold; if backup rates do apply to onsite wind generators, the portion of transmission and distributions rates which can be avoided may be less than assumed in this Report.

6.1.3 ANALYSIS MODEL AND FINANCIAL ASSUMPTIONS

The team has constructed a dedicated set of financial models to undertake the financial analysis under Phase I of the RIWINDS program. The models are designed to evaluate the cost of energy for each project type selected for each of the final study areas under three different financing structures. The financing structures are profiled in Section 4.6.2. These include the All-equity financing, equity plus commercial debt financing, and bond financing scenarios. These cost of energy values are then compared both across study areas and to the estimated wholesale electricity market values of production outlined in Section 4.6.3.

The financial model set is comprised of two spreadsheet workbooks. The first workbook aggregates the energy production, fixed cost and variable cost estimates (the “Costs Model”). The details and functions of the Costs Model are described in Sections 4.4 and 4.5. The second workbook draws these production and cost estimates into a detailed analysis model (the “Analysis Model”) which – with the addition of further operating and financing assumptions (discussed below) – calculates the projected financial performance of the representative project type for each study area.

The Analysis Model projects the financial performance of the representative project type three times – once for each financing scenario. For review, the three financing scenarios are as follows.

- All-equity financing: This scenario assumes that the project is fully funded by its equity owner(s). This structure does not incorporate either construction or term financing. When calculating the cost of energy, the model requires the project to provide its equity investor with a stipulated after-tax internal rate of return (IRR” over the 20-year project life.
- Equity plus commercial debt financing: This scenario assumes the project is financed with a combination of both debt (both construction and term) and equity, where the project takes on its maximum sustainable debt. The maximum sustainable debt is the largest loan the project can afford while maintaining the minimum coverage ratio required by the lender. For example, if the required debt service coverage ratio is 1.45X, the project must have $1.45 in available operating income for every $1.00 it contributes toward debt repayment (both principal and interest). In this example, the remaining $0.45 is used to pay any non-operating expenses, i.e., taxes, with any remaining cash being distributed to equity. The cost of energy figure in this scenario is calculated as the

rate that provides project equity investors with the stipulated IRR over the expected 20-year life of the project. For this report, the team assumes only cash-based borrowing. A few wind power projects have secured incremental debt financing by monetizing the PTCs generated. This allows a project to obtain more debt up-front, but the lenders generally require the equity investor to assume a contingent obligation to make additional equity contributions as the debt is borrowed against a non-cash item (the PTCs are a tax credit rather than cash flow from project operations). Since such PTC monetization ultimately adds a relatively small amount of debt, the equity plus commercial debt financing scenario does not include them.

- Bond financing. This scenario sets the bond amount equal to the total project cost, including financing costs. These bonds are assumed to be taxable. For the bond financing scenario only, the projects are assumed to be undertaken by a public sector entity, so that the projects are not liable for Federal or state income taxes, nor do they capture the benefit of the Federal production tax credit or accelerated depreciation tax incentives.

The following describes each of the worksheets that comprise the financial model, and introduces the key assumptions necessary to complete the analysis:

6.1.3.1. <u>Description of Analysis Model</u>

The Analysis Model (referred to above as the second workbook) is comprised of six worksheets. The assumptions and results are contained on one sheet, while each of the three financing structures is on a separate sheet. The Analysis Model has two figures illustrating the results for the selected study area on both a levelized and annual basis relative to estimated wholesale price forecasts. A description of the tabs for each financing structure is below:

- Assumptions & Results: This worksheet contains all of the inputs and assumptions for the Analysis Model, as well as the generated cost of energy figures for a selected study area. The project size, net capacity factor, net energy production, capital cost and annual operating cost assumptions are all imported from the Cost Model, as described above. All other assumptions are input directly into the Assumptions page. There is a separate column for each study area. Each study area is represented by a particular project type considered most indicative of the type and scale of project development for such study area. This enables assumptions to differ among study areas, as necessary.

- A drop-down menu at the top of the page allows the user to select an individual study area for analysis. Only one study area can be evaluated at a time. A “COE Solver” macro button at the top of the Assumptions worksheet enables calculation of the first year cost of energy for the selected study area under each financing scenario, subject to the user-defined assumptions. This first year cost of energy is that price (in $/MWh) that the project type for that study area needs to receive in the first year of operation for its power sales so that (i) any associated project debt (for the two scenarios involving debt) is repaid and (ii) the project equity investors (for the two scenarios involving equity) receive the IRR stipulated on the Assumptions & Results sheet.
- For a selected study area, the Analysis Model in effect solves for the lowest cost of energy in the first year, assuming the price increases over time by inflation, which will satisfy the various assumed debt terms and equity return hurdles. These calculations solve for an all-in commodity and REC price; the two components are not separated. For purposes of the ranking analysis described in Section 4.6.5, the annual cost of energy results are levelized to provide a single life-of-project figure. This is discussed further in Section 4.6.5.
- Model--100 percent equity: This worksheet contains all of the underlying calculations for calculating the first year cost of energy for the selected study area assuming use of the all-equity financing scenario. The calculated first year required cost of energy is shown in the Assumptions & Results worksheet. This worksheet calculates total project revenues, expenses, tax benefits/liabilities and the resulting cash flow to equity on a semi-annual basis. This stream of cash flows and tax benefits/liabilities, including the PTC, is used to calculate the IRR to the project’s equity investor. The cost of energy for this financing scenario is calculated by setting an initial year energy price to generate an IRR equal to the value prescribed on the Assumptions & Results page.
- Model--Equity + Debt: This worksheet contains all of the underlying calculations that support the calculation of the cost of energy for the selected Study Area assuming use of the Equity plus Commercial Debt Financing scenario. The required cost of energy result is shown in the Assumptions & Results worksheet. This sheet calculates total project revenues, expenses, debt service, tax benefits/expenses and the resulting cash flow to equity on a semi-annual basis. This stream of cash flows and tax benefits, including the PTC, is used to calculate the IRR to the project’s equity investor. The cost of energy for this financing scenario is calculated by setting this equity IRR equal to the value prescribed on the Assumptions & Results page.

- Model--100 percent bond financing: This worksheet contains all of the underlying calculations that support the calculation of the first year cost of energy for the selected study area assuming use of the bond financing scenario. The calculated first year required cost of energy result is shown in the Assumptions & Results worksheet. This sheet calculates total project revenues, expenses and debt service. The tax benefit/expense calculations are disabled in this worksheet. Like the two other financing scenarios, all calculations are semi-annual. The cost of energy for this financing scenario is calculated by setting total project debt, i.e., the bonds, equal to total project capital cost. In this way, the model realizes 100 percent bond financing. It is important to note that the debt service coverage ratio assumption is an input in this scenario, as it is under the equity plus commercial debt financing scenario. The calculated cost of energy will be that rate that generates sufficient project cash flow to repay debt service and meet the minimum debt service coverage ratio. For example, if the bond issuer requires 1.1X coverage, the project needs to realize $1.10 of operating profit for every $1.00 of debt service.

6.1.3.2. Discussion of Key Assumptions

The evaluation of thirteen separate study areas and three distinct financing structures requires the identification and use of a number of operating and financing assumptions. In this analysis, many operating assumptions are common to all study areas. The financing assumptions are unique to each financing scenario. Table 6-5 provides a general description of the key assumptions, their respective purpose, and the basis or source from which each assumption is drawn.

The initial capital and the ongoing O&M cost estimates are detailed in Section 4.5. Note that soft capital costs, i.e. financing costs such as debt fees, debt and equity legal and consultants, debt service reserves, interest during construction, etc., are separate and in addition to the hard capital costs. Estimated soft costs are vary according to the size of the project and are based on estimate market trends.

One of the largest factors influencing wind project returns is annual net capacity factor (NCF). NCF, or the annual number of kWhs produced by a project, drives the generation of both revenues and PTCs. As discussed earlier, a general wind project return profile is comprised of roughly one-third from each cash, PTCs, and tax benefits. The NCF estimates, which range from 27.0 percent for the customer-connected study area to 42 percent for the offshore J & K areas, are discussed further in Section 4.5.

The financing assumptions associated with the all-equity financing scenario are minimal. Under this structure, the project is financed using the equity investor's internal resources. Therefore, there are no financing costs associated with the project. The assumed 10.0 percent after-tax 20-year equity IRR is reflective of current market returns for an on-shore wind project with a long-term power purchase agreement in place.

The debt in the equity plus commercial debt financing scenario increases the financing costs associated with a project. This analysis assumes 100.0 percent construction financing at an annual rate of 7.0 percent. Construction financing normally is drawn as project costs are incurred. For purposes of this analysis, the Analysis Model assumes that half of a project's hard costs are outstanding for six months, i.e., one-half of the year-long construction period. The Analysis Model assumes that the lender charges a one-time arranging fee equal to 1.5 percent of the total amount borrowed. Lender closing costs for legal and third-party consulting services are assumed to be between $75,000 and $250,000, depending on the size of the project. Similarly, equity legal and consultant costs are between $125,000 and $250,000 for all projects except for those for the customer-connected and community study areas. For the projects in these areas, no such fees are assumed, as the sponsors are assumed to minimize or undertake such services internally.

The debt term is assumed to be 15 years, with an annual all-in interest rate of 7.0 percent and a coverage ratio of 1.45 times operating profit. The required 20-year after-tax equity IRR for projects in the equity plus commercial debt financing scenario is modeled at 12.0 percent. The two percent premium relative to the equity IRR assumed for projects financed using the all-equity financing scenario reflects the closing and default risks associated with the use of debt. In the Analysis Model, the amount of debt is not a discrete input but is determined as the maximum sustainable debt based on project economics and debt terms. This reflects market practice by lenders financing wind projects.

Financing costs in the bond financing scenario are similar to those associated with debt. However, this structure does not include an equity investor. The assumptions used for interest rate for construction financing (annual 7.0 percent), placement fee (1.5 percent of bond amount), and closing costs (between $75,000 and $250,000) are the same as those used for the debt under the equity plus commercial debt financing scenario. However, in this scenario there is no equity investor and therefore no associated transaction costs. The bond financing is assumed to have a 20 year term, an annual all-in interest rate of 7.0 percent, and a coverage ratio of 1.10 times operating profit. The longer term and lower coverage ratio reflect the assumption that the projects in this scenario are undertaken by a public sector entity, i.e., have at least some degree of implied support, and assume that the bonds are taxable obligations. These terms will vary with the degree of state backing beyond the level of cash flow generated by the projects.

The financing inputs developed by the team are based on the underlying assumption that the projects have long-term off-take contracts with creditworthy counterparties. The terms and counterparty credit strength of other project contracts also will affect the pricing and other terms of the financing scenarios. Such agreements include the initial turbine equipment supply contracts and warranty agreements, the initial engineering/ procurement/construction (EPC) agreements, and O&M agreements.

6.1.3.3. <u>Model Assumptions as Estimates and not Actual Values</u>

It is important to recognize that the economics of wind energy diverge widely depending on the specific characteristics of the project and site being evaluated. The financial analysis in this report uses available industry data and practices to estimate the cost of energy for a range of indicative projects at a number of generalized locations. Nonetheless, it is important to remember that these assumptions and results are estimates, and cannot replace the evaluation of site-specific data, once such data is available.

6.1.4 FINANCIAL ANALYSIS

Using the Analysis Model described in the prior subsection, the team evaluated the relative financial feasibility of the representative project types for the thirteen defined study areas. The analyses undertook these evaluations using each of the three different financing scenarios outlined in subsection 4.6.2. The team then ranked these configurations by the cost of energy. To enable comparability, these rankings use the same financing scenario (the equity plus commercial debt financing scenario). The cost of energy for a given study area is a levelized figure over the assumed twenty year lifetime of the projects. The projected required costs of energy for the representative project type for each study area is then compared to the projected market value of wind energy production over the next two decades. Finally, this section discusses the impact of using the three financing scenarios for projects in selected study areas.

6.1.4.1. Ranking of Study Areas by Levelized Costs of Energy

This analysis calculates the total revenue per MWh that a project in each Study Area must collect from the sale of all commodities (energy, capacity and RECs) in order to meet the minimum repayment and return requirements of project debt and equity investors, respectively. This total revenue requirement is referred to as the cost of energy. The costs of energy are shown as a levelized value that reflects all 20 years of expected project life in a single number. Table 6-6 ranks the study areas by their projected levelized cost of energy. Table 6-6 shows the values calculated using the equity plus commercial debt financing scenario.

