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Economic and Environmental Performance of Potential Northeast Offshore Wind Energy Resources

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ECONOMIC AND ENVIRONMENTAL PERFORMANCE OF POTENTIAL NORTHEAST OFFSHORE WIND ENERGY RESOURCES

FINAL REPORT

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OFFSHORE WIND COLLABORATIVE
PILOT RESEARCH PROJECT

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ONE: INTRODUCTION

This project, entitled "Economic and Environmental Performance of Potential Northeast Offshore Wind Energy Resources" was a pilot research project of the MTC-DOE-GE Offshore Wind Collaborative (OWC). This document summarizes the work at MIT from September 2004 through December 2005.

Key questions related to the potential of offshore wind in the Northeastern United States are whether there are *better* winds further offshore, and whether they are *substantially better* to justify the additional investment and operational costs of developing wind farms further from shore, and in deeper waters. Additionally, how variable are offshore winds, from season-to-season and from year-to-year? How might these factors affect the revenue potential and emissions benefits of offshore wind relative to regional power markets and the displacement of fossil generation?

This project focused on gathering and assessing offshore wind resource information along the Northeastern United States coast, and evaluating the potential economic and environmental performance of these resources. The MIT research team collected publicly available windspeed data to calculate parameters such as energy generation, revenue, and avoided emissions from wind turbines if located in environments similar to what exist off the Northeast coast.

This project addresses fundamental economic and environmental issues related to the costs and benefits of deep-water offshore wind for New England. We identify key performance thresholds including cost, and we quantify the variability of the offshore wind regime. Finally, we highlight areas for further research needed to refine and extend these and other performance metrics.

We collected and analyzed windspeed information from the National Oceanic & Atmospheric Administration (NOAA) National Data Buoy Center (NDBC) (www.ndbc.noaa.gov) and the National Climatic Data Center (NCDC) (www.ncdc.noaa.gov). This information was used to evaluate the potential economic and environmental performance of Northeast offshore wind energy resources. Based upon the available data, seventeen "data sites" were analyzed (see map in Figure 2.1). They represent a subset of the NOAA stations, and were chosen because they have at least one recent year of data available.

The research team analyzed historical NOAA windspeed data and calculated windspeed at wind turbine hub height for each individual data site, and estimated potential generation, wholesale power market revenue, and avoided emissions from locating wind turbines in similar environments. These calculations were based on historical *hourly* values of: NOAA windspeeds, New England Independent System Operator (ISO-NE) wholesale power prices, and U.S. Environmental Protection Agency (EPA) emission rates for fossil generators.

Throughout this study, collaboration with other institutions took place, especially with the RENEWABLE ENERGY RESOURCE LABORATORY at the University of Massachusetts–Amherst. The MIT research team met frequently with our UMass colleagues, and with the larger OWC pilot project research group (Dec. 2004, Jun. 2005) throughout the research period. We would like to thank the Massachusetts Technology Collaborative for their funding for this pilot research project.

TWO: SUMMARY OF KEY RESULTS

This study analyzed detailed temporal windspeed data over long time series and a wide geographic area to assess the offshore wind resource in the Northeast and to investigate the potential economic and environmental performance of those resources. The study results support the research team's belief that to estimate economic and environmental performance, an understanding of temporal and spatial variability is necessary in addition to long-term average values.

The research team verified that there are better winds offshore, and that the winds generally get better the further from shore one goes. We believe there is significant revenue potential for offshore wind resources, but the net economic performance will depend on the costs involved. Also, the strong winter offshore winds could produce major environmental benefits from avoided emissions from fossil power plants.

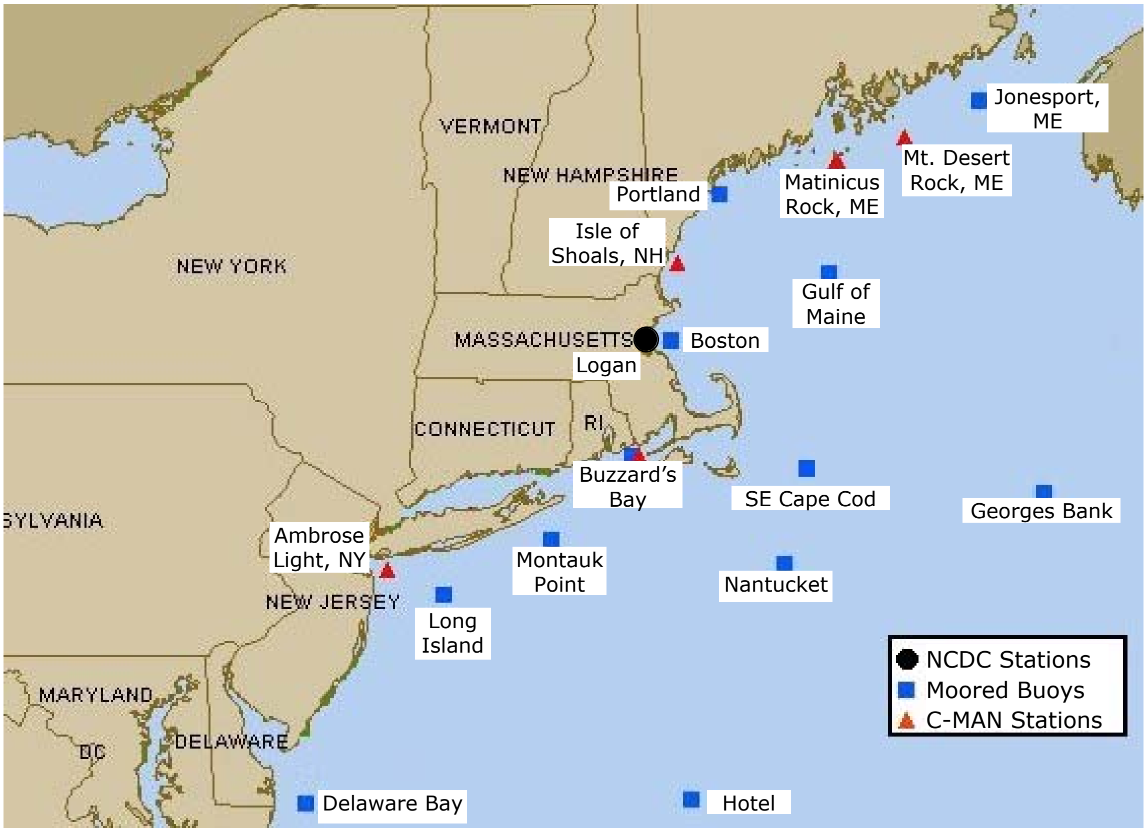
Figure 2.1 shows the locations of the data sites used for the wind resource analysis. Table 2.1 summarizes the results of our work resource, market revenue and avoided emissions research, which are displayed graphically in several figures following the table. In addition to these summary graphs, "Fact Sheets" that show detailed results for each data site's wind resources, economic, and environmental performance are included in the Appendix, along with other supplementary results.

Table 2.1 ranks the 17 data sites from lowest to highest average windspeed so one can see how much stronger offshore winds can be compared to onshore winds (up to 40%).[1] Our research verifies that there are large areas off the Northeast coast with excellent or outstanding wind resources (with Wind Power Class of 5 or 6—average windspeeds of 8 m/s or higher at 75m). One uncertainty in the analysis is the estimation of wind speeds at wind turbine hub height. NOAA data is measured at 5m for buoys, and from 25-33 for towers (C-MAN Stations). Without field measurements with which to benchmark height scaling calculations, we have used industry best practice (log law scaling, see Section Three). As the results will show, this represents a conservative (perhaps pessimistic) estimate of windspeeds at 75m.

In addition to long-term average windspeeds and power generation, it is important to know how much offshore winds vary from year-to-year. Maps showing the magnitude of offshore winds, such as the one produced for the National Renewable Energy Laboratory (NREL) (see Appendix A.3), are good for showing overall average wind and wind energy magnitudes. However, the fiscal viability of offshore winds also depends on how wind farms perform in above-, and especially below-, average windspeed years. Figures 2.2 and 2.3 below show annual results for all the data sites analyzed, with two sites highlighted for purposes of discussion. Our research indicates that changes in windspeed of ± 10% year-to-year are not uncommon. As Figure 2.2 shows, offshore windspeeds generally—but not always—increase with distance from shore.

[1] While comparing the results across data sites it is important to keep in mind that only one onshore site (Logan) was analyzed, and that it is in a relatively poor area for windpower purposes (Class 2).

Figure MIT-OWC.2.1: Locations of the 17 Data Sites Selected for Analysis



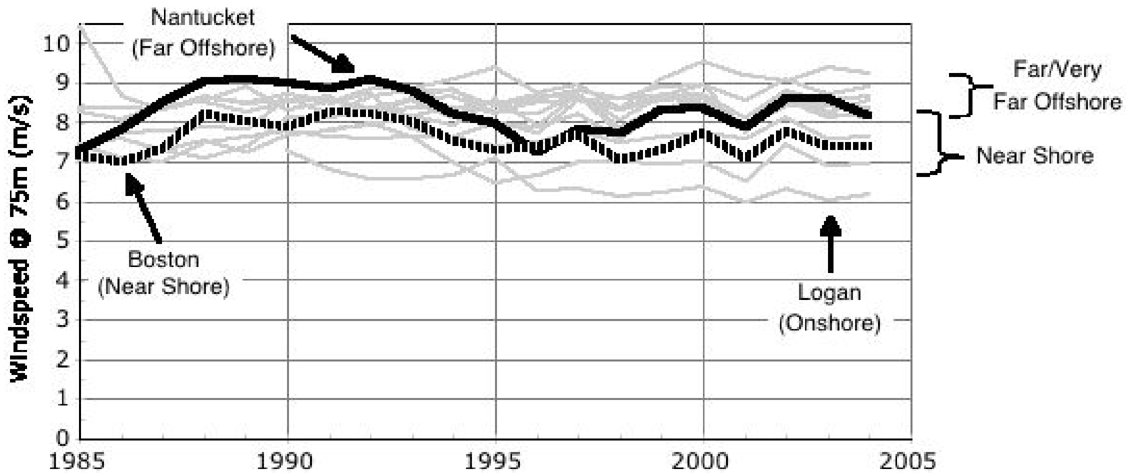
Source: www.ndbc.noaa.gov/Maps/northeast_hist.shtml

Table MIT-OWC.2.1: Summary of Key Parameters at Data Sites

NOAA Data Site	Ave Windspeed @ 75m	Wind Power Class	Ave Ann Generation	Ave Capacity Factor	Ann Revenue	Unit Revenue	Avoided Emissions		
							SO2	NOx	CO2
Logan	6.46	2	2.2	25.5	113	5.54	4.52	1.59	1,613
Portland	7.16	3	3.1	34.9	161	5.40	7.18	2.56	2,535
Isle of Shoals	7.58	4	3.3	38.2	189	5.43	8.29	2.91	2,932
Boston	7.60	4	3.3	37.9	177	5.52	7.57	2.71	2,665
Jonesport	7.88	5	3.5	40.3	190	5.37	N/A	N/A	N/A
Georges Bank	8.03	5	3.6	41.1	206	5.48	8.46	3.01	2,993
Delaware Bay	8.15	5	3.7	42.7	211	5.41	8.93	3.17	3,166
Long Island	8.26	5	3.8	43.7	212	5.42	8.99	3.19	3,170
Nantucket	8.34	6	3.8	43.7	202	5.50	8.82	3.13	3,113
Gulf of Maine	8.36	6	3.9	44.3	226	5.41	9.13	3.24	3,206
Ambrose Light	8.38	6	3.9	44.9	202	5.34	8.90	3.14	3,167
SE Cape Cod	8.39	6	3.8	43.6	208	5.48	N/A	N/A	N/A
Buzzards Bay	8.40	6	4.0	45.1	212	5.40	9.26	3.29	3,281
Matinicus Rock	8.47	6	3.9	45.0	221	5.39	9.17	3.24	3,226
Montauk Point	8.61	6	4.1	46.4	219	5.47	N/A	N/A	N/A
Mt. Desert Rock	8.63	6	4.1	46.3	234	5.41	9.65	3.41	3,402
Hotel	8.98	6	4.3	49.5	237	5.39	9.48	3.37	3,353
	(m/s)		(GWh/MWi)	(%)	(000$/MWi)	(¢/kWh)	(metric tonnes/yr)		

Notes: Unless otherwise noted, averages are taken from all available years for each data site. Generation, revenue, and avoided emissions are presented on a per megawatt installed (/MWi) basis. Revenue values are calculated from 2004 energy prices. Avoided emissions are per year and are calculated from 2002 emission rates.

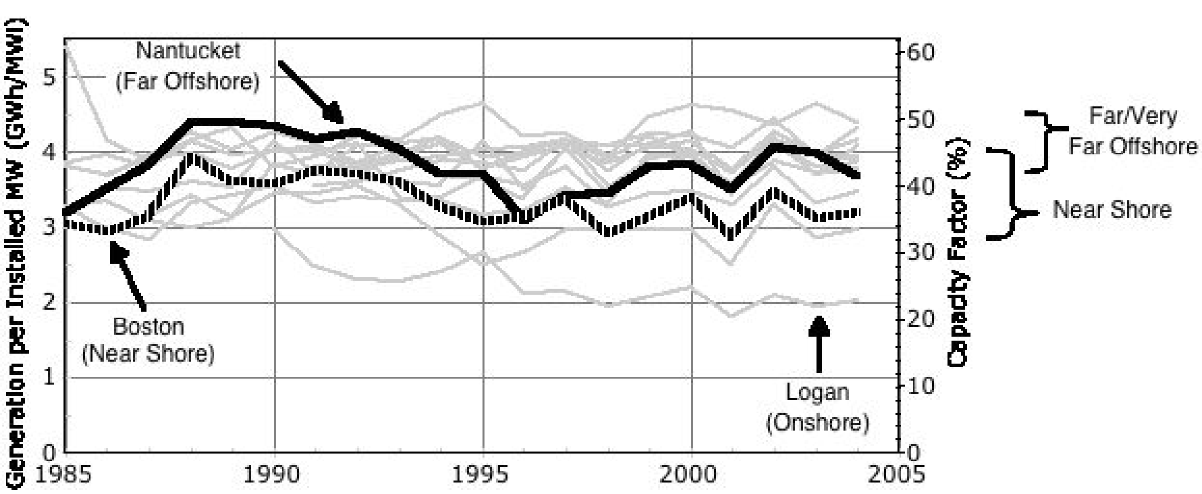
Figure MIT-OWC.2.2: Average Annual Windspeeds at 75m



The solid black line in Figure 2.2 above shows how a "far offshore" data site like Nantucket will often have stronger winds compared to nearer-to-shore sites, but not always (see Figure 3.1 for definitions of "far/very far offshore" and "near shore"). The dashed line belonging to the "near shore" Boston data site is usually among the lower windspeed tracks, though at some points it matches or even exceeds the lines representing further-from-shore sites. This reminds us that further from shore only sometimes means higher windspeeds, and that the variability year-to-year in the wind must be taken into account when assessing the offshore resource and its implications on the financial viability of potential offshore wind farms.

As to whether offshore winds are *substantially better* than onshore winds, to justify the additional costs of going offshore, more information than windspeed is needed. Capacity factor, and with it generation, are important parameters to track in order to answer questions on revenue potential. Figure 2.3 below shows the variability in annual generation, when hourly windspeeds are run through the power curve for a large offshore wind turbine (GE 3.6sl power curve used).

Figure MIT-OWC.2.3: Annual Generation and Capacity Factors

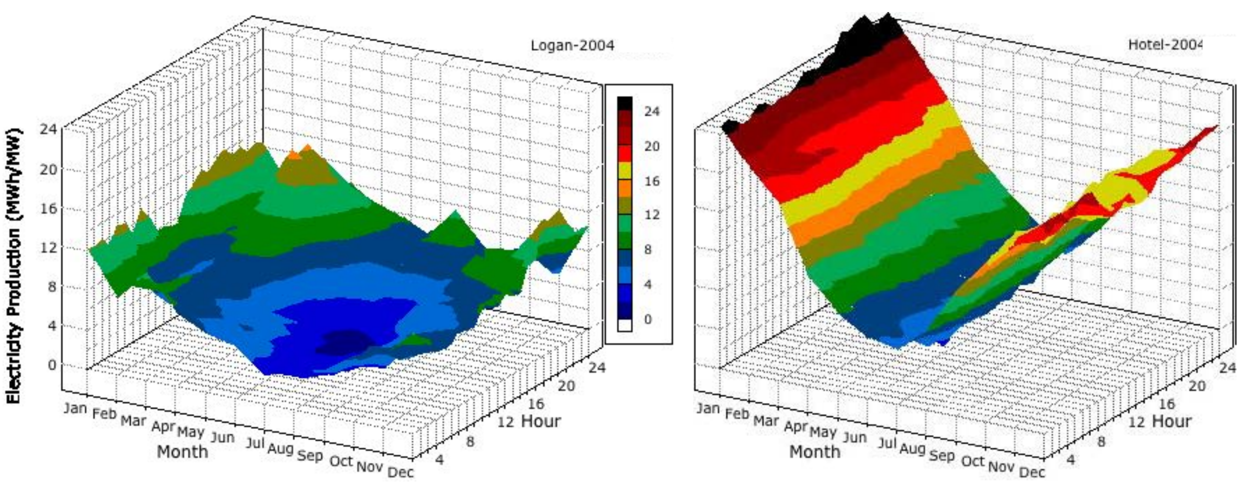


The above figure shows annual generation per installed MW and capacity factor for the same data sites as in Figure 2.2, with Nantucket and Boston again highlighted. As can be seen from Figures 2.2 and 2.3, the differences in windspeeds across sites cause greater disparities in performance across onshore and offshore wind resources.

Capacity factors in the 40s and 50s reveal that offshore winds hold much potential for significant energy generation. The timing of the offshore wind relative to power prices and fossil power plant operations is the remaining piece of information needed to address questions of performance.

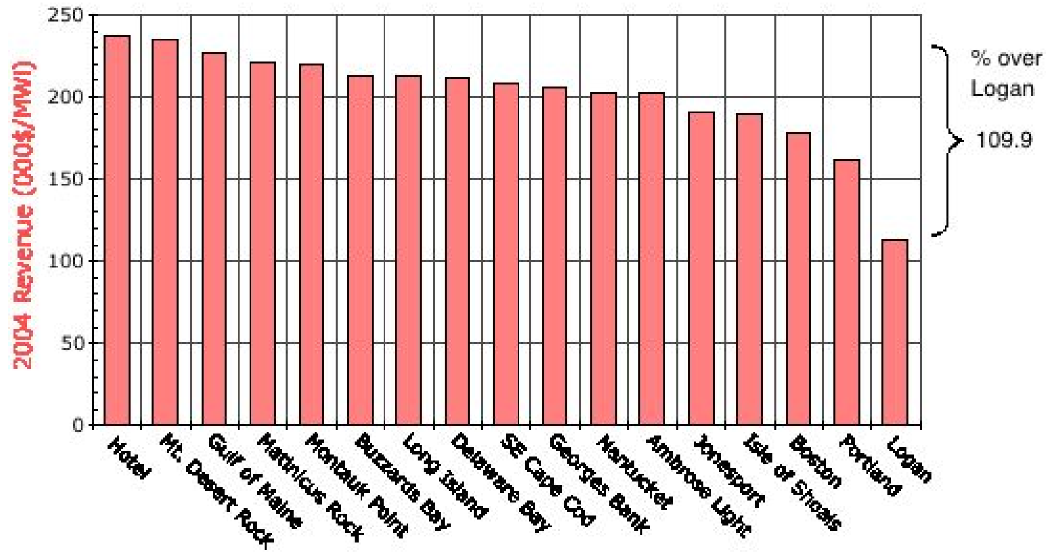
In addition to year-to-year changes, it is important to understand the variations in offshore wind energy production on a seasonal and daily basis. Figure 2.4 below shows estimated generation per installed MW at the Logan and Hotel data sites for 2004, summed by month and hour of day. The surface plots tell us that offshore winds are *much* stronger in the winter, and roughly uniform across the day (slightly higher later in the day in some cases). Far offshore winds tend to show a greater winter to summer variation (see figures in the Appendix). While wintertime peak electricity demand is not the highest in the year, it is moderately high, which in recent years means winter wholesale electricity prices have been good. Inter-annual variations in electricity generation therefore occur mostly in winter as well.

Figure MIT-OWC.2.4: Generation for the Logan and Hotel Data Sites



How might these inter-annual and seasonal factors affect the revenue potential and emissions benefits of offshore wind relative to regional power markets and the displacement of fossil generation? The figures below display these results. The magnitude and timing of the offshore wind is such that the data sites furthest from shore, as well as several near shore, have up to twice the revenue from the wholesale electricity sales as the reference onshore site (Logan).

