New England
Wind Supply Curve

Prepared by:

Sustainable Energy Advantage, LLC

Robert C. Grace

Mimi Q. Zhang

Jason S. Gifford

For:

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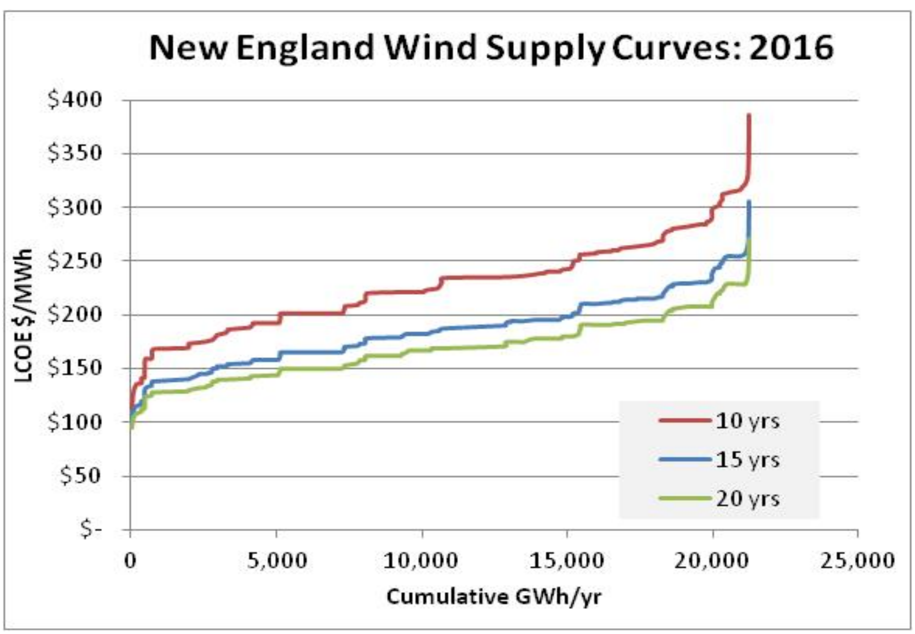
Notice

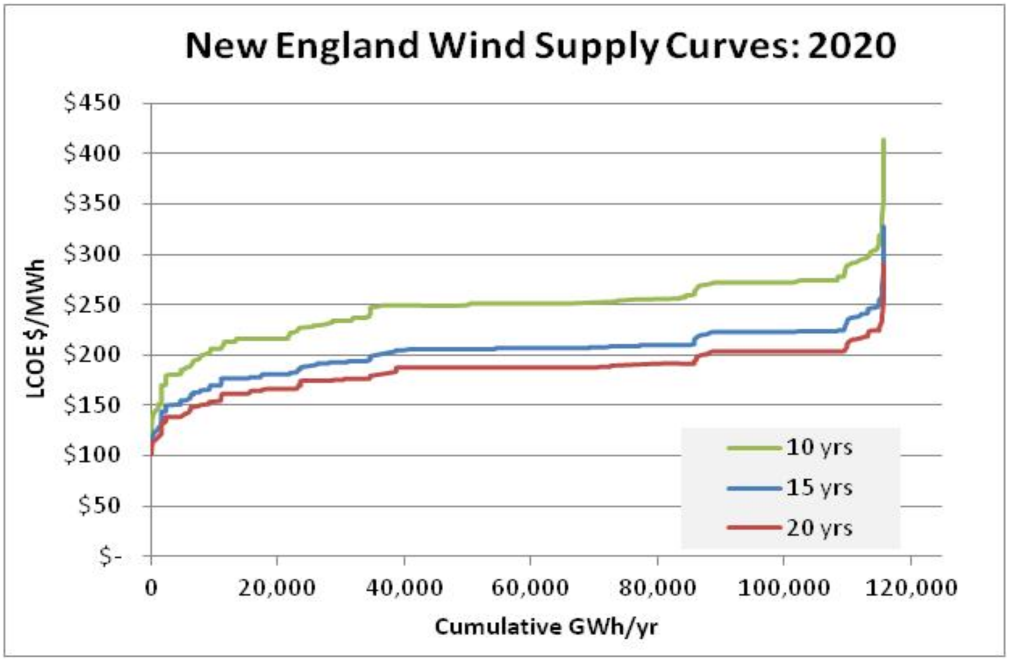
Executive Summary

The New England States Committee on Electricity (NESCOE) is seeking to develop a “baseline” of indicative costs for various representative renewable energy development scenarios in support of its exploration of coordinated competitive renewable energy procurement. To this end, NESCOE has retained Sustainable Energy Advantage, LLC (SEA) to provide an indicative ‘supply curve’ representing the cost and quantity of new on-and off-shore wind resources in New England. This report describes the results and process of developing the New England wind supply curve.

Six supply curves were derived, showing the levelized cost of energy (LCOE) and associated quantities of wind that may be available to New England assuming two different start years (2016 or 2020) and three different contract terms (10, 15, and 20 years). These baseline LCOEs assume no Federal financial incentives, and as described in the report, are built upon a series of conservative assumptions. This conservatism, discussed below, suggests several reasons that wind energy could be procured at prices below those indicated in these supply curves.

The graphs shown below represent the supply curve results for 2016 and 2020, respectively. Detailed supply curves indicating the type of wind generation (small, medium or large on-shore wind projects, and shallow or deep water offshore wind projects) are shown in the body of the report, as well as focused supply curves that concentrate on the quantities of energy that are most relevant to anticipated renewable energy needs of New England.





The supply curve analysis reveals some important high level conclusions including:

- Longer contract terms yield materially lower LCOEs.
- A few large onshore wind resources are the cheapest, but other medium and offshore wind resources are not far behind. Offshore wind (shallow and deep water) tends to be more expensive than the cheapest onshore wind, but is competitive with some of the medium scale to more expensive onshore resources.
- There is a large amount of potential supply when offshore and deep water wind is factored in. Even accounting for uncertainty in how much of the wind resources can be permitted and developed, and industry limits to the pace of wind development, the total quantities are far in excess of the quantities required to meet regional renewable energy demand.

Sensitivity analyses were conducted to explore the impact of three material underlying assumptions, each of which may cause actual contract prices to fall below the LCOEs shown in the supply curves. These assumptions include:

- **Federal Incentives**. The supply curve analysis results shown above assume that Federal tax incentives currently available to the wind industry expire. The sensitivity analysis indicates that if the current Federal Production Tax Credit (PTC) was extended under its current structure, LCOEs would decrease around $23 per MWh for 15 year contracts, with greater decreases for shorter-term contracts and smaller decreases for longer-term contracts.

- **Interest rates**. Current interest rates are at historic lows and these lower interest rates are allowing wind projects to be developed and built at present for lower contract prices than indicated in the supply curves, even after adjusting for Federal incentives. The supply curve LCOEs shown above were calculated based on debt financing assumptions representative of longer-term expectations regarding future economic conditions. The sensitivity analysis indicates that if interest rates remain at levels consistent with current conditions, LCOEs would be roughly $4 to $20/MWH less than indicated in the supply curves.

- **Taller Towers, Longer Blades**. The underlying wind dataset is based on wind speed measurements at a height of 80 meters. This height is a reasonable representation of the fleet currently operating. However, looking forward, wind developers are starting to move to taller towers and longer blades capable of capturing higher wind speeds and producing higher plant capacity factors when feasible or required to make project economics work. While not every project is able to (or will desire to) use higher towers and longer blades for a variety of reasons, projects that do so may have lower LCOEs, as the cost increases to move to taller towers and longer blades are modest compared to the increased production. For reasons described in the report, medium to large projects in the lower power ranges are most likely to pursue taller towers. A sensitivity analysis explored the impact of movement from 80 meters to 100 meters, and concluded that such a movement could result in LCOEs under 20 year contracts of $30/MWh or more below the LCOEs indicated in the supply curve (with even greater savings for shorter term contracts). While we believe this represents the upper limit to the cost reduction potential (since many projects may use towers in the 84 – 94 meter range, and because incremental equipment costs were not fully assessed in the sensitivity), it is clear that reliance on higher towers and longer blades could have a material impact on cost and is likely to occur where logistical and permitting concerns allow.

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1 Introduction

1.1 Background

The New England States Committee on Electricity (NESCOE) is a not-for-profit organization representing the collective interests of the six New England States on regional electricity matters. NESCOE advances policies that will provide electricity at the lowest possible price over the long term, while maintaining reliable electric service and environmental quality.[1]

NESCOE conducted a Request for Information (RFI) in early 2011, the responses to which provided the New England states with a reasonable basis to conclude, preliminarily, that coordinating the states' efforts with respect to the competitive procurement and delivery of renewable energy resources may enable the states to achieve their various objectives in a more cost-effective manner than if each state sought to independently satisfy all of their individual clean energy objectives. In July 2011, the six New England Governors adopted a Resolution which expressed the Governors' continued interest in exploring the potential for joint or separate but coordinated competitive procurement as a means to identify those renewable resources able to serve customers at the lowest over-all delivered cost. The Governors directed continued investigation into the potential for coordinated competitive procurement.

To meet that directive from the Governors, NESCOE is seeking to develop a "baseline" of indicative costs for various representative renewable energy development scenarios. To this end, NESCOE has retained Sustainable Energy Advantage, LLC to provide an indicative cost and quantity analysis associated with developing new on- and off-shore wind resources in New England and New York. Separately, NESCOE has commissioned RLC Engineering to provide indicative, high-level cost estimates associated with representative transmission development scenarios that could facilitate the delivery of energy from new renewable generators in New England. The resulting renewable resource supply curves for two study years, 2016 and 2020, will help signal to the states the potential ranges of "all-in" costs associated with meeting regional renewable goals and inform the next steps.

1.2 Purpose

The purpose of this report is to describe the results and process of developing the New England wind supply curve built by Sustainable Energy Advantage, LLC (SEA) for NESCOE. The supply curve models potential build-out for different types of wind resources (delineated by wind speed, location, project size, proximity to transmission, as well as on-shore or offshore) in 2016 and 2020, as well as levelized cost of energy (LCOE)[2] measured at the point of injection into the electric system[3]. To understand how supply potential and costs could vary over time, two different start years ((2016 and 2020)[4] were considered. To identify the potential variations in the costs associated with different contract terms, three different contract terms (10, 15, and 20 years) were considered.