Given the data limitations, the team has grouped the rankings in roughly comparable sub-groups; study areas in a particular group essentially have the levelized cost of energy. The same information also can be seen in graphical form in Figure 6-1.

The levelized cost figures add to the initial capital costs the impact of several operational aspects that vary across the study areas, most notably the estimated wind resources and the operation and maintenance costs. These factors, combined with those mentioned above, highlight the importance of the underlying wind resource in the overall financial feasibility of a wind project in a given study area. As expected, the analysis suggests that those study areas with strong wind resources, e.g., offshore areas J and K, other matters held equal, will allow for a lower requisite cost of energy to be viable. The analysis also suggests that the lower wind resource for study area H is essentially offset by the reduced costs of bringing the project's electricity onshore. Table 6-6 also suggests that projects in study areas with relatively weaker wind resources costs of energy in order to be viable, even if they are located closer to shore.

6.1.4.2. Comparison of Study Area Levelized Costs to Levelized Electricity Price Forecasts

The levelized projected costs of energy for each of the study areas can be compared to levelized estimated wholesale electricity price forecasts. The 20-year levelized electricity price forecast below reflect both a low case ($92/MWh) and a high case ($138/MWh), based solely on different assumptions for future REC market values. These electricity price forecasts are. The figure suggests that the projected levelized costs of energy for virtually all of the study areas are within the range of forecasted wholesale electricity values. The higher that actual REC prices prove to be, the greater the prospects for financial feasibility of wind projects in the final study areas. REC prices at levels near the $20 floor used for this report over a sustained basis will limit the financial feasibility of wind projects to just a few study areas – principally those study areas able to support the largest projects and with the greatest wind resources. Conversely, REC prices at or near ACP limits may make wind projects feasible in virtually all of the study areas.

The figure understates the potential financial feasibility of wind projects for the customer-connected and community study areas relative to their avoided electricity costs. As described in Section 4.6.3, the project types for these two study areas assume that portions of the electricity will be sold in varying percentages to the on-site host. The levelized twenty-year avoided prices for each of these two study areas even for the lower Case 2 scenario (assuming a $20 REC value) are $123/MWh for the customer-connected study area and $120/MWh for the community study area and. These values exceed the projected levelized costs of energy for these two study areas ($116/MWh for the customer-connected study area and $103/MWh for the community study area), strengthening the prospects that wind projects for such study areas are likely to be financially feasible. Figure 6-2 shows the estimated levelized cost of wind energy compared to levelized wholesale electricity price forecasts.

6.1.4.3. Comparison of Selected Study areas to the 20-Year Wholesale Electricity Price Forecasting Scenario

The projected costs of energy for the study areas can be compared to the forecast wholesale electricity prices over time. Using the annual projected cost of energy for three of the study areas (customer-connected, offshore area E, and offshore area H), Figure 6-1 compares the projected cost of energy of these projects to the long-term wholesale electricity price forecast. The team selected these three study areas as illustrative of the full group, as the three vary in their locations, size of the representative project type, and the strength of their wind resource. As described in Section 4.6.3, the forecast is of the total commodity market value at the plant busbar, i.e., the price received by the wind project for power sold wholesale to the grid. The wholesale price forecast below includes both a low case and a high case to capture uncertainty in potential future REC prices. The prices in the two cases differ based solely on the projected market value of RECs over the next 20 years.

Figure 6-3 shows a comparison of annual costs of energy to energy price forecasts. The figure illustrates that the relative profitability of a wind project in a given study area likely may vary from year to year. However, it is important to note that the projections of the costs of energy are based on the calculated first year cost of energy, with later years being trended out for inflation. In practice, the pricing terms contained in most long-term power purchase agreements either are flat line or trended simply for an assumed inflation rate. Relative profitability on a year-by-year basis is more important if the sponsors of a given wind project elect to avoid locking in the certainty of a long-term power purchase commitment and instead elect to sell the project power on the merchant market. Such an option likely is only a potential option for projects in the three onshore study areas considered in this report (customer-connected, community, and onshore). Developers and owners of projects in the offshore study areas likely will need to seek the lower risk profile of long-term purchase commitments in order to attract third party financing for the capital costs.

6.1.4.4. Assessment of Impact of Varying Financing Options

Finally, the Analysis Model can be used to gain insights into the impact of financing assumptions on a representative sample of study areas. Section 4.6.2 profiles three different financing scenarios. The previous analyses in this section use calculated data assuming the projects in the selected study areas using just the equity plus commercial debt financing scenario. A comparison can be made among the estimated levelized costs of energy using the alternative financing scenarios. Figure 6-4 shows the results for the three selected study areas (community, offshore area C, and offshore area H).

Figure 6-4 shows the equity plus commercial debt financing scenario consistently generating the lowest estimated levelized cost of energy. By contrast, the 100 percent bond financing scenario generates the highest cost of energy for each of the selected study areas. These same relationships hold true for the remaining study areas. Wind projects using the bond financing scenario benefit by not having to pay income or property taxes (as the projects are assumed owned by public sector entities) and are assumed able to secure longer term (20 year) bonds (compared with 15 year for commercial loans in the equity plus commercial debt financing scenario). These benefits are outweighed, however, by losing the Federal tax incentives of the PTC and accelerated depreciation (which are not available for public sector projects). Generally speaking, these tax incentives outweigh the tax-free status, particularly when the cost of debt is assumed to be equal in both cases – as it is in this Report.

The Analysis Model may overstate the actual costs of energy for wind projects using the bond financing scenario for a separate reason. The bond financing scenario requires that the underlying wind projects generate an excess of cash flow to provide a stipulated margin over the annual bond amortization requirements. The requisite cost of energy in the bond financing scenarios is set so that the sustainable bond amount covers the full amount of the project costs. In the equity plus commercial debt scenario, the comparable “excess” cash flows accrue to the equity owner to help achieve the required IRR. Such analogous flows in this scenario might be utilized to prepay portions of the bond offering. Any such prepayments would shorten the effective life of the bond and presumably lower the required cost of energy for wind projects using the bond financing scenario. This report does not attempt to layer in this level of financing complexity.

All three of the financing assumptions assume equity return levels and/or debt financing terms that are consistent with current market practices in the onshore U.S. wind market. They do not factor in any risk premiums associated with the use of novel technology, construction practices, and/or operations. The team elected this approach, due to the lack of representative offshore wind projects in the United States and the paucity of projects in Europe. Use of such assumptions in the Analysis Model implies, however, that sufficient numbers of offshore wind projects elsewhere in the United States, e.g., in Massachusetts, or possibly in Europe will have attracted third party financing such that the capital providers no longer perceive there to be novelty risk in financing the Rhode Island wind projects. Alternatively, it may be necessary for a third party entity, e.g., a public sector entity, to assume such risks in order to enable third party capital providers or investors to assume the remaining, known risks of wind project development of the wind projects in the offshore study areas. This is consistent with the approach taken, for example, by the Federal government and selected states in encouraging the adoption of other emerging energy technologies, e.g., long-term purchases, loan guaranties, grants, permit delay insurance, and other support being extended to encourage cellulosic ethanol, photovoltaic, nuclear, and clean coal projects.

6.2 SENSITIVITY ANALYSES

The nascent status of the offshore wind industry in the United States and the preliminary scope of the technical and financial analyses of this report create a significant degree of uncertainty about the eventual costs and financial prospects for the wind projects discussed in this report. Sensitivity analyses of key inputs and assumptions will help to understand the impact of possible changes of these inputs on the economics of wind projects in the study areas. The team conducted sensitivity analyses for five such inputs: capital costs, wind energy resource, availability of the Federal PTC, net metering rules, and the costs of financing. For the capital cost analysis, the team considered the impact on the economics of all of the study areas. For the net metering rule change impact, the team looked only at the customer-connected and community study areas, as these are the only study areas involving sales of the output at retail rates. For the remaining analyses, the team considered the impact of a change in the relevant base case assumption on the three representative study areas: the community study area, offshore area C, and offshore area H. To focus the analysis, the team assessed the impact on the levelized cost of energy for each study area using the equity plus commercial debt financing scenario. The premise of each analysis and the corresponding results are discussed further below.

6.2.1 CHANGES IN CAPITAL COSTS

The capital cost estimates prepared by the team for this report are feasibility level estimates. Actual costs almost certainly will differ. Detailed cost estimates taking into account local site conditions will vary. Construction techniques for offshore projects still have to be refined. There will be general inflation of costs between now and the onset of construction of offshore wind projects. Most significantly, the price of wind turbine generators has risen significantly in the last few years and likely will change again as the balance of wind turbine supply and demand evolves in the U.S. market.

For the report, the team elected to vary the price of wind turbines. Prices fifteen percent below and above the base case price are utilized. Figure 6-5 portrays the results.

The analysis confirms the expected direct correlation between capital cost changes and the levelized cost of energy. For each study area, the levelized cost of energy will increase if turbine prices rise, assuming other variables remain unchanged. In each case, a fifteen percent change in the turbine cost causes about a 7-8 percent corresponding change in total project cost. For buyers of the output of such projects, the analysis highlights the need for buyers of the output of such projects, even if on a long-term basis, to acknowledge that broader market factors outside the control of developers of the projects will affect the requisite power price.

6.2.2 CHANGES IN THE WIND RESOURCE

The wind energy analyses in this report are based on existing regional wind data, rather than site specific data. As a consequence, there is a degree of uncertainty about the actual wind resource in any specific site. To measure the potential impact of differences in the actual wind resource from the report estimates, the team conducted a sensitivity analysis by varying the estimated wind resource by 0.5 meters per second above and below the base case estimate for the selected study areas. Figure 6-6 portrays the results.

The analysis confirms the expected negative correlation between changes in the wind resource and the levelized cost of energy. For each study area, the requisite levelized cost of energy will increase if the site-specific wind resource proves less than estimated, assuming other variables remain unchanged. Similarly, the levelized cost of energy will drop if the wind resource proves stronger than estimated. The analysis highlights the need for gathering site-specific data of proposed wind projects in order to support negotiations on the sustainable power price.

6.2.3 UNAVAILABILITY OF THE FEDERAL PRODUCTION TAX CREDIT

The report estimates are based on the continuation of the Federal production tax credit as currently structured. By reducing total tax obligations otherwise owed, the PTC represents a key inducement for institutional investors to support wind project investments. Put another way, this benefit enables the required levelized cost of energy to be less than would otherwise be necessary for the project to attract such third party investment capital. Although not a permanent incentive, the PTC has been reauthorized several times and currently is available for projects put into service prior to January 1, 2009. There is no guarantee that the PTC will be extended thereafter. The importance of its reauthorization for the economics of potential RIWINDS wind projects can be seen by estimating the levelized cost of energy required if projects were only able to draw upon cash flows and depreciation benefits. As the PTC only is available to private sector investors in wind projects, it would not affect projects owned by the public sector. Figure 6-7 portrays the results.

The sensitivity analysis demonstrates the important value of the Federal PTC to project economics. For private sector projects financed by equity and debt, the loss of the PTC would require the levelized cost of energy to consumers buying power from the projects to be approximately $20/MWh higher over the twenty year life of the project. As projects in the offshore areas are unlikely to go into operations prior to the current expiration date, Federal Government action to renew the PTC will yield a substantive benefit for the RIWINDS program.

6.2.4 CHANGE IN PRICING FOR COMMUNITY-SCALE WIND PROJECTS

Two of the study areas in the report – the customer-connected and community study areas – assume that portions of the project output are sold to an on-site host at an assumed retail rate, with the balance sold at the estimated wholesale rate. In many states, a significant incentive for smaller renewable power projects is the ability to receive the higher retail rate for power sold to the utility, i.e., to receive the same rate for power sold from the project as paid for by the host for its other requirements. This is known as a net-metering incentive. The projects assumed for these two study areas currently are too large to qualify for the Rhode Island incentive. The project economics would improve slightly if the incentive rule were to be changed to enable the full output from projects in these study areas to be sold at their avoided costs, i.e., at their retail rates. Figure 6-8 compares the estimated required levelized prices for each of the two study areas with the estimated wholesale and retail avoided cost prices outlined in Section 4.6.3.

Figure 6-8 illustrates the higher levelized prices estimated for avoided retail prices. These are projected to be essentially at the levels needed for projects in these two study areas.