Figure MIT-OWC.2.4: 2004 Revenue per Installed MW

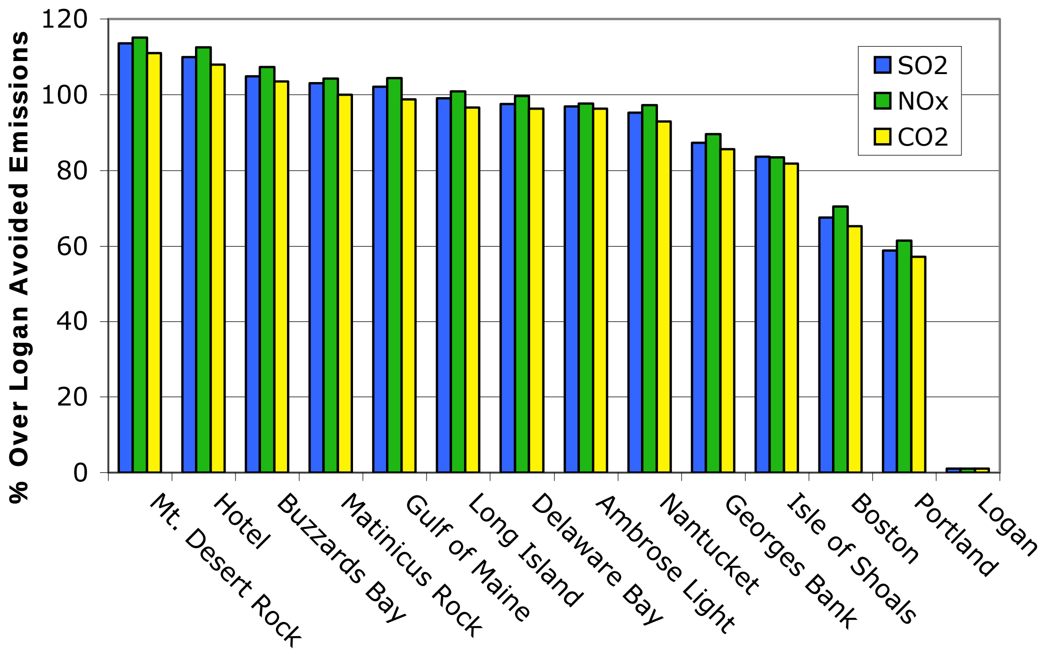


By looking at hourly winds as well as whole market electricity revenues, Class 5 and 6 locations can expect to generate 25-35% more electricity *on average*, compared to a Class 3 site, and roughly 15-30% more compared to a Class 4 site. Revenues will be slightly higher due to the magnitude of wintertime electricity prices. In light of the substantial (or modest) increases in annual generation and revenue, the central question is whether deep water wind farms will really only cost 30% more than shallow water, close to shore, facilities.

With consistently high winds (45% capacity factor), and subsidies helping reach a revenue of 9¢/kWh, a developer *may* be able to spend around $3000/kW to permit, construct, and operate a wind *farm* (including grid integration). More conservative estimates (40% capacity factor and 7¢/kWh sales), which take into account the variability of the wind and the uncertainties in market prices and government subsidies, makes $2000/kW for offshore wind *farms* a much more robust target for the (financial) viability of offshore wind projects (see Table 5.4).

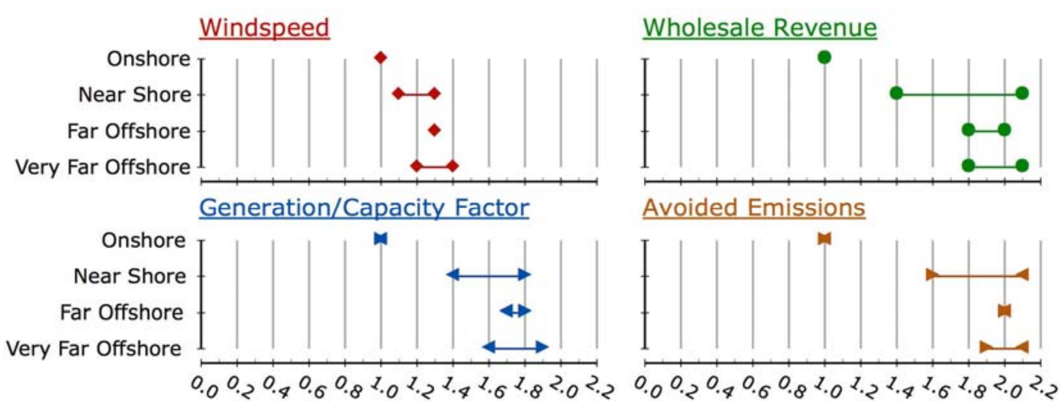
In addition to earning revenue from power sales, environmental performance in terms of avoided emissions is of interest. As Figure 2.5 below shows, data sites with significant annual generation, both those very far offshore (Hotel) and those in outstanding near-shore wind regimes (Mt. Desert Rock), may offer roughly twice as much in terms of avoided emissions from onshore sites (Logan). Also, near shore sites that provide 50-60% more annual generation will offer 60-70% more avoided emissions than onshore sites. The hourly generation approach applied in this research captures not only the market price dynamics, but fossil dispatch dynamics as well. These often make windpower more effective at reducing emissions, as it is likely that higher emissions fossil generation (coal, oil), often running at partial load, will be displaced rather than natural-gas fired (often peak) generation.

Figure MIT-OWC.2.5: Avoided Emissions from Fossil Generating Units in New England (Relative to Logan) (2002)



While there is a great deal of detail in the results contained in this report, Figure 2.7 summarizes the relative performance of Onshore (Logan), Near Shore (shallow water offshore), Far Offshore and Very Far Offshore groupings of the 17 data sites. Additional revenue streams (production tax credits, renewable portfolio certificates, and green power premiums), especially if accrued on a per-kWh basis, will further increase wind farm revenues.

Figure MIT-OWC.2.6: Relative Performance of Onshore, Near Shore, Far and Very Far Offshore Data Sites for Annual Windspeed, Generation, Electricity Sales and Avoided Power Plant Emissions



A more detailed presentation and discussion of these results appears in sections Four and Five of this report.

THREE: METHODOLOGY

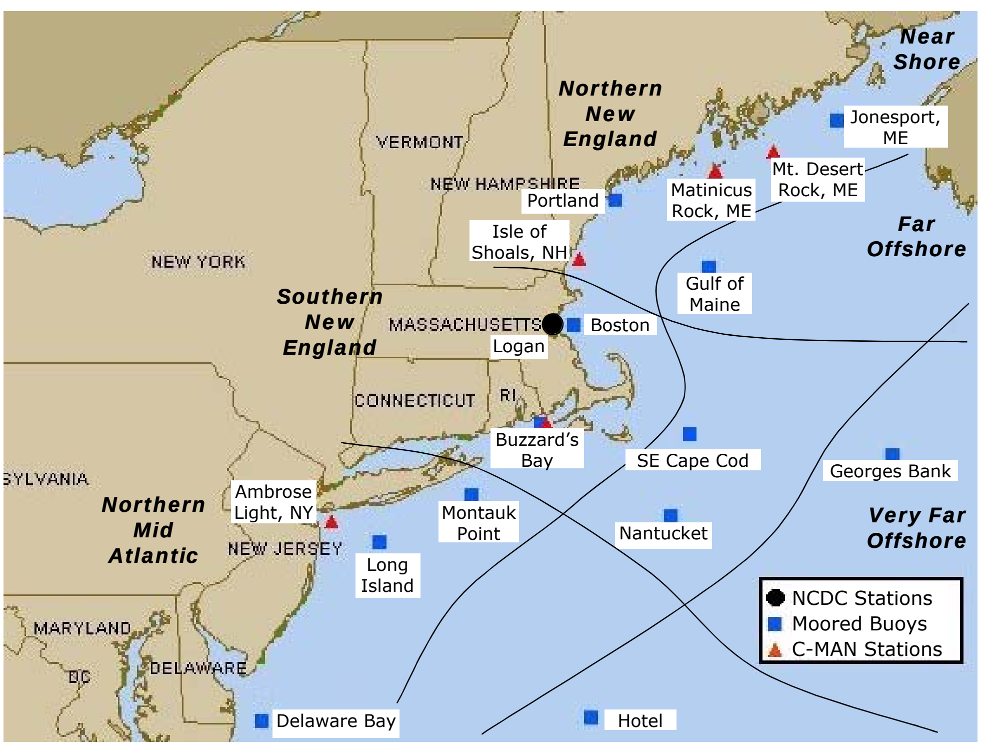
To get the required temporal and geographic resolution and scope to assess offshore wind performance, this project required hourly windspeed data from various offshore locations for a number of consecutive years. Historical hourly windspeed data were gathered from the National Oceanic & Atmospheric Administration (NOAA) National Data Buoy Center (NDBC) (www.ndbc.noaa.gov) for stations off the Northeastern United States.

The NOAA data set containing historical windspeed information reported hourly is Standard Meteorological Data (www.ndbc.noaa.gov/historical_data.shtml). This data set contains information such as air and sea temperature, atmospheric pressure, and windspeed, peak gust speed, and wind direction (for descriptions of measurements see www.ndbc.noaa.gov/measdes.shtml). For this study, only windspeed data was collected and cleaned.

Data Site Selection / Data Collection

The research team gathered data *for all* of the stations in the Northeast United States with at least one recent, complete year of data. 16 NDBC stations, located offshore between Maine and Delaware, were identified as candidates for analysis. For comparative purposes, we also reviewed airport data from the NOAA National Climatic Data Center (NCDC) (www.ncdc.noaa.gov) and selected Boston's Logan Airport from the Surface Data for inclusion in the analysis. Figure 3.1 shows the locations of the Northeast NOAA Stations selected for this analysis.

Figure MIT-OWC.3.1: The 17 NOAA Stations Selected for Analysis



Source: www.ndbc.noaa.gov/Maps/northeast_hist.shtml

The majority of these stations are moored buoys while the rest are C-MAN[2] towers located on small rock formations off the coast. As the map shows, the majority of these stations are located "near offshore" (from several to several dozen miles from the coast), while the rest are located "far offshore" or "very far offshore" (up to several hundred miles from the coast). We also divided the Northeast into Northern and Southern New England, and included the Northern Mid Atlantic, to determine how latitude might affect wind resource performance.

A little over half of the stations (11 out of 17) have at least 20 years of data, and 17 years is the average amount. The period of 1984 to 2004 is the most common. The table below shows station names, ID numbers, and other reference information.

Table MIT-OWC.3.1: NOAA Station Information

Station Name	Station ID	Location, Latitude Longitude	Distance From Shore, nautical miles (miles)	Location, Direction from Shore Point	Anem. Height, m	Water Depth, m	Number of Years of Data
Ambrose Light	ALSN6	40.46 N 73.83 W	20 nm (23 mi)	SE of Ambrose Light, NY	29	-	14
Boston	44013	42.35 N 70.69 W	20 nm (23 mi)	East of Boston, MA	5	60	20
Buzzards Bay	BUZM3	41.40 N 71.03 W	30 nm (35 mi)	SW of Buzzards Bay, MA	25	-	19
Delaware Bay	44009	38.46 N 74.70 W	30 nm (35 mi)	SE of Cape May, NJ	5	30	14
Georges Bank	44011	41.11 N 66.62 W	170 nm (196 mi)	East of Hyannis, MA	5	90	20
Gulf of Maine[3]	44005	43.18 N 69.18 W	80 nm (92 mi)	East of Portsmouth, NH	5	20[3]	20
Hotel	44004	38.47 N 70.56 W	200 nm (230 mi)	East of Cape May, NJ	5	3120	20
Isle of Shoals	IOSN3	42.97 N 70.62 W	8 nm (9 mi)	SE of Portsmouth, NH	32	-	20
Jonesport	44027	44.27 N 67.31 W	20 nm (23 mi)	SE of Jonesport, ME	5	180	1
Logan	14739	42.37 N 71.03 W	0 nm (0 mi)	Logan Airport, Boston, MA	8	-	15
Long Island	44025	40.25 N 73.17 W	30 nm (35 mi)	South of Islip, NY	5	40	14
Matinicus Rock	MISM1	43.78 N 68.86 W	4 nm (5 mi)	SE of Matinicus Island, ME	33	-	20
Montauk Point	44017	40.70 N 72.00 W	20 nm (23 mi)	SW of Montauk Point, NY	5	50	2
Mt. Desert Rock	MDRM1	43.97 N 68.13 W	20 nm (23 mi)	SE of Mt. Desert Island, ME	32	-	20
Nantucket	44008	40.50 N 69.43 W	50 nm (58 mi)	SE of Nantucket, MA	5	60	20
Portland	44007	43.53 N 70.14 W	10 nm (12 mi)	SE of Portland, ME	5	20	20
SE Cape Cod	44018	41.26 N 69.29 W	30 nm (35 mi)	East of Nantucket, MA	5	70	2

Source: NOAA NDBC and NCDC Station Pages

It is important to note the water depth and distance from shore values, as these will be factors in estimating offshore wind plant costs.

Data Quality

The quality of the NOAA data is an important issue. Completeness of data is a major challenge as many hours and even some years are missing for many sites. For the data that exist, we assumed that the wind data were accurate. While no sophisticated error checking techniques were performed, we used gust speed and wind direction to determine whether raw data were credible.

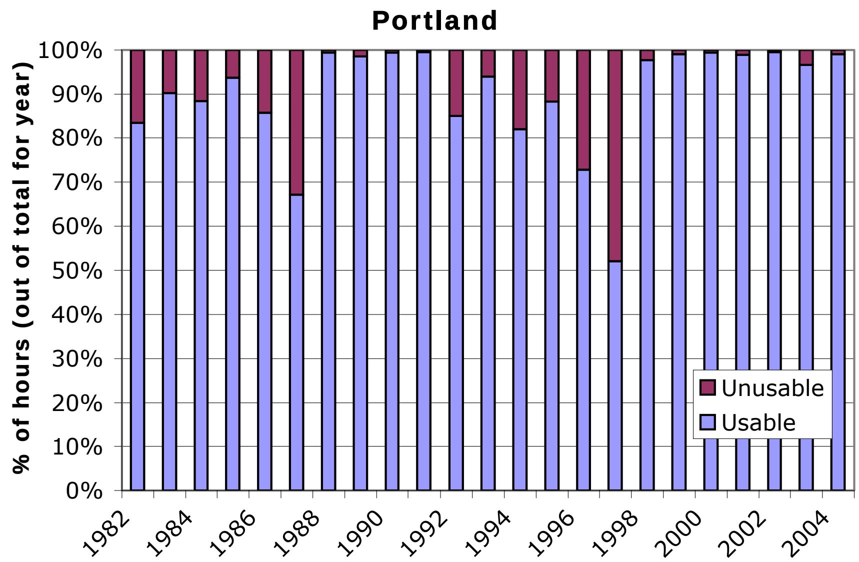
An investigation of the raw data showed that only a few stations have any years that are totally complete—meaning they are not missing hours and do not have

[2] Coastal-Marine Automated Network (C-MAN) (www.ndbc.noaa.gov/cman.php)

[3] Gulf of Maine (44005) has recently (mid-2005) been re-established .88 nautical miles west of its original position to reduce the shoaling hazards experienced in storms. Its depth is now 640 meters. (NOAA NDBC)

hours with bad data.[4] Although most of the years are more than half complete, some stations have years where usable data are only 15-20% of total hours. Figure 3.2 shows a representation of the completeness of one station's data (Portland buoy has the most complete data set of the 17 Northeast data sites).

Figure MIT-OWC.3.2: Representation of Completeness of One Station's Data



Source: NOAA NDBC Historical Standard Meteorological Data

A "quality score" was created using criteria including number of years of data, number of complete years, and average completeness for all years in order to compare the data integrity of each station. Figure 3.3 shows the 17 Northeast stations ranked by their "quality score." As one can see from the figure, most of the far and very far offshore stations NOAA maintains have below-average data quality.

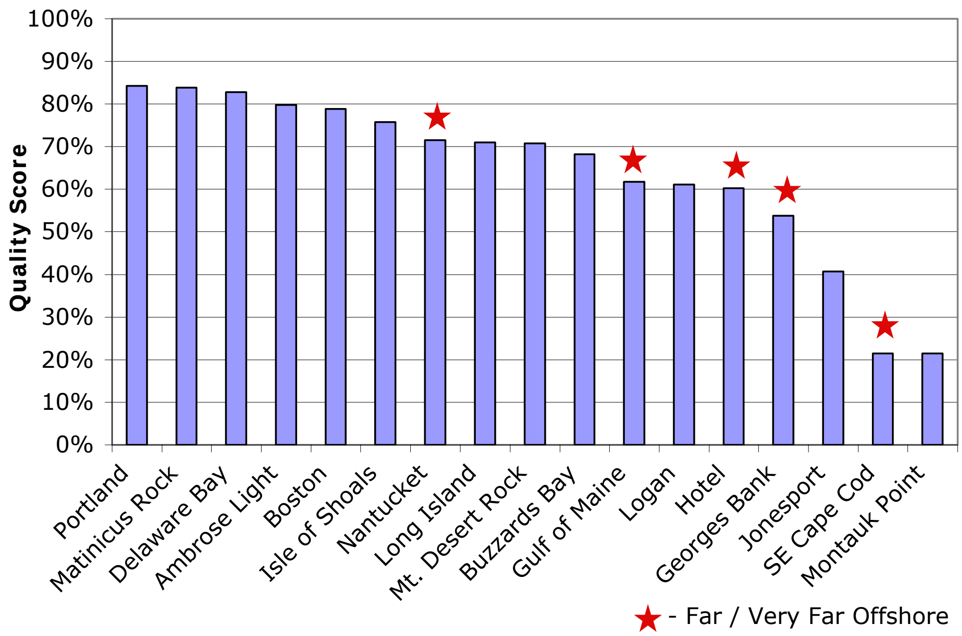
Data Gap Filling

In order to appropriately assess the potential economic and environmental impacts of offshore wind energy, complete long-term hourly data sets are needed. Because most of the NOAA station years are not complete, some filling in had to be done. Filling the gaps in the data posed quite a challenge for this project. Small gaps (of several hours) were easy to handle. For larger gaps (on the order of days, weeks, or months), more sophisticated routines were needed.

Small gaps (of 1-2 hours) within a year were fixed by simple interpolation. Because interpolation does not work as well with larger gaps, we used more sophisticated routines for these gaps. We filled in large gaps with representative data from a similar temporal and geographic location using routines developed at UMass-Amherst.

[4] Bad data means there is a data record but it includes some error code, such as 999.

Figure MIT-OWC.3.3: NOAA Station Data Quality



For this project, large gaps were filled using the technique known as Measure-Correlate-Predict (MCP). Rogers, Rogers, and Manwell (Rogers et al., 2005) describe MCP as a method to predict the windspeed (and direction) at a target site using data from a nearby reference site. Of the many existing MCP algorithms (such as linear regression), a recently developed one called the "Variance Ratio" method was chosen because it is better at predicting wind data in terms of four metrics: mean windspeed, windspeed distribution, annual energy production (assuming a certain wind turbine power curve), and wind direction (Rogers et al., 2005, p.250).

To use the MCP Variance Ratio method to fill in windspeed data gaps, an appropriate reference site for the target site must first be identified. We did this for each data site by calculating the correlation of its windspeeds to those of its neighboring data sites (by using the hours in which both target and reference site had data), and then choosing the pair of sites with the highest correlation.

For better accuracy, we used six-month periods (instead of calendar years) to compare sites and to fill in the large gaps in the data. Splitting years into two seasons (Winter and Summer) allowed us to look at periods with similar weather. For analytic purposes, we defined Winter as October–March and Summer as April–September.

If there were not enough concurrent data between the target site and the reference site with the highest correlation (less than 2,000 hours in common for a six-month period), the next best reference site was used. Table 3.2 below shows the correlations between Nantucket and its potential reference sites for 2003. Correlations for the other pairs of data sites are included in Appendix A.

Table MIT-OWC.3.2: Correlations of Nantucket with Neighboring Stations

Time Period	**2003**			**W–2002-2003**			**S–2003**			**W–2003-2004**		
Neighboring Site	buzm	gbnk	htl	buzm	gbnk	htl	buzm	gbnk	htl	buzm	gbnk	htl
Correlation	0.705	0.770	0.674	0.699	0.705	0.683	0.583	0.530	0.582	0.737	0.753	0.766
# hours in common	7862	4546	7570	4356	3485	4356	4320	2345	4028	3404	2831	3404
# hours in time period	8760			4368			4392			4392		

Shaded cells indicate highest correlation with Nantucket for given time period.
Neighboring stations are Buzzards Bay, Georges Bank, and Hotel.

