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Carolina Offshore Wind Integration Case Study
Phase 1 Final Technical Report

March 2013

PHASE 1 FINAL TECHNICAL REPORT for PROJECT: CAROLINA OFFSHORE WIND INTEGRATION CASE STUDY (COWICS)

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1.0 EXECUTIVE SUMMARY

It is the collective opinion of the Carolina Offshore Wind Integration Case Study (COWICS) principal sponsor and contributing investigators that all DOE phase 1 project goals have been accomplished and addressed in this phase 1 final report. Further, it is recommended to proceed with the stated goals of phase 2 to produce a comprehensive report of the feasibility and cost of developing renewable wind resources off the coast of the Carolinas.

AWS Truepower (AWST) has produced a wind plant output data set spanning 1999–2008 at a 10-minute temporal resolution. The data set includes hypothetical wind farms offshore North and South Carolina fulfilling potential scenarios of 1000 MW, 3000 MW, and 5600 MW of offshore wind capacity. Sites were selected to minimize the cost of energy based on the mean annual wind speed, water depth, and distance to shore. In spite of more restrictive criteria for excluding areas from development in North Carolina than South Carolina, the wind resource dictated more potential build out in North Carolina waters.

Wind resource and plant output were simulated at each potential site using AWST's proprietary numerical weather prediction model and power output software. Although comparison with existing offshore wind farms was not possible, the simulated wind speeds were thoroughly validated against measurements from elevated offshore platforms. The model predictions correlate closely with existing meteorological data near the siting areas. Annual and diurnal wind speeds are uniform over the 10 year historical simulation. Monthly wind speeds are higher during winter months versus summer months as expected. Validation results confirmed that the data reflect realistic annual, seasonal, and diurnal averages, and should be suitable for use in COWICS.

The University of North Carolina (UNC) and the National Renewable Energy Laboratory (NREL) provided an extensive list of 26 exclusion criteria as realistic inputs to the potential site selection process as known at the time the study was performed. Visual impact was not one of the criteria considered and may warrant further investigation.

The siting study demonstrated that there is an abundance of high quality development areas offshore North and South Carolina at relatively shallow depths (i.e. $\leq$ 30 m) sufficient to meet the DOE study target of 17,000 GWH annual production from offshore wind resources.

Three distinct zones emerged from the selection/exclusion criteria in the siting model output referred to as the north, central, and south zones. The north zone is northern NC near the Virginia border, the central zone is near the NC outer banks, and the southern zone is near Myrtle Beach SC.

ABB analysis of the siting data recommended that a combination of AC and DC connections from offshore collector stations to onshore interconnection substations would be appropriate given the diversity of distances from offshore collector platforms to onshore substations and also the breadth of the wind turbine siting fields. AC connections were recommended for shorter distances with inherent advantage of lower cost but limited current carrying capability due to capacitive charging current and DC connections were recommended for longer distances with the advantage of reduced losses but higher converter terminal cost. The recommended connections change for each generation scenario in all three zones.

The Duke Energy Carolinas (DEC) transmission planning group performed the steady state interconnection analysis using latest NERC Multiregional Modeling Working Group (MMWG) and North Carolina Transmission Planning Collaborative (NCTPC) load flow models available. The steady state analysis results indicate interconnection reinforcements to integrate offshore wind generation range from $30 M in the 1000 MW scenario, to approximately $92 M in the 3000 MW scenario with all upgrades in the central and southern zones, and $130 M in the 5600 MW scenario with all upgrades again exclusively in the central and southern zones. In all scenarios no cost estimates are included for DC-AC converter equipment or wind turbine collector networks.

The Northern zone connection in the 1000 MW and 3000 MW scenarios is to the Kitty Hawk 230 kV substation. In the 5600 MW scenario the northern NC zone sites should be connected to PJM either onshore at the Dominion Virginia Power (DVP) Landstown substation or offshore to the planned Atlantic Wind Connection (AWC) DC bus.

The Central zone connection in the 1000 MW scenario is through an onshore DC converter station to the Silver Hill 230 kV substation. In the 3000 MW scenario a second connection at AC is recommended to the Morehead 230 kV substation. In the 5600 MW connection the Silver Hill DC connection is moved to New Bern 230 kV substation and the AC connection to Morehead remains.

The southern study zone does not have any wind turbine sites in the 1000 MW scenario. In the 3000 MW scenario connection is to the future Bucksville 230 kV substation. In the 5600 MW scenario the connection to Bucksville is converted to DC.