6.2.5 CHANGES IN FINANCING COSTS

Financing terms will be a function of the perceived risks of the wind projects. The project risks for larger onshore wind projects are reasonably well known and digested by prospective investors and lenders. Financing sources for smaller wind projects such as projects in the community study area are not as well-developed. As a result, available financing terms can be more stringent. Financing terms may well prove more stringent also for the offshore wind projects. No offshore wind projects have come on line yet in the United States, and limited recourse debt financing for European wind projects is still novel. Thus, the financing terms required by financiers for offshore wind projects in the U.S. may differ from those of onshore projects. The financial analysis in Section 4.6.5 assumes that investors and lenders set terms as currently seen for large-scale onshore wind projects. A sensitivity analysis can be done by assessing the impact on the estimated required levelized costs of energy of changes in certain financing terms. In the analysis below, the team compares the base case estimated required levelized costs of energy for the three selected study areas with two progressive alternate financing frameworks. The frameworks both use the equity plus commercial debt financing scenario. The first alternative raises the required equity rate of return from 12 percent to 15 percent. The second adds more stringent lender requirements of a higher debt service coverage ratio (from 1.45x to 1.75x) and a higher interest rate (from 7 percent to 8 percent). Figure 6-9 portrays these results.

The analysis confirms the expected direct correlation between changes in the stringency in equity and debt financing terms and the requisite levelized cost of energy. For each study area, the levelized cost of energy will increase if equity investors perceive a greater risk with the project and require a higher return. The estimated cost will rise further if project lenders also seek to compensate for perceived uncertainty by boosting interest rates and requiring higher cash flows to cover debt service. While still within the band of uncertainty wholesale market price forecasts in most cases, the estimated required prices will need higher REC prices in order for the projects to be viable. The analysis highlights both the central impact played by financing costs in the overall required costs of energy and the value that reducing perceived project uncertainties can have for financing costs and, hence, the estimated required energy prices needed by the projects.

6.3 OVERALL FINANCIAL ANALYSIS ASSESMENTS

The financial analysis of the various wind project types for the study areas suggests several overall observations.

- At current projected electricity prices, wind projects in those study areas with robust wind regimes are financially feasible. The degree of feasibility will depend on assumptions for future REC prices.
- The strength of the wind resource and the distance to interconnect are key drivers in the relative financial feasibility of wind projects among the study areas. More precise wind resource analysis will help qualify study area prospects further.
- The limited availability of capital cost and operating cost information for offshore wind projects serves as an impediment to confident assessments of specific project opportunities. Support for further analysis would help to reduce the current uncertainty levels.
- Creating a means whereby multiple projects can support initial interconnection costs or perhaps shifting financing of these costs to a separate financing mechanism altogether, also may improve the relative financial feasibility of offshore wind projects.
- Tapping both private sector equity and commercial debt sources to support the wind projects may be the most cost-effective means to finance the projects.

Table 6-1. Projected Energy Value of Wind Production in Rhode Island

	Energy Value							Capacity Value					
	All-Hours Average Value ($/MWh @ busbar)	Production Profile Adjustment Factor	Production Profile-Adjusted Value ($/MWh) @ busbar	Derate to Market Value of Intermittent Production Stream ($/MWh)	Adjusted Energy Market Value ($/MWh)	Estimated Carbon Allowance Adder to spot energy prices ($/MWh)	Projected Energy Value of Wind Production ($/MWh, nominal)	Projected Forward Capacity Market Price ($/kw-mo)	Projected Forward Capacity Market Price ($/kw-yr)	Wind capacity credit (% of nameplate)	Wind c.f.	FCM Capacity Value for wind ($/MWh)	Total Commodity Market Value Forecast ($/MWh at plant busbar)
2007	$ 68	1.006	$ 69	$ (2.5)	$ 66		$ 66.3	$ 3.1	$ 37	20%	30%	$ 2.8	$ 69
2008	$ 74	1.006	$ 75	$ (2.5)	$ 72		$ 72.3	$ 3.5	$ 42	20%	30%	$ 3.2	$ 75
2009	$ 72	1.006	$ 72	$ (2.5)	$ 70	$ 1.3	$ 71.0	$ 4.0	$ 47	20%	30%	$ 3.6	$ 75
2010	$ 68	1.006	$ 69	$ (2.5)	$ 66	$ 1.4	$ 67.5	$ 5.8	$ 70	20%	30%	$ 5.3	$ 73
2011	$ 64	1.006	$ 65	$ (2.5)	$ 62	$ 1.5	$ 63.8	$ 7.0	$ 84	20%	30%	$ 6.4	$ 70
2012	$ 61	1.006	$ 61	$ (2.5)	$ 59	$ 1.6	$ 60.3	$ 7.0	$ 84	20%	30%	$ 6.4	$ 67
2013	$ 57	1.006	$ 58	$ (2.5)	$ 55	$ 1.7	$ 56.8	$ 7.0	$ 84	20%	30%	$ 6.4	$ 63
2014	$ 58	1.006	$ 58	$ (2.5)	$ 56	$ 1.8	$ 57.6	$ 7.0	$ 84	20%	30%	$ 6.4	$ 64
2015	$ 58	1.006	$ 58	$ (2.5)	$ 56	$ 1.9	$ 57.8	$ 7.0	$ 84	20%	30%	$ 6.4	$ 64
2016	$ 60	1.006	$ 61	$ (2.5)	$ 58	$ 2.1	$ 60.2	$ 7.0	$ 84	20%	30%	$ 6.4	$ 67
2017	$ 64	1.006	$ 64	$ (2.5)	$ 62	$ 2.2	$ 63.9	$ 7.0	$ 84	20%	30%	$ 6.4	$ 70
2018	$ 64	1.006	$ 64	$ (2.5)	$ 62	$ 2.4	$ 64.2	$ 7.0	$ 84	20%	30%	$ 6.4	$ 71
2019	$ 65	1.006	$ 65	$ (2.5)	$ 62	$ 2.5	$ 65.0	$ 7.0	$ 84	20%	30%	$ 6.4	$ 71
2020	$ 67	1.006	$ 67	$ (2.5)	$ 65	$ 2.7	$ 67.3	$ 7.0	$ 84	20%	30%	$ 6.4	$ 74
2021	$ 68	1.006	$ 68	$ (2.5)	$ 66	$ 2.9	$ 68.7	$ 7.0	$ 84	20%	30%	$ 6.4	$ 75
2022	$ 71	1.006	$ 72	$ (2.5)	$ 69	$ 3.1	$ 72.2	$ 7.0	$ 84	20%	30%	$ 6.4	$ 79
2023	$ 74	1.006	$ 75	$ (2.5)	$ 72	$ 3.3	$ 75.4	$ 7.0	$ 84	20%	30%	$ 6.4	$ 82
2024	$ 78	1.006	$ 78	$ (2.5)	$ 76	$ 3.5	$ 79.3	$ 7.0	$ 84	20%	30%	$ 6.4	$ 86
2025	$ 79	1.006	$ 80	$ (2.5)	$ 77	$ 3.5	$ 81.0	$ 7.0	$ 84	20%	30%	$ 6.4	$ 87
2026	$ 81	1.006	$ 82	$ (2.5)	$ 79	$ 3.5	$ 82.6	$ 7.0	$ 84	20%	30%	$ 6.4	$ 89
2027	$ 84	1.006	$ 85	$ (2.5)	$ 82	$ 3.5	$ 85.7	$ 7.0	$ 84	20%	30%	$ 6.4	$ 92
2028	$ 88	1.006	$ 88	$ (2.5)	$ 86	$ 3.5	$ 89.5	$ 7.0	$ 84	20%	30%	$ 6.4	$ 96

Table 6-2. Projected Wholesale Market Prices for a Wind Generator in Rhode Island

	REC Value: Case 1 (ACP, Upper Bound)			REC Value: Case 2 (Lower Bound)		
	REC Price Forecast ($/MWh)		Total Market Value ($/MWh)	REC Price Forecast ($/MWh)		Total Market Value ($/MWh)
2007	$ 56.51		$ 125.58	$ 20.00		$ 89.08
2008	$ 57.92		$ 133.41	$ 20.00		$ 95.49
2009	$ 59.37		$ 134.02	$ 20.00		$ 94.65
2010	$ 60.85		$ 133.69	$ 20.00		$ 92.83
2011	$ 62.37		$ 132.53	$ 20.00		$ 90.15
2012	$ 63.93		$ 130.65	$ 20.00		$ 86.71
2013	$ 65.53		$ 128.71	$ 20.00		$ 83.18
2014	$ 67.17		$ 131.18	$ 20.00		$ 84.01
2015	$ 68.85		$ 133.04	$ 20.00		$ 84.19
2016	$ 70.57		$ 137.12	$ 20.00		$ 86.55
2017	$ 72.34		$ 142.60	$ 20.00		$ 90.27
2018	$ 74.14		$ 144.73	$ 20.00		$ 90.59
2019	$ 76.00		$ 147.41	$ 20.00		$ 91.41
2020	$ 77.90		$ 151.57	$ 20.00		$ 93.68
2021	$ 79.84		$ 154.90	$ 20.00		$ 95.05
2022	$ 81.84		$ 160.43	$ 20.00		$ 98.59
2023	$ 83.89		$ 165.65	$ 20.00		$ 101.77
2024	$ 85.98		$ 171.73	$ 20.00		$ 105.74
2025	$ 88.13		$ 175.49	$ 20.00		$ 107.36
2026	$ 90.34		$ 179.37	$ 20.00		$ 109.03

Table 6-3. Projected Avoided Retail Market Prices for Industrial/Institutional and Community Wind Projects (Assuming the Case 2 $20/MWh REC Price Forecast

	Generation Service							Avoided T&D Rate Components					Summary
	All-Hours Average Value ($/MWh @ busbar)	Adjustment: Shaping, ancillary services & reserves	Est. Carbon Allowance Adder to spot energy prices ($/MWh)	est. FCM Cost @15% reserve margin, 59.7% c.f.	RPS compliance ($/MWh)	Loss Adjustmt	Forecast of Competitive Market Generation Service Price ($/MWh)	Distribution Charges ($/MWh)	Transmission Charges ($/MWh)	Transition Charges ($/MWh)	Conservation Charge ($/MWh)	Total Avoided T&D Charges ($/MWh)	Total Avoided Retail Rates ($/MWh)
2007	$ 68	$ 10		$ 8	$ 0.6	$ 5.7	$ 93	$ 11	$ 6	$ -	$ 2.3	$ 19	$ 112
2008	$ 74	$ 11		$ 9	$ 0.9	$ 6.2	$ 101	$ 11	$ 6	$ -	$ 2.3	$ 19	$ 121
2009	$ 72	$ 11	$ 1.3	$ 10	$ 1.2	$ 6.2	$ 101	$ 11	$ 6	$ -	$ 2.3	$ 20	$ 121
2010	$ 68	$ 10	$ 1.4	$ 15	$ 1.5	$ 6.3	$ 103	$ 12	$ 6	$ -	$ 2.3	$ 20	$ 123
2011	$ 64	$ 9	$ 1.5	$ 18	$ 2.2	$ 6.2	$ 102	$ 12	$ 7	$ -	$ 2.3	$ 21	$ 123
2012	$ 61	$ 9	$ 1.6	$ 18	$ 2.9	$ 6.0	$ 99	$ 12	$ 7	$ -	$ 2.3	$ 21	$ 120
2013	$ 57	$ 8	$ 1.7	$ 18	$ 3.6	$ 5.8	$ 95	$ 12	$ 7	$ -	$ 2.3	$ 22	$ 117
2014	$ 58	$ 8	$ 1.8	$ 18	$ 4.4	$ 5.9	$ 97	$ 13	$ 7	$ -	$ 2.3	$ 22	$ 119
2015	$ 58	$ 8	$ 1.9	$ 18	$ 5.5	$ 6.0	$ 98	$ 13	$ 7	$ -	$ 2.3	$ 23	$ 121
2016	$ 60	$ 9	$ 2.1	$ 18	$ 6.7	$ 6.3	$ 102	$ 13	$ 7	$ -	$ 2.3	$ 23	$ 126
2017	$ 64	$ 9	$ 2.2	$ 18	$ 8.0	$ 6.6	$ 108	$ 14	$ 8	$ -	$ 2.3	$ 24	$ 132
2018	$ 64	$ 9	$ 2.4	$ 18	$ 9.3	$ 6.7	$ 110	$ 14	$ 8	$ -	$ 2.3	$ 24	$ 134
2019	$ 65	$ 9	$ 2.5	$ 18	$ 10.6	$ 6.9	$ 113	$ 14	$ 8	$ -	$ 2.3	$ 25	$ 137
2020	$ 67	$ 10	$ 2.7	$ 18	$ 12.5	$ 7.2	$ 117	$ 15	$ 8	$ -	$ 2.3	$ 25	$ 142
2021	$ 68	$ 10	$ 2.9	$ 18	$ 12.8	$ 7.3	$ 119	$ 15	$ 8	$ -	$ 2.3	$ 26	$ 145
2022	$ 71	$ 10	$ 3.1	$ 18	$ 13.1	$ 7.6	$ 124	$ 16	$ 9	$ -	$ 2.3	$ 26	$ 150
2023	$ 74	$ 11	$ 3.3	$ 18	$ 13.4	$ 7.8	$ 128	$ 16	$ 9	$ -	$ 2.3	$ 27	$ 155
2024	$ 78	$ 11	$ 3.5	$ 18	$ 13.8	$ 8.1	$ 133	$ 16	$ 9	$ -	$ 2.3	$ 28	$ 161
2025	$ 79	$ 12	$ 3.5	$ 18	$ 14.1	$ 8.3	$ 135	$ 17	$ 9	$ -	$ 2.3	$ 28	$ 164
2026	$ 81	$ 12	$ 3.5	$ 18	$ 14.5	$ 8.4	$ 138	$ 17	$ 9	$ -	$ 2.3	$ 29	$ 167