[1] http://www.nescoe.com/

[2] LCOE is the fixed unit cost of energy, in $/MWh, that would allow the project to meet the investment criteria of the project's lenders and equity investors, if that amount were collected for each MWh produced over the contract term.

[3] This cost includes the cost of radial interconnection to the transmission system including stepping up to the voltage of the interconnecting line.

[4] The supply potential modeled in 2020 includes the supply potential available in 2016, as well as new supply expected to become available between 2016 and 2020.

Thus, a total of six sets of levelized costs were developed. All of these costs were developed assuming no Federal Production Tax Credit (PTC) or Investment Tax Credit (ITC) incentives. The underlying data represent wind speeds and quantities of wind land area at 80 meter hub heights.

These six supply curves will give NESCOE an idea of:

- the total amount of developable wind in New England;
- how that total grows between 2016 and 2020
- how the total potential is broken down between the different supply blocks[5];
- the LCOE associated with the available supply, assuming that Federal incentives expire according to current law;
- the quantities of wind potentially available at different prices (or alternatively, the marginal cost of procuring various quantities of wind power);
- how different contract terms affect LCOE;
- how the expected LCOE differs between projects starting in 2016 vs. 2020;
- the sensitivity of the results to continued availability of today's Federal incentives (specifically, the Production Tax Credit);
- the sensitivity of the results to continued availability of debt at today's historically low interest rates; and;
- the sensitivity of annual capacity factors and associated LCOE to the recent movement to more frequent use of towers higher than 80 meters.

1.3 Organization of this Paper

Section 2 discusses the key results of the supply curve analysis.

Section 3 summarizes the methodology used to develop the New England wind supply curves.

Section 4 provides information on key assumptions and describes the data sources used in developing the New England Wind supply curves.

Finally, Section 5 provides illustrative results under three critical sensitivities to (i) continued availability of Federal tax incentives, (ii) continuation of low interest rates, and (iii) greater use of taller towers.

[5] A supply block is a grouping of potential wind resources with similar geographic, wind profile and cost characteristics. SEA's analysis identified a total of 141 wind supply blocks within New England.

2 Results

In this study, we have developed a projection of potential supply quantities (in GWh per year) and levelized cost of energy (LCOE) for both onshore and offshore wind in New England. Wind potential was considered for different wind speeds, project sizes, distances from interconnection points, and water depths for offshore projects. Onshore wind sizes were broken down into three categories: small (up to 20 MW), medium (20-100 MW), and large (100+ MW)[6]. Offshore wind was categorized as shallow water (within 30m depth) and deep water (more than 30m depth), which are likely to use different foundation technologies. Each grouping of technology and size was further segregated by 'wind power factor' (a representation of power in the wind at that location), and by distance from the transmission system. Each of these small groupings is a "supply block" and is represented in the following charts as a single data point (note that some supply blocks with identical LCOEs will appear as a single merged data point).

2.1 Conclusions & Observations

The supply curve analysis reveals some important high level conclusions including:

- There is a large amount of potential supply when offshore and deep water wind is factored in. Even accounting for uncertainty in how much of the resource potential can ultimately be permitted, the total developable wind resources greatly exceeds the quantities required to meet likely regional needs for incremental renewable energy.
- Longer contract terms lead to significant cost reductions. The higher LCOEs for shorter contract terms are in large part driven by the need to amortize much of a project's fixed capital costs over a shorter contract term. In turn, this need to amortize most of the capital costs during the contract terms arises from the lower and more uncertain market-based revenues after the contract term.[7]
- Due to scale economies, large onshore wind blocks typically have the lowest LCOEs, but medium onshore blocks and various offshore blocks for comparable wind speeds are not far behind. Offshore wind (shallow and deep water) tends to be more expensive than the cheapest onshore blocks, but is competitive with some of the medium scale onshore blocks.
- As discussed below, the capital costs of off-shore wind projects are expected to decline over time in absolute terms and relative to the capital costs of on-shore wind projects. Thus, the difference in LCOEs between on-shore wind resources and off-shore wind resources will decline, and by 2020, off-shore wind may become competitive on the margin with onshore resources in New England.

2.2 Scenarios

The nominal LCOE of all supply blocks was modeled using National Renewable Energy Laboratory's (NREL) Cost of Renewable Energy Spreadsheet Tool (CREST) model under six different scenarios. These six scenarios were

[6] Community-scale and distributed generation projects were ignored for the purposes of this study, as the underlying wind data set was not developed at a sufficient level of granularity. These resources, if modeled, would add hundreds of MW to the supply curve. Many of these projects are being driven by state incentive programs and/or net metering regulations, and therefore are unlikely to be contributors to the type of coordinated procurement activities being considered by the New England states.

[7] Assumptions regarding market revenues after the contract term, and the resulting estimate of post-contract project value, are discussed further below.

developed from the two different years for the starting date of the contract (2016 and 2020), and three different contract terms (10, 15, and 20 years). The resulting supply curve quantities and costs for each scenario are shown graphically in following six sections. The results shown in each section assume that Federal incentives currently available to wind projects- Production Tax Credit (PTC), Investment Tax Credit and Cash Grant in lieu of Investment Tax Credit, have all expired at the end of 2012, their current sunset date. Section 5.2 considers the reductions in LCOE that would result from a long-term extension of the PTC.

2.3 Supply Curve for 2016, 10 Year Contracts

A supply curve shows the cost of energy for increasing quantities. Available supply is sorted from lowest cost to highest cost. A supply curve can be used to find the marginal cost for a particular volume of wind. The supply curve for 2016, showing the LCOE that would be expected for 10-year contracts, is shown in Figure 1.

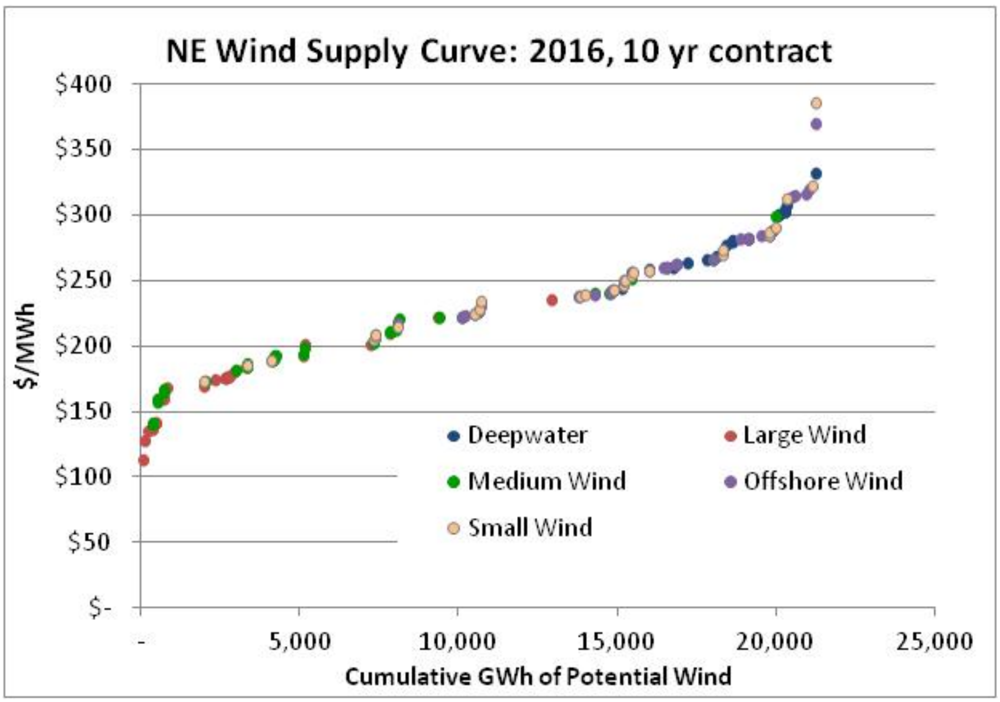

Figure 1

The amount of wind potential available, particularly considering the vast amount of offshore wind potential, greatly exceeds the quantities that may be considered for coordinated state procurement in this time frame. As a result, the 'big picture' above provides 'excess' information, since New England's incremental renewable energy needs in 2016 are unlikely to exceed 7,000 GWh per year. Therefore, we also provide a depiction of the first 7,000 GWh/year of wind potential in Figure 2, in order to better illustrate the portion of the supply curve of greatest relevance.[8]

[8] At a notional capacity factor of 30%, an annual energy production of 7,000 GWh would correspond to approximately 2,700 MW of installed wind capacity.

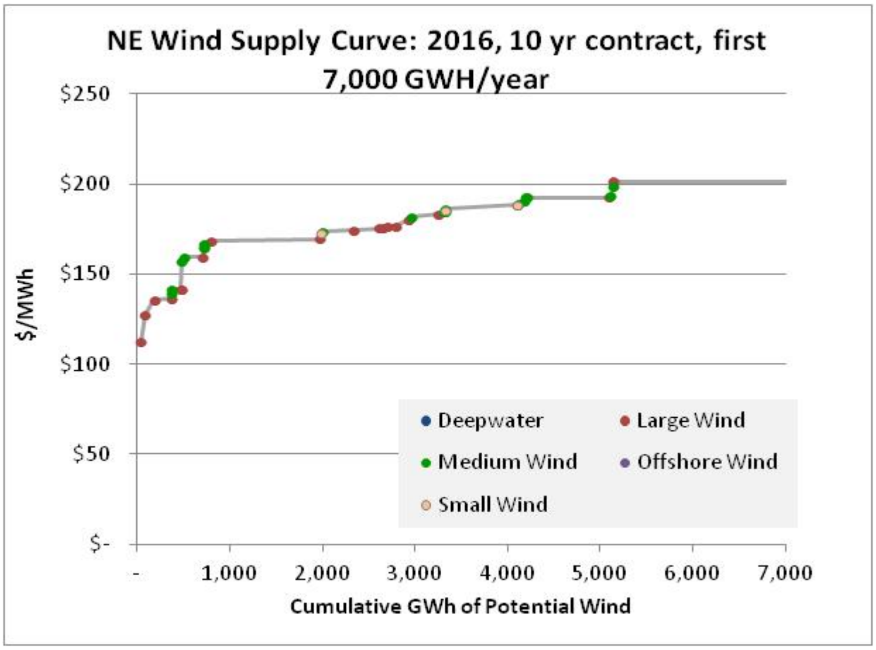

Figure 2

Figure 2 shows that LCOE ranges from around $110 to $200/MWh (in nominal dollars) for the first 7,000 GWh of potential new supply in 2016 under a 10 yr contract term, and includes a mixture of all sizes and technology types with the exception of Offshore Wind. Large Onshore Wind is the cheapest resource, although other onshore wind can have LCOEs that place it within the first 5,000 GWh of cheapest wind resource. Offshore wind[9] is found at around 10,000 GWh on the supply curve.