After the target and reference sites were identified, the mean windspeed and standard deviation for each of the concurrent six-month data sets were calculated. Then the following Variance Ratio algorithm was used to calculate windspeeds for each hour of the target site data set where data were missing:

$$y = (my - sy/sx) \cdot mx) + (sy/sx) \cdot x$$

where y is the predicted speed at the target site, mx , my , sx , and sy are the mean and standard deviations of the two concurrent data sets, and x is the speed at the reference site (Rogers et al., p. 250). If negative windspeeds resulted from the arithmetic expression, the resulting velocity was set to zero.

After all of the data sets were filled in, we performed several more calculations to find the windspeed and other parameters of interest for wind generation. These calculations included: scaling windspeeds to hub height, estimating electricity generation using a wind turbine power curve, calculating revenue using hourly wholesale electricity prices, and calculating avoided emissions from fossil power plants using marginal emission rates.

Height Scaling

After all of the data sets were filled in, the windspeeds were scaled up to wind turbine hub height (75m for this report). A major drawback of the NOAA data for estimating potential wind generation is that the heights of the anemometers on the measurement platforms are much lower than the anticipated hub heights of offshore wind turbines. NOAA anemometer heights range from 5 to 14 meters for buoys and 25 to 33 meters for towers. Offshore hub heights are expected to be 70 to 100 meters tall (Bell, 2005). Because windspeeds are generally higher at higher elevations, the windspeeds recorded at low heights need to be scaled up to equal those that occur at higher elevations. There exist several routines to do this, but there exists considerable uncertainty over which method is the most accurate.[5]

[5] The two main height scaling methods are the "power law" and the "log law," which are similar but give different results (the power law predicts 5-15% higher speeds at a hub height of 75 meters, from a 5-30 meter measurement height). For descriptions of these methods, see Manwell et.al., 2002, p.44.

Based on recommendations from the UMass-Amherst team, we used the logarithmic profile (log law) for height scaling purposes. The relationship between the speed at the target height and the speed at the reference height is given by:

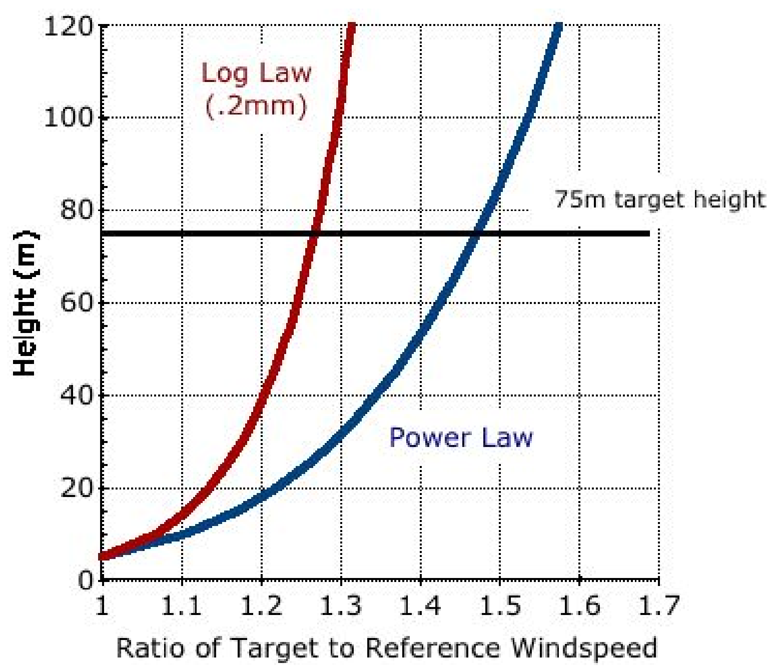
$$U = Ur \cdot \ln(z/zo) / \ln(zr/zo)$$

where U is windspeed at the target height, Ur is the speed at the reference height, z is the target height, zo is the surface roughness length, and zr is the height at which the measurement was taken (Manwell et.al., 2002, p.44).

The UMass-Amherst team recommended using a roughness length equal to 0.2mm, corresponding to conditions of calm, open seas. The log law method and roughness length value were used over other methods (like the power law) and other roughness lengths (0.5mm, for blown sea) to give a *conservative*, best estimate of windspeed at hub height. One scaling value was used for each reference (anemometer) height. Effects of seasonal weather patterns (temperature changes, etc.) on roughness length were not taken into account, but would have had little impact on scaling values compared to the impact from using different methods of scaling.

Using roughness length equal to 0.2mm, the log law height scaling formula gives an 8% increase in windspeed from 30 meters to 75 meters, while from 5 meters to 75 meters it gives a 27% increase. Figure 3.4 below shows the scaling factors of the log law and power law from a 5m reference height.

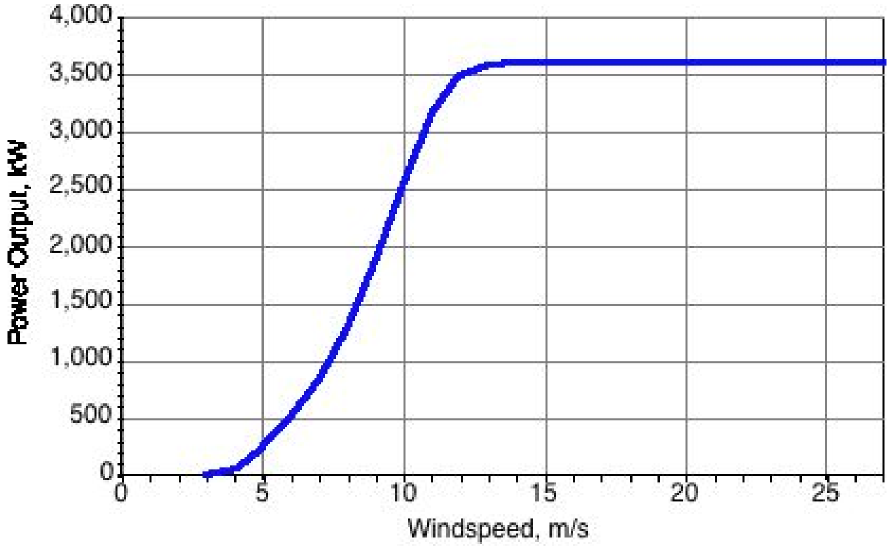
Figure MIT-OWC.3.4: Height Scaling Factors for the Log Law and Power Law (from 5m reference height)



Estimation of Generation

After windspeeds were scaled to hub height, wind generation for each hour was calculated. The power curve for a representative turbine was used to convert the historical windspeeds to possible energy produced, and is reproduced below. The wind turbine used was the GE 3.6sl Offshore machine with 111-meter rotor diameter (GE 3.6sl Offshore Wind Turbine Brochure, 2005, and Bell, 2005).

Figure MIT-OWC.3.5: Power Curve for GE 3.6sl Offshore Wind Turbine



Source: GE 3.6sl Offshore Wind Turbine Brochure

Some important parameters to note include the cut-in windspeed, which is 4 m/s (8.9 mph), and the cut-out speed, which is 27 m/s (60.4 mph). Rated power occurs at 14 m/s. For this project, we let the turbine hub height be 75 meters.

Generation was estimated for each hour by converting the windspeed to the corresponding power output level, producing kilowatt-hours (kWh). We then divided the hourly gross generation (in kWh) by the turbine capacity (3,600 kW) to calculate the generation per installed kilowatt (in kWh/kWi), or per installed megawatt (in MWh/MWi). This normalization of the generation allows one to more easily apply the offshore wind performance calculations to any size wind farm.

We made some important assumptions that affect generation that must be noted. The capacity was taken as 100% available, with no parasitic power loss (auxiliary loads) beyond what is represented in the power curve, and with no performance degradation over time. Also, the turbine was allowed always to have proper alignment to the wind direction (zero yaw error) and wake effects from neighboring turbines were not taken into account. While these assumptions overestimate the amount of energy available from turbines, the use of the log law for height scaling provides a conservative estimate of the windspeed, which compensates, to some degree, for this overestimation of the generation.

After we estimated wind generation, we calculated the annual generation and capacity factor for a wind turbine located at each "data site." Capacity factor is defined as the ratio of actual generation to the maximum output from the installed capacity operating for all hours of a given time period.

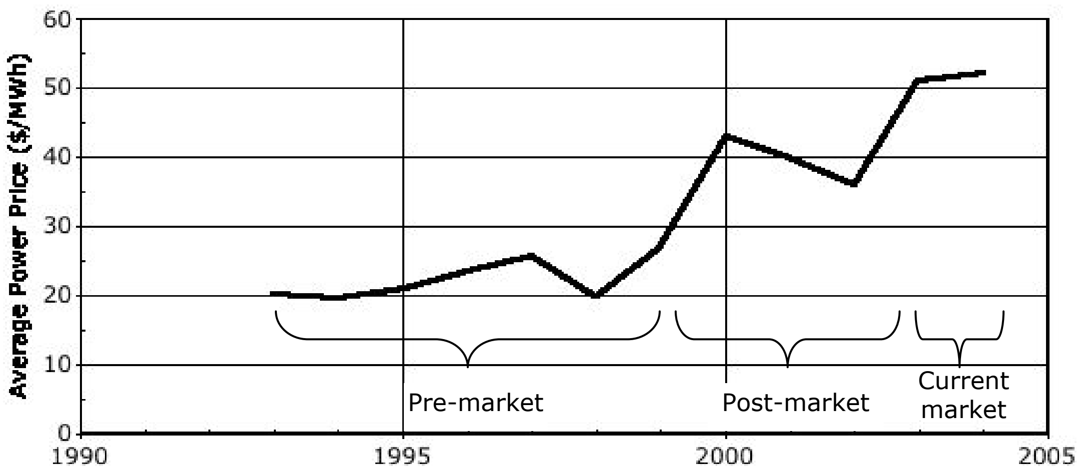
Capacity Factor (in %) = generation (in MWh) / [rated capacity (in MW) · time (in hours)] · 100

Calculation of Wholesale Revenue

After generation was estimated, we calculated the potential energy revenues of wind power using New England wholesale power prices. We obtained real-time locational marginal prices (LMP) for the New England Power Pool (NEPOOL) for the current market structure (3/2003-present), energy prices for the post-market period (5/1999 - 2/2003), and system lambdas for the pre-market period (prior to 5/1999), from the Independent System Operator of New England (ISO-NE). We multiplied the estimated hourly generation per installed MW by the hourly energy prices to get hourly revenue per installed MW.

The New England wholesale power market and its power prices have changed significantly over time, and it is difficult to compare earnings from different market structures. Figure 3.6 below shows the historical average annual wholesale power prices that are available from the ISO-NE website. For this project, we used nominal prices, and did not adjust for inflation. We treated the wind generator as a price taker for all hours, regardless of its likely bid price. The wind generator earned revenue assuming no dispatch or transmission constraints.

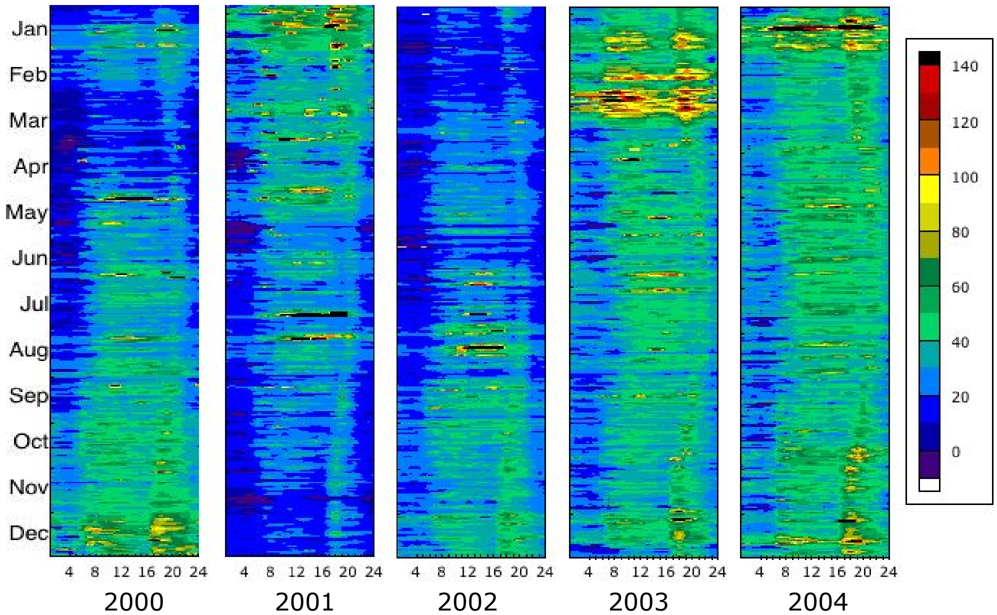
Figure MIT-OWC.3.6: ISO-NE Average Annual Wholesale Power Prices



Source: ISO-NE Historical Hourly Data

To get a better sense of hourly price dynamics, the figures below show NE wholesale power prices for the last five years (365 days along the vertical axis and 24 hours along the horizontal).

Figure MIT-OWC.3.7: Hourly ISO-NE Market Clearing Prices ($/MWh)



Source: ISO-NE Historical Hourly Data

Note that hourly prices are very situational, with peak prices in 2000–2002 occurring during Summer peaks (heat waves). In recent years, 2003 and 2004, higher priced hours have tended to occur in Winter, influenced by both relatively high demand for power and seasonally high natural gas prices.

Calculation of Avoided Emissions

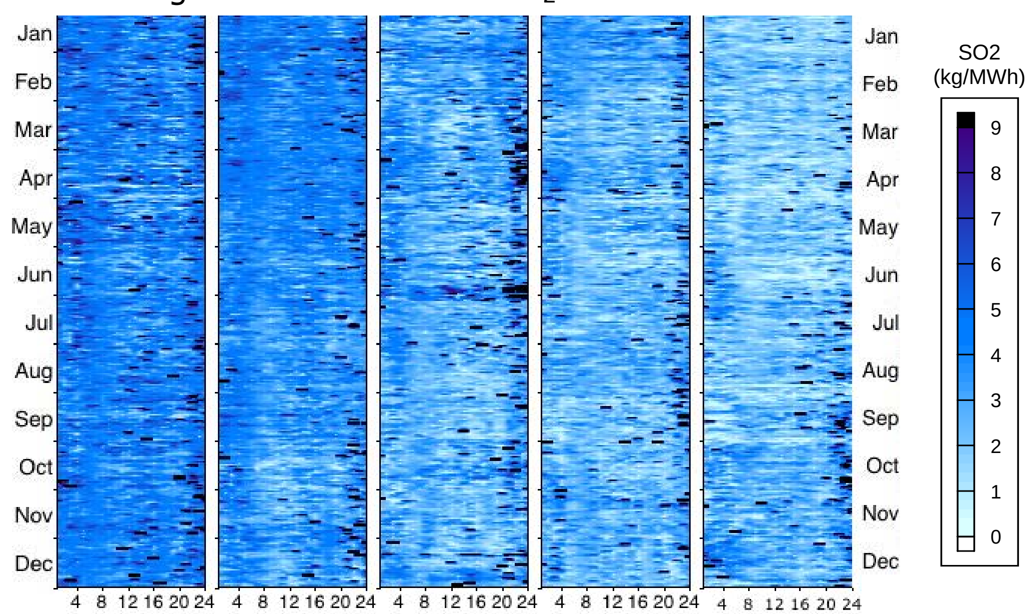
To inform discussions of the environmental (air emissions) impacts of wind, we calculated avoided emissions from fossil fuel power plants in New England due to wind generation. We used the database of "marginal" (hourly 'Load Shape Following' (LSF)) emissions rates developed by Connors et.al. for a project with EPA completed in 2004. Their methodology for calculating marginal emissions rates is described in detail in their report (please refer to the References at the end of this paper for where to access the report). While a detailed description of Connors et.al.'s LSF emissions rate methodology is beyond the scope of this report, a brief summary follows.

Hourly avoided fossil power plant emissions were calculated by multiplying hourly renewable generation with the corresponding hourly "Load Shape Following" emissions rate. LSF emissions rates were derived from EPA Acid Rain / Ozone Transport Commission (OTC) Program Hourly Emissions Data. Connors et.al. calculated potential power system-wide emissions reductions for small changes in demand/centralized power generation by looking at which power plants were responding to changes in (net) load (e.g. Load Shape Following), and calculating the corresponding rate for CO_2, NO_x and SO_2 emissions, weighted by how much each LSF unit was responding to changes in electricity demand. This method provides a more accurate representation of avoided emissions than the simpler methods that use an average emissions rate for all fossil units operating in a given hour or over a year. For their analysis, Connors et.al. calculated hourly emission reductions for the period of 1998-2002.

The following contour plots show SO_2, NO_x, and CO_2 emissions (in kg/MWh of load shape following fossil generation) in each hour in New England for the years 1998 through 2002. Annual average emission rates (in kg/MWh) and total emissions (in metric tonnes) from 1 MWh generated in each hour of the year are shown below the profiles. As one can see by the lighter colors in later years, the emission rates of load shape following units improve over time. (This trend post-2002 has likely reverted to higher emissions rates, due to increases in natural gas costs.) Also note how evening hours tend to be darker, and dirtier, than mid-day peak hours.

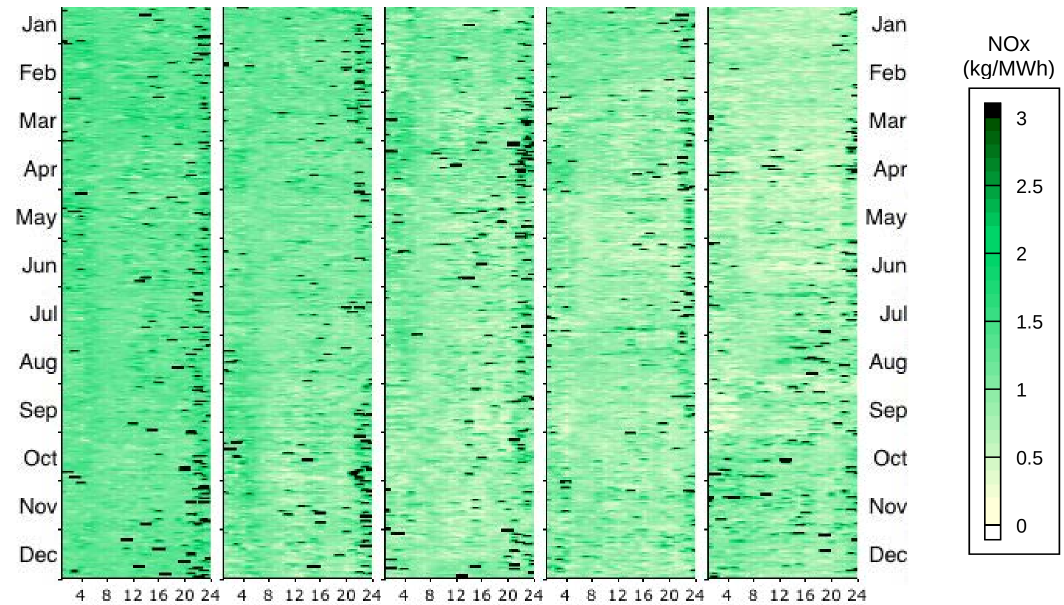
Once all of these calculations were completed, we analyzed the Northeast offshore wind resource to assess its temporal and geographic variability and its economic and environmental performance. This information was used to gain insight into determining under what circumstances offshore wind farms are likely to be economically viable. The following sections present the main results of our analysis.