Table 6-3. (continued)

	Generation Service							Avoided T&D Rate Components					Summary
	All-Hours Average Value ($/MWh @ busbar)	Adjustment: Shaping, ancillary services & reserves	Est. Carbon Allowance Adder to spot energy prices ($/MWh)	est. FCM Cost @15% reserve margin, 59.7% c.f.	RPS compliance ($/MWh)	Loss Adjustmt	Forecast of Competitive Market Generation Service Price ($/MWh)	Distribution Charges ($/MWh)	Transmission Charges ($/MWh)	Transition Charges ($/MWh)	Conservation Charge ($/MWh)	Total Avoided T&D Charges ($/MWh)	Total Avoided Retail Rates ($/MWh)
2007	$ 68	$ 10		$ 8	$ 0.6	$ 5.7	$ 93	$ 9	$ 5.0	$ -	$ 2.3	$ 17	$ 109
2008	$ 74	$ 11		$ 9	$ 0.9	$ 6.2	$ 101	$ 10	$ 5.1	$ -	$ 2.3	$ 17	$ 118
2009	$ 72	$ 11	$ 1.3	$ 10	$ 1.2	$ 6.2	$ 101	$ 10	$ 5.2	$ -	$ 2.3	$ 17	$ 119
2010	$ 68	$ 10	$ 1.4	$ 15	$ 1.5	$ 6.3	$ 103	$ 10	$ 5.4	$ -	$ 2.3	$ 18	$ 120
2011	$ 64	$ 9	$ 1.5	$ 18	$ 2.2	$ 6.2	$ 102	$ 10	$ 5.5	$ -	$ 2.3	$ 18	$ 120
2012	$ 61	$ 9	$ 1.6	$ 18	$ 2.9	$ 6.0	$ 99	$ 11	$ 5.6	$ -	$ 2.3	$ 18	$ 117
2013	$ 57	$ 8	$ 1.7	$ 18	$ 3.6	$ 5.8	$ 95	$ 11	$ 5.8	$ -	$ 2.3	$ 19	$ 114
2014	$ 58	$ 8	$ 1.8	$ 18	$ 4.4	$ 5.9	$ 97	$ 11	$ 5.9	$ -	$ 2.3	$ 19	$ 116
2015	$ 58	$ 8	$ 1.9	$ 18	$ 5.5	$ 6.0	$ 98	$ 11	$ 6.1	$ -	$ 2.3	$ 20	$ 118
2016	$ 60	$ 9	$ 2.1	$ 18	$ 6.7	$ 6.3	$ 102	$ 12	$ 6.2	$ -	$ 2.3	$ 20	$ 123
2017	$ 64	$ 9	$ 2.2	$ 18	$ 8.0	$ 6.6	$ 108	$ 12	$ 6.4	$ -	$ 2.3	$ 21	$ 129
2018	$ 64	$ 9	$ 2.4	$ 18	$ 9.3	$ 6.7	$ 110	$ 12	$ 6.5	$ -	$ 2.3	$ 21	$ 131
2019	$ 65	$ 9	$ 2.5	$ 18	$ 10.6	$ 6.9	$ 113	$ 13	$ 6.7	$ -	$ 2.3	$ 22	$ 134
2020	$ 67	$ 10	$ 2.7	$ 18	$ 12.5	$ 7.2	$ 117	$ 13	$ 6.9	$ -	$ 2.3	$ 22	$ 139
2021	$ 68	$ 10	$ 2.9	$ 18	$ 12.8	$ 7.3	$ 119	$ 13	$ 7.0	$ -	$ 2.3	$ 23	$ 142
2022	$ 71	$ 10	$ 3.1	$ 18	$ 13.1	$ 7.6	$ 124	$ 13	$ 7.2	$ -	$ 2.3	$ 23	$ 147
2023	$ 74	$ 11	$ 3.3	$ 18	$ 13.4	$ 7.8	$ 128	$ 14	$ 7.4	$ -	$ 2.3	$ 24	$ 151
2024	$ 78	$ 11	$ 3.5	$ 18	$ 13.8	$ 8.1	$ 133	$ 14	$ 7.6	$ -	$ 2.3	$ 24	$ 157
2025	$ 79	$ 12	$ 3.5	$ 18	$ 14.1	$ 8.3	$ 135	$ 15	$ 7.8	$ -	$ 2.3	$ 25	$ 160
2026	$ 81	$ 12	$ 3.5	$ 18	$ 14.5	$ 8.4	$ 138	$ 15	$ 8.0	$ -	$ 2.3	$ 25	$ 163

Table 6-4. Projected Avoided Retail Market Prices for Customer-Connected and Community Study Area Wind Projects (Assuming the Case 1 ACP-based REC Price Forecast)

	Generation Service							Avoided T&D Rate Components					Summary
	All-Hours Average Value ($/MWh @ busbar)	Adjustment: Shaping, ancillary services & reserves	Est. Carbon Allowance Adder to spot energy prices ($/MWh)	est. FCM Cost @15% reserve margin, 59.7% c.f.	RPS compliance ($/MWh)	Loss Adjustmt	Forecast of Competitive Market Generation Service Price ($/MWh)	Distribution Charges ($/MWh)	Transmission Charges ($/MWh)	Transition Charges ($/MWh)	Conservation Charge ($/MWh)	Total Avoided T&D Charges ($/MWh)	Total Avoided Retail Rates ($/MWh)
2007	$ 68	$ 10		$ 8	$ 0	$ 6	$ 92	$ 11	$ 6	$ -	$ 2	$ 19	$ 111
2008	$ 74	$ 11		$ 9	$ 0	$ 6	$ 101	$ 11	$ 6	$ -	$ 2	$ 19	$ 120
2009	$ 72	$ 11	$ 1	$ 10	$ 0	$ 6	$ 101	$ 11	$ 6	$ -	$ 2	$ 20	$ 120
2010	$ 68	$ 10	$ 1	$ 15	$ 1	$ 6	$ 102	$ 12	$ 6	$ -	$ 2	$ 20	$ 122
2011	$ 64	$ 9	$ 1	$ 18	$ 1	$ 6	$ 101	$ 12	$ 7	$ -	$ 2	$ 21	$ 121
2012	$ 61	$ 9	$ 2	$ 18	$ 1	$ 6	$ 97	$ 12	$ 7	$ -	$ 2	$ 21	$ 118
2013	$ 57	$ 8	$ 2	$ 18	$ 1	$ 6	$ 92	$ 12	$ 7	$ -	$ 2	$ 22	$ 114
2014	$ 58	$ 8	$ 2	$ 18	$ 1	$ 6	$ 94	$ 13	$ 7	$ -	$ 2	$ 22	$ 116
2015	$ 58	$ 8	$ 2	$ 18	$ 2	$ 6	$ 94	$ 13	$ 7	$ -	$ 2	$ 23	$ 117
2016	$ 60	$ 9	$ 2	$ 18	$ 2	$ 6	$ 97	$ 13	$ 7	$ -	$ 2	$ 23	$ 121
2017	$ 64	$ 9	$ 2	$ 18	$ 2	$ 6	$ 102	$ 14	$ 8	$ -	$ 2	$ 24	$ 126
2018	$ 64	$ 9	$ 2	$ 18	$ 3	$ 6	$ 103	$ 14	$ 8	$ -	$ 2	$ 24	$ 127
2019	$ 65	$ 9	$ 3	$ 18	$ 3	$ 6	$ 104	$ 14	$ 8	$ -	$ 2	$ 25	$ 129
2020	$ 67	$ 10	$ 3	$ 18	$ 3	$ 7	$ 107	$ 15	$ 8	$ -	$ 2	$ 25	$ 133
2021	$ 68	$ 10	$ 3	$ 18	$ 3	$ 7	$ 109	$ 15	$ 8	$ -	$ 2	$ 26	$ 135
2022	$ 71	$ 10	$ 3	$ 18	$ 3	$ 7	$ 113	$ 16	$ 9	$ -	$ 2	$ 26	$ 140
2023	$ 74	$ 11	$ 3	$ 18	$ 3	$ 7	$ 117	$ 16	$ 9	$ -	$ 2	$ 27	$ 144
2024	$ 78	$ 11	$ 4	$ 18	$ 3	$ 7	$ 122	$ 16	$ 9	$ -	$ 2	$ 28	$ 150
2025	$ 79	$ 12	$ 4	$ 18	$ 3	$ 8	$ 124	$ 17	$ 9	$ -	$ 2	$ 28	$ 152
2026	$ 81	$ 12	$ 4	$ 18	$ 3	$ 8	$ 126	$ 17	$ 9	$ -	$ 2	$ 29	$ 155

Avoided Retail Costs for Community Study Area wind projects *Case 2 ($20/MWh) REC Price Forecast*

	Generation Service							Avoided T&D Rate Components					Summary
	All-Hours Average Value ($/MWh @ busbar)	Adjustment: Shaping, ancillary services & reserves	Est. Carbon Allowance Adder to spot energy prices ($/MWh)	est. FCM Cost @15% reserve margin, 59.7% c.f.	RPS compliance ($/MWh)	Loss Adjustmt	Forecast of Competitive Market Generation Service Price ($/MWh)	Distribution Charges ($/MWh)	Transmission Charges ($/MWh)	Transition Charges ($/MWh)	Conservation Charge ($/MWh)	Total Avoided T&D Charges ($/MWh)	Total Avoided Retail Rates ($/MWh)
2007	$ 68	$ 10		$ 8	$ 0	$ 6	$ 92	$ 9	$ 5	$ -	$ 2.3	$ 17	$ 109
2008	$ 74	$ 11		$ 9	$ 0	$ 6	$ 101	$ 10	$ 5	$ -	$ 2.3	$ 17	$ 118
2009	$ 72	$ 11	$ 1.3	$ 10	$ 0	$ 6	$ 101	$ 10	$ 5	$ -	$ 2.3	$ 17	$ 118
2010	$ 68	$ 10	$ 1.4	$ 15	$ 1	$ 6	$ 102	$ 10	$ 5	$ -	$ 2.3	$ 18	$ 119
2011	$ 64	$ 9	$ 1.5	$ 18	$ 1	$ 6	$ 101	$ 10	$ 6	$ -	$ 2.3	$ 18	$ 119
2012	$ 61	$ 9	$ 1.6	$ 18	$ 1	$ 6	$ 97	$ 11	$ 6	$ -	$ 2.3	$ 18	$ 115
2013	$ 57	$ 8	$ 1.7	$ 18	$ 1	$ 6	$ 92	$ 11	$ 6	$ -	$ 2.3	$ 19	$ 111
2014	$ 58	$ 8	$ 1.8	$ 18	$ 1	$ 6	$ 94	$ 11	$ 6	$ -	$ 2.3	$ 19	$ 113
2015	$ 58	$ 8	$ 1.9	$ 18	$ 2	$ 6	$ 94	$ 11	$ 6	$ -	$ 2.3	$ 20	$ 114
2016	$ 60	$ 9	$ 2.1	$ 18	$ 2	$ 6	$ 97	$ 12	$ 6	$ -	$ 2.3	$ 20	$ 118
2017	$ 64	$ 9	$ 2.2	$ 18	$ 2	$ 6	$ 102	$ 12	$ 6	$ -	$ 2.3	$ 21	$ 123
2018	$ 64	$ 9	$ 2.4	$ 18	$ 3	$ 6	$ 103	$ 12	$ 7	$ -	$ 2.3	$ 21	$ 124
2019	$ 65	$ 9	$ 2.5	$ 18	$ 3	$ 6	$ 104	$ 13	$ 7	$ -	$ 2.3	$ 22	$ 126
2020	$ 67	$ 10	$ 2.7	$ 18	$ 3	$ 7	$ 107	$ 13	$ 7	$ -	$ 2.3	$ 22	$ 129
2021	$ 68	$ 10	$ 2.9	$ 18	$ 3	$ 7	$ 109	$ 13	$ 7	$ -	$ 2.3	$ 23	$ 131
2022	$ 71	$ 10	$ 3.1	$ 18	$ 3	$ 7	$ 113	$ 13	$ 7	$ -	$ 2.3	$ 23	$ 136