2.4 Supply Curve for 2016, 15 Year Contracts

The supply curves for 2016, showing the LCOE that would be expected for 15-year contracts, are shown in Figure 3 for the full supply curve and Figure 4 for the first 7,000 GWh/yr[10]. These graphs show that LCOE ranges from under $100 to about $165/MWh for the first 7,000 GWh of potential new supply in 2016 under a 15 yr contract term and includes a mixture of all land-based technology types. This is $10-35/MWh lower than the LCOE range for 10 year contracts. Large Onshore Wind is the cheapest resource, but all other onshore technologies and offshore wind can have LCOEs that place it within the first 10,000 GWh of cheapest wind resources.

[9] As references in these results, "offshore wind" represents development using monopole foundations in depths of less than 30 meters; "deep water" represents offshore wind installations in greater depths.

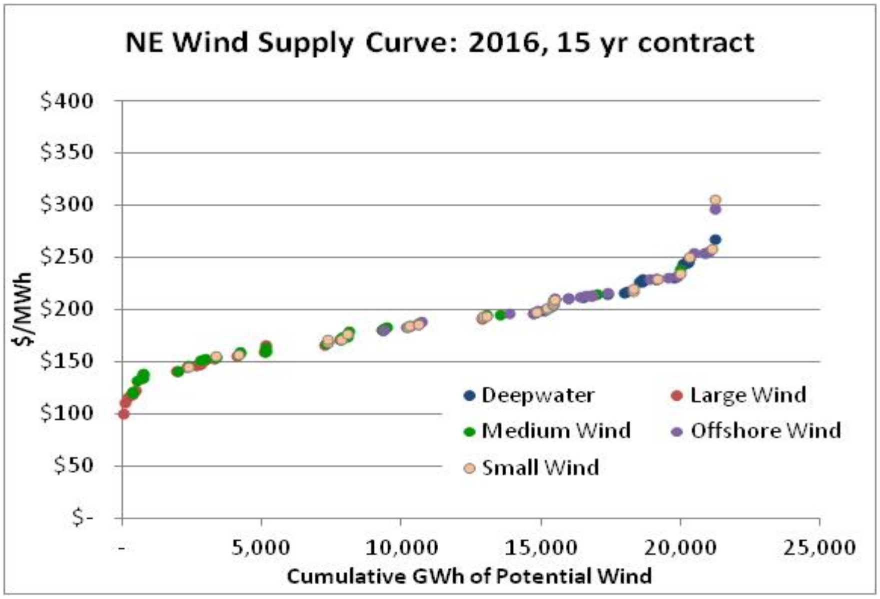

Figure 3

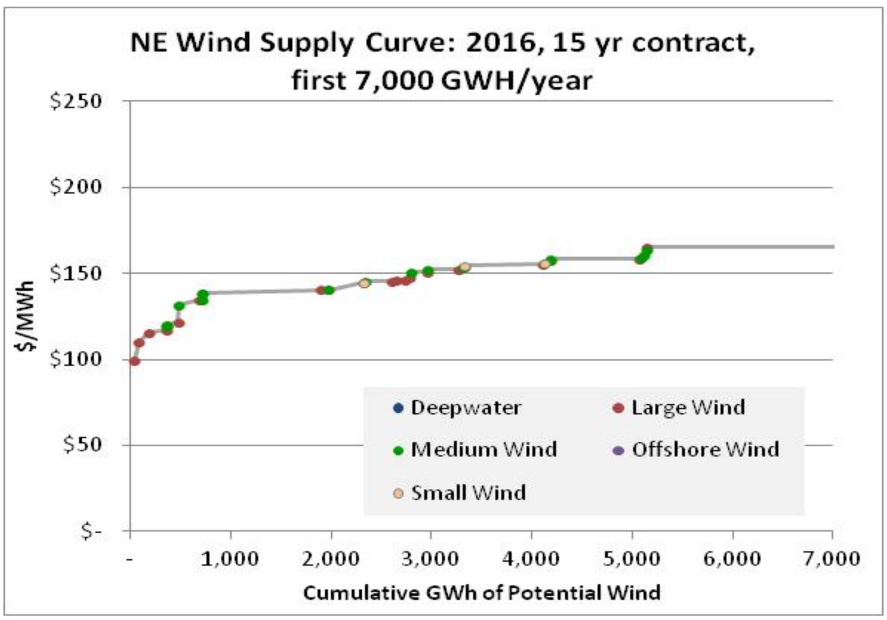

Figure 4

While the longer contract term reduces the LCOEs of all supply blocks, the reductions are not equal, since the relative benefits of a longer contract term can differ between supply blocks with different cost characteristics. Supply blocks with higher unit capital costs may realize greater reductions in LCOE than supply blocks with lower unit capital costs. For example, a medium sized on-shore supply block with higher unit capital costs but good wind characteristics could be less expensive than a large on-shore supply block with lower unit capital costs but poor wind characteristics. A shift to longer contract terms can affect the mix of supply blocks in the lower portions of the supply curve, as well as the overall magnitude of the LCOE. This shift in the relative order of supply blocks is also seen for the 20 year contract term, and for the different contract terms of projects entering service in 2020.

2.5 *Supply Curve for 2016, 20 Year Contracts*

The supply curves for 2016, showing the LCOE that would be expected for 20-year contracts, are shown in Figure 5 for the full supply curve and Figure 6 for the first 7,000 GWh/yr.

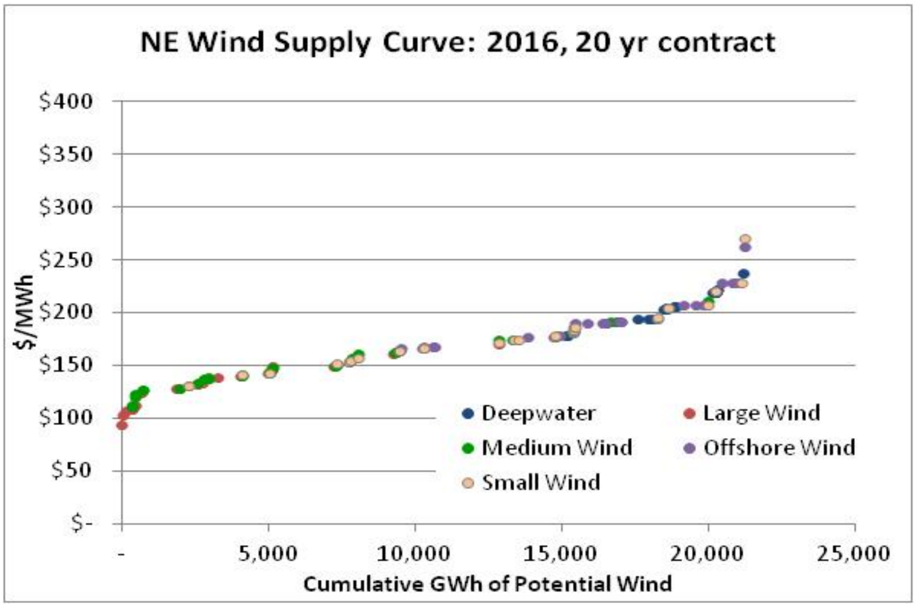

Figure 5

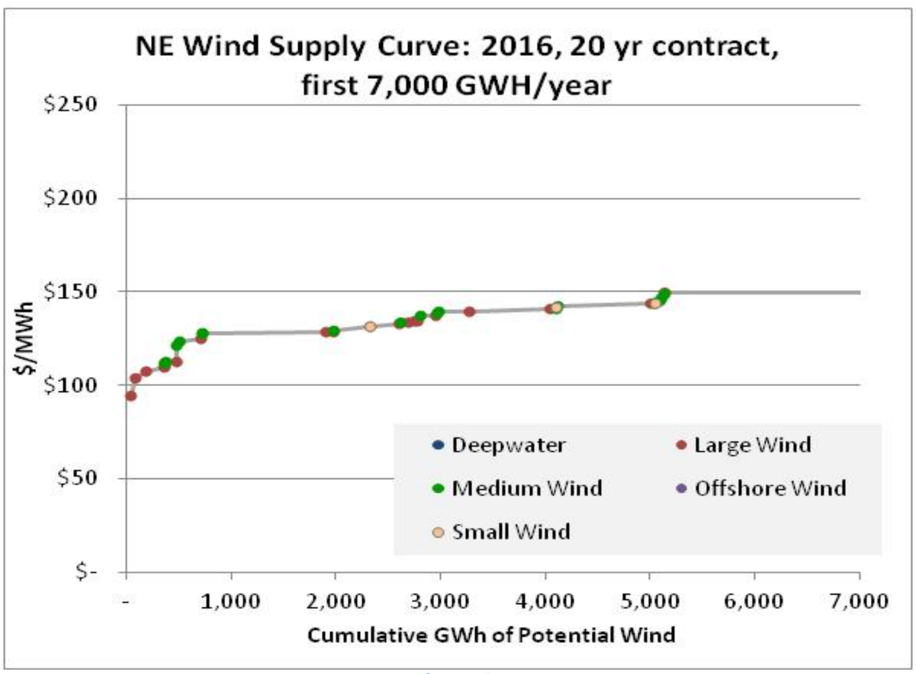

Figure 6

These graphs shows that LCOE ranges from $90-$150/MWh for the first 7,000 GWh of potential new supply in 2016 under a 20 yr contract term and includes a mixture of all land-based technology types. This is $10-15 lower than LCOEs for the 15 year contract term and $20-50 lower than LCOEs for the 10 year contract term.