Figure MIT-OWC.3.8: SO_2 Emission Rate Profiles



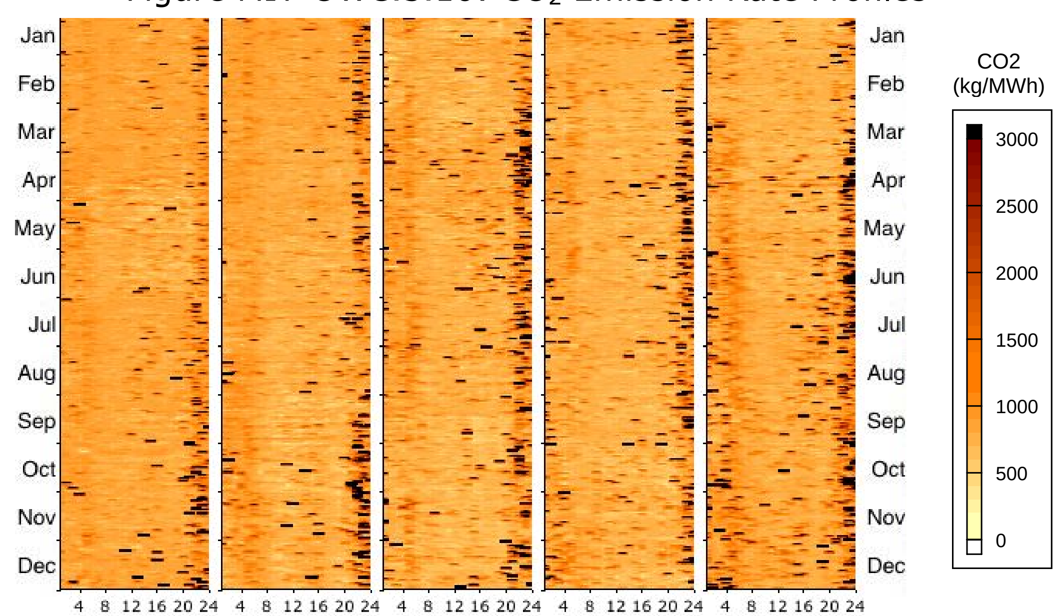
	1998	1999	2000	2001	2002
Ave (kg/MWh)	4.2	3.7	2.9	2.5	2.1
Total (mt/8760MWh)	37	33	25	22	19

Figure MIT-OWC.3.9: NO_x Emission Rate Profiles



	1998	1999	2000	2001	2002
Ave (kg/MWh)	1.2	1.1	0.9	0.8	0.7
Total (mt/8760MWh)	11	9	8	7	7

Figure MIT-OWC.3.10: CO_2 Emission Rate Profiles



	1998	1999	2000	2001	2002
Ave (kg/MWh)	831	797	750	738	763
Total (mt/8760MWh)	7279	6981	6590	6467	6686

FOUR: ASSESSMENT OF NORTHEAST OFFSHORE WIND RESOURCE AND POTENTIAL ENERGY OUTPUT

We have divided the results of our analysis into several sections. First, we present an overview of the key annual average results. Next, we present and discuss our findings on the offshore windspeed and its variability along with our estimates of potential generation from offshore wind plants. Lastly, we analyze the potential economic and environmental performance of offshore wind farms and identify cost thresholds for development.

Results Overview

Table 4.1 shows the average annual windspeed, wind power class, average generation, capacity, wholesale power revenues, and avoided emissions for the seventeen "data sites." This includes the sixteen NOAA data buoy sites plus Logan International Airport, which was included for reference purposes only, although it is within several miles of the wind turbines owned by Hull Municipal Light. Table 4.2 shows how windspeeds map to Wind Power Classes.

Table MIT-OWC.4.1: Summary of Key Parameters at Data Sites

NOAA Data Site	Ave Windspeed @ 75m	Wind Power Class	Ave Ann Generation	Ave Capacity Factor	Ann Revenue	Unit Revenue	Avoided Emissions		
							SO2	NOx	CO2
Logan	6.46	2	2.2	25.5	113	5.54	4.52	1.59	1,613
Portland	7.16	3	3.1	34.9	161	5.40	7.18	2.56	2,535
Isle of Shoals	7.58	4	3.3	38.2	189	5.43	8.29	2.91	2,932
Boston	7.60	4	3.3	37.9	177	5.52	7.57	2.71	2,665
Jonesport	7.88	5	3.5	40.3	190	5.37	N/A	N/A	N/A
Georges Bank	8.03	5	3.6	41.1	206	5.48	8.46	3.01	2,993
Delaware Bay	8.15	5	3.7	42.7	211	5.41	8.93	3.17	3,166
Long Island	8.26	5	3.8	43.7	212	5.42	8.99	3.19	3,170
Nantucket	8.34	6	3.8	43.7	202	5.50	8.82	3.13	3,113
Gulf of Maine	8.36	6	3.9	44.3	226	5.41	9.13	3.24	3,206
Ambrose Light	8.38	6	3.9	44.9	202	5.34	8.90	3.14	3,167
SE Cape Cod	8.39	6	3.8	43.6	208	5.48	N/A	N/A	N/A
Buzzards Bay	8.40	6	4.0	45.1	212	5.40	9.26	3.29	3,281
Matinicus Rock	8.47	6	3.9	45.0	221	5.39	9.17	3.24	3,226
Montauk Point	8.61	6	4.1	46.4	219	5.47	N/A	N/A	N/A
Mt. Desert Rock	8.63	6	4.1	46.3	234	5.41	9.65	3.41	3,402
Hotel	8.98	6	4.3	49.5	237	5.39	9.48	3.37	3,353
	(m/s)		(GWh/MWi)	(%)	(000$/MWi)	(¢/kWh)	(metric tonnes/yr)		

Notes: Unless otherwise noted, averages are taken from all available years for each data site. Generation, revenue, and avoided emissions are presented on a per installed megawatt (/MWi) basis. Revenue values are calculated from 2004 energy prices and shown in nominal values. Avoided emissions are per year and are calculated from 2002 emission rates.

Table MIT-OWC.4.2: Reference Wind Power Classes by Windspeed at Different Heights

Wind Power Class	Windspeed @ 50m (m/s)	Windspeed @ 75m (m/s)
2	5.6 - 6.4	5.8 - 6.6
3	6.4 - 7.0	6.6 - 7.2
4	7.0 - 7.5	7.2 - 7.7
5	7.5 - 8.0	7.7 - 8.3
6	8.0 - 8.8	8.3 - 9.1
7	> 8.8	> 9.1

Note: using the log law, the multiplier for scaling the windspeed from 50m to 75 m is 1.033. (Manwell et al., and AGREA)

Single "Data Site" Performance (Fact Sheets)

The figures on the next two pages represent the core computational work of this project. Collecting, correcting, converting and correlating the NOAA hourly windspeed data with power system prices and emissions data was—to say the least—a data intensive set of tasks. Work preliminary to the start of this project suggested that the variability of wind, not just long-term annual or seasonal averages, might be important to assessing the viability of future wind farms, both near and far from shore. And so, once all the data were in place, we developed a suite of graphical results (Fact Sheets) for each of the fourteen "data sites" with long-term data.[6]

The following two figures show the Fact Sheet for the Nantucket buoy as an example of the Fact Sheets, which appear in full in the Appendix. Figure 4.1 shows the template for the first page for each of the two-sheet data site Fact Sheets. The first sheet shows annual statistics for windspeed, capacity factor and energy production, wholesale power market revenue, year-to-year variation in capacity factors, and the variations in windspeeds within each year (boxplots). [Size and resolution of the Fact Sheets are better in the Appendix.] A Fact Sheet "cheat sheet" with definitions is also included in the Appendix.

Figure 4.2 shows the second sheet, where monthly and seasonal equivalents are shown, along with seasonal boxplots, and a multi-year table of key results that also shows unit revenues and avoided emissions. Note how large the seasonal variations for windspeed and power generation are, and how variable winds can be one year to the next. This is a key insight from the hourly analysis. As will be shown below, use of average windspeeds may lead to systematically under- or over-estimating annual generation, depending on the magnitude of the average annual windspeed, and on the statistical profile of the wind at the site.

The following sections look across the wind data sites, and discuss how the nature of the wind resource changes as we get further from shore, and deeper.

[6] 14 of the 17 stations (excluding Jonesport, Montauk Point, and SE Cape Cod) have at least 14 years of data and have Fact Sheets.

Figure MIT-OWC.4.1: Example Annual Results for Data Site – Nantucket

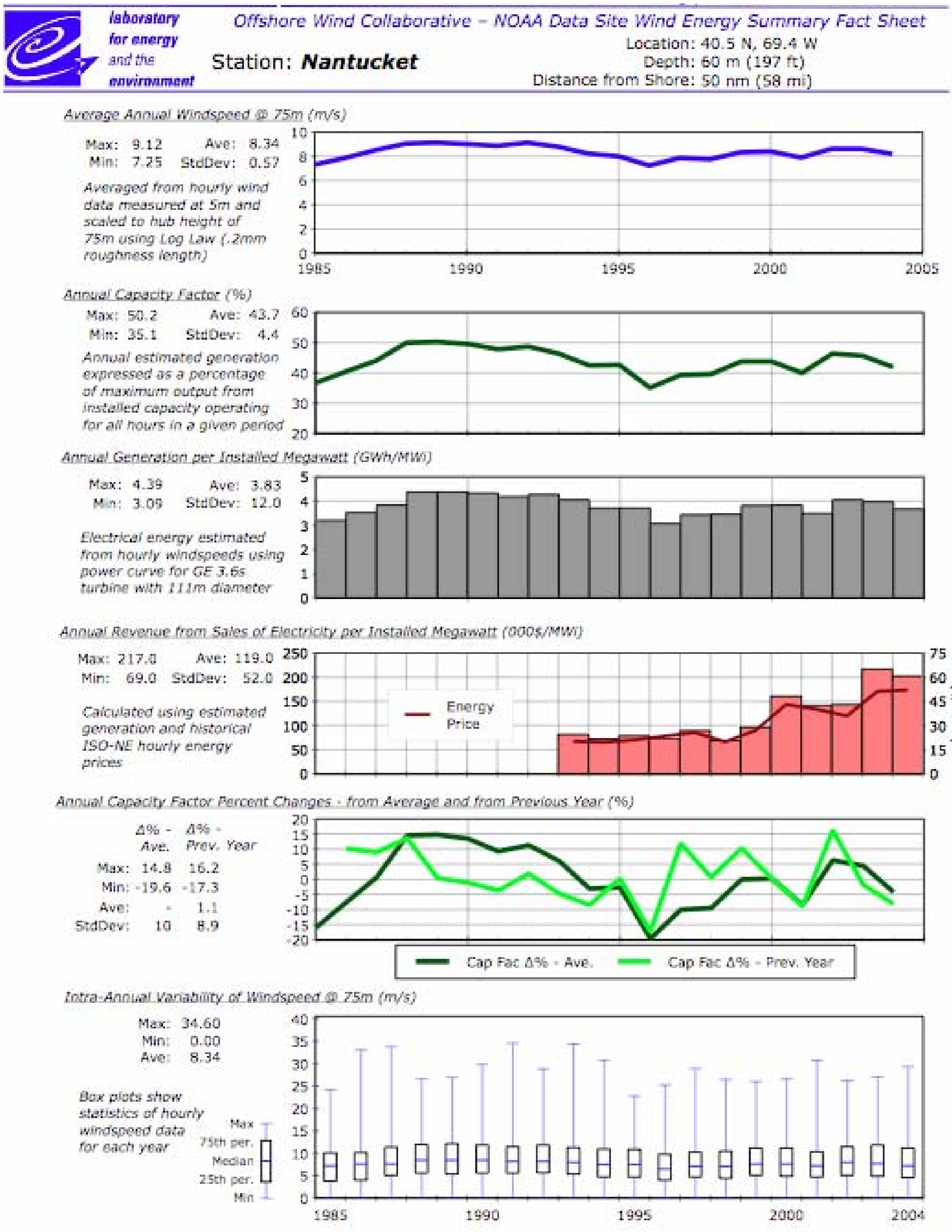
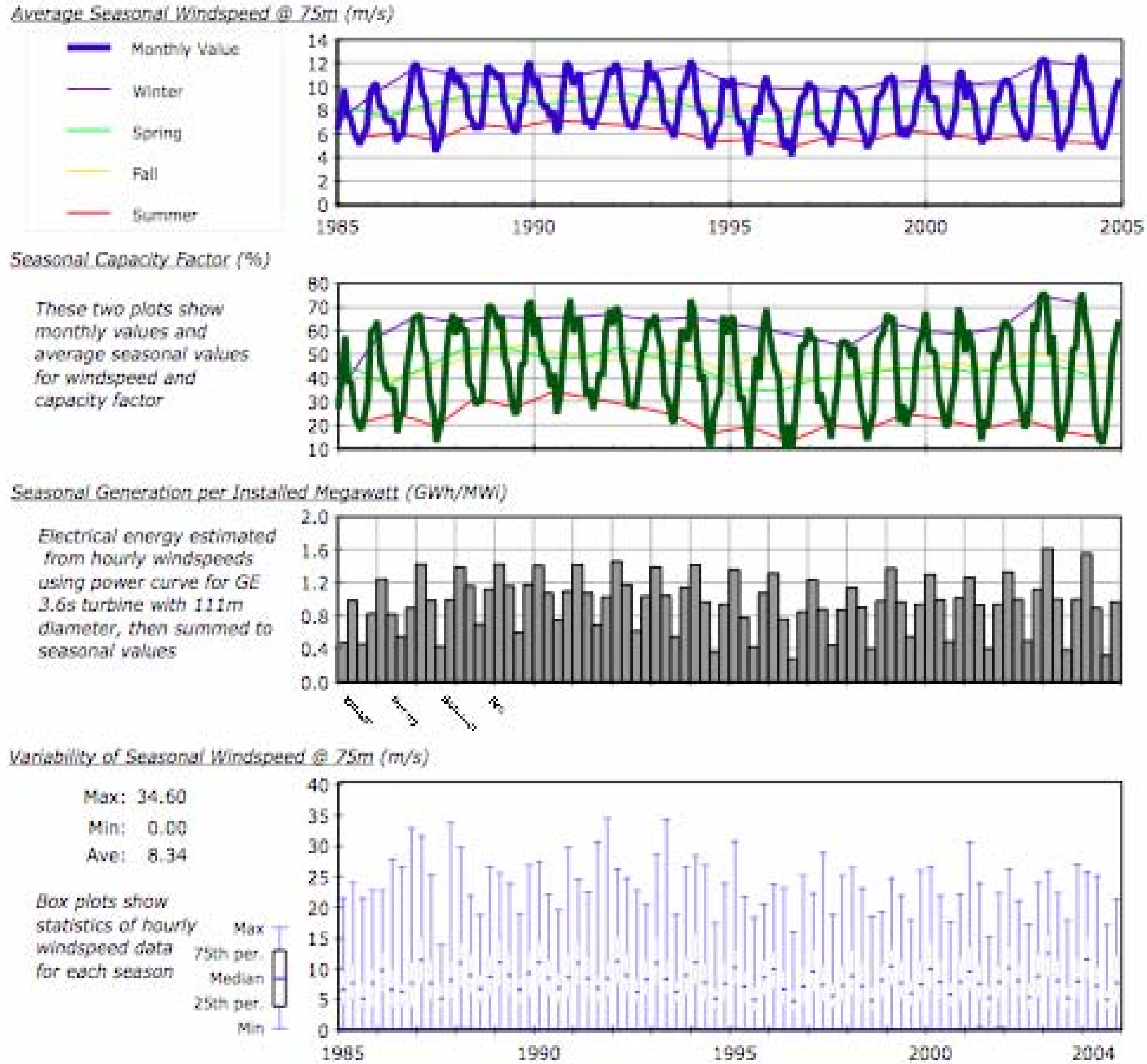


Figure MIT-OWC.4.2: Example Seasonal Results for Data Site – Nantucket



Year	Ave. Ann. Windspeed @ 75m (m/s)	Ann. Gen (GWh/MW)	Ann. Capacity Factor (%)	Ann. Revenue (000$/MW)	Unit Revenue (¢/kWh)	Cap Fac Δ% - Ave.	Cap Fac Δ% - Prev. Year	Avoided Emissions per Installed Megawatt SO2 (tonne)	SO2 (kg/MWh)	NOx (tonne)	NOx (kg/MWh)	CO2 (tonne)	CO2 (kg/MWh)
1985	7.32	3.21	36.7			-16.0							
1986	7.85	3.54	40.4			-7.5	10.1						
1987	8.52	3.85	44.0			0.7	8.9						
1988	9.04	4.39	50.0			14.4	13.6						
1989	9.12	4.39	50.2			14.8	0.4						
1990	9.02	4.34	49.6			13.5	-1.1						
1991	8.87	4.18	47.8			9.3	-3.7						
1992	9.12	4.27	48.6			11.3	1.8						
1993	8.80	4.06	46.3	82.0	2.0	6.0	-4.7						
1994	8.23	3.71	42.4	73.0	2.0	-3.0	-8.5						
1995	8.01	3.72	42.5	79.0	2.1	-2.7	0.3						
1996	7.25	3.09	35.1	74.0	2.4	-19.6	-17.3						
1997	7.87	3.44	39.3	90.0	2.6	-10.0	11.9						
1998	7.74	3.47	39.6	69.0	2.0	-9.4	0.7	14.7	4.2	4.3	1.3	2,886	832
1999	8.33	3.83	43.7	96.0	2.5	0.0	10.3	14.4	3.8	4.1	1.1	3,067	802
2000	8.39	3.85	43.8	161.0	4.2	0.3	0.3	11.1	2.9	3.4	0.9	2,851	746
2001	7.91	3.50	39.9	142.0	4.1	-8.5	-8.8	9.1	2.6	3.0	0.9	2,582	738
2002	8.64	4.07	46.4	143.0	3.5	6.2	16.2	8.8	2.2	3.1	0.8	3,113	765
2003	8.64	3.99	45.6	217.0	5.4	4.4	-1.8						
2004	8.18	3.68	41.8	202.0	5.5	-4.2	-8.2						

Where Is It Windy?

In order to be cost-competitive, wind farms further from shore *require* better winds. Being further from shore, and deeper, increases costs substantially—from the submerged portions of the wind turbines, the farm-to-shore power cables, and the size and complexity of wind farm servicing and repair. Our sister UMass-Amherst OWC pilot research project on offshore wind farm design and configuration is focusing on these engineering costs. This MIT analysis focuses on answering the questions:

Is it windier further from shore?
The short—but not simple—answer is Yes.

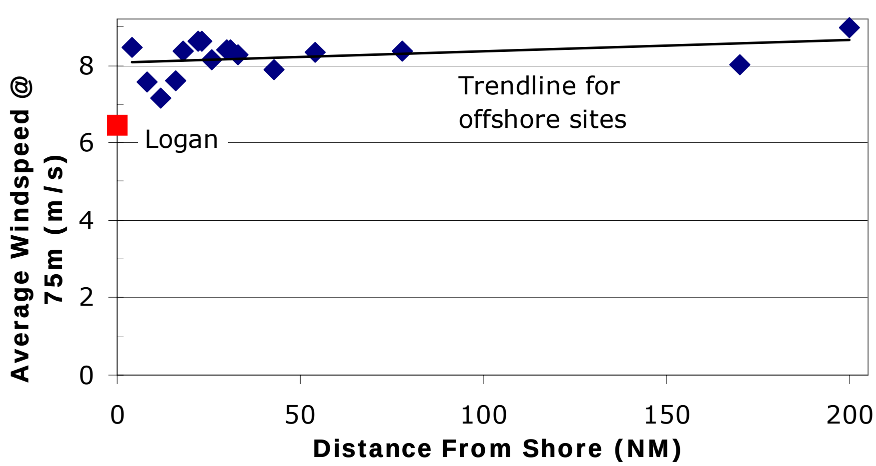
And if so, how much more can we afford to spend on deep vs. shallow water wind farms given the amount and variability of the wind?

How does the temporal distribution of winds affect the wholesale power market revenue potential, and avoided fossil power plant emissions?

How much windier tells us how much more we can afford to pay for longer transmission cables, deeper foundations or other mounting structures, and for servicing wind farms in more difficult, and distant, environments. The majority of the interpretive analysis in this report focuses on this topic.

Figure 4.3 displays the relationship between distance from shore (DFS) and average windspeed for the seventeen data sites. As can be seen, most are "near shore" with only three being "far offshore" and two being "very far offshore. [See map in Figure 3.1.]

Figure MIT-OWC.4.3: Distance from Shore (DFS) vs. Average Windspeed

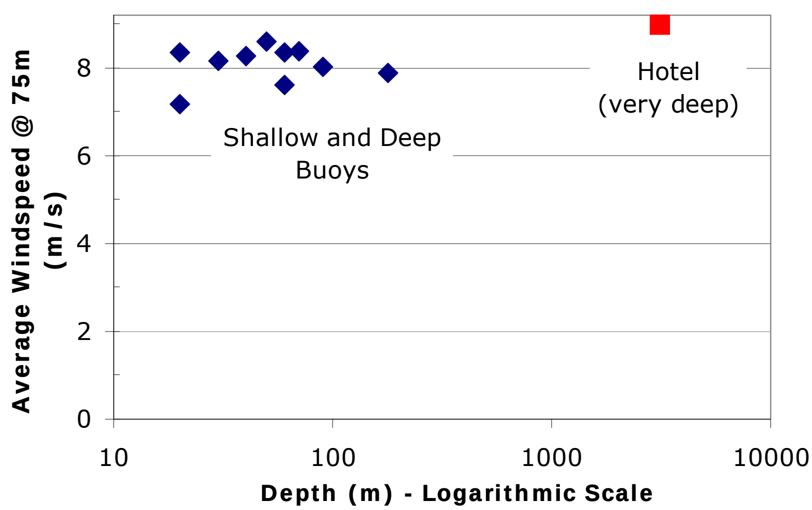


As one can see, there is slight positive correlation (R^2 = .13) between DFS and average annual windspeed. The slope of the trend line suggests that for every 350 nautical miles (400 miles) from shore, an increase in average windspeed of 1 m/s can be expected. As will be discussed later in this section, this translates to "near shore" locations having average windspeeds roughly 20% higher than Logan, and "far" and "very far" locations having 30% and 40% higher windspeeds. Since much more generation occurs at higher windspeeds, this translates into increased annual wind generation of 50% to 80%.