Table 6-5. Overview of Analysis Model Assumptions

Assumption	Application in Model	Source / Basis
Project & Operating Assumptions		
Project Size	Determines the MWs of capacity for each Project Type. Separates projects into representative size categories.	Defined jointly by the Team and RIEDC.
Net Energy Production	Identifies the expected annual MWhs generated by the Project Type. This value is used to calculate project revenues and production tax benefits, if applicable. See Section 4.5 for details.	Team evaluation of regional wind maps and other meteorological resources.
Project Life	Assumes the project has a 20-year useful life.	Industry standard practice.
Capital Cost	Determines total cost of the project (excluding financing costs). See Section 4.5 for details.	Team evaluation of comparables and industry expectations.
Depreciation	Tax benefits, which account for roughly one-third of equity returns, are dependent on the allocation of total project costs to various depreciation schedules. For tax purposes virtually all of a wind project's hard costs qualify for treatment under the Modified Accelerated Cost Recover System ("MACRS") 5-year schedule. In this analysis, the Team assumes that 94.0 percent of the total project cost qualifies for 5-year MACRS. Depreciating almost all of the project costs in the first five years creates significant taxable losses at the project level in those years. These losses represent an additional project benefit, as equity investors in the project can use these losses to offset profits generated from other business activities.	Industry standard values.
O&M Cost Inflation	Used to calculate annual operating cost of the project. The model also assumes an additional cost inflation, which can be adjusted in the later years to simulate the increase in costs as equipment ages. A general inflation rate of 2.50 percent is used for both revenues and O&M costs. In general, as the equipment ages, it will require more maintenance. Aging of the project turbine fleet can be accounted for in a financial analysis by either (i) increasing O&M costs faster than inflation (more money is needed to keep the fleet running the same number of hours) or (ii) decreasing the net capacity factor (the same amount of money is spent on O&M so the fleet has a reduced operational availability and reduced output). The Team employs the former method and adds a 0.25 percent real cost increase to the general inflation rate (for an all-in rate of 2.75 percent) for O&M costs beginning in	Best available industry data.

	the twelfth year of operation.	
Income Taxes	Used to calculate annual tax benefit or expense. A combined (federal and state) rate is assumed. Income tax rates used to calculate the tax benefits are the standard Federal (35.0 percent) and state corporate income tax rates (9.0 percent).	Standard corporate values.
Financing Assumptions		
Capital Structure	Determines whether project investment is equity, debt or both.	Defined jointly by the Team and RIEDC.
Debt Tenor, Interest Rate and Coverage Ratio	These key debt parameters determine the semi-annual debt service amount and the amount of cash flow that must be available for the project to maintain compliance with lender requirements. Specific assumptions are noted below.	Best available industry data.
Financing Costs	Reflects the cost of completing the transaction and obtaining equity and debt capital, e.g., legal, consultants, fees, etc..	Best available industry data.

Table 6-6. Projected Cost of Wind Energy in Rhode Island Estimated Capital Cost per kW of Capacity Ranked by Study Area

Study Area	*Representative Project Type*	*Projected Avg Wind Speed (m/s)*	*US$/MWh*
Offshore Area J	200 MW	9.25	**$96/MW**
Offshore Area K	200 MW	9.25	**$96/MW**
Offshore Area H	200 MW	8.75	**$97/MW**
Onshore	10 MW	7.00	**$97/MW**
Community	1.5 MW	7.00	**$102/MW**
Offshore Area G	200 MW	8.25	**$104/MW**
Offshore Area F	200 MW	7.75	**$114/MW**
Customer-Connected	1.5 MW	6.50	**$116/MW**
Offshore Area E	30 MW	8.75	**$120/MW**
Offshore Area C	30 MW	8.25	**$121/MW**
Offshore Area B	30 MW	8.25	**$121/MW**
Offshore Area A	30 MW	7.75	**$129/MW**
Offshore Area D	30 MW	7.75	**$137/MW**

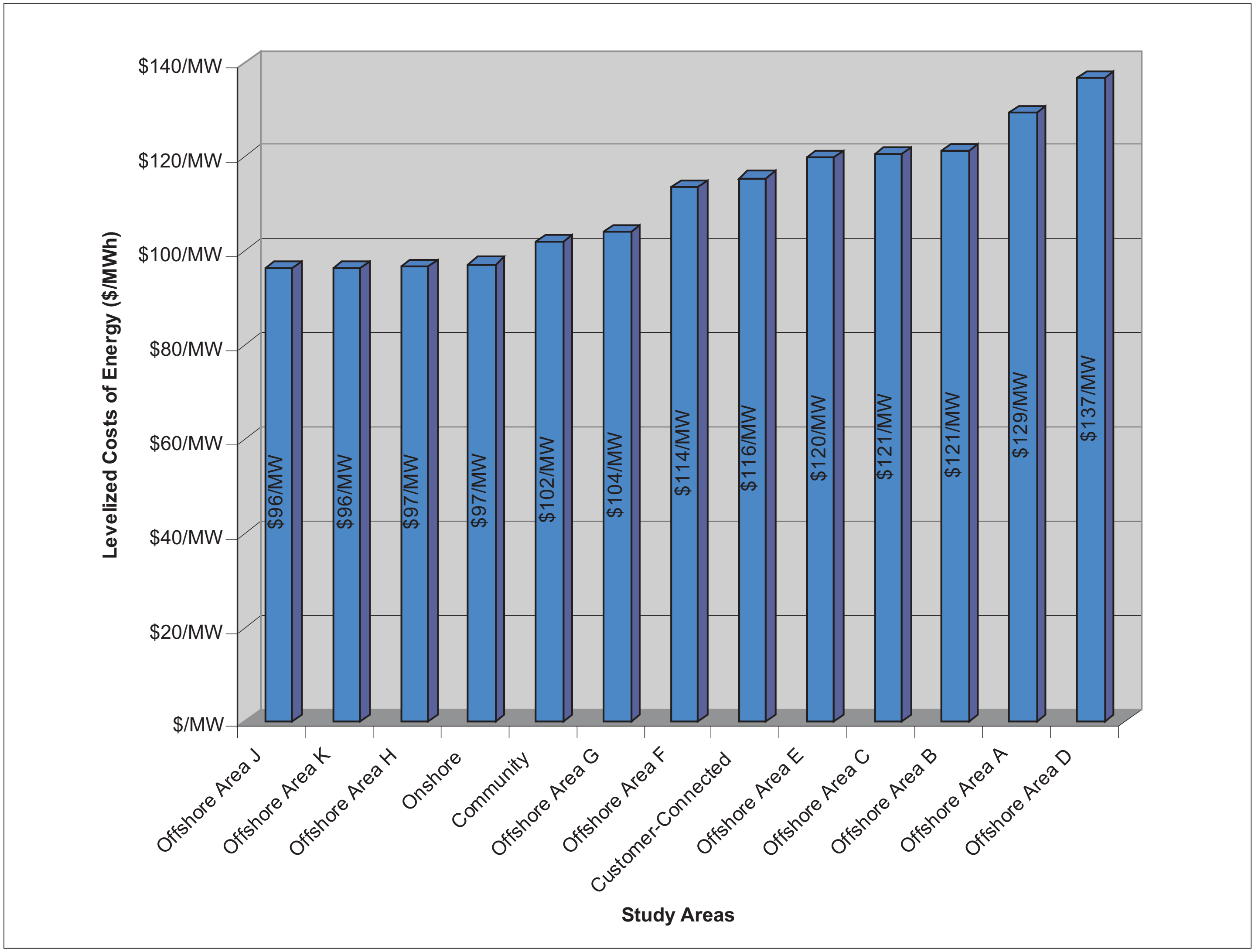

Figure 6-1
Projected Cost of Wind Energy in Rhode Island Estimated Capital Cost per kW of Capacity
Ranked by Study Area
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

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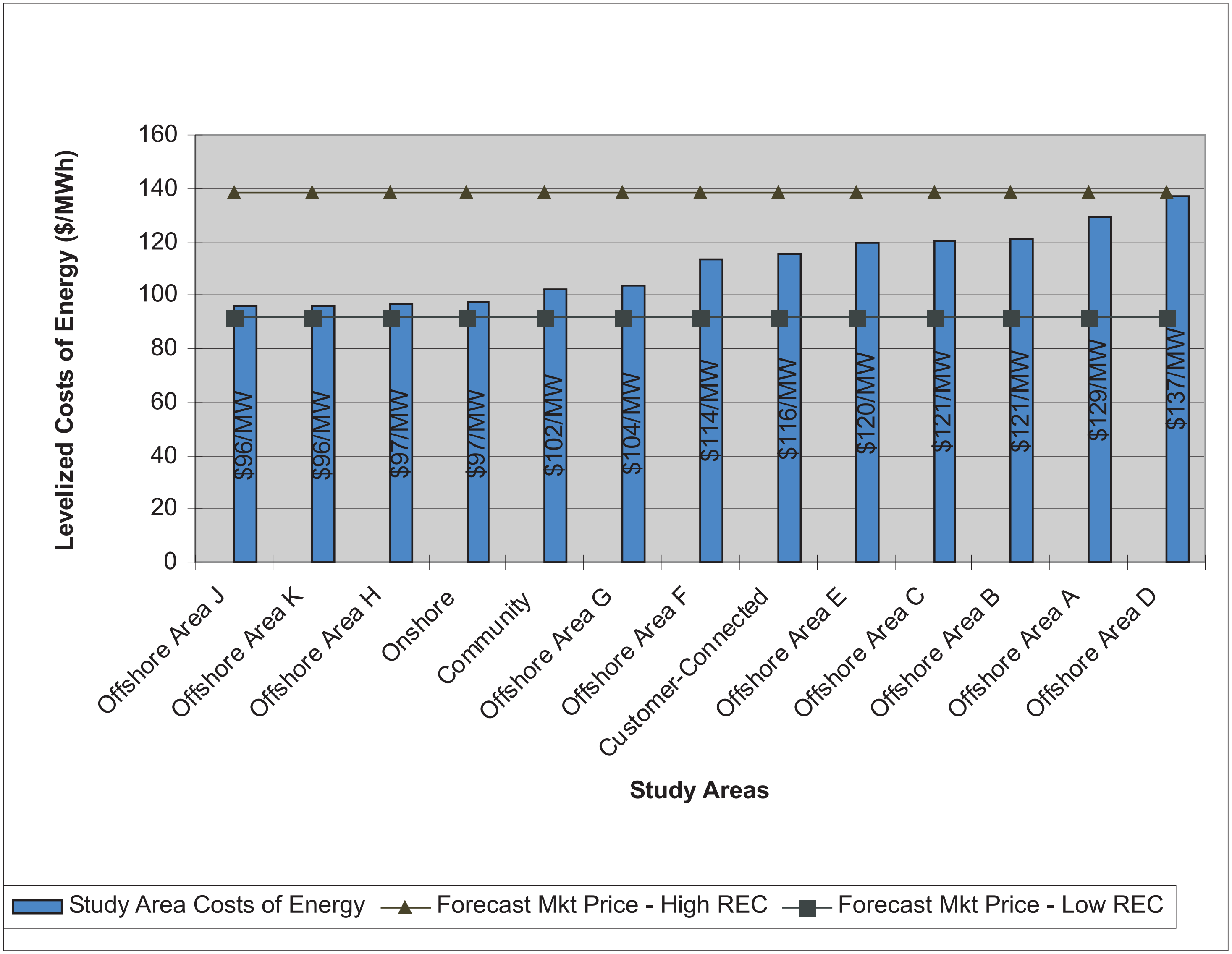

Figure 6-2

Estimated Levelized Cost of Wind Energy Compared to Levelized Wholesale Electricity Price Forecasts
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