2.6 Supply Curve for 2020, 10 Year Contracts

A second set of supply curves was developed for procurement in 2020. By 2020, a far greater quantity of resources is developable[11]. As with the 2016 results shown in the prior sections, we provide a set of supply curves that focus on the least costly 12,000 GWh/yr[12], to highlight the range that is most relevant to NESCOE's coordinated procurement analyses. The supply curves for 2020, showing the LCOE that would be expected for 10-year contracts, are shown in Figure 7 for the full supply curve and Figure 8 for the first 12,000 GWh/yr.

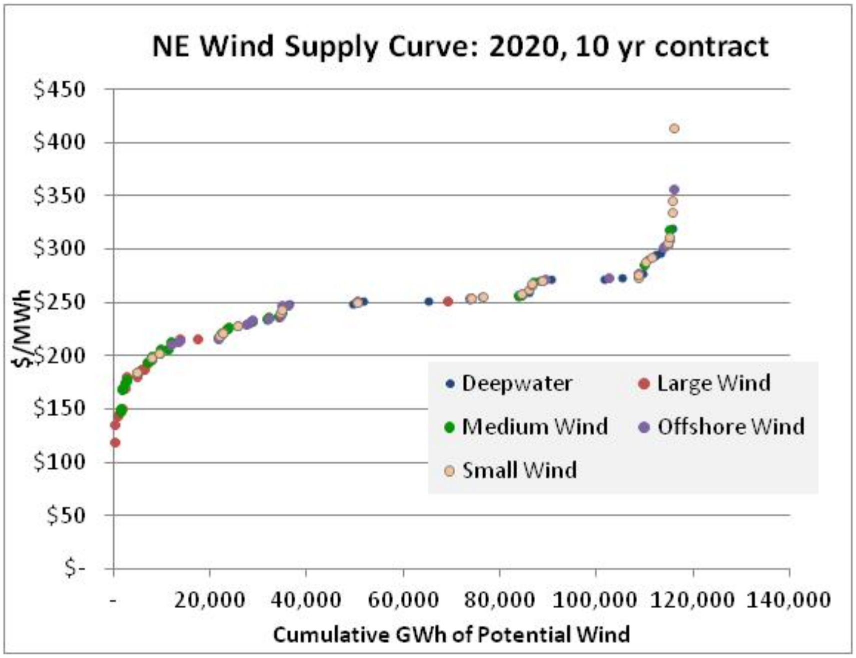

Figure 7

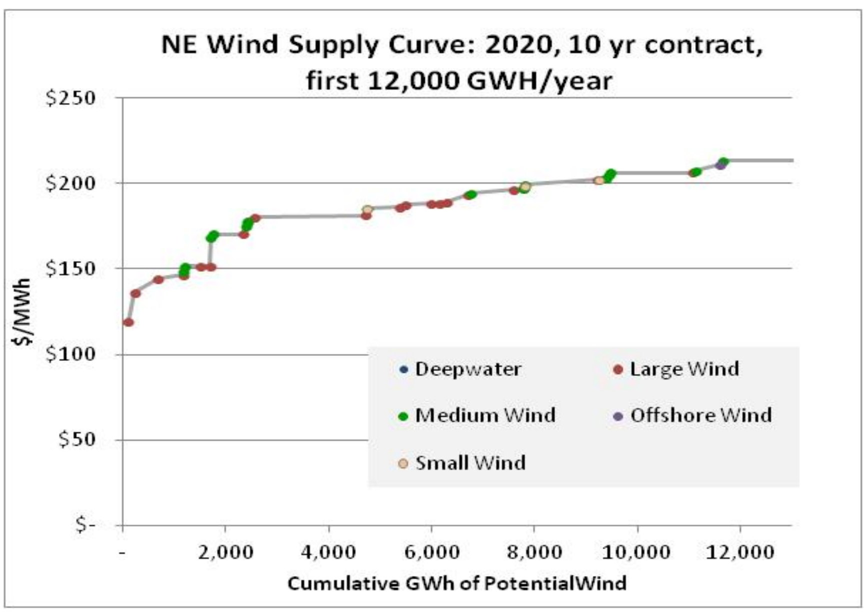

Figure 8

[11] The quantity of resources available in each study year (2016 and 2020) represent what could be developed in that year assuming no new development from what is currently operating or under construction. Section 19 explains phase-in of wind potential in greater detail.

[12] Approximate estimate of total new renewable energy demand in 2020, beyond current resources.

These graphs show that LCOE ranges from $120-$215/MWh for the first 12,000 GWh of potential new supply[13] in 2020 under a 10 yr contract term and includes a mixture of all technology types with the exception of Deep Water Offshore Wind, which comes in just before 30,000 GWh. Large Onshore Wind is the cheapest resource, but other onshore technologies and even offshore wind can have LCOEs that place it within the first 12,000 GWh of cheapest wind resource. Large Wind and Offshore wind dominate supply between 10,000 and 20,000 GWh, with Offshore and Deep Water Offshore Wind dominating in the 20,000 GWh+ range.

2.7 *Supply Curve for 2020, 15 Year Contracts*

The supply curves for 2020, showing the LCOE that would be expected for 15-year contracts, are shown in Figure 9 for the full supply curve and Figure 10 for the first 12,000 GWh/yr.

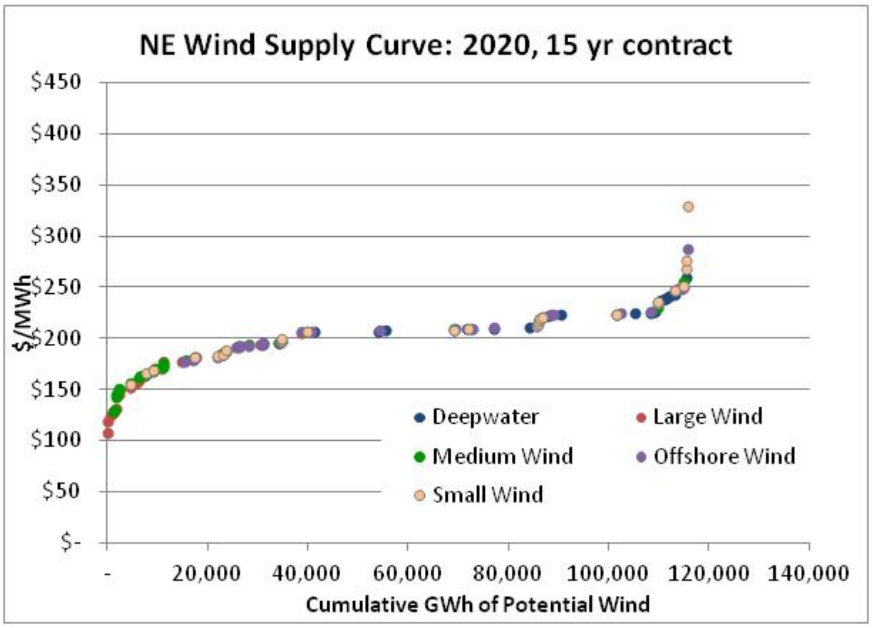

Figure 9

[13] The 2020 supply curves include supply represented in the 2016 supply curves as well as incremental resource potential that is expected to become available between 2016 and 2020.

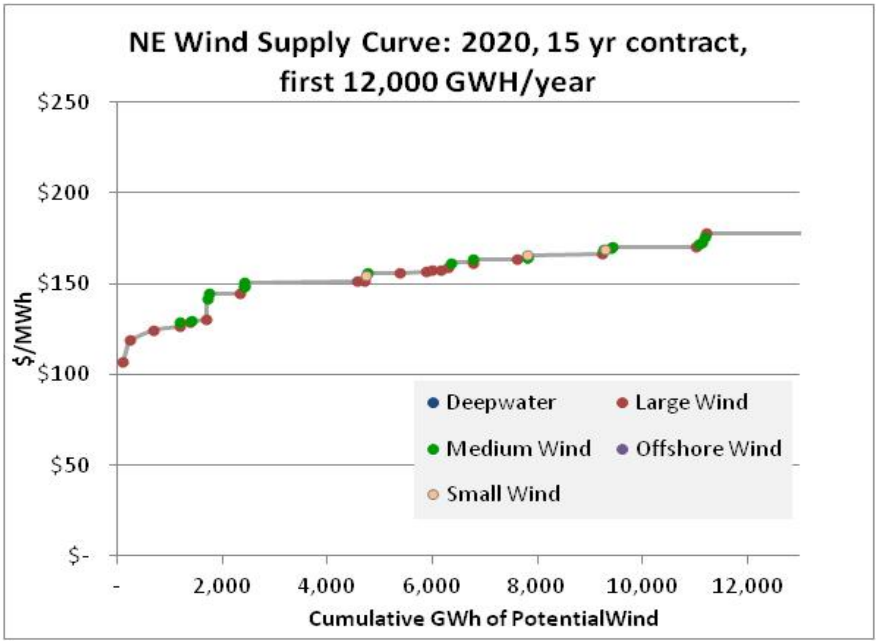

Figure 10

These graphs shows that LCOE ranges from $110-$180/MWh for the first 12,000 GWh of potential new supply[14] in 2020 under a 15 yr contract term and includes a mixture of all land-based technology types. This is $10-35/MWh lower than LCOEs with a 10 year contract term. Large Wind and Offshore wind dominate supply between 10,000 and 20,000 GWh, with Offshore and Deep Water Offshore Wind dominating in the 20,000 GWh+ range.

2.8 Supply Curve for 2020, 20 Year Contracts

The supply curves for 2020, showing the LCOE that would be expected for 20-year contracts, are shown in Figure 11 for the full supply curve and Figure 12 for the first 12,000 GWh/yr.

[14] The 2020 supply curves include supply represented in the 2016 supply curves as well as incremental resource potential that is expected to become available between 2016 and 2020.