On a *seasonal* basis however, average winter windspeeds are better correlated (R^2 = .42) with DFS and show a stronger relationship (for every 140 nautical miles [160 miles] average winter windspeed increases 1 m/s), while summer windspeeds are not well correlated to DFS. This suggests that windspeeds are more variable on a seasonal basis farther from shore. We will discuss windspeed variability shortly.

Water depth is also a major factor in the cost of offshore wind systems. Since depth generally increases with distance from shore, it is important to know how windspeed, and therefore revenue potential, relates to depth. Unfortunately, it is difficult for us to use depth as a parameter because several of the NOAA measurement sites (the C-MAN stations) are located on rock outcrops and the stations that are floating buoys are often located over shallows for easier mooring. They therefore do not give a good representation of general area depth. However, the depth data that is available is presented in Figure 4.4 below.

Figure MIT-OWC.4.4: Depth vs. Average Windspeed



Looking at the 11 anchored buoys, there is a very slight positive correlation (R^2 = .30) between water depth and windspeed. However, if Hotel is removed there is no correlation whatsoever between depth and windspeed. So, "data site" depth is not a useful attribute in this analysis.

The impact of latitude on windspeed was difficult to determine due to the relatively small number of comparable data sites in each region. However, it seems that offshore winds are slightly stronger in the Northern Mid-Atlantic than in New England, based on the 16 offshore data sites analyzed.

Figure MIT-OWC.4.5: Average Annual Windspeed at Select Data Sites

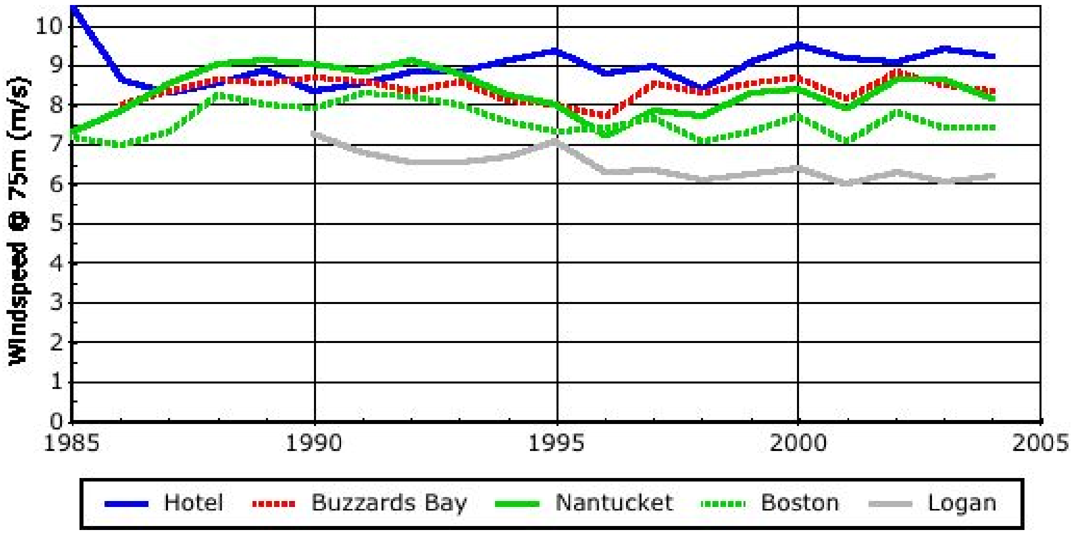


Figure 4.5 above shows historical average annual windspeeds at selected data sites. These five sites will be used throughout this section to illustrate cross-site results from our analysis. They were selected to represent the different locations of the data sites: far/very far offshore (Hotel and Nantucket) near shore (Buzzards Bay and Boston) and onshore (Logan). Please see the Appendix for graphs containing all 17 data sites.

As one can see, the far and very far sites show higher average windspeeds than the near shore and onshore sites. Looking at the range of annual average windspeeds, Logan averages between 6 and 7 m/s, Boston 7-9, Nantucket and Buzzards Bay 8-9 and Hotel 8.5-9.5. Referring back to Table 4.2, these are the equivalent of Wind Power Classes 2-3, 3-4, 5-6 and 6 respectively.

It is important to note that Buzzards Bay, while located near shore, has average windspeeds as high as Nantucket, located much further from shore. Is Buzzards Bay truly as windy as a site well south of Nantucket Island? Resolving the height scaling (wind shear) uncertainty used to move from anemometer to hub heights is a very important issue, and needs to be resolved through future experimentation. The equivalent average windspeeds of the Buzzards Bay and Nantucket data sites may be explained by the fact that windspeed measurements are taken at a higher elevation at the Buzzards Bay. As was explained in the Methodology section, height scaling introduces significant uncertainty in these windspeed calculations and must be kept in mind as these results are considered.

Since the height difference is less when scaling the C-MAN towers (25-33m) to 75m, than the buoys (5-8m), it is reasonable to assume that the windspeed, and therefore generation calculated at the buoy data sites is more conservative than that for C-MAN sites. To what degree we can not say at present.

When Is It Windy?

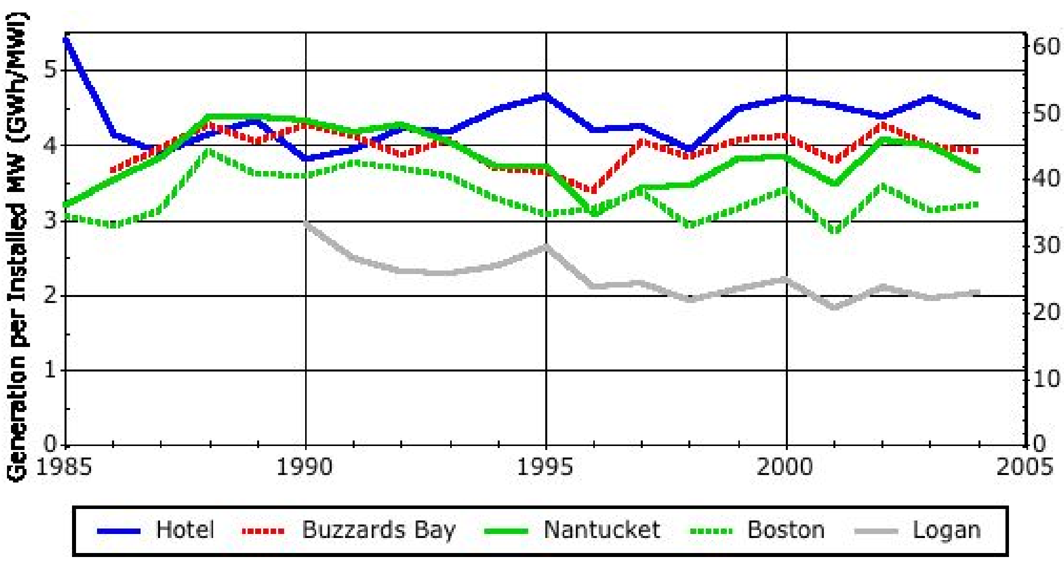
Now that we have discussed how windy it is offshore versus onshore—primarily on an annual basis, let us turn to investigating the variability of offshore wind. This is important because variability directly impacts economic and environmental performance and because it is not obvious simply from reviewing long-term annual average windspeed values what the earning and emissions reduction potential is of offshore wind.

Variability can be discussed in several terms. The first and most obvious dimension is geographic—on- versus off-shore, near versus far offshore, northern versus southern New England, etc. The other dimension is time—hourly, daily, monthly, seasonal, annual, decadal.

Inter-Annual Variability

We will first look at annual variability. The figure below shows estimated annual generation and associated capacity factors for the five selected sites. The annual changes in the windspeed are magnified when viewed through the estimated generation, due to wind turbines' power curves. Also note how the far offshore site, Hotel, generates about twice as much energy as the onshore site, Logan.

Figure MIT-OWC.4.6: Variation in Annual Generation (and Capacity Factor) for Five Selected Data Sites



Annual generation can *easily* change by up to 10% year-to-year. The following figures (4.7, 4.8) show how the annual capacity factor may change for the five selected sites, both from year-to-year, and relative to its long-term average capacity factor.

The capacity factor usually changes 5-10% each year and may change by up to ± 20% one year to the next. Also, the capacity factor in any one year can be up to 20% different than that location's long-term average.

Figure MIT-OWC.4.7: Change in Capacity Factor from Previous Year

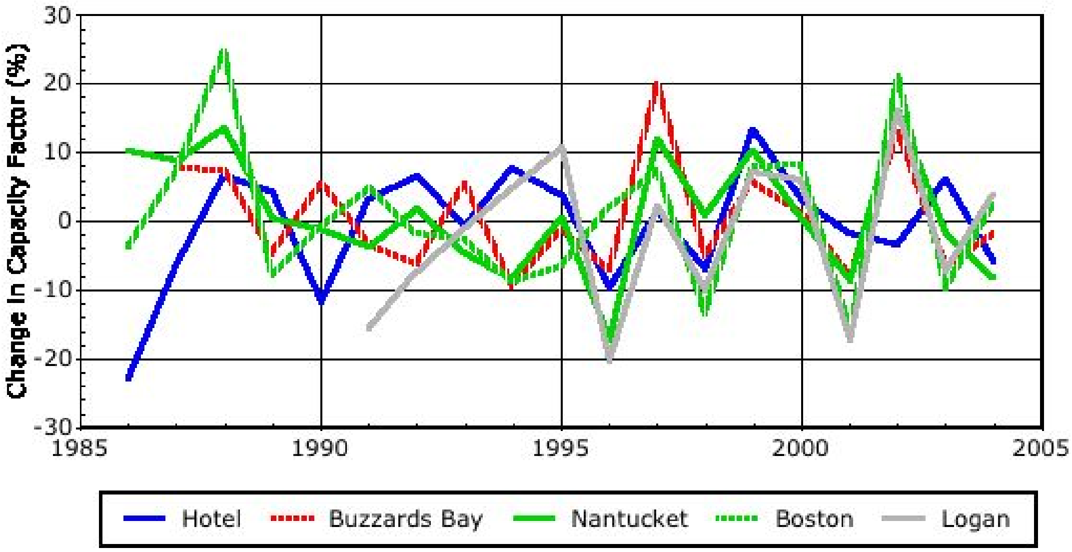
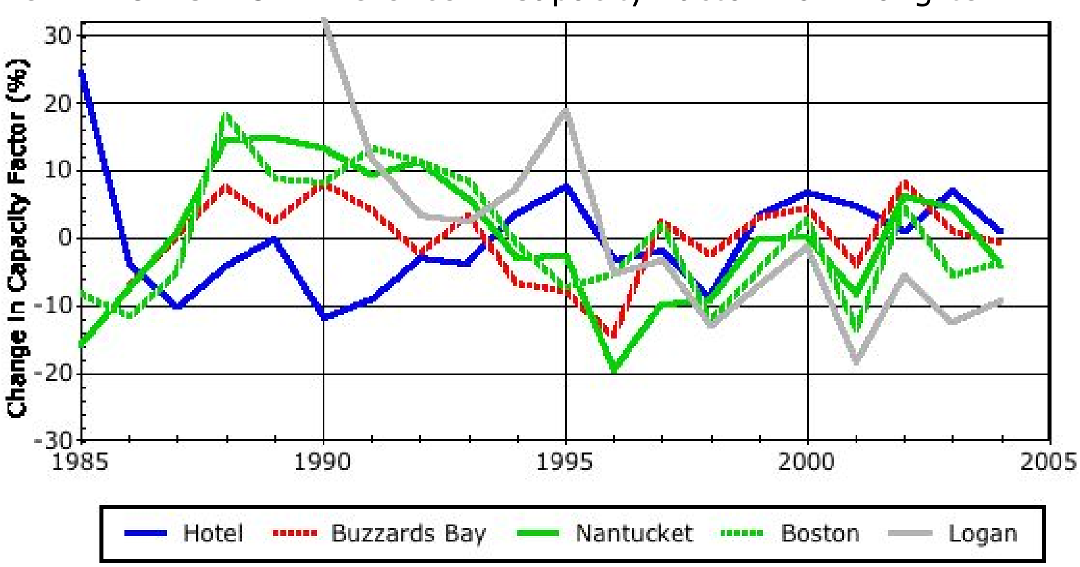
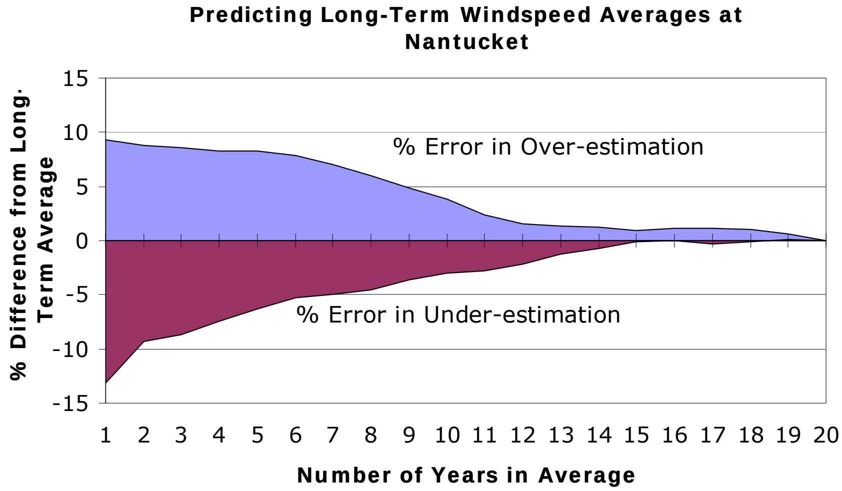


Figure MIT-OWC.4.8: Difference in Capacity Factor from Long-term Average



These findings suggest that using a short time series instead of longer ones for analysis can have a significant effect on one's interpretation of a site's potential performance. Figure 4.9 shows how using a short time series may over- or under-estimate average windspeed. When the time series is "short" (1-9 years), average annual windspeeds may easily be ± 5-10% that of the locations true long-term average windspeed. Therefore the more years that can be included into the calculation of the average windspeed, the closer that value will be to the actual long-term average. This highlights a "public goods" issue in data collection and wind resource estimation, as few wind farms developers can afford to collect data for such long time periods prior to moving forward on a particular project.

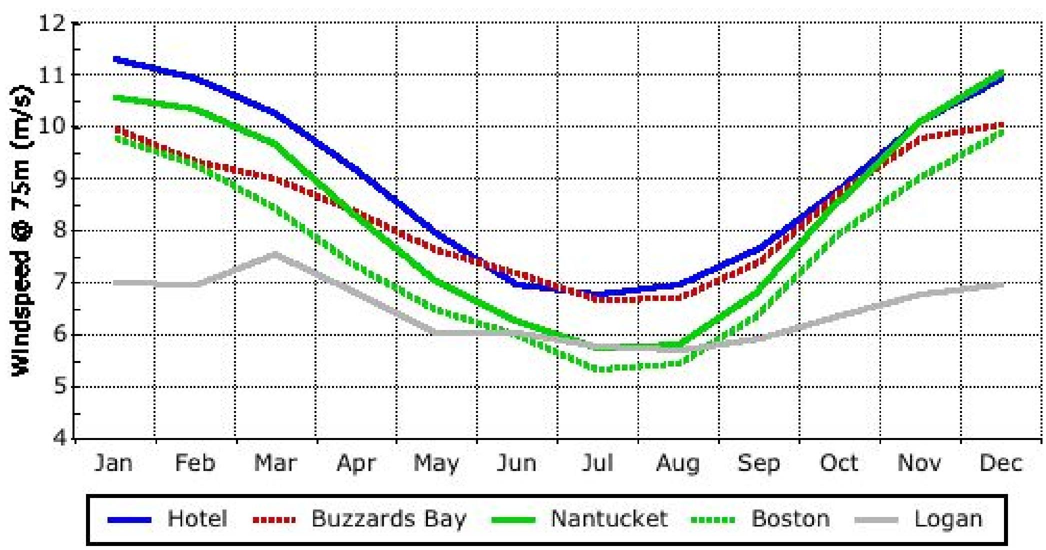
Figure MIT-OWC.4.9: Difference in Estimated Windspeed from Actual Based on Number of Years in Calculation



Intra-Annual Variability

As shown in Figures 4.1 and 4.2 above, there is a lot happening within each year when it comes to both windspeed and power generation. Figure 4.10 shows monthly average windspeeds for the five selected NOAA data sites. The variation from winter to summer is dramatic. Nantucket has very high winter windspeeds, but they drop lower than some of the other data sites in summer (≈ 20% lower). Buzzards Bay and Boston have roughly equivalent average winter windspeeds, but Buzzards Bay has relatively high summer windspeeds, while Boston has quite low summer windspeeds. As discussed above, this variability is magnified when converted into power production.

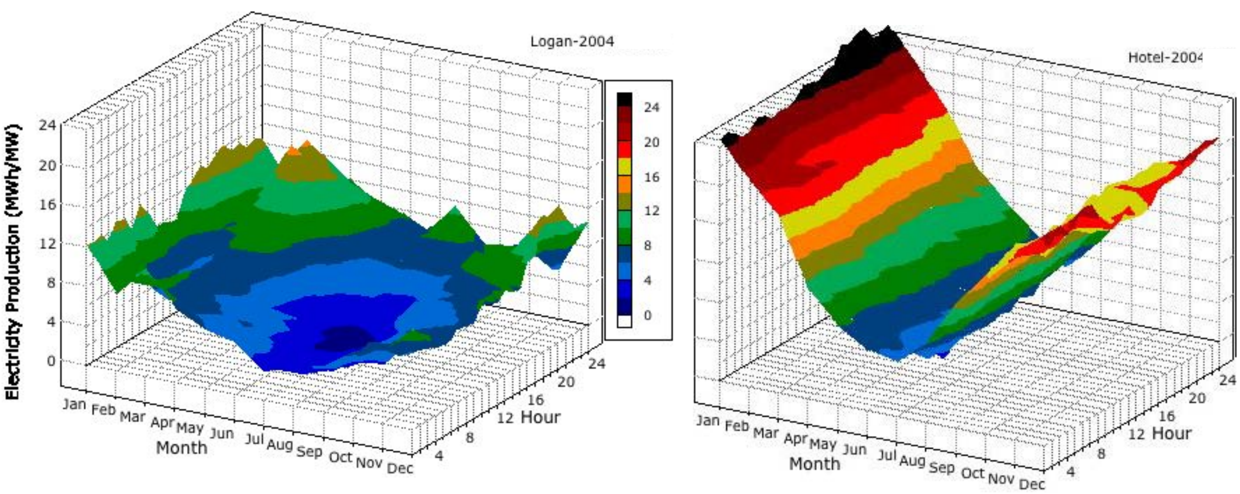
Figure MIT-OWC.4.10: Monthly Average Windspeed at Select Data Sites



As wholesale power prices generally follow daily electricity demand profiles, what do daily wind profiles look like? Since seasonal variability of winds is so large, showing annual average hour-of-day windspeeds would not be very informative. Fig. 4.11 shows the power generation by month and hour-of-day shown as a surface plot for the Logan and Hotel data sites in 2004.

Surface plots for all of the data sites are included in the Appendix, and all of them show the same trends as the two data sites illustrated in Figure 4.11. The majority of power generation, and therefore revenue and avoided emissions, occurs in winter, with little daily profile in wind output. Although there appears to be slightly more generation later in the day, particularly for near shore data sites, it is a much smaller shift than usually seen for onshore wind regimes. Offshore winds follow the passing of weather fronts with little or no land-sea interactions, such as sea breezes, which might better match electricity demand.

Figure MIT-OWC.4.11: Electricity Generation per MW installed for the Logan and Hotel Data Sites



As is becoming clear, there are challenges to estimating wind generation from short-term, average windspeed information. From a more statistical basis, variability is often evaluated by looking at the standard deviation (SD) of a data set. For our discussions, we used the Coefficient of Variation (CV, the ratio of the standard deviation to the long-term average), as our metric of variability. Table 4.3 shows the average windspeed and the variability (SD and CV) for each of the three data site groups.