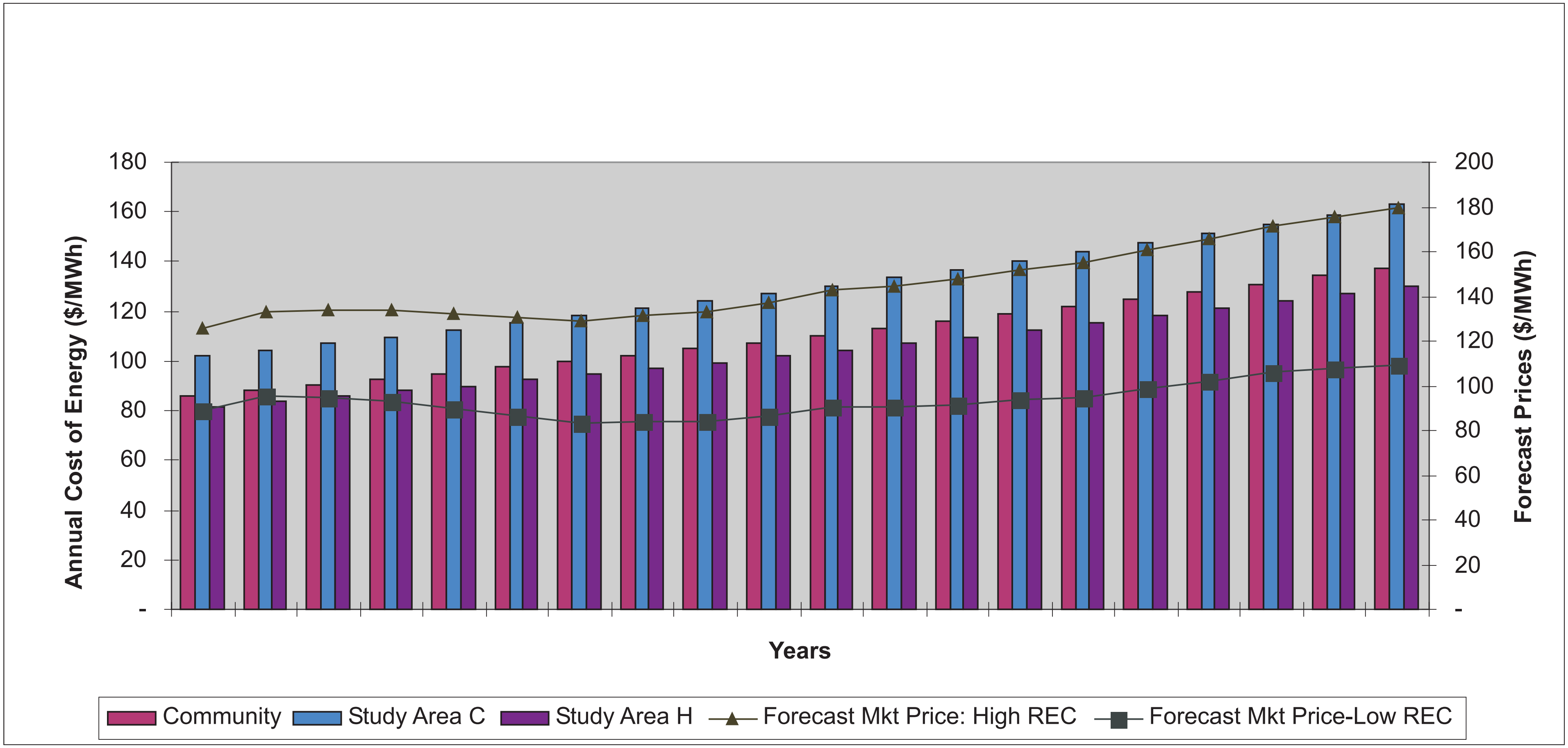

Figure 6-3

Comparison of Annual Costs of Energy to Energy Price Forecasts
RIWINDS Siting Study

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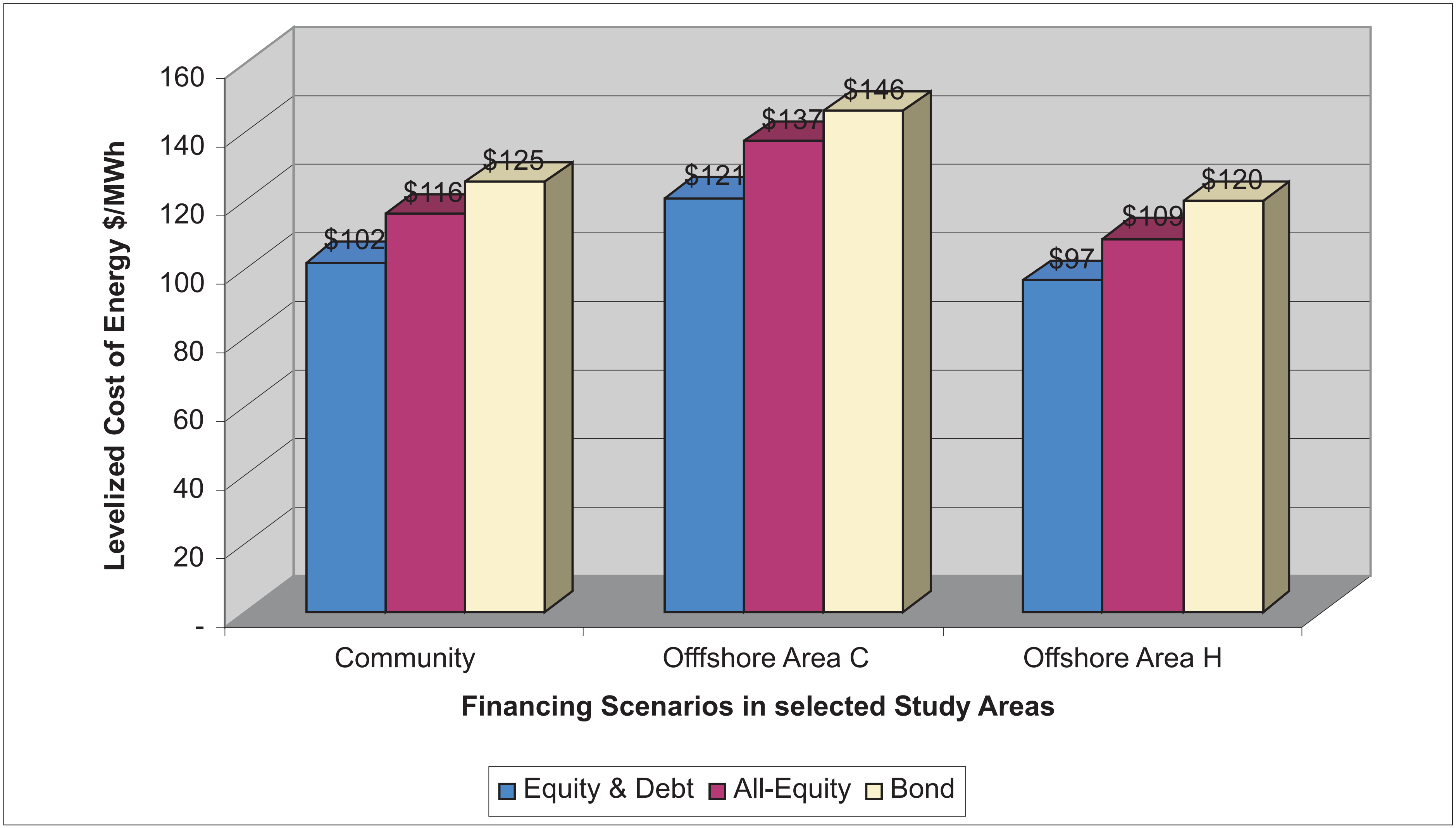

Figure 6-4

Comparison of Levelized Costs of Energy using Different Financing Scenarios
RIWINDS Siting Study

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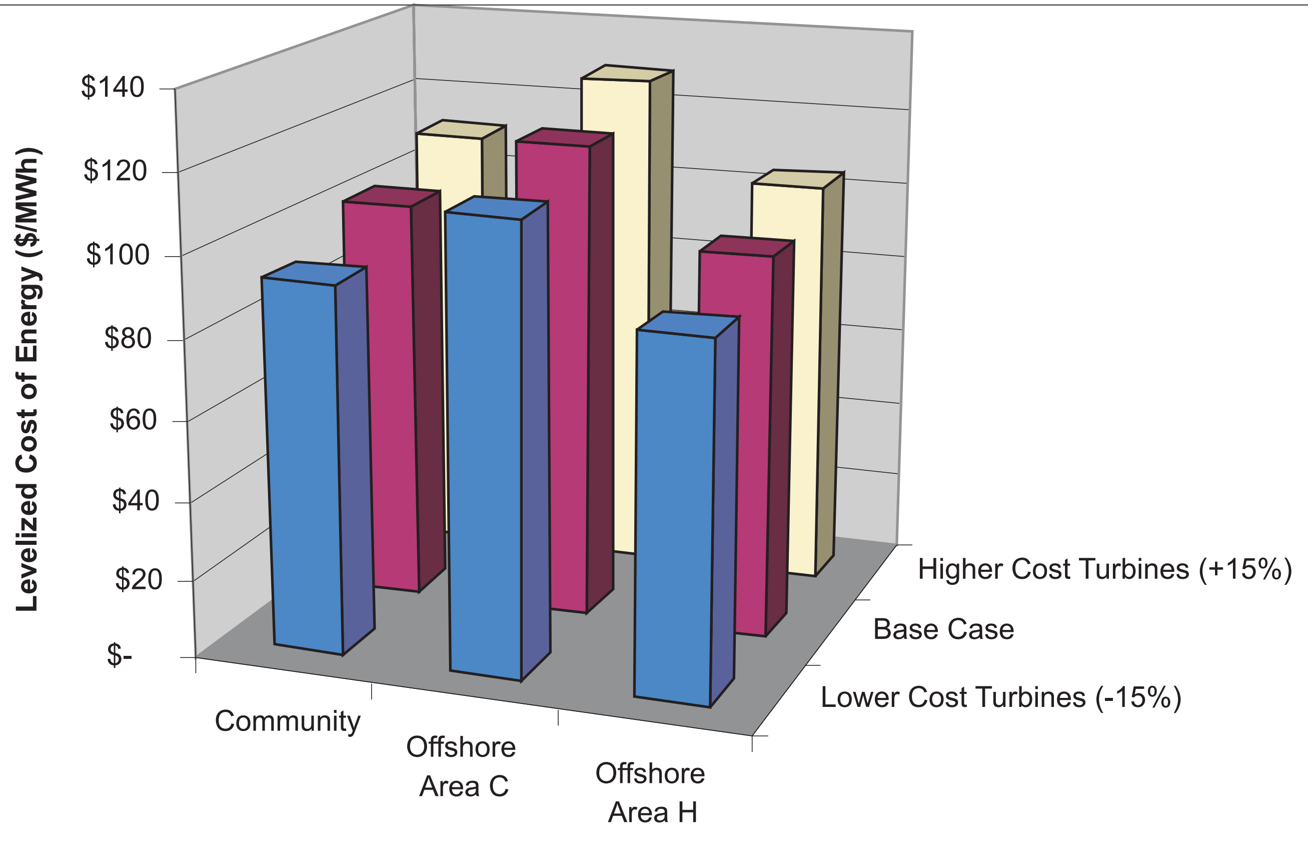
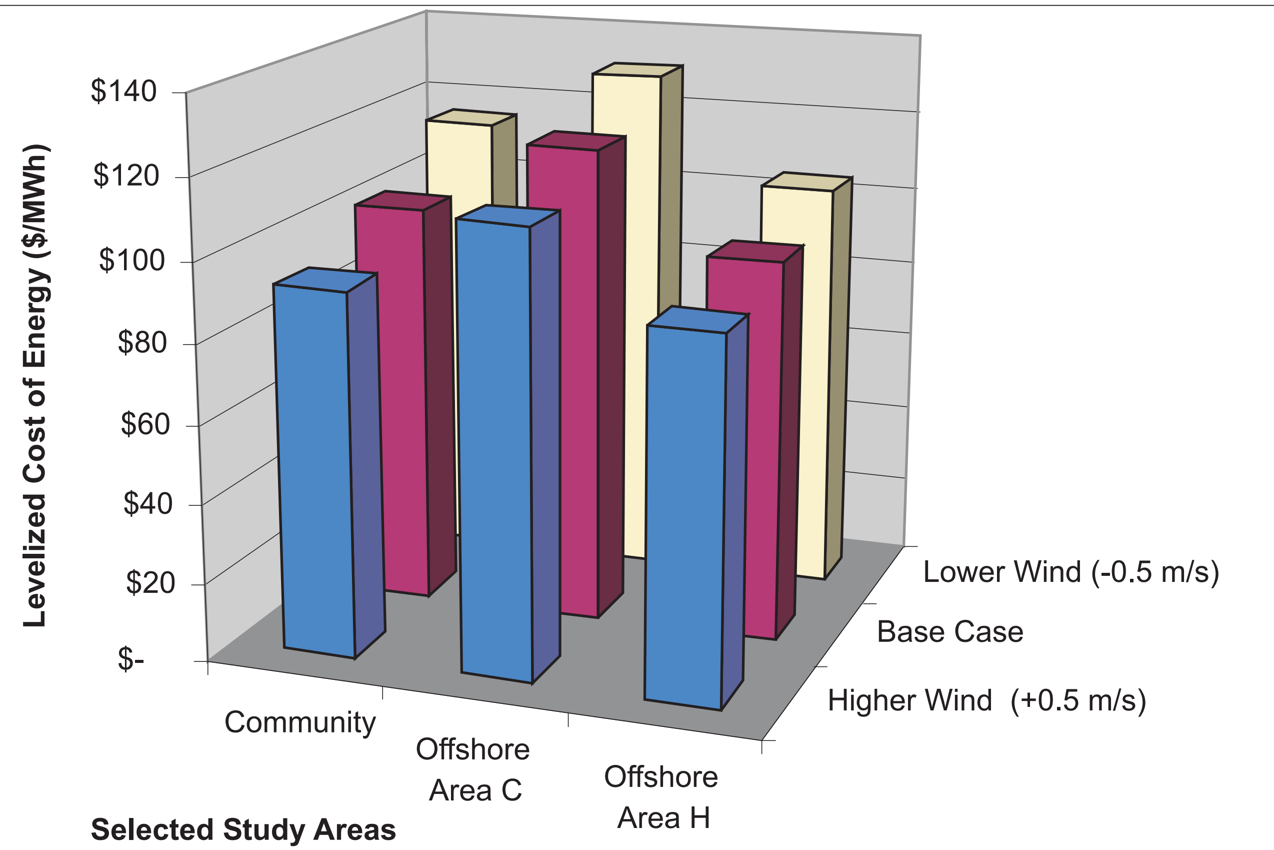