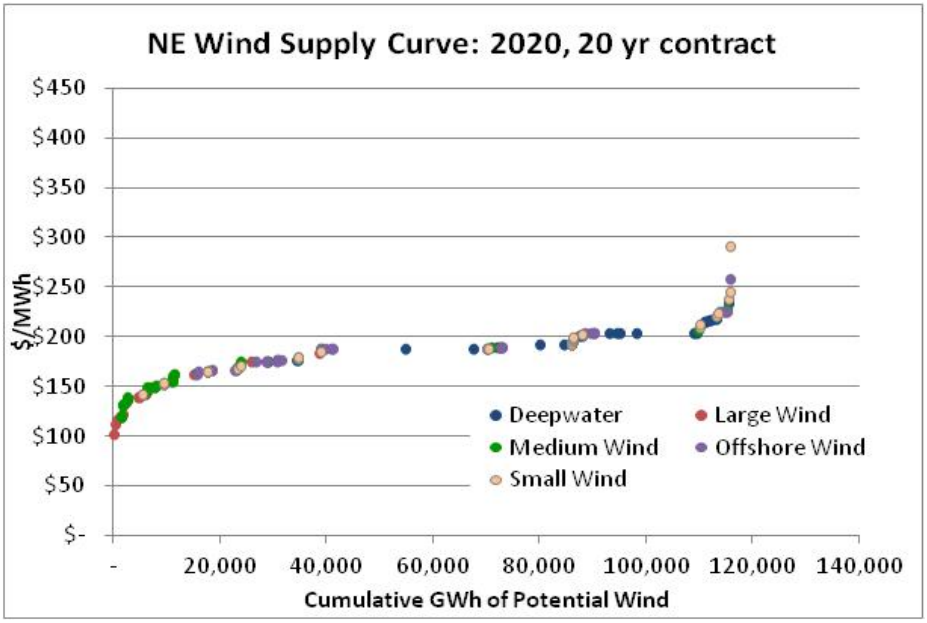

Figure 11

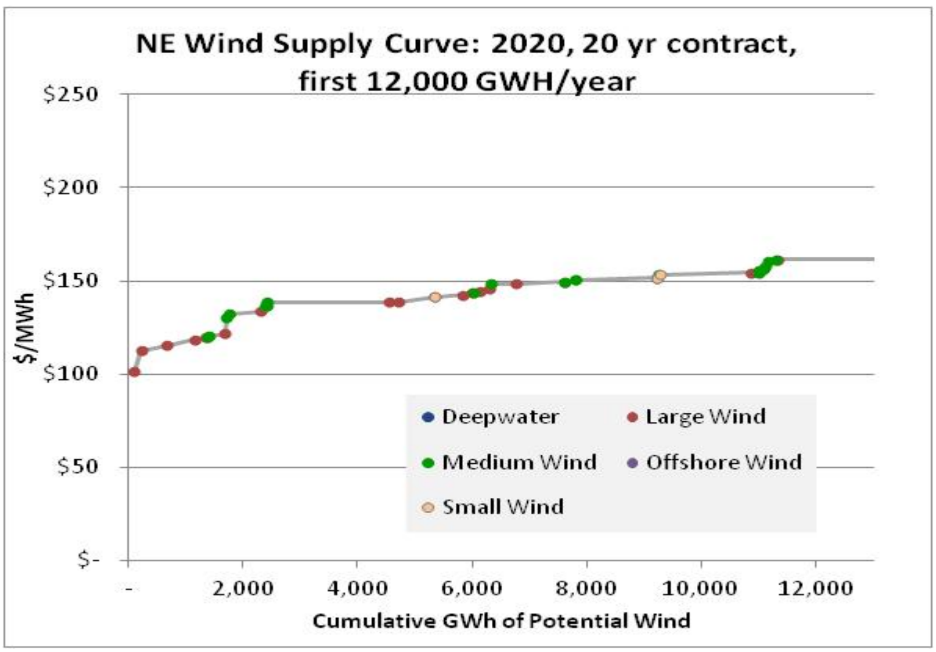

Figure 12

These graphs show that LCOE ranges from $100 to $165/MWh for the first 12,000 GWh of potential new supply[15] in 2020 under a 20 yr contract term and includes a mixture of all land-based technology types. This is about $10-15/MWh lower than the LCOE spread for projects in 2020 with a 15 year contract term. Large Wind and Offshore wind dominate supply between 10,000 and 20,000 GWh, with Offshore and Deep Water Offshore Wind dominating in the 20,000 GWh+ range.

[15] The 2020 supply curves include supply represented in the 2016 supply curves as well as incremental resource potential that is expected to become available between 2016 and 2020.

3 Methodology

The NESCOE supply curve was constructed in a manner similar to that used by SEA in a number of other studies: SEA's New England Renewable Energy Market Outlook (REMO) market fundamentals analysis, the Maine Governor's Task Force, and several state Renewable Portfolio Standards (RPS) supply cost studies. The core methodology focuses on dividing New England's wind potential into a number of supply blocks, each defined by different combinations of geographic location, wind power density and resultant capacity factor, project scale (based on contiguous wind land area) and proximity to transmission. Each supply block is then associated with a 'cost profile'. In turn, a cost profile is characterized by a notional wind project size, and typical capital and operating costs (which in turn depend on location, size and distance to transmission). For each supply block, a levelized cost of energy is calculated for each start year (2016, 2020) and contract term (10, 15, and 20 yrs), based on the associated cost profile and the supply block's capacity factor. SEA utilized public available data where possible for maximum transparency, including using the publicly-available CREST model. The CREST model described further in Section 3.5, was developed by SEA for NREL to calculate levelized cost of energy under various assumptions.

3.1 Supply "Blocks"

Resource blocks were developed by allocating the total potential regional supply for both on-shore and off-shore wind into 141 blocks with common characteristics:

-Geographic location (state, and on-shore vs. off-shore)
-Typical Project Size (for on-shore resources)
-Water Depth (for off-shore resources)
-Wind Quality
-Distance from Transmission
-Expected Capacity Factor

All blocks were initially delineated by state, then by distance from transmission. Blocks were also characterized by wind power density[16] and project size. Where the underlying wind potential analysis showed very small quantities of wind land area with a particular power density, some wind land area was condensed into composite blocks that combine smaller supply blocks with different power densities. Thus, the composite blocks use averaged power densities.

Blocks are defined at a 'typical' project size for purposes of spreading fixed costs (e.g. interconnection) over an associated volume of energy production. The supply curve does not require that the amount shown in a given year for a given block equal or exceed the typical project size. This approach is consistent with the fact that actual projects often span different wind speed classes.

3.2 Quantity (Nameplate MW)

The total quantity potential (in nameplate MW) for each supply block was estimated by taking into account total land area in each block, and then making three sets of adjustments. First, certain land use categories were completely excluded from consideration as incompatible with wind development. Such land use categories

[16] Wind Power Density, in units of Watts/m^2, is a measure of the power in the wind. It is a function of both wind speed and air density. Air density is in turn a function of elevation, temperature and humidity. The higher the air density, the higher the power output predicted from a wind turbine for a given wind speed. Since air density differs at different elevations, the use of power density is a somewhat more accurate determinant of wind project output than is the wind speed alone. The area in the expression represents the swept area of the blades.

included airports, cities, national parks, etc. A set of secondary exclusions was applied to the remaining windy land area to reduce the maximum feasible generation in land use categories for which development is expected to be challenging. Different levels of such derating were applied to different land use categories (*e.g.,* some land use categories were fully excluded from development, while other land use categories were only partially excluded). This step addresses the reality that wind projects cannot be sited on all available land. The remaining land quantity was then converted to MW potential using a development density assumption, which is a MW/km^2 conversion from raw wind analysis procured from AWS Truepower (AWST). Finally, an "ability to permit" derating factor was applied to reflect the expected influence of various siting and permitting challenges, further reducing the available supply.

The total potential MW for each block represents the final total wind power that each block area can support. A phase-in schedule was developed to reflect the inability to build all supply potential overnight. This schedule was somewhat subjective, but based on assessment of several factors, including historic rate of build for wind projects, the capacity of industry installation capability, and project development lead times.

In order to assure that there was no double counting of wind generation potential, SEA identified all wind generation that is either currently operating or under construction, assigned it to a corresponding block, and subtracted that 'committed capacity' from the projected resource potential.

3.3 Performance

For each wind power class in each state, an associated annual average capacity factor was developed to represent the mean expected annual production. Each block was assigned a corresponding capacity factor that was used to estimate its annual energy production (in GWh/yr).

3.4 Cost Inputs

Cost assumptions were used as inputs in the CREST model to calculate the LCOE for each typical project in each supply block. There were three cost components:

- Installed Capital Cost, excluding the cost of interconnection, on a $/kW basis. This category includes all categories of hard and soft costs typically financed upon a project's date of initial commercial operation, including construction interest, financing fees, engineering and permitting costs, etc.

- Operations and Maintenance (O&M): inputs for both variable and fixed O&M costs were developed for each supply block. This category includes all cost categories not included in Installed Capital Costs, including property taxes, site lease/royalty payments, and insurance.

- Direct Interconnection Costs: these costs were estimated as a function of (a) distance from the point of interconnection to the transmission system and (b) project size, and each project was assumed to require both substation and line costs. Assumptions vary depending on the size of the project, different voltage requirements and substation costs.

3.5 Cost of Renewable Energy Spreadsheet Tool (CREST)

The Cost of Renewable Energy Spreadsheet Tool (CREST) was developed by SEA for NREL. CREST has three technology-specific versions, including one for wind energy.[17] Inputs to the CREST model include capital and

[17] The model and supporting documentation are available at the NREL web site. http://financere.nrel.gov/finance/content/CREST-model

operating costs, system performance, and incentive and financing parameters. Model outputs include the cost of energy on a levelized basis.

CREST was developed as a publicly available and transparent tool to aid policymakers in estimating renewable energy cost of energy for various public policy purposes, such as establishing performance based incentives including feed-in-tariffs. The model is designed to calculate the cost of energy, or minimum revenue per unit of production needed, required for the modeled renewable energy project to meet its equity investors' assumed minimum required after-tax rate of return. As the model was developed in Microsoft Excel, it offers the user a high level of transparency including full comprehension of the underlying equations and model logic.