Generally, offshore windspeeds are not only higher but also more variable than onshore winds. Also, there seems to be slightly more variability far/very far offshore than near shore. While seasonal and hourly variability's are greater offshore than onshore, the annual variability of onshore winds look similar to that for offshore. To get a better idea of the relationship between average windspeed and variability, the three graphs below plot each data site on different time scales.

Table MIT-OWC.4.3: Windspeed Variability by Location

Average Windspeed @ 75m (m/s)	**Onshore**		**Near Shore**		**Far/Very Far Offshore**	
	6.5		7.0 - 8.5		8.0 - 9.0	
Variability	SD (m/s)	CV (%)	SD (m/s)	CV (%)	SD (m/s)	CV (%)
Annual	.4	5 - 6	.2 - .4	3 - 6	.5 - .6	6 - 7
Seasonal	.6	9 - 10	1.0 - 1.5	13 - 20	1.7 - 1.9	19 - 23
Hourly	2.8	40 - 45	3.9 - 4.4	50 - 60	4.5 - 4.6	50 - 60

Notes: Values represent all available data for the 14 data sites[7] with many years of data. Variability metrics for each time scale represent variations over the entire data set at the frequencies listed (year-to-year, season-to-season, and hour-to-hour). While generalizations for onshore variability are difficult since only one site (Logan) was analyzed, other onshore studies[8] agree with the Logan results.

Fig. MIT-OWC.4.12a: Annual Windspeed vs. CV

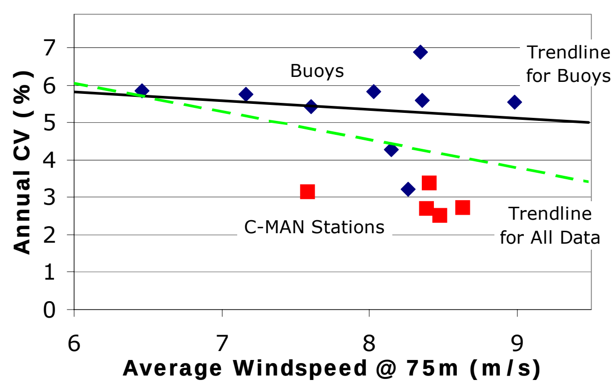


Fig. MIT-OWC.4.12b: Seasonal Windspeed vs. CV

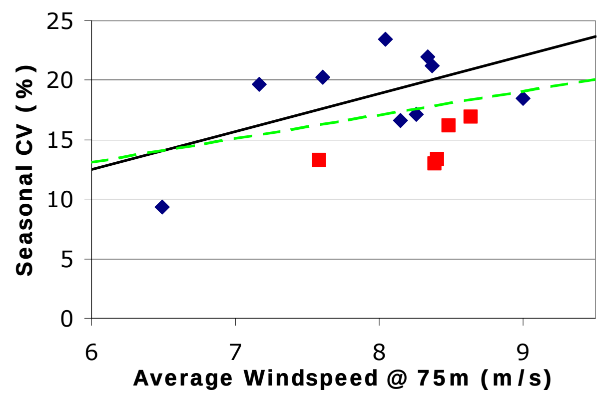
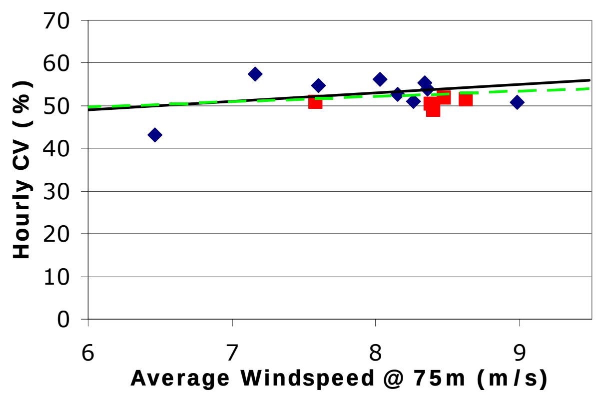


Fig. MIT-OWC.4.12c: Hourly Windspeed vs. CV



[7] The three data sites Jonesport, SE Cape Cod, and Montauk Point are excluded from these calculations and graphs as they only have several years of data, which is not enough to establish long-term variability.

[8] For example, Klink (2002) analyzed 20-30 years of wind data for seven sites in and around Minnesota.

There seems to be a sight negative relationship between average windspeed and annual CV. At higher average windspeeds, annual variation is less. However, seasonal and hourly variations *increase* with higher average windspeed. So, the better the average windspeed, and therefore the desirability of a given location, the more variations in windspeed need to be paid attention to.

After reviewing these variability values, it became apparent that the C-MAN station data were significantly different than the buoy data. It seems that anemometer height, in addition to average windspeed and geography, matters in the variability calculations. All of the C-MAN tower data showed relatively low variability, on all time scales, regardless of average windspeed and latitude. This again points to the need of understanding windspeed height scaling/wind shear dynamics, as greater low-height windspeed variability may be translated to hub-height windspeeds, when higher altitude winds may in fact be less chaotic.

On the broader geographic (North-South) dimension, more Northerly (higher latitude) sites appeared to be more variable across all time scales. On the impact of water depth, there is a slight positive relationship between depth and variability, on all time scales. But it is important to keep in mind the above disclaimer regarding buoy depths versus surrounding ocean depths.

Windspeed Probability Distributions – Variability in Windspeeds vs. Generation

Another way to analyze windspeed variability is to look at probability distributions. The probability distribution function most often used in wind analysis is the Weibull distribution, and in special cases the Rayleigh distribution is used.[9] We used a Rayleigh distribution to represent the probability distributions of the NOAA data,[10] a sample of which is shown in Figure 4.13 below.

As would be expected, a higher average windspeed provides a greater probability of higher windspeeds. It is important to note that the instantaneous windspeed (on an hourly basis) will be less than the average windspeed slightly over half of the time (54%), due to the asymmetric nature of Weibull and Rayleigh distributions. The temporal distribution of the wind over a year has significant implications for the amount of energy that can be produced at a site.

As is becoming clear in this report, using detailed temporal values in windspeed analysis can produce different and more insightful results than from just using aggregate (annual average) values. Figure 4.14 below shows the effects of using average windspeed in estimating generation for a wind data site. Each data point corresponds to the average windspeed at Nantucket for each year of available data (1985-2004) plotted against the difference in estimated annual generation from using annual versus hourly windspeed values.

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[9] The Weibull function uses two parameters: shape factor (k) and scale factor (c), which depend on the mean (U) and standard deviation (SD) of the data set (Manwell et.al., 2002, p.57). The Rayleigh distribution applies when the shape factor (k) equals 2.

[10] Shape factor, $k = (SD/U)^{-1.086}$ (Manwell et.al., p.58). So when SD/U equals .523, as is generally the case with the NOAA data, k = 2, and the Rayleigh distribution applies.

Figure MIT-OWC.4.13: Rayleigh Distribution of Windspeeds (2004)

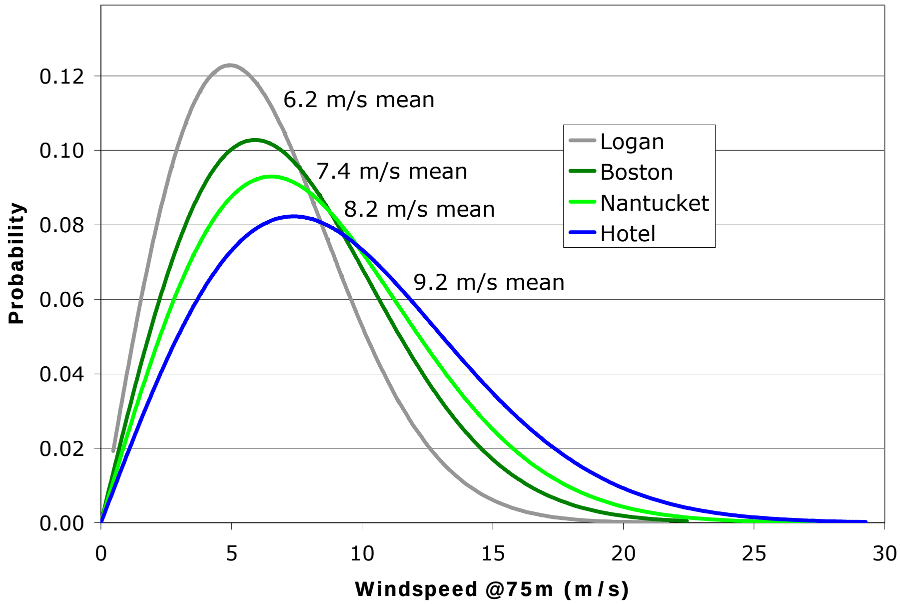
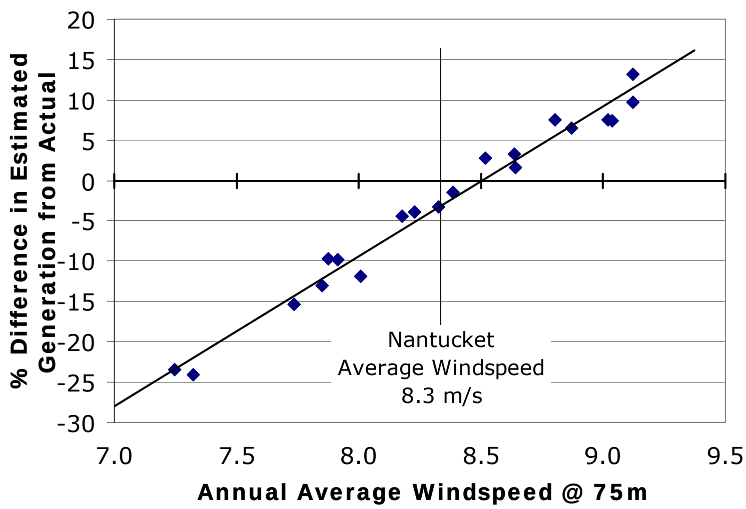
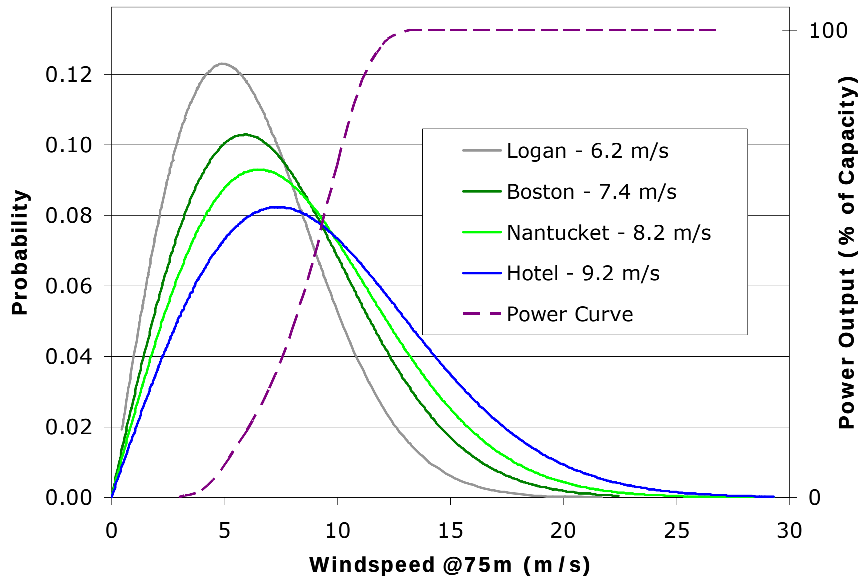


Figure MIT-OWC.4.14: Relationship Between Windspeed and the Magnitude of Generation Miscalculation



As Figure 4.14 above shows, the higher the average annual windspeed, the more likely it is that annual generation will be *overestimated*. Similarly, annual average windspeeds below 8.5 m/s (with the Nantucket buoy having a long-term annual average of 8.3 m/s), systematically underestimates annual generation. Using Nantucket as an example, shifts of ± 10% in annual generation are common if annual average windspeeds are used to estimate annual power production instead of hourly calculations. The reason for this is the shape of the power curve relative to actual windspeed distributions, illustrated in Figure 4.15 below.

Figure MIT-OWC.4.15: Power Curve and Coincidence with Windspeed Probability Distribution



The most important point to note from Figure 4.15 is that low probabilities of windspeeds at and above the rated power point on the power curve (14 m/s) dramatically change overall generation. The shapes of the windspeed distributions and power curves show why using annual average windspeeds may grossly under- or over-estimate generation.

The above figure begs the question, "What are the probabilities of various windspeeds along the power curve?" Table 4.4 below addresses this. What is most surprising is that wind turbines operate at rated power for only a small percentage of hours each year. Offshore sites are expected to see rated power levels only up to 10-15% of the time. However, our analysis shows that for offshore sites these few hours (at rated capacity) may produce up to 40-50% of total annual generation. Table 4.5 below shows different temporal measures of the variability of *generation* (capacity factor has the same CV as generation).

Table MIT-OWC.4.4: Probabilities of Various Windspeeds

	Ave Windspeed @ 75m (m/s)	Probability (%) Windspeed is Greater Than: Cut in (4 m/s)	1/2 Rated (9 m/s)	Rated (14 m/s)	Cut out (27 m/s)
Onshore (Logan)	6.5	80	17	1	< 1
Near Shore	7.0 - 8.5	74 - 86	32 - 41	6 - 12	< 1
Far/Very Far Offshore	8.0 - 9.0	81 - 87	36 - 45	11 - 15	< 1

Note: Probabilities based on all available hourly windspeeds and not on a cumulative distribution function (CDF), though a CDF would produce similar results.

Table MIT-OWC.4.5: Variability of Generation by Location

Generation	Onshore		Near Shore		Far / Very Far Offshore	
(Annual) (GWh/MWi)	2.2		3.0 - 4.0		3.5 - 4.5	
Variability	SD (MWh)	CV (%)	SD (MWh)	CV (%)	SD (MWh)	CV (%)
Annual	300	13 - 14	200 - 300	4 - 10	300 - 400	8 - 10
Seasonal	100	24 - 25	200 - 300	20 - 37	300	27 - 39
Hourly	.3	140	.4	80 - 100	.4	80 - 90

Notes: Values represent all available data for the 14 data sites[11] with many years of data. Variability metrics for each time scale represent variations over the entire data set at the frequencies listed (year-to-year, season-to-season, and hour-to-hour). While generalizations for onshore variability are difficult since only one site (Logan) was analyzed, other sources agree with the findings.[12]

The findings are generally similar to what we saw for variabilities in windspeed. Annual generation variability onshore is similar to that for offshore, but seasonal generation variability is greater offshore. However, variability of hourly generation is higher onshore than offshore. This may be explained by the exponential shape of the power curve and the different operating levels of turbines in low-speed versus high-speed environments.

The above findings begin to address the question of whether offshore wind development is viable. It is true that it is generally windier offshore than onshore. It is also generally true that the further from shore one goes, the windier it gets, however seasonal variability increases, while diurnal variability decreases.

The next section addresses whether it is sufficiently windier, and at the right times, to justify the costs of developing offshore wind farms, especially farther from shore.

[11] The three data sites Jonesport, SE Cape Cod, and Montauk Point are excluded from these calculations as they only have several years of data, which is not enough to establish long-term variability.

[12] In Denmark, annual output from wind turbines typically have a CV of 9-10%. (www.windpower.org)

FIVE: ECONOMIC AND ENVIRONMENTAL PERFORMANCE OF OFFSHORE WIND

The main question this research seeks to answer is whether it is sufficiently windier, and at the right times, to justify the higher costs of building and operating wind farms further from shore. We approach this by evaluating, not the cost of wind technologies, but the magnitude of the wind, and how it matches the price of electricity at different times during the year. The environmental benefits of offshore wind are also of interest, and again the timing of the wind relative to fossil unit operation is a principal determinant of whether higher emissions coal and oil-fired units are offset, versus cleaner natural gas-fired generation.

In the previous section we focused primarily on the wind resource, and how that influences the magnitude and distribution of wind generation across and within years. In this section, we extend that analysis to look at the potential revenue and avoided emissions of offshore wind resources. We begin with wind farm price-taker earnings using historical ISO-New England wholesale hourly market prices, then add to them prospective additional revenues from production tax credits (federal), renewable energy certificates (state), and shadow-revenues associated with the economic value of avoided air emissions that might arise from cap-and-trade air quality regulations. Then we quickly look at what the avoided emissions from offshore wind resources might be.

Economic Performance

Electricity Demand and Offshore Wind Generation Temporal Dynamics

We will start by addressing the economic implications of offshore wind. First, it is important to consider the electricity demand profile of New England, as this determines much of the "value" of wind generation in terms of "peak coincidence" and the hourly price of wholesale electricity.

Figure 5.1 shows electricity demand for New England in 2004. Electricity demand is summed by month and hour-of-day, similar to how wind generation was presented in Figure 4.11. In general, the pattern of wind generation is the inverse of the load pattern. Mid-day summer electricity demand is highest, however late-day winter electricity demand is also high. At first cut, this would not bode well for wind generation, which occurs mostly in wintertime, and therefore is not very peak coincident. From a power system planning perspective, the more peak coincident a renewable resource is, the more it will avoid investment in peak generation (often called the "capacity credit"), as well as displace conventional (primarily fossil) generation. In this analysis, we give zero for the capacity credit and focus exclusively on windpower's value from electrical energy production.

So, the degree to which summer and wintertime electric loads vary from year-to-year are very weather dependent—heat waves in summer, and cold snaps in winter. Late night/early morning electricity demand is usually very low, generally half that of peak day electricity demand. However, the wholesale prices associated with these variations in electricity demand are much more dynamic, depending not only on demand, but also on the amount of available generation (including nuclear and hydropower), the price of natural gas, and other factors.

Figure MIT-OWC.5.1: New England Electricity Demand, 2004

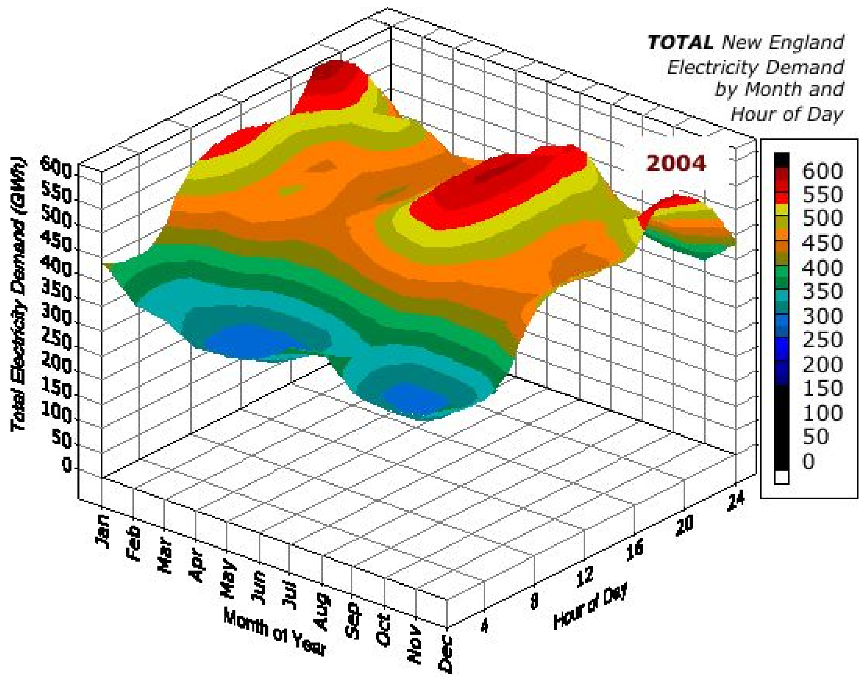


Figure 3.6, earlier in this report, displays the hourly wholesale electricity prices for 2000-2004, and shows that over the last couple years wintertime wholesale prices have been higher than summer. This means that although summertime wind generation is poor, due to the distribution of wind relative to annual peak demand, the revenue potential is still good. As we shall see below, the seasonal wind pattern also improves the environmental performance of windpower.

Is it Windy Enough Further from Shore to Justify the Greater Cost?

Table 5.1 below shows how much windier, and how much more generation can be expected as we go from the least to highest wind data sites. Also shown in Table 5.1 is the relative increase in annual price-taker revenue for 2004 and avoided (air) emissions for 2002. As discussed earlier, due to the influence of wind turbines' power curves, *increases in annual wind generation are roughly double the increases in average windspeeds*. 2004 was a also a good year for wintertime wholesale electricity prices, and so increases in revenue were greater than the increase in wind generation

In general, it is up to 40% windier offshore than onshore (using the Logan data site[13]). Further, offshore wind turbines may be expected to produce up to twice as much energy as onshore ones. When comparing the best offshore sites, it is important to note that the Hotel data site is very far from shore (200 nautical miles) and in very deep water (3,000 m). The above findings may be grouped by location and are summarized in Table 5.2 below. This information is also presented graphically in Figure 5.2.