	Community	Offshore Area C	Offshore Area H
Lower Cost Turbines (-15%)	$93	$112	$89
Base Case	$102	$121	$97
Higher Cost Turbines (+15%)	$111	$129	$104

Figure 6-5

Effect of Varying Turbine Costs on the Levelized Cost of Energy
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT



	Community	Offshore Area C	Offshore Area H
Higher Wind (+0.5 m/s)	$92	$112	$91
Base Case	$102	$121	$97
Lower Wind (-0.5 m/s)	$116	$131	$104

Figure 6-6
Effect of Varying Wind Resource on the Levelized Cost of Energy
RIWINDS Siting Study

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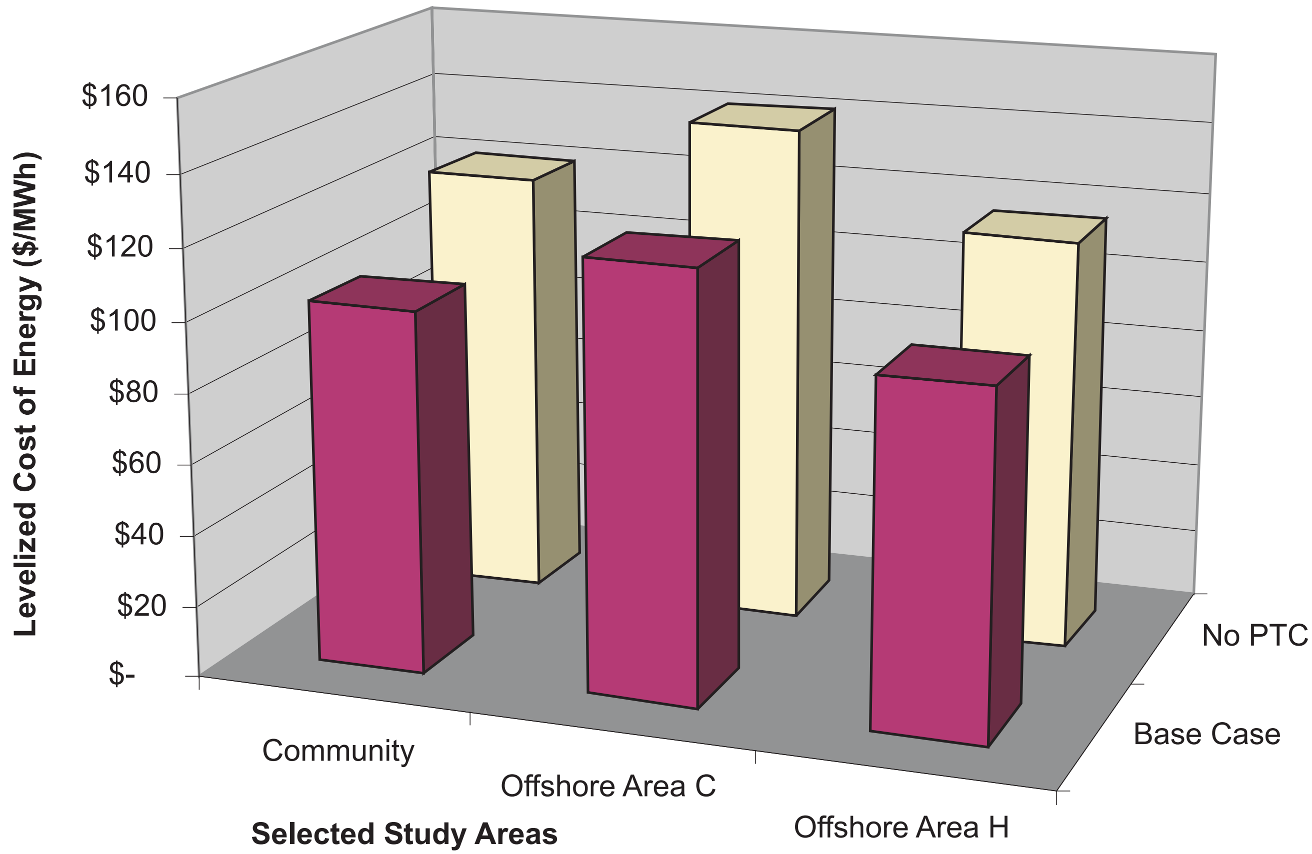

	Community	Offshore Area C	Offshore Area H
Base Case	$102	$121	$97
No PTC	$121	$141	$116

Figure 6-7
Effect of PTC Availability on the Levelized Cost of Energy
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

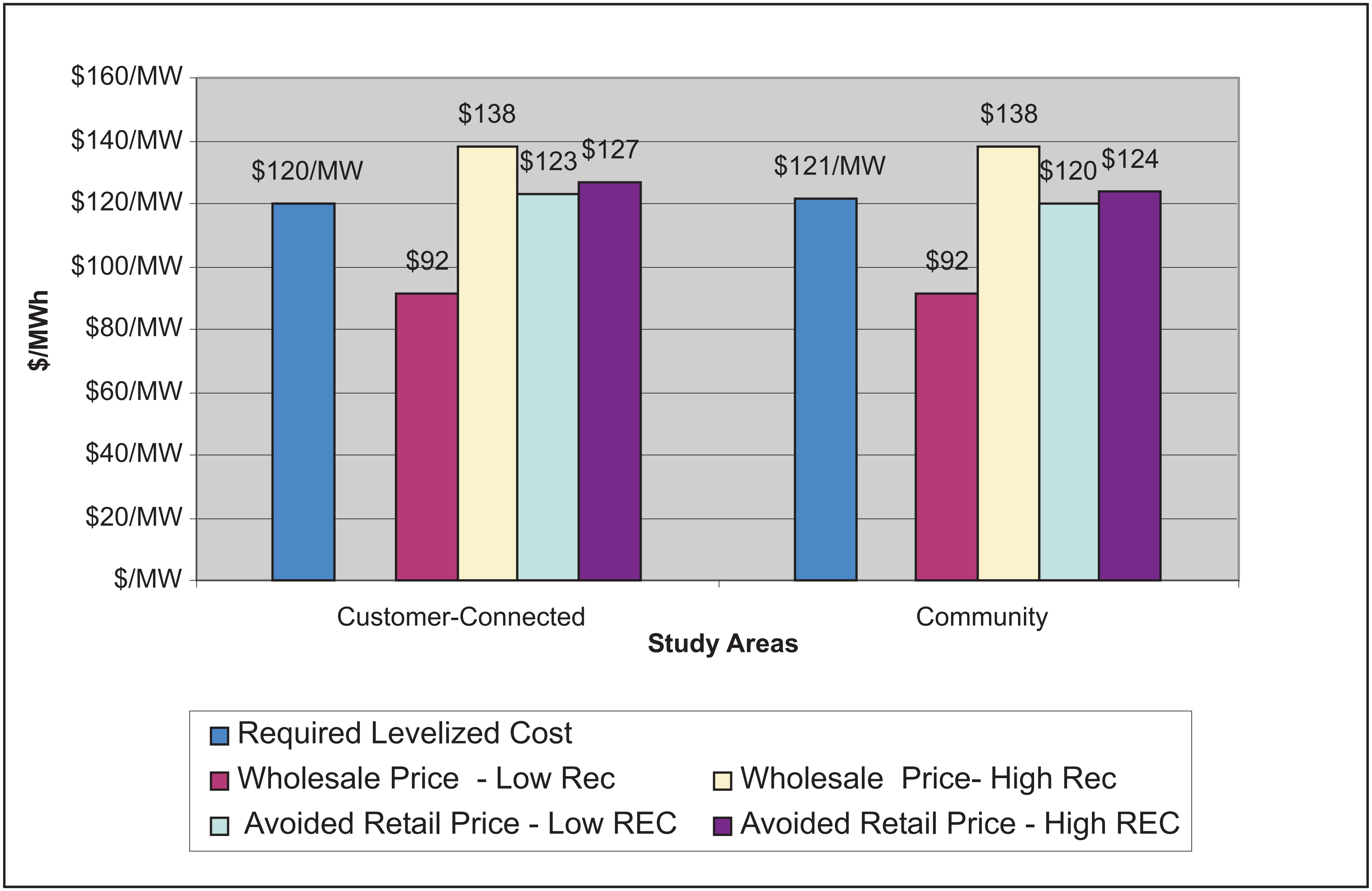

Figure 6-8
Comparison of Estimated Cost of Energy to Estimated Market Wholesale and Retail Prices
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