The CREST model allows the user to specify varying levels of capital and operating cost detail. With respect to capital costs, CREST allows the user a range of input options from a simple $/kW value to a highly detailed cost component list. For this analysis, the "intermediate" approach was selected allowing for separate modeling of installed cost components for generation equipment and interconnection. The CREST model also allows the user to easily conduct sensitivity analyses, including variations in incentive payment durations, and the ability of equity investors to efficiently utilize tax incentives.

3.6 Levelized Cost of Energy

For each combination of in-service year and contract term, the LCOE for each supply block was calculated using the CREST model, which models the LCOE as the expected unit price under a long-term contract. In addition to cost and performance inputs described above, the calculation of LCOE on a nominal dollar basis required assumptions for:

- Capital structure (percentage of debt versus equity, while assuming a single mortgage-type loan for debt financing)
- Cost of capital (cost of debt, threshold after-tax return required by equity investors)
- Incentives assumptions (the base LCOEs were calculated without any Federal or state incentives)
- Depreciation
- Decommissioning
- Lender Debt Service Coverage requirements
- Post-contract revenue assumptions.

CREST modeling of LCOE is a simplified representation of project cash flows. While CREST does not reflect the level of detail used by developers for project finance purposes, it has been thoroughly vetted in development for NREL, and is considered to provide a good approximation of LCOE for policy analysis purposes. Furthermore, CREST is capable of modeling inputs at a simple, intermediate or complex level of detail. For purposes of this study, we have used a combination of simple and intermediate inputs, reflective of a representative financing structure and use of cost input assumptions based on aggregated project cost data, rather than detailed component-level cost estimates.

4 Detailed Assumptions / Data Sources

4.1 Supply Blocks

The specific number, type and characterization of supply blocks depend on the factors described below. Block names include shorthand notation for wind power class and distance from transmission.

On-shore Wind

Characteristics of on-shore supply blocks included:

- **State**
- **Size:** one of three classes of project size:
  - Small: < 20MW
  - Medium: 20-100MW, or
  - Large: > 100MW.
- **Distance from Transmission:** distance from each group of wind resource to the closest transmission line of 69 kV or higher, classified as one of four distances:
  - T1: 0-5 Miles
  - T2: 5-10 Miles
  - T3: 10-20 Miles
  - T4: 20+Miles.
- **Wind Speed:** by power class (which takes into account air density) at 80 meters:
  - Power Range 0: 300-400 W/m^2 *(used in Maine only)*[18]
  - Power Range 1: 400-500 W/m^2
  - Power Range 2: 500-600 W/m^2
  - Power Range 3: 600-700 W/m^2
  - Power Range 4: 700-800 W/m^2
  - Power Range 5: > 800 W/m^2

Offshore Wind

Blocks were defined for:

- **State**
- **Depth**: Shallow (<30 m) vs. deep (> 30 m)
- **Distance from Transmission:** distance from each group of wind resources to shore, classified as one of three distances:
  - T1: 0-3 Nautical Miles
  - T2: 3-12 Nautical Miles, and
  - T3: 12-50 Nautical Miles).
- **Wind Speed:** by wind class at 90 meters:

[18] This is a limitation of our dataset, but also represents the larger areas in Maine being considered for development with wind at lower wind speed than being explored for grid-scale wind development in other New England states. To be economically viable at such low wind speeds, a project needs to be larger than is likely to be feasible in any New England state other than Maine.

Class	wind speeds (m/s)	Approx. Equivalent Power Density (@ sea level, 15^{O} C)
1	7.0 - 7.5	219-269 W/m^2
2	7.5 - 8.0	269-326 W/m^2
3	8.0 - 8.5	326-392 W/m^2
4	8.5 - 9.0	392-465 W/m^2
5	9.0 - 9.5	465-547 W/m^2
6	9.5 - 10.5	547-738 W/m^2

4.1.1 Raw Windy Land (and Sea) Area

The data sets representing windy land area on land or sea identify the square kilometers (km^2) in each category identified above. The underlying data comes from two distinct sources. On-shore wind was based on an analysis developed for SEA by AWST in late 2007, for use in a study presented to the Maine Governor's Wind Energy Task Force. The data was based on 80 meter wind data characterized on a 200 m resolution Geographic Information System (GIS) grid. A standard minimum distance of 500 m was applied to abutters to account for setbacks, and the remaining land was grouped into 'developable' regions of at least 1 km^2 in size. The offshore data was derived from National Renewable Energy Laboratory's 2010 Offshore Wind Report.[19]

4.1.2 Progressive Reduction in Developable Wind Capacity (Exclusions)

A series of exclusions were applied to the onshore raw wind data. First, a 100% exclusion layer was applied to remove much of the wind land area from further consideration. It was assumed that no wind would be built in regions matching the criteria shown in Table 1.

[19] W. Musial and B. Ram, Large-Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers, National Renewable Energy Laboratory (Sept. 2010). Available at http://www.nrel.gov/wind/pdfs/40745.pdf. The study's authors provided us with underlying data and assumptions used in developing supply curve model inputs.

Table 1 –Land Use Categories Subject to 100% Exclusion[20]

	NREL Analysis	AWS/SEA/LCA Analysis
Protected Lands		
National Historic Preserves	100%	100%
Natural Resource Land	100%	100%
Wildlife Management Areas	100%	100%
State Parks	100%	100%
State and Local Parks	100%	100%
National Historic Parks	100%	100%
National Recreation Areas	100%	100%
National Monuments	100%	100%
National Wildlife Refuges	100%	100%
National Park Service Land	100%	100%
Fish and Wildlife Service Lands	100%	100%
State Parks, Recreation & Historic Lands	100%	100%
Land Use/Land Cover		
Urban Areas	100%	100%
Wetlands & Water bodies	100%	100%
Large Airports	100%	100%
Medium Airports	100%	100%
Small Airports	100%	100%
Existing Wind Farms	NA	100%
Slopes > 20%	100%	100%

Secondary Exclusions

The land area remaining after the first exclusion was then subject to secondary exclusions. SEA developed additional derating factors to further reduce the windy land area in various 'secondary exclusion' land use categories. This additional reduction reflects the reduced likelihood of development in the areas meeting the applicable descriptions. The secondary exclusion classifications and assumptions are described in Table 2. To prevent duplication in classifying the secondary exclusion classes, the land area for Bureau of Indian Affairs, Department of Defense, Forest Service and State Forest lands were first calculated, followed by the remaining areas. A two mile buffer was applied to the Appalachian Trail (AT). All remaining land area was grouped into either ridgecrest (land with a slope of more than 20%) and non-ridgecrest areas, with further allocation to forest, agricultural, grassland and other land use categories. The tables below show reductions applied to each type of land for exclusions.

[20] 100% refers to the amount of land that is not available for development

Table 2: Assumption for On-Shore Wind Reductions to Available Potential

	NREL Analysis	This Analysis Excludes…	Notes
Indian Affairs	NA	0%	Projects proposed on Indian lands
Department of Defense	50%	50%	
National Forest	50%	50% (VT=75%)	VT given higher exclusion percentage due to greater permitting challenges
State Forest	50%	50% (VT=75%)	VT given higher exclusion percentage due to greater permitting challenges
Appalachian Trail 2-mile buffer region	NA	100%	Proximity to AT has caused controversy; 2 mile buffer modeled
Ridgecrest: Forest	NA	50% (VT=75%)	VT given higher exclusion percentage due to greater permitting challenges
Ridgecrest: Agricultural	NA	25%	Low exclusion percentage due to favorable view of wind power on agricultural land
Ridgecrest: Grassland	NA	50% (VT=75%)	VT given higher exclusion percentage due to greater permitting challenges
Ridgecrest: Other	NA	50% (VT=75%)	VT given higher exclusion percentage due to greater permitting challenges
Non-Ridgecrest: Forest	50%	50% in ME, VT, NH, CT; 75% in MA and 100% in RI	Higher exclusion percentage in MA and RI to exclude Martha's Vineyard and Block Island
Non-Ridgecrest: Agricultural	NA	0% everywhere but RI, 100% in RI	Higher exclusion percentage RI to exclude Block Island
Non-Ridgecrest: Grassland	NA	25% everywhere but RI, 100% in RI	Higher exclusion percentage RI to exclude Block Island
Non-Ridgecrest: Other	NA	25% everywhere but RI, 100% in RI	Higher exclusion percentage RI to exclude Block Island

To illustrate, Table 3 shows the impact on application of secondary exclusions for wind potential in Maine.

Table 3: Maine Impact of Secondary Exclusions

	Total Land Area with Wind Potential (km^2)	Land Area after Reductions due to Secondary Exclusions(km^2)
Indian Affairs	0.04	0.04
Department of Defense	13.64	6.82
National Forest Service Land	0.00	0.00
State Forest Land	10.16	5.08
Appalachian Trail Buffer	158.84	0.00
Ridgecrest		
Forest	50.72	25.36
Agricultural	0.00	0.00
Grassland	0.00	0.00
Other	1.72	0.86
Non-Ridgecrest		
Forest	709.16	354.58
Agricultural	34.92	34.92
Grassland	14.04	10.53
Other	227.08	170.31
Grand Total	1,220.32	608.50

Exclusions were not applied directly to offshore wind potential due to the lack of available data. As discussed further in Section 4.1.4, further derating for both onshore and offshore wind was applied to account for more realistic limits to the development potential.

4.1.3 Development Density

For the purposes of this study, SEA commissioned an updated analysis from AWST in August 2011 to assess the development density (in MW per km^2) to be applied to the remaining windy land. SEA applied a figure in the middle of the range provided by AWST, as follows.

- 7.5 MW/km^2 for onshore land other than ridgecrest areas
- 10.5 MW/km^2 for onshore ridgecrest areas
- 3.5 MW/km^2 for shallow offshore wind, and
- 5 MW/km^2 for deep water offshore wind.