[13] Logan is in a Class 2 wind area. Later, we will compare the offshore data sites to Class 3 & 4 sites.

Table MIT-OWC.5.1: Relative Performance of Onshore to Very Far Offshore Wind Data Sites

	Relative to Onshore Value (%)			
Station	**Windspeed**	**Generation / Capacity Factor**	**Revenue**	**Avoided Emissions**
Logan	0	0	0	0
Portland	11	36	42	59
Isle of Shoals	17	50	68	84
Boston	18	48	57	68
Jonesport	22	58	69	N/A
Georges Bank	24	61	82	87
Delaware Bay	26	67	87	98
Long Island	28	71	88	99
Nantucket	29	71	79	95
Gulf of Maine	29	74	101	102
Ambrose Light	30	76	79	97
SE Cape Cod	30	71	85	N/A
Buzzards Bay	30	77	88	105
Matinicus Rock	31	76	96	103
Montauk Point	33	82	94	N/A
Mt. Desert Rock	34	81	107	114
Hotel	39	94	110	110

Notes: Relative values based on long-term averages. Revenue for 2004. Avoided emissions for 2002, for all emissions types.

Table MIT-OWC.5.2: Relative Performance of Parameters Summarized, Relative to Class 2 Winds (Δ%, Logan)

Relative to Class 2 (%)

	Windspeed	**Generation / Capacity Factor**	**Revenue**	**Avoided Emissions**
Onshore	0	0	0	0
Near Shore	10 - 35	35 - 80	40 - 105	60 - 115
Far Offshore	30	70 - 75	80 - 100	95 - 100
Very Far Offshore	25 - 40	60 - 95	80 - 110	90 - 110

Figure MIT-OWC.5.2: Relative Values of Parameters Summarized

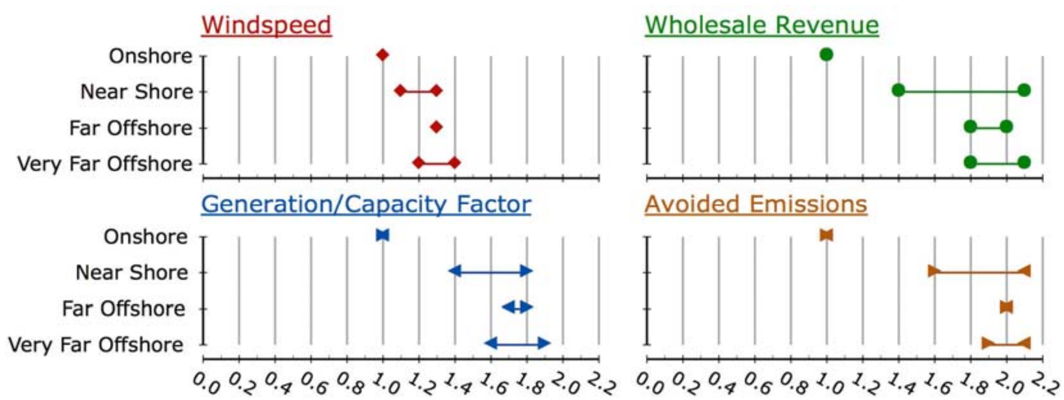


Table 5.2 and Figure 5.2 show that offshore wind turbines may be expected to produce *up to* twice as much energy as onshore ones. Further, *up to* twice as much revenue and avoided emissions as onshore sites may be expected. This is great news to the wind and power development communities. However, these relative values must be tempered with the knowledge that in this case the offshore wind performance is being compared to that of a Class 2 site (Logan), and that due to inter-annual variability, this is not the case in all years. A more realistic comparison of potential offshore sites versus actual onshore wind farms would involve Class 3 and 4 values. Table 5.3 shows that these comparisons, while favorable to offshore wind development, are not as superior.

Table MIT-OWC.5.3a: Relative Performance of Parameters Compared to Class 3 Site (Portland)

Relative to Class 3 (%)

	Windspeed	Generation / Capacity Factor	Revenue	Avoided Emissions
Onshore	0	0	0	0
Near Shore	5 - 20	10 - 35	10 - 45	5 - 35
Far Offshore	15 - 20	25 - 30	25 - 40	20 - 25
Very Far Offshore	10 - 25	20 - 40	30 - 50	20 - 30

Table MIT-OWC.5.3b: Relative Performance of Parameters Compared to Class 4 Site (Boston)

Relative to Class 4 (%)

	Windspeed	Generation / Capacity Factor	Revenue	Avoided Emissions
Onshore	0	0	0	0
Near Shore	5 - 15	5 - 25	5 - 30	5 - 30
Far Offshore	5 - 15	15 - 20	15 - 30	15 - 20
Very Far Offshore	5 - 20	10 - 30	15 - 35	10 - 25

As one can see in the above tables, when compared to the performance of wind resource in onshore areas likely to have projects (Class 4 sites), the best that offshore resources can do is about 30% more energy, revenue, and avoided emissions. This must be kept in mind when discussing the additional costs of going offshore.

Figures 5.4 and 5.5 translate these relative increases into dollars and cents for the five select data sites. Historically, both total and unit revenues that a wind farm at these data sites might have earned have increased substantially in the last several years. Since both graphs show the same general trend, increases are due primarily to increases in wholesale power prices, and so could decline if less expensive conventional generation comes on-line. Recent (2003-2004) unit revenue at these data sites averaged 5.4¢/kWh, with the higher offshore capacity factors accounting for the dispersion among the total annual revenues in Figure 5.3. While going very far offshore may nearly double generation and revenue potential from staying onshore, near shore sites still provide 40-50% more generation and total revenue than onshore sites (compared to Logan). Looking at the recent years, which reflect current market structure and prices, one notices how much more revenue is possible from offshore wind.

Figure MIT-OWC.5.4: Total Wholesale Revenue per Installed MW from the Five Select Data Sites

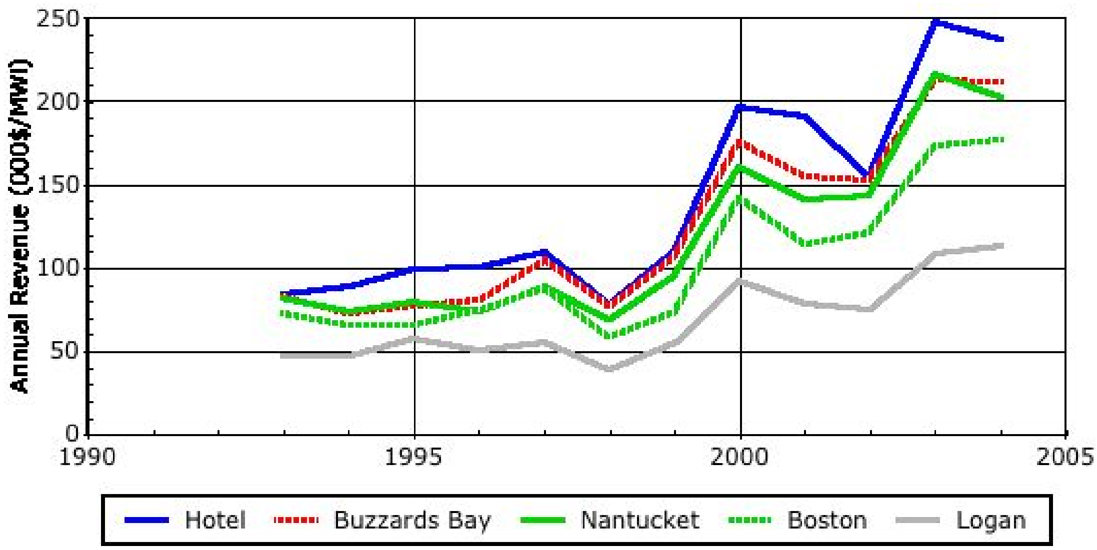
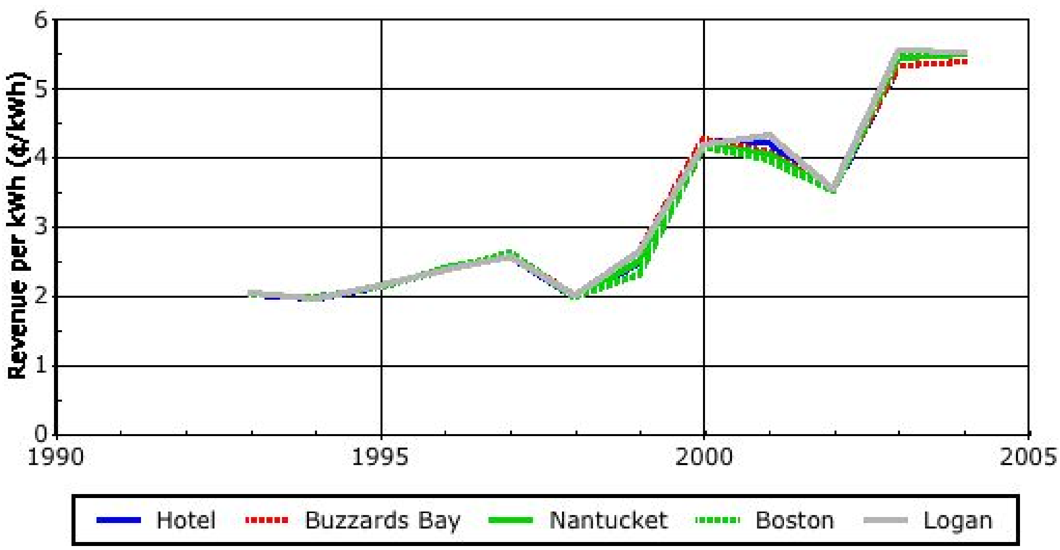


Figure MIT-OWC.5.5: Unit Wholesale Revenue per Installed MW from the Five Select Data Sites



Revenue Implications on the Affordability of Offshore Wind Facilities

Just because revenues are greater offshore, it does not necessarily mean facilities are cost effective. To see if offshore wind power is economically viable, we must look at these increases in revenue, relative to the cost of building and operating a wind farm further from shore. We want to know what is the "required revenue" per kWh based upon the cost of the wind farm and the ability to spread those costs over a greater number of kWhs. As the synthesized results above show, *at best*, far offshore wind locations may be expected to make *up to* twice as much revenue from electricity sales as onshore ones (Tables 5.1 and 5.2).

How do these differences affect the earnings/revenue potential of a prospective wind site, or the ability to pay more for installing a wind farm further offshore?

Cost Thresholds

From this analysis, what thresholds in terms of higher winds, deeper waters, and increased capital and installation costs, can be established for the viability of some offshore areas over others? Near shore (shallow water) offshore installations have 50-100% higher capital costs than the least economical (but still profitable) onshore systems, with deepwater installations costing considerably more than that (Musial and Butterfield, 2004, and AWEA). Can such increased costs be absorbed by the increased output of the installation, and if not, how much must they come down?

The U.S. Department of Energy has set the following goal for offshore wind:

> *"By 2012, reduce the cost of electricity from large wind systems in Class 4 winds to … 5 cents per kilowatt-hour for offshore systems"* (USDOE).

In Europe, existing offshore wind projects have cost between 8-15¢/kWh (MTC, 2005, p.11). This is almost twice the cost of typical onshore projects. The main reason cited for such higher costs has been that construction and maintenance are more difficult "at sea."

Our results show recent (2003-2004) unit revenue at data sites would have averaged 5.4¢/kWh. While this value is based on some overly optimistic assumptions (offset by some conservative measures), it excludes any subsidies.

One subsidy available to wind power is the Production Tax Credit[14] (PTC), which the Energy Policy Act of 2005 renewed at a value of 1.9 ¢/kWh (adjusted annually for inflation) (AWEA). The PTC applies to energy produced from renewable sources during the first ten years of a project's life.

Another source of revenue for renewable energy generators are green energy certificates, which are marketed at the wholesale and retail level for voluntary and compliance purposes. The New England Renewable Energy Certificates (RECs) market is mainly fueled by the Renewable Portfolio Standards (RPS) in four New England states (MA, ME, CT, RI).[15] RPS compliance fees in these states are about

[14] The PTC is set to expire at the end of 2007 (AWEA).

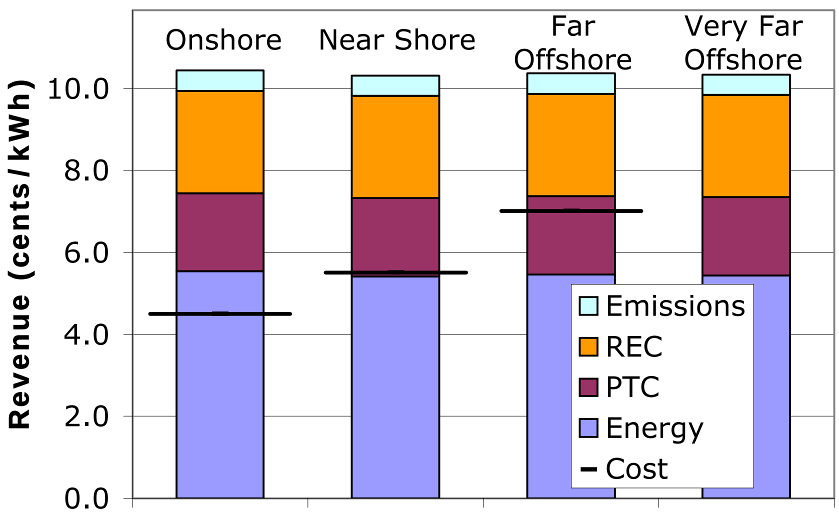
[15] In June 2005, VT enacted a renewable portfolio goal and will consider a RPS (www.dsireusa.org). NH is considering the issue (www.renewableenergyaccess.com).

\$50/MWh (5¢/kWh), which puts an upper limit on compliance RECs. However, recent market prices for RECs have been as low as 0.1¢/kWh in ME and as high as 4-5¢/kWh in CT and MA. REC values for compliance are expected to be around 2.5 ¢/kWh in 2010 in New England (Holt and Bird, 2005, p.27).

Markets for emissions permits may provide another opportunity for renewables to secure revenue. While in most cases renewables are not eligible to participate, opportunities are emerging.[16] Holt and Bird report that renewables may be able to obtain 0.1-0.2¢/kWh if they were allowed to participate directly in emissions markets (p.54).[17]

When we add all these revenue components together (unit wholesale revenues from Fig. 5.5 [for 2004], PTC, RECs and Emissions), we get the bar graph below. This looks like good news, with solid revenues between 6-9¢/kWh depending on how much credence is given to stability in power markets, or government mandated subsidies.

Figure MIT-OWC.5.6: Comparison of Revenue Potentials



Note: Cost values estimated based on industry experiences and goals.

Given this range of unit costs, how much could be spent for offshore wind? Current ranges of costs for offshore wind range from \$1200 to \$2000/kW, with costs in 2012 ranging from \$1000 to \$1600/kW (Musial and Butterfield, pp. 7, 9). Assuming all operation and maintenance (O&M) costs are included in Fixed O&M, we have similar ranges of \$55-\$65/kW-yr currently and \$50/kW-yr in 2012 (pp. 7, 9).

[16] The national SO2 market discourages renewable participation, and only seven states (including MA and NH) currently allow participation in NOx programs. Further, CO2 markets are currently unregulated. However, the northeast states may make renewables eligible for CO2 allowances under the Regional Greenhouse Gas Initiative.

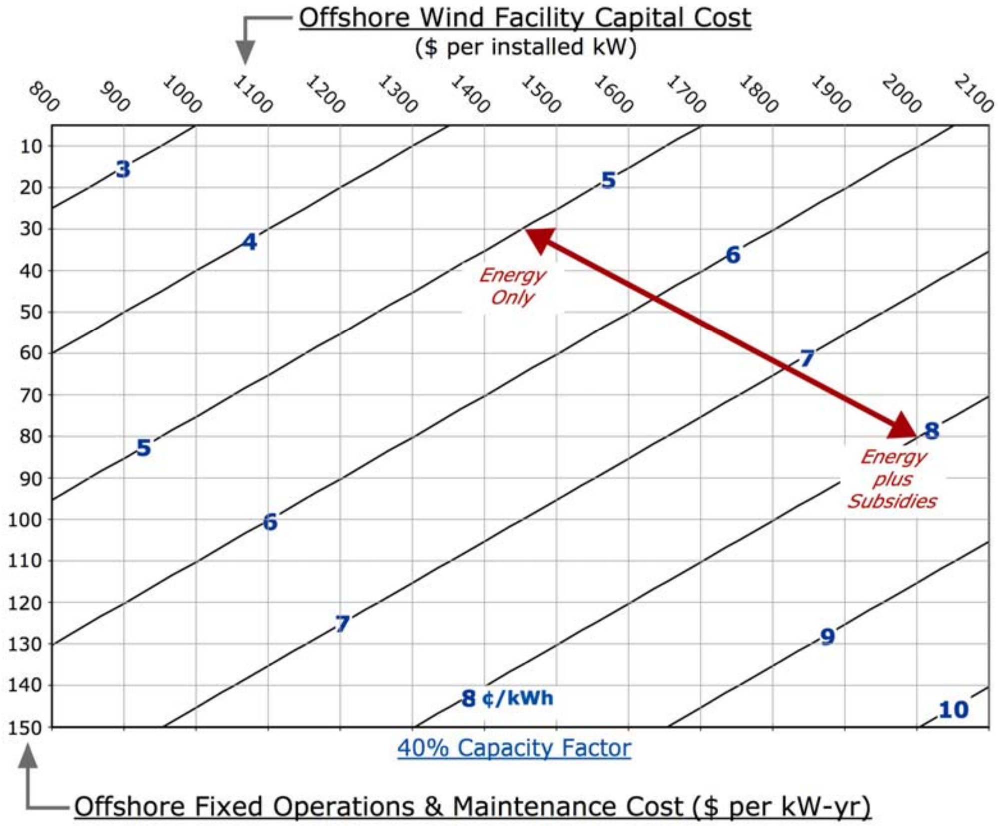
[17] Values based on Holt and Bird's estimates of emissions monetary values and Connors et.al.'s calculations of avoided emissions.

With these two numbers and some assumptions on the annual capital carrying charge (CC)[18] and capacity factor (CF), we can calculate a rough revenue requirement of an offshore wind farm using the following equation:

¢/kWh = [(Capacity (in kW) · Capital Cost · CC/100) + FOM] / [CF/100 · 8760 hr]

In this formulation, taxes and other similar charges are reflected in Fixed O&M assumptions. Assuming a Carrying Charge of 10 (%) for capital costs, and a capacity factor of 40%, we get the combinations allowable capital costs and fixed O&M rates for various levels of ¢/kWh illustrated in Figure 5.7.

Figure MIT-OWC.5.7: Revenue Requirements for an Assumed Level of Offshore Wind Capital Costs and Fixed O&M
(10% Carrying Charge, 40% Capacity Factor)



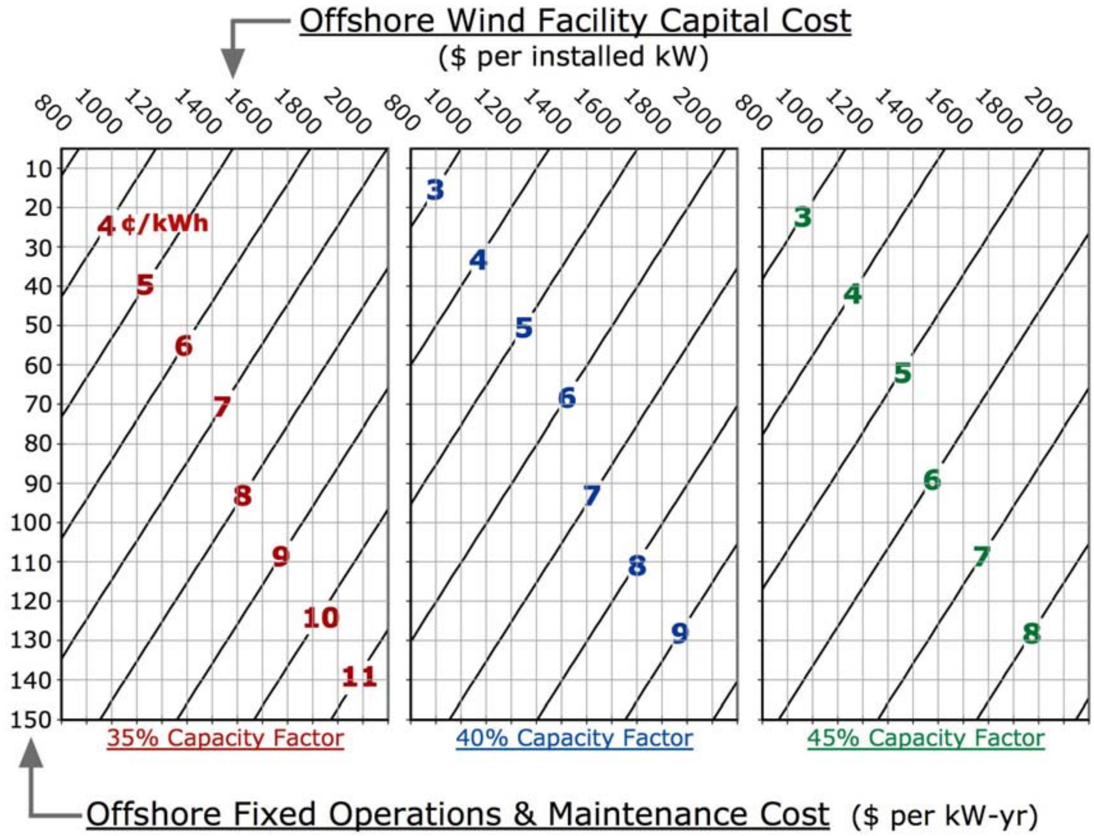
In this figure we can quickly see that if we anticipate revenues of 8¢/kWh, then the most we would be able to pay for the offshore wind farm would be $2000/kW and $80/kW-yr, or, staying on that "iso-cost" curve, $2100/kW and $70/kW-yr. In the (very) long-term, where some or all subsidies might disappear, then $1450/kW and $30/kW-yr would be sufficient to break roughly even at 5¢/kWh.