These interconnection study results are consistent with previous studies conducted by DVP and the NCTPC.

2.0 PROJECT GOALS

2.1 PROJECT OBJECTIVES

The project's objective is to provide a thorough and detailed analysis of specific issues, impacts, and costs associated with integrating various amounts of offshore wind generation into the Duke Energy Carolinas system. The study's authors expect the information provided by the study to inform policy decision-makers, industry participants, and utility planners as they evaluate the positives and negatives of offshore wind development.

2.2 PROJECT SCOPE

Duke Energy performed a phase 1 study to assess the impact of offshore wind development in the waters off the coasts of North Carolina and South Carolina. The study analyzed the impacts to the Duke Energy Carolinas electric power system of multiple wind deployment scenarios. Focusing on an integrated utility system in the Carolinas provided a unique opportunity to assess the impacts of offshore wind development in a region that has received less attention regarding renewables than others in the US. North Carolina is the only state in the Southeastern United States that currently has a renewable portfolio standard (RPS) which requires that 12.5% of the state's total energy requirements be met with renewable resources by 2021. 12.5% of the state's total energy requirements in 2021 equates to approximately 17,000 GWH of energy needed from renewable resources. Wind resources represent one of the ways to potentially meet this requirement. The study builds upon and augments ongoing work, including a study by UNC to identify potential wind development sites and the analysis of impacts to the regional transmission system performed by the NCTPC, an Order 890 planning entity of which DEC is a member. Furthermore, because the region does not have an independent system operator (ISO) or regional transmission organization (RTO), the study will provide additional information unique to non-RTO/ISO systems.

The Wind and Water Power Program within the Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy instituted the Offshore Wind Innovation and Demonstration Initiative to promote and accelerate responsible commercial offshore wind development in the US. Duke Energy's study will provide policy decision-makers, industry participants, and utility planners with important information which will potentially impact the growth of offshore wind energy in the US.

2.3 TASKS TO BE PERFORMED – BUDGET PERIOD 1

The goal of budget period 1 (12 months) of the study was to build a base of information about the capacity and energy that would be produced by varying levels of offshore wind development and perform a high level assessment of the impact to the transmission system. The information developed and studied at a high level in budget period 1 is significantly more detailed than that used in previous studies. If the results of budget period 1 suggest further study is worthwhile, budget period 2 work will commence and build upon the results of from budget period 1 by performing a detailed analysis of the operational impacts and economic impacts of varying levels of offshore wind development under multiple system scenarios. Work during budget period 2 would represent the first study, as far as the team is aware, of the impacts of integrating offshore wind under multiple scenarios into a regulated utility system.

2.3.1 SITE SELECTION

The first activity of budget period 1 was to analyze wind resource data for the coast of North Carolina and South Carolina. The Duke Energy project team used proprietary wind models. The Duke Energy project team ran a geographic information system (GIS) based site screening algorithm to select likely locations and associated amounts of capacity for commercially viable offshore wind projects. Both North Carolina and South Carolina were screened for potential development. A variety of factors were considered with this approach, including the wind resource and predicted plant output, distance to potential interconnection points, and proximity to sensitive or protected areas. The GIS-based approach to site screening is designed to ensure that all quantifiable factors affecting a site's suitability are considered in a systematic fashion. An appropriate offshore plant size, or range of sizes, and distance between wind farms to minimize the impact of wakes was considered. The primary result was a preliminary map of identified sites within the study area. A list of the prospective sites and their basic characteristics was also included. The sites were then screened for water depth, access to relevant on-shore infrastructure such as ports, ability to lease, environmental issues, and other use conflicts. The analysis indicated potential sites that were most likely to be developed.

2.3.2 CAPACITY & ENERGY PROFILE

The chosen sites were then evaluated to determine the amount of capacity that could feasibly be developed. More detailed analyses of the wind resource for the selected sites was performed to determine the capacity and energy profile associated with each wind development as well as the variability of the resource. The Duke Energy project team then ran a proprietary numerical weather prediction model, to create time series of wind speed and direction, air density, and turbulence kinetic energy at 100-m above ground level for locations of potential offshore wind farms identified in the Site Selection. One time series was created for each wind farm, each encompassing multiple turbine locations. The simulations were run at 10-km horizontal resolution, which is sufficient to capture spatial variations in the wind resource over the ocean. The mesoscale simulations were used to generate 10-year time series (1999-2008) of hourly and 10-minute wind power output for each offshore project