4.1.4 Permitability

To reduce the developable windy land (and sea) area to reflect expected limits on permitting, SEA further reduced all remaining land and sea areas to by the following factors: for on-shore wind, 65% of the total potential reflecting SEA's subjective assumption on the proportion that would be developable; and for offshore wind, the assumption for total potential developable was 10% for areas within 3 nautical miles (nm) of shore and 15% for regions beyond 3 nm.

4.1.5 Phase-in

SEA includes its own subjective estimates for the maximum buildout rate for regional wind generation, based on both development timelines for potential projects, and expected limits to the wind industry's infrastructure installation capabilities. The purpose of these assumptions is to constrain the model from projecting unrealistically high proportions of resource potential buildout before the industry would be physically capable of accomplishing the buildout. In short, it keeps the model from indicating the feasibility of building all potential resources in the first year, or even first several years, as such an outcome would be highly unrealistic.

4.1.6 Subtracted Committed Supply

Contracted committed supply, calculated as MW already operating or under construction, were removed from the total potential for each block to calculate incremental developable potential. Around 600 MWs were removed.

4.2 Performance

To project energy production associated with each supply block, SEA commissioned an updated analysis from AWST in August 2011 to analyze the average annual capacity factors associated with each supply block by state, at 80 meters hub height. The updated data reflect the latest understanding of the performance of current and near-term wind generation technology, and also corrects for historical industry forecast bias experienced prior to 2008/2009. The AWST analysis provided an expected capacity value for each wind power class on a "P50" basis, representing the quantity of energy production with a 50% probability of being exceeded. The actual capacity factor may vary by year, but using the P50 value is a conventional planning assumption.

For offshore wind, capacity factors were estimated for each class by converting NREL's wind speed classes from its 2010 study to capacity factors using standard industry conversion factors and methodology provided by NREL. The NREL methodology used Weibull distribution curves[21] to convert from wind resource measured in m/s to capacity factors. A 85% availability estimate was then applied to the converted capacity factors to account for down times due to technical or weather-related issues.

As noted, the on-shore data set available to SEA for purposes of this analysis is at 80 m wind speeds. We note here that the onshore wind capacity factors, and associated costs, are potentially quite conservative. Current development practices are moving to higher towers and longer blades where possible to capture higher wind speeds available. The difference can result in as much as approximately 8% higher annual energy production for a 100 meter tower (the highest being planned for the region). Use of higher towers would materially impact the capacity factor, and significantly reduce the calculated LCOEs for each block. We explore this sensitivity later in this report.

Capacity factor degradation over time: Onshore wind capacity factors from AWST, which represented year 1 capacity factors, were levelized over a 20 year period assuming a 0.25% annual production degradation. This resulted in a levelized capacity factor that was approximately 1% lower than the initial value. For example, a block with an initial value of 30% would become around 29%. Offshore capacity factors were derived using NREL data and estimates, and were not adjusted for annual production degradation in the same way.

4.3 Cost

4.3.1 Capital Cost

Installed capital costs, on a nominal $/kW basis excluding interconnection costs, were derived by SEA based on review of a wide range of publicly available data sources as well as extensive interviewing of market participants active in New England. Sources considered included NREL compilations of other study results[22], the Lawrence

[21] A probability distribution commonly used to model wind speeds
[22] http://www.nrel.gov/analysis/docs/re_costs_20100618.xls

Berkeley Laboratory/Department of Energy's 2010 Wind Technologies Market Report[23], EIA's 2011 Annual Energy Outlook,[24] a 2009 Cost of Generation Study, components of which were developed by KEMA[25] and the California Energy Commission[26] (the '2009 KEMA/CEC Cost of Generation Report'), NREL studies, and additional research and interviews.

Capital cost estimates for onshore wind and shallow offshore wind were developed by combining data points from reports and calls with developers and the Lawrence Berkeley National Labs. Deep water offshore wind capital cost was estimated by taking the Annual Energy Outlook (AEO) 2011 estimated costs adjusted for inflation and further adjusted to refine interconnection cost using confidential data provided by an offshore wind developer.

To project capital costs by year, technology learning curve indices for both onshore and offshore wind were taken from the 2009 KEMA/CEC Cost of Generation Report and combined with the AEO2011 GDP Index to account for inflation.

4.3.2 O&M Cost

O&M Cost estimates for onshore wind were adapted from the KEMA/CEC Cost of Generation Report. For small on-shore wind projects, a 5% adder was applied to fixed O&M costs. Variable O&M costs were held constant across all onshore wind blocks. The variable O&M cost estimates for shallow and deep water offshore wind were the same, both from the KEMA/CEC Cost of Generation Report, which estimated offshore wind variable O&M to be approximately twice that of onshore wind. For fixed O&M, the shallow offshore wind estimate was taken from AEO2011. The deep water offshore wind fixed O&M cost was derived by adding up three components of O&M cost from the KEMA report: insurance, fixed O&M, and a reduced ad valorem component. Both onshore and offshore O&M costs are escalated using an experience curve ratio from the KEMA/CEC study and the CPI index.

4.3.3 Interconnection Costs

Current interconnection costs were estimated as a function of distance from the transmission grid based on a simple model developed by SEA. Each project was assumed to require both substation and line costs. Depending on the size of the project, different voltage requirements and substation costs were assigned in consultation with an electrical engineering firm involved in numerous interconnection studies for New England wind projects.

Interconnection costs were escalated by year using a hybrid index that combined the AEO2011 indices for commodities, metals and metal products, and the consumer price index. Different substation and line costs were assumed for each size category to match different voltage assumptions by category, and deep water offshore projects were assumed to have higher substation and platform costs for the offshore terminal.

For onshore wind blocks, the distance from transmission used to estimate line costs was the midpoint in the range for each transmission category (e.g. 0-5 miles used 2.5 miles). Offshore wind cabling distances were estimated as the midpoint in distance converted from nautical miles. The T1 category for offshore wind used 1.0 miles as the lower bound because many projects in this range may be more likely to lie on the higher end of the 0-3 nm distance. The cabling distance for offshore wind projects was increased to reflect the fact that the best point of interconnection to a suitable point on the transmission grid would not be the closest shoreline. We

[23] http://www1.eere.energy.gov/wind/pdfs/51783.pdf
[24] http://www.eia.gov/forecasts/aeo/assumptions/pdf/renewable.pdf
[25] KEMA, Inc., **RENEWABLE ENERGY COST OF GENERATION UPDATE**, prepared for **California Energy Commission** Public Interest Energy Research Program (Aug, 2009).
[26] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

assumed that interconnection would be made at a point at a 30 degree angle to the nearest shoreline, to better approximate realistic distances to the interconnection point, rather than as a straight line to shore.

4.4 LCOE

4.4.1 Financing Assumptions

The following assumptions were made for project financing for the reference case (whose results are presented in Section 2) and for a low-interest sensitivity case discussed later in Section 5.2.

	Debt Term	Capital Structure: % Debt	
		Reference	Low interest
Contract Term (yrs)	yrs	interest rates	rates
10	9	62%	62%
15	14	64%	65%
20	18	65%	67%

Technology Type	Cost of Equity	Cost of Debt	
	%	Reference	Low Interest
Wind (<20 MW)	13.0%	8.5%	7.0%
Wind (20-100 MW)	12.0%	8.0%	6.0%
Wind (>100 MW)	11.0%	7.0%	5.5%
Wind (Offshore)	14.5%	10.0%	8.0%
Wind (Deepwater)	14.5%	10.0%	8.0%

4.4.2 Incentives

The reference case assumed no state or Federal incentives, but a sensitivity case described in Section 5.1 models the impact of the extended availability of a 10-year PTC, with a current value of 2.3 ¢/kWh.

4.4.3 Financing Constraints

Lenders require minimum cash flow to assure their payment by establishing minimum debt service coverage (DSC) ratios. Assumptions for the percentage of debt were developed to meet a minimum DSC Ratio of 1.25 and an average DSC ratio of 1.45.

4.4.4 Terminal Revenue

Wind projects were assumed for CREST modeling to have a 20 year economic life. In cases where contracts were for 10 or 15 years, assumptions were required for post-contract revenue.

Terminal revenue beyond the contract end date, for scenarios with 10 and 15 year contract terms, used AESC 2011[27] energy & capacity value by state, plus an assumed $5/MWH for each renewable energy credit (REC). This is typically more value than traditionally conservative lenders would attribute to these post-contract values, and therefore may slightly understate the LCOEs in 10 and 15 year cases (note: most other assumptions would tend to overstate LCOEs, as discussed in Section 5.)

[27] Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2011 Report* (July 21, 2011 , Amended August 11, 2011).
http://www.ma-eeac.org/docs/PAcites/AESC%202011%20Final%20-amended%208-11-11%20-Synapse.pdf

5 Sensitivity Cases

In this section, we provide sample results to illustrate the sensitivity of results shown in Section 2, to key assumptions. The first sensitivity case shows the potential impact of continuation of Federal incentives currently slated to expire by the end of 2012. The last two sensitivity cases discuss factors that we believe should be considered by NESCOE and its managers in interpreting the results. As described in each section, each factor suggests that the results shown in Section 2 may be quite conservative, meaning that there is a good probability that competitive procurement under long-term contracts could yield prices *lower* than those indicated by the results in Section 2.

5.1 Continuation of Production Tax Credit

In order to quantify the LCOE impact of a Federal production tax credit (PTC), the LCOE with PTC was calculated for a number of sample blocks and compared to the LCOE without PTC. For purposes of this sensitivity, we assumed that the current Federal PTC was extended under its current structure (we ignored the short-term stimulus ITC and cash grant programs). The effect on LCOE is magnified for shorter contract terms because the value of the PTC is concentrated in the 10 years of the contract term, whereas the value of the PTC value is spread out over 15 or 20 years (5 or 10 years beyond the 10-year PTC) for the longer contracts. Table 4 shows the **LCOE decreases** that could be expected for a sampling of blocks.