As discussed above, capacity factors can vary substantially from site to site, and from year-to-year. Figure 5.8. below shows the affordable costs and revenue requirement targets for 35%, 40% and 45% capacity factors. Not surprisingly, the

[18] The Carrying Charge is the percent of total capital expenditures that must be "paid back" per year, and is a rule of thumb which generally reflects financing terms (interest rate, loan duration).

better the wind, the higher the capacity factor, the more kWhs you have to spread your costs over, and the more you could afford to spend for the offshore wind farm.

Figure MIT-OWC.5.8: Revenue Requirements and Affordable Capital and Fixed O&M Costs for Different Capacity Factors
(10% Carrying Charge, 35-40-45% Capacity Factors)



So, what required $2000 and $80 to yield 8¢/kWh at a capacity factor of 40%, now requires a little over 9¢/kWh at 35%, but only a little over 7¢/kWh at 45%. The DOE targets for deepwater wind energy of 6¢/kWh in 2012 (Musial and Butterfield, p. 9) imply a capital cost of $1600/kW and $40/kW-yr for a capacity factor of 40%.

How difficult a cost/price target are these numbers to reach given the insights from the NOAA data buoy analysis? Referring back to Table 4.1, we see that most of the "not Near Offshore" data sites have capacity factors in the 40-45% range, with "worst years" being around 35%. A conservative interpretation of Figure 5.6 would yield a unit revenue requirement of 9¢/kWh (5-market + 2-PTC + 2-REC), with a worst case revenue requirement of 5¢/kWh (4-market + 0-PTC + 1-REC).

With a 45% capacity factor, almost anything in Fig. 5.8 (right most figure) is "affordable." With these rough calculations, assuming $60/kW-yr and a 45%, capacity factor, a wind developer could pay *almost* $3000/kW to install everything. Those are best case/optimistic assumptions for capacity factor and revenues. For a medium case (9¢/kWh, 40% CF), combinations of $2550/kW and $60/kW-yr,

$2400 and $75, and $2100 and $105 represent upper thresholds. $2400 represents a 50% increase from what was spent to install the Horns Rev offshore wind farm in Denmark (Musial, 2005). Is this a high or low number from an engineering cost perspective, for "deep water" wind? Our sister OWC Pilot Research Project being conducted by RERL/UMass-Amherst is approaching the topic from that direction. Worst case assumptions of 5¢/kWh and a 35% capacity factor set long-term cost targets of $1300/kW at $25/kW-yr. If offshore wind farm costs were to drop to those levels, there would be almost no years when a wind farm did not earn a profit. At those costs and a 45% capacity factor, wind energy is generated at just below 4¢/kWh.

These numbers are all calculated using the 10% Carrying Charge. Municipal investors have access to cheaper capital (e.g. municipal bonds), and while prime rates are generally low at present, this may not be the case well out into the future.

Table 5.4 shows how "allowable" capital costs change as we shift Carrying Charges up and down, across three assumptions for Capacity Factor and fixed O&M. For our reasonable revenue requirement of 9¢/kWh, and a 40% Capacity Factor, at $50/kW-yr, we could afford to pay a little over $2600/kW to permit and build a wind farm. If financing terms are good (5% CC), then nearly twice that amount is affordable (≈$5300/kW). If they are bad (15% CC), then two-thirds of that is affordable (≈$1800/kW). As most power plant developers know, *the cost of capital is as important as capital costs*, when it comes actually implementing the project. So, when a $/kW figure is given as a goal for capital costs, be mindful of what the base financial assumptions are.

Table MIT-OWC.5.4: Allowable Wind Farm Capital Costs with Varying Carrying Charge, Capacity Factor Fixed O&M and Revenue Targets

Carrying Charge	Fixed O&M ($/kW-yr) 25	50	75	Fixed O&M ($/kW-yr) 25	50	75	Fixed O&M ($/kW-yr) 25	50	75
Capacity Factor:	***35.0*** %			***40.0*** %			***45.0*** %		
Cost Target:	**5.0** ¢/kWh								
5	2,566	2,066	1,566	3,004	2,504	2,004	3,442	2,942	2,442
10	1,283	**1,033**	783	1,502	1,252	1,002	1,721	1,471	1,221
15	855	689	522	1,001	835	668	1,147	981	814
Cost Target:	**7.0** ¢/kWh								
5	3,792	3,292	2,792	4,406	3,906	3,406	5,019	4,519	4,019
10	1,896	1,646	1,396	2,203	**1,953**	1,703	2,509	2,259	2,009
15	1,264	1,097	931	1,469	1,302	1,135	1,673	1,506	1,340
Cost Target:	**9.0** ¢/kWh								
5	5,019	4,519	4,019	5,807	5,307	4,807	6,596	6,096	5,596
10	2,509	2,259	2,009	2,904	2,654	2,404	3,298	**3,048**	2,798
15	1,673	1,506	1,340	1,936	1,769	1,602	2,199	2,032	1,865
(%)	($/kW)			($/kW)			($/kW)		

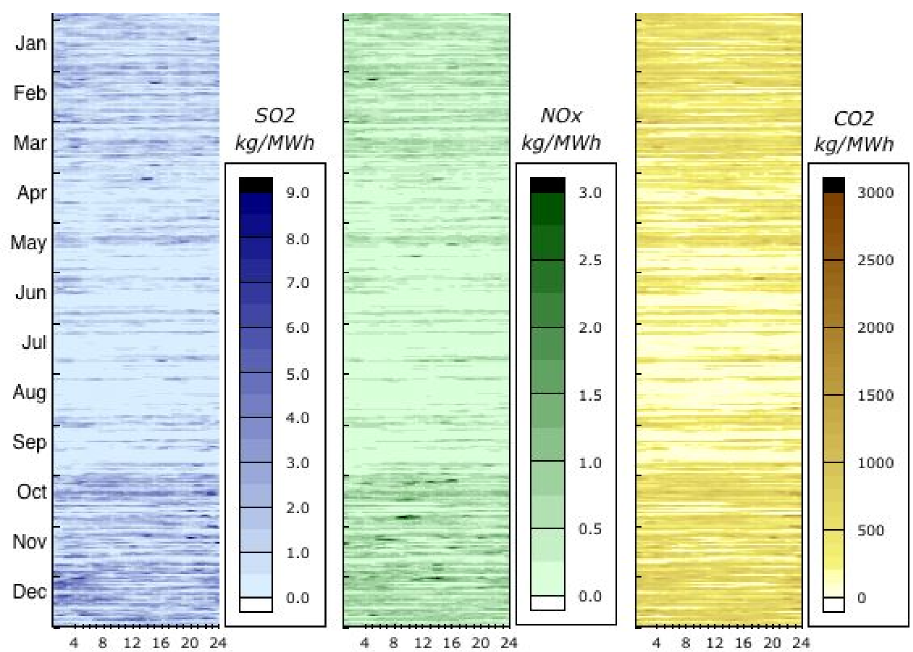
Should standard Carrying Charges be assumed for "riskier" projects? Should Fixed O&M charges be higher to reflect higher insurance premiums? Table 5.4 gives us insights into the cost impacts of these questions. An optimistic set of assumptions (9¢/kWh, 45% CF, 10% CC, $50/kW-yr) yields an allowable $3000/kW. If revenue targets and capacity factors drop, allowable capital expenditures drop to ≈$2000 (7¢, 40% CF) and ≈$1000 (5¢, 35% CF). An increase in estimated Fixed O&M means that less can be spent on capital for the same set of revenue and resource assumptions. A detailed understanding of the quality and variability of the offshore wind resource will significantly reduce these uncertainties.

Environmental Performance: Avoided Fossil Generation Emissions

Now that we have addressed the economic performance of offshore wind resources we turn our attention to the potential benefits of wind power in terms of avoided fossil generation emissions. Wind power may reduce emissions in two ways: by deferring investment in fossil power and by displacing some generation of existing fossil plants. We focus on the latter environmental performance in this analysis.

Because wind power may offset emissions in the region it serves, it is important to look at the potential avoided emissions from wind generation for both environmental and economic perspectives. Figure 5.9 below shows the potential avoided emissions from the wind resource at the Nantucket data site.

Figure 5.9: Avoided Emissions from Select Data site - Nantucket (2002)



Recall from Figures 3.7, 3.8, and 3.9 that the marginal emissions rates from load shape following fossil generators are highest at night and in the winter. The avoided emissions results for Nantucket show that the correlation is high between strong winter offshore winds and load shape following operation of the dirtier power plants. The amount of emissions avoided from wind or other renewable plants depends not only on the average marginal emissions rate and the total renewable generation, but also on the hourly and seasonal profile of the generation.

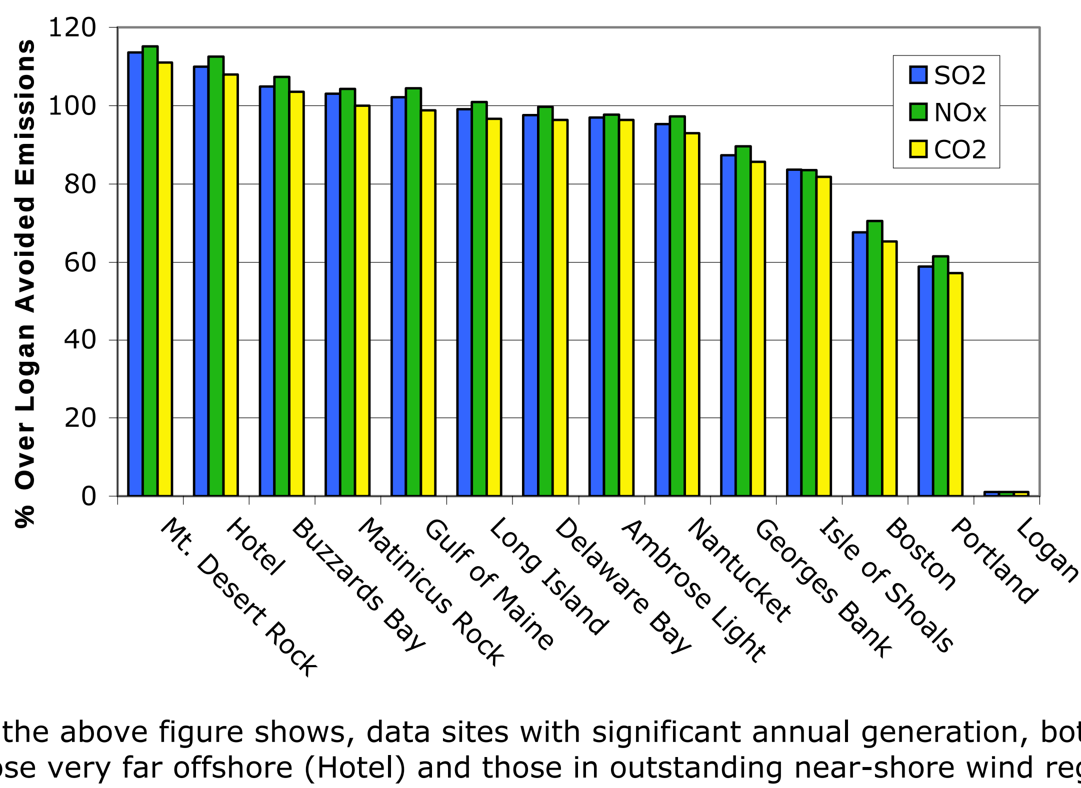
Table 5.5 below shows annual avoided emissions totals and rates, as well as generation, for the Logan and Hotel data sites, representing low and high ranges. Referring back to Figures 3.7 through 3.9, one can see how closely related the rates of avoided emissions are to the marginal emissions rates for each year. While the avoided emissions rates are similar across data sites, the total amount of emissions avoided each year depend on the total generation, as well as on the marginal emissions rates.

Table 5.5: Avoided Emissions from Selected Data Sites

Logan	**Generation (GWh)**	**SO2 (tonne)**	**SO2 (kg/MWh)**	**NOx (tonne)**	**NOx (kg/MWh)**	**CO2 (tonne)**	**CO2 (kg/MWh)**
1998	1.94	8.2	4.2	2.4	1.3	1,612	829
1999	2.08	7.7	3.7	2.2	1.1	1,658	797
2000	2.21	6.4	2.9	2	0.9	1,651	752
2001	1.82	4.6	2.5	1.5	0.8	1,337	733
2002	2.11	4.5	2.1	1.6	0.8	1,613	764

Hotel	**Generation (GWh)**	**SO2 (tonne)**	**SO2 (kg/MWh)**	**NOx (tonne)**	**NOx (kg/MWh)**	**CO2 (tonne)**	**CO2 (kg/MWh)**
1998	3.95	16.7	4.2	4.9	1.2	3,293	833
1999	4.48	16.9	3.8	4.8	1.1	3,593	801
2000	4.64	13.3	2.9	4.1	0.9	3,446	747
2001	4.54	11.8	2.6	3.9	0.8	3,346	737
2002	4.38	9.5	2.2	3.4	0.8	3,353	765

Figure 5.7: Relative Avoided Emissions as Compared to Logan (2002)



As the above figure shows, data sites with significant annual generation, both those very far offshore (Hotel) and those in outstanding near-shore wind regimes (Mt. Desert Rock), may offer roughly twice as much in terms of avoided emissions from onshore sites (Logan). Also, near shore sites that provide 50-60% more annual generation will offer 60-70% more avoided emissions than onshore sites. These changes must be tempered with whatever power transmission losses might occur getting power ashore, but relative differences remain fairly large.

In additional to the environmental benefits of reduced impact on ecosystems and human health, avoided emissions may be a potential source of revenue for clean energy generators. In the U.S., there are currently values for SO_2 and NO_x emissions offsets, though renewable power plants have no or little access to these markets. Further, many energy industry experts have suggested that a value for CO_2 offsets, in the form of a tax or a permit program, is likely in the future. Therefore, the emissions markets provide another potential source of revenue for renewable energy generators such as wind plants. Offshore wind resources, with their significant generation potentials year-round and their strong winter peaks, are well positioned to benefit from any offered monetization of these environmental externalities.

SIX: CONCLUSION

This study analyzed detailed temporal windspeed data over long time scales and a wide geographic area to assess the offshore wind resource in the Northeast and to investigate the potential economic and environmental performance of those resources. Drawing hourly data from a variety of sources allowed the research team to accurately capture offshore wind behavior and electricity industry dynamics and to better estimate the offshore resource potential. The main results of this study have been discussed in the body of the report, and supplemental results are included in the Appendix.

Our research confirmed our belief that to adequately address questions of offshore wind economic and environmental performance, *an understanding of temporal and spatial variability is necessary* in addition to long-term average values. Simply using annual average windspeeds to estimate overall electricity production may substantially over- or under- estimates annual generation. Using annual average windspeeds, even when knowing the statistical distribution of the wind, will not capture the seasonal dynamics and variability, especially in how they relate to wholesale market revenues and potential avoided emissions. Similarly, using emission rates from system-averaged fossil plants instead of load shape following units will likely misrepresent the amount of emissions avoided by introducing wind generation.

To accurately analyze the economic and environmental potential of the wind resource one must take into account time scales from annual (because some years are windier than others)—to seasonal (it is windier in winter but electric demand is highest in summer)—to hourly (it is windy at night when dirtier plants will be offset, but more cost effective in the middle of the day and evening when prices are higher). Further, the longer the time series of windspeed data collected, the more accurate the long-term windspeed average will be.

Our research verified, by using hourly windspeed data from 17 data sites, that there are better wind resources offshore than onshore, and that the winds generally get stronger further from shore. In addition, offshore winds can be more or less variable than onshore winds depending on the time scale. Generally, offshore winds are not only higher but also more variable than onshore winds for time scales from annual to hourly, and variability increases with distance from shore. While annual variation is less at higher average windspeeds, seasonal and hourly variations increase with higher average windspeed.

The impact of latitude on windspeed and variability was difficult to determine due to the relatively small number of comparable data sites in each region. However, it seems that offshore winds are slightly stronger in the Mid-Atlantic, while variability on all time scales is slightly larger in the Northeast. The impact of water depth was difficult to determine because of the site-specific conditions for each NOAA station.

While significant winds exist near shore, the highest winds occur far from shore. The offshore winds we analyzed may be up to 50% higher than the coastal onshore resources that exist in New England. Further, some offshore turbines may generate *up to* twice as much energy and revenue as onshore sites. Offshore turbines also may offset significant amount of emissions—*up to* twice as much as onshore ones.

Therefore, we believe there is significant revenue potential for offshore wind resources in the Northeast, but the net economic performance will depend on the costs of constructing and operating the wind farm. Also, strong winter offshore winds could produce major environmental benefits from avoided emissions from fossil power plants.

Due to the current knowledge surrounding offshore wind resource and the costs of developing wind farms further from shore and in deeper water, the research team had to make many assumptions for this analysis, both conservative and optimistic. The height scaling of windspeeds most likely under-estimates the windspeed at hub height, while the turbine availability, power output, and access to market likely over-estimate the generation and revenue. As there is a lack of consensus on many of these issues, there remains major uncertainty over several of the key assumptions and the impacts they may have on the results.

Future Research Needs

While this study covered a broad range of topics in the growing field of offshore wind, it also highlights a number of issues yet to be addressed. For example, determination of the appropriate height scaling method for windspeeds is an issue that needs to be resolved if accurate estimates of hub height windspeeds are to be made. Alternatively, more at-height windspeed measurement, coupled with long-term resource estimation, would benefit the wind community. Along these lines, the Measure-Correlate-Predict (MCP) methodology should be further investigated to determine its potential for filling in gaps in knowledge about sites' windspeeds.

Because this study only looked at one onshore data site (Logan, principally for use with the MCP technique), future studies would benefit from the use of more onshore data sites in order to get a better understanding of the range of onshore windspeeds and performance potential. To better appreciate the complexity of offshore wind farm operations, the European experience, and its associated data, should be made available to the wind community at large. More detailed resource maps and computer models should be created to help familiarize interested parties with the offshore resource potential.

Not surprisingly, the amount of emissions offset by renewable energy generators has been attracting increasing attention. As such, the methodologies for calculating these avoided emissions should be investigated further. The avoided emissions from offshore wind should be compared to those from other energy technologies (such as solar power), and clean energy generators should be considered for participation in existing and future emissions markets.

This OWC Pilot research project has focused exclusively on available windspeed, avoided emissions, historical electricity price and electricity demand data, and has shown that "the details matter." The same is likely to be true for parallel studies on marine ecosystem impacts, subsea sediments and geology, ocean sea state and other factors that impact the cost and viability of offshore wind at different locations.

Future policies (on research and development, environmental issues, and industry practices) aimed at facilitating the responsible development of offshore wind resources will need to take into account the need for such detailed factors, if offshore wind is to develop in a timely and cost-effective manner. This includes public and direct stakeholder involvement, as only such detailed analysis will provide communities with an understanding of the real costs and benefits of hosting offshore wind facilities. Since longer, more detailed time series information provides a considerable degree of insight on not only the costs and benefits of offshore wind energy, but also its associated variability and risks, leaving these topics to the project permitting process will be a detriment to both the wind industry and society. These issues need to be considered in the design and operation of institutions charged with overseeing the development of the offshore wind industry.

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