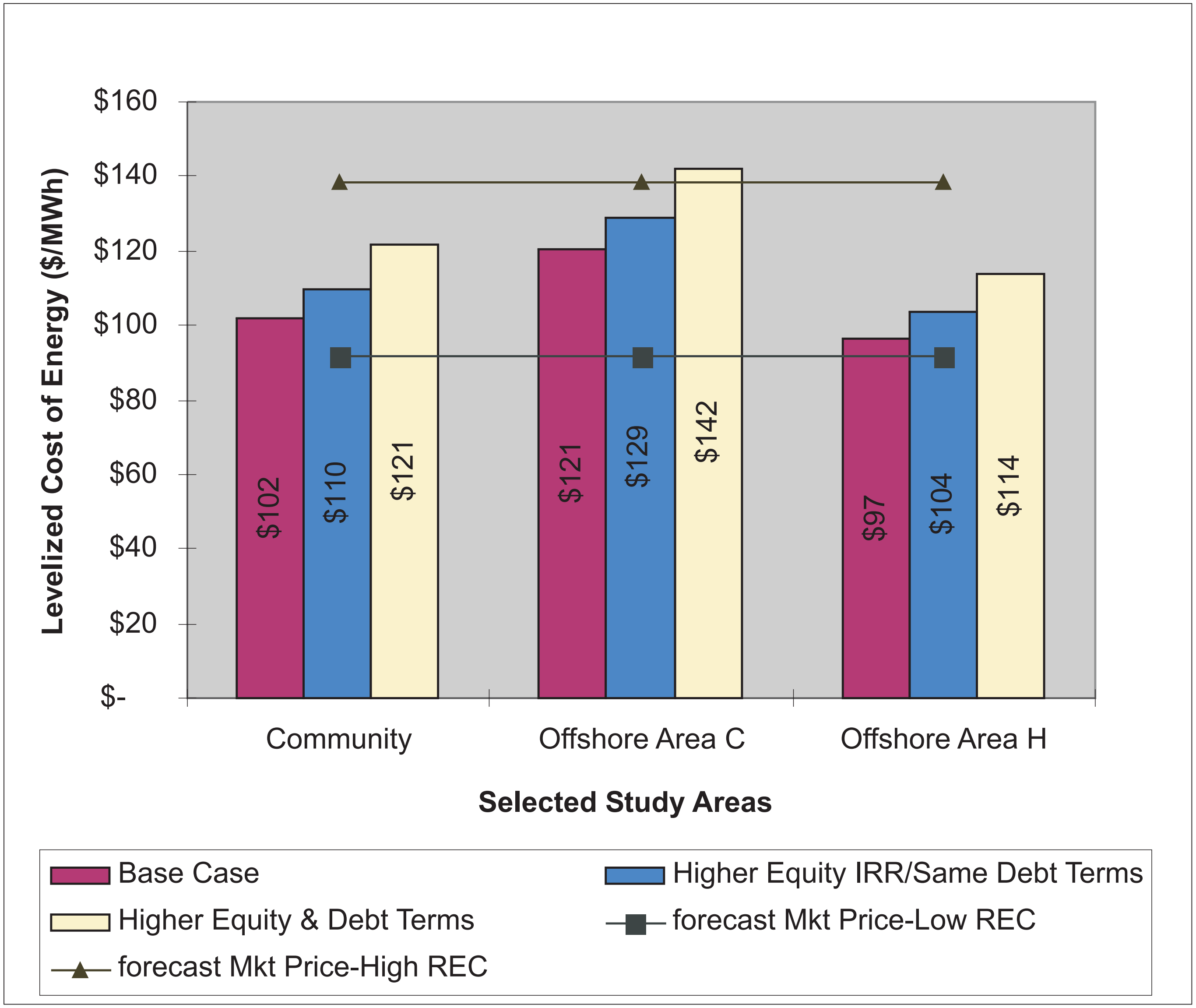

Figure 6-9
Effect of Varying Financing Costs on the Levelized Cost of Energy
RIWINDS Siting Study

APPLIED TECHNOLOGY & MANAGEMENT

7.0 SUMMARY AND CONCLUSIONS

The ATM team has completed the RIWINDS Siting Study. The study evaluated the entire state of Rhode Island including the State and Federal waters directly to the south of Rhode Island for economic wind energy potential. This process was conducted by implementing a number of sequential and parallel activities as briefly described below:

1. A range of five different indicative projects were identified that could be used to reach the RIWINDS goal of 1.3 million MWh/yr. These indicative projects are based on using utility-scale turbines and covered the range from small, onshore, customer-connected projects to large, offshore, grid-connected projects
2. Selection criteria were developed for each type of indicative project to identify the areas of the state that would be appropriate for these projects. These criteria included minimum economic wind speed, area requirements, land use, electric load and environmental criteria.
3. A thorough and comprehensive screening analysis was performed using the selection criteria to determine the “technically viable” areas of the state where these projects could be implemented. To facilitate the analysis and the decision making process, the evaluation data and results were integrated into a comprehensive Geographic Information System (GIS) database.
4. Wind turbine generator (WTG) performance estimates were prepared to determine the average annual wind energy (in kWh) that would be generated from each type of indicative project in each of the viable areas. The analysis was based on regional, model predicted annual average wind speed from AWS Truewind prepared for the National Renewable Energy Lab and on historical data from the NOAA wind monitoring station located in Buzzards Bay, MA. This offshore data is believed to be the most representative wind data for offshore projects located south of Rhode Island.
5. An evaluation of the spatial distribution of annual average wind speeds at the standard WTG hub heights was performed to determine the preferred hub height. Evaluation of the 65m, 80m and 100m elevation wind speeds and land use mapping indicated that the 80m and 100m elevations both showed a significant improvement over the 65m results. The incremental improvement of the 100m over the 80m resources did not warrant the expected increased costs and construction challenges of the larger tower. In addition, a hub height of 80 meters is currently common practice for utility scale WTGs. The study therefore used 80m elevation wind speed predictions.

6. Feasibility level project capital and O&M cost estimates were prepared for each of the indicative projects in the viable areas. The project cost estimates were developed using design basis assumptions for each of the indicative projects and included allowances for project development costs.
7. A detailed financial analysis was performed to determine if wind generated electricity can compete with conventionally generated electricity in Rhode Island. The analysis included a projection of the wholesale and retail market prices for electricity in Rhode Island over the next 20 years. The analysis also evaluated alternate project financing arrangements.

The study analysis relied upon published documents, information from the ATM team in-house database, confidential information received from potential industrial project customers, and upon information derived from conversations with National Grid and offshore wind project developers. The results of the study are very encouraging and the program offers many positive opportunities for the State. While the results of the study are encouraging, it is important to note that there are many challenges to meeting the RIWINDS goal. The results, opportunities and challenges are relevant to this study are summarized below.

7.1 KEY RESULTS OF THE STUDY

1. The RIWINDS goal is achievable.
2. The cost of wind energy to meet this goal appears to be competitive with the projected cost of electricity in Rhode Island.
3. There are significant wind resources in the state of Rhode Island both onshore and offshore.
4. Eight towns or cities have expressed interest in developing small wind projects in their communities.
5. Only four sites were identified as potential industrial/institutional customer connected project sites using utility scale wind turbines.
6. Only one viable area for a 10MW onshore project has been identified.
7. Over 95 percent of the wind energy opportunity in Rhode Island is offshore. A total of 10 potential different offshore areas were identified with a total of 98 square miles which could produce over 6 Million MWh of wind energy per year.
8. Approximately 75 percent of the offshore wind opportunity is in State waters. The remainder is in Federal waters.

7.2 CHALLENGES TO IMPLEMENTATION

1. This siting study is the first step in the development of the RIWINDS project. The results of this study need to be refined by a development entity as part of the project implementation. Unlike onshore wind energy projects, there are currently no offshore wind projects in operation in the US. There are a number of small offshore projects in Europe, but many of these are demonstration projects which have been funded by their respective governments. These projects are viewed as successful and there are plans to significantly increase the number of offshore projects in Europe. There are a number of offshore projects under development or being studied in the US in the Northeast, Southeast, Gulf of Mexico, and in the Great Lakes, but none have received final approval.
2. There is insufficient electric transmission system capacity in Rhode Island to distribute the power generated from large offshore projects to electric customers. The transmission lines are not located near the shore and the transmission lines closest to the shore do not have the capacity to transmit the electric generation to the electric loads in Rhode Island.
3. Financing capital-intensive projects, such as wind energy projects, in the de-regulated New England electric market will be difficult due to the lack of long term power contracts to finance projects. The certainty of long term power contracts would make investors and financial institutions more willing to invest in these projects by reducing revenue risk. This, in-turn, reduces the cost of financing these projects.
4. Public acceptance of the offshore wind projects is critical to the success of the RIWINDS program, however, public perception of these wind projects is difficult to predict. For example, a recent study of the public perception to offshore wind in Delaware is generally positive, yet there has been a good deal of public resistance to the Cape Wind project off of Cape Cod, Massachusetts, in spite of the fact that the majority of public sentiment is in favor of wind energy generation.

7.3 OPPORTUNITIES FOR CITIZENS AND ELECTRIC RATE PAYERS

1. The cost of electricity from wind energy is stable and predictable unlike the cost of electricity from conventional fossil fuels. The predominant component for the cost of electricity from wind energy is the capital cost which is fixed after the plant has been constructed. The predominant cost component for conventional fossil fuel plants is the cost of the fuel which historically has varied significantly and this variability and

uncertainty is expected to continue in the future. The certainty of future electricity prices also offers intrinsic economic benefits to large energy customers such as industry and institutions.

2. Electricity generated from wind energy offers significant environmental benefits compared to electricity produced by non-renewable energy sources. There are no air emissions from wind projects. There may be environmental disturbances during the construction of the project, but these are temporary and can be avoided by proper site selection. Concerns over avian impacts may overestimate actual impacts for modern wind turbines, according to new studies performed at European offshore sites, and can also be mitigated by proper site section and avoiding nesting areas.
3. Rhode Island is well situated to take advantage of the significant opportunities for coastal industries and businesses supporting the construction, operation, and maintenance of offshore wind projects developed off of Rhode Island, Massachusetts, and New York. If a large scale project proceeds in Rhode Island, there is a potential to lure wind turbine related industries to Quonset and/or Fields Point.
4. The availability of Federal, State, and regional financial incentives for clean, renewable energy will decrease the relative cost of wind energy to rate payers. Federal Production Tax Credits (PTC) are currently available for projects that go into operation by the end of 2008 and the PTCs are expected to be extended beyond 2008. Renewable Energy Credits are available as financial incentives to qualified facilities that meet the State's Renewable Energy Standard. The Regional Greenhouse Gas Initiative is expected to increase the cost of fossil fired (carbon dioxide emitting) generated electricity. These financial incentives help to balance the cost of renewable versus non-renewable energy generated electricity and take into account the positive environmental attributes of renewable energy and the externalities associated with non-renewable energy sources.
5. Development of offshore wind projects in State waters versus Federal waters could provide additional revenue for the State. The owner of wind projects typically provides a lease payment to the "property" owner for beneficial use of the property. If the projects are located on state owned property, potential lease payments could generate revenue for the State.
6. One of the concepts behind the RIWINDS program is that Rhode Island would invest some of its natural resources in the production of clean, affordable energy. The ability to keep the energy generated by this program within the state at least implies that title to that energy be held by an entity willing to do so. Within the current New England

electricity market structure, electricity generated anywhere in the system is distributed throughout the system. Since Rhode Island comprises a very small portion of the overall system load (approximately 6 percent), Rhode Island ratepayers would only receive a small portion of the energy generated from wind projects in the state and the benefits derived there from. A state power authority could ensure that energy generated from in-state wind projects would serve Rhode Island first.

7. Another concept behind the RIWINDS program is to provide stable electricity prices. The price for electricity within the current New England electricity market is established through a clearing price auction mechanism. Most often, the clearing price is set by power plants that operate on natural gas so the clearing price is a function of the price of natural gas. As recent history has demonstrated, the price of natural gas has increased dramatically and can fluctuate significantly. Within the construct of the current electricity market, the price of wind generated electricity would most often be established by clearing price, would fluctuate significantly, and most likely increase over time. A state power authority could take advantage of the inherently stable prices of wind energy and pass these stable prices directly on to the ratepayers of Rhode Island.

7.4 RECOMMENDATIONS

To continue the progress of the RIWINDS program, we offer the following independent recommendations.

1. It has been shown that there is a strong correlation between summer high wind speeds far offshore of New England and peak electricity demand/prices. If this is true for near shore locations, it would increase the value of the energy produced by offshore wind energy projects. A more detailed wind energy assessment should be performed for the offshore areas identified in this study to quantify how this correlation would improve the economic benefit of wind energy projects off of Rhode Island.

2. To encourage the development of community wind projects, a series of workshops should be conducted with representatives of interested municipalities around Rhode Island to carefully review the results of this Phase I Siting Study and what it means for these municipalities.

3. As this study had demonstrated, a large percentage of the wind resource to economically meet goals of the RIWINDS program is offshore. The success of the Program will depend

on the perception of the citizens of Rhode Island to offshore wind. To properly gauge pubic perception of offshore wind, a public opinion study should be conducted.

4. Several European countries have successfully adopted wind energy generation policies and installed offshore wind farms, including Germany, Denmark, Great Britain and the Netherlands. As in the fledgling U.S. market the offshore wind farms faced initial public scrutiny, objection and rejection. The counties mentioned were able to overcome those obstacles and eventually develop a series of successful offshore wind power facilities. Preliminary discussions with developers, engineers and government officials from those countries indicated that many of the public concerns are similar to those facing the offshore industry her in the U.S. There are many lessons that may be learned from the European experience and implemented here in Rhode Island in a proactive manner. An investigation into the European experience should be conducted with a focus on what factors, policies and/or regulations contributed to acceptance of offshore wind projects.
   The European experience indicates that community involvement in the development of wind projects must be fostered. A positive connection between any wind project development and the public (particularly local) should be made such that the public are beneficiaries of the project and it therefore becomes “our” project rather than “their” project.

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