Table 4. Impact of Production Tax Credit

	2016			2020		
Contract Term:	10	15	20	10	15	20
Wind Small MA P1T1	33.00	24.00	18.00	32.00	23.00	18.00
Wind Medium NH P3T1	31.00	23.00	18.00	31.00	22.00	19.00
Wind Medium NH P3T2	32.00	23.00	19.00	32.00	23.00	18.00
Wind Large ME P1T1	32.00	22.00	18.00	31.00	23.00	18.00
Wind Large ME P2345T1	30.00	22.00	19.00	29.00	22.00	18.00
Wind Offshore RI C5T1	34.00	23.00	18.00	33.00	24.00	19.00
Wind Offshore MA C5T3	33.00	24.00	19.00	32.00	25.00	18.00
Wind Deepwater MA C6T2	34.00	23.00	18.00	32.00	23.00	18.00

5.2 Low Interest Rates

Even after adjusting for the availability of Federal incentives for projects that are being built in the current timeframe, contract prices well below those projected herein are feasible (for instance, recent contracts entered into as a result of the Massachusetts Green Communities Act Long-Term Contracting Pilot Program[28]). One of the reasons is that today's interest rates are at historic lows. The reference case presented in Section 2 was based on debt financing assumptions representative of longer-term expectations, as it is unrealistic to assume that today's interest rates would continue indefinitely. However, it is certainly possible that a lower real interest rate environment may continue into the future.

[28] See http://www.massachusettsrenewableenergyrfp.com/, http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu/dpu-divisions/legal-division/dpu-and-green-communities-act/long-term-contracts-for-renewable-energy.html.

To help illustrate the potential impact of these assumptions, a sensitivity analysis was performed using lower interest rates for cost of debt, which yields lower LCOE results. Interest rates for this case were 1.5-2% lower than for the reference case and varied by technology type, as shown in Table 5. The reference case used long-term estimates of cost of capital for purposes of estimating projects built in 2016 and 2020. Due to the uncertain future of this low-cost capital environment, the reference and sensitivity case results can be treated as high and low bounds, with expectations likely somewhere in between.

Table 5. Cost of Debt Assumptions

Technology Type	Cost of Debt	
	Reference	Low Interest
Wind (<20 MW)	8.5%	7.0%
Wind (20-100 MW)	8.0%	6.0%
Wind (>100 MW)	7.0%	5.5%
Wind (Offshore)	10.0%	8.0%
Wind (Deepwater)	10.0%	8.0%

The LCOE results shown in Table 6 for the lower interest rate case show the **LCOE reductions** that would result under the lower interest rates. The results were between $4-20/MWh lower than for the reference case. The difference was higher for the 10 year contract terms and lowest for the 20 year contract terms.

Table 6. Impact of Low Interest Assumptions

	2016			2020		
Contract Term:	10	15	20	10	15	20
Wind Small MA P1T1	7.00	9.00	10.00	7.00	9.00	11.00
Wind Medium NH P3T1	7.00	8.00	10.00	8.00	9.00	11.00
Wind Medium NH P3T2	7.00	9.00	10.00	8.00	10.00	11.00
Wind Large ME P1T1	5.00	6.00	7.00	5.00	6.00	7.00
Wind Large ME P2345T1	4.00	5.00	6.00	4.00	6.00	6.00
Wind Offshore RI C5T1	8.00	10.00	12.00	8.00	10.00	12.00
Wind Offshore MA C5T3	8.00	11.00	13.00	8.00	11.00	12.00
Wind Deepwater MA C6T2	9.00	11.00	13.00	8.00	11.00	12.00

5.3 Taller Towers, Longer Blades

Our data set for onshore wind resource potential is based on 80 meter data, corresponding to 80 m hub heights. This height has historically been a reasonable representation of the fleet currently operating. We polled the leading wind developers in the region to assess the mix of hub heights being used in projects currently under development, and concluded that looking forward, the industry seems to be moving (for larger regional projects) to a mix of 84, 90, 94 and 100 m towers. Higher hub heights are usually associated with longer blades. The combination substantially improves expected energy output (capacity factor) for a small incremental cost. Many projects will not use higher towers and longer blades for a variety of reasons, including site suitability, access, transportation or construction logistics, and permitting (greater visual and sound impacts, leading to the need for greater buffer zones).

At our request, AWST estimated that a move from 80 to 100 m and associated longer blades may impact a site materially in terms of improved output, with only small increases in capital costs. An example: this move could make a 16% capacity factor site into a 24% capacity factor site, or a 24% capacity factor site into a 32% capacity factor site. Analytically, it is not possible to project a mix of hub heights, because a developer could select from a range on a particular site, and the choices are driven by a range of factors and constraints, only one of which is economics. This impact is more likely to affect medium to large projects in the lower power ranges (e.g. power ranges 0, 1 and 2), since (i) small projects closer to residential areas are unlikely to allow higher hub heights, (ii) projects that are already in high power classes tend to be on ridgelines or areas that may be difficult to permit or deliver taller turbines, and (iii) the marginal economics of lower wind sites yield a higher relative value for the additional production, thus providing greater incentive to pursue higher hub heights despite the additional challenges described above.

To estimate the potential impact of moving all towers in a given project to a 100 m hub height, we adjusted the capacity factors by AWST's 8% additional annual production.[29] Due to the mix of tower heights expected, the values shown in Table 7 represent the upper limit to the **LCOE decreases** that could be expected from moving to 100 m towers. A 90 m tower would likely produce reductions in the LCOE that are less than 50% of the reductions from moving to 100 m towers, due to the non-linear relationship of wind speed and capacity factor. Nonetheless, the results show the *potential* for LCOEs to be $30 to $50 per MWh lower than indicated in Section 2 if developers move to the tallest turbines and longest blades available. Table 7 includes the results for a few example blocks. Note that these figures may be somewhat overstated, as a detailed analysis of cost differences (expected to be modest on a $/kW basis) was not conducted.

Table 7. Impact of Higher Hub Height Assumptions

	2016			2020		
Contract Term:	10	15	20	10	15	20
Wind Medium VT P2T1	41.00	32.00	28.00	44.00	34.00	30.00
Wind Medium ME P0T1	62.00	48.00	42.00	66.00	52.00	45.00
Wind Large VT P1T1	46.00	35.00	31.00	49.00	38.00	32.00
Wind Large NH P1T3	49.00	38.00	32.00	53.00	40.00	35.00
Wind Large ME P0T1	55.00	41.00	36.00	58.00	44.00	39.00
Wind Large ME P1T1	41.00	31.00	27.00	44.00	34.00	29.00

[29] This is an approximation. It is important to note that not all blocks would experience an 8% capacity factor increase if a new capacity factor study was done at 100m, but the 8% value was used as a benchmark to gauge the impact of a significant capacity factor increase. A more costly AWST study at different hub heights would be required for a more accurate estimate of the capacity factor increases that would be expected for various supply blocks.

Appendix A – Land-Based Wind Classifications and Exclusions

New England Site Screening Criteria

Wind Resource Data

	Data Source	Date	Applied Buffer
New England Power Density @ 80m	AWS Truewind & NYSERDA (wind data resolution 200m)	2005	N/A
New England Mean Wind Speed @ 80m	AWS Truewind & NYSERDA (wind data resolution 200m)	2005	N/A

100% Exclusionary Lands
(Land Areas that were completely excluded from this analysis)

Protected Lands			
National Historic Preserves	CT,MA,ME,NH,RI,VT State GIS Clearinghouse of Protected Lands	2006-07	N/A
Natural Resource Land	CT,MA,ME,NH,RI,VT State GIS Clearinghouse of Protected Lands	2006-07	N/A
Wildlife Management Areas	CT,MA,ME,NH,RI,VT State GIS Clearinghouse of Protected Lands	2006-07	N/A
State Parks	CT,MA,ME,NH,RI,VT State GIS Clearinghouse of Protected Lands	2006-07	N/A
State and Local Parks	ESRI Parks	2006-07	N/A
National Historic Parks	ESRI Parks	2006-07	N/A
National Recreation Areas	ESRI Parks	2006-07	N/A
National Monuments	ESRI Parks	2006-07	N/A
National Wildlife Refuges	ESRI Parks	2006-07	N/A
National Park Service Land	USGS National Atlas	2006-07	N/A
Fish and Wildlife Serivice Lands	USGS National Atlas	2006-07	N/A
State Parks, Recreation & Historic Lands	CT,MA,ME,NH,RI,VT State GIS Clearinghouse of Protected Lands	2006-07	N/A

Land Use/Land Cover			
Urban Areas	USGS National Land Cover Data: Medium and High Intensity Developed Lands (NLCD Classes 23&24)	2001	Class (23) 0.5 Miles Class (24) 1 Mile
Wetlands & Waterbodies	USGS National Land Cover Data: Open Water (NLCD Class 11 & 90-95)	2001	N/A
Large Airports	ESRI Airports	2007	20,000 Feet
Medium Airports	ESRI Airports	2007	10,000 Feet
Small Airports	ESRI Airports	2007	N/A
Existing Wind Farms	AWS Truewind Wind Farm Data	2007	N/A
Slopes > 20%	Derived From National Elevation Data DEM 30m	2001	N/A

Secondary Exclusion: Land Classifications
(Layers are in order of how they were applied in the secondary analysis)

Protected Lands			
Bureau of Indian Affairs Lands	USGS National Atlas	2007	
Deparment of Defense Lands	USGS National Atlas	2007	N/A
Forest Service Lands	NH, VT GIS Clearinghouse of Protected Lands & ESRI Federal L	2006-07	N/A
State Forest Lands	CT,MA,ME,NH,RI,VT GIS Clearinghouse of Protected Lands	2006-07	N/A
2 Mile Buffer of Appalachian Trail	Appalachian Trail Conference	2001	N/A

Land Use/Land Cover			
Non Ridgecrest Forest Analysis	Intersection of Slopes ≤ 10 Degrees (NED) that are > 5 km2, USGS National Land Cover Data: Deciduous Forest, Evergreen Forest, & Mixed Forest (Classes 41-43)	2001	N/A
Ridgecrest Forest Analysis	Intersection of Slopes < 10 Degrees (NED) that are < 5 km2 and USGS National Land Cover Data: Deciduous Forest, Evergreen Forest, & Mixed Forest (Classes 41-43)	2001	N/A
Agricultural Land	USGS National Land Cover Data: Agriculture (Classes 81-84)	2001	N/A
Grassland	USGS National Land Cover Data: Grasslands (Class 71)	2001	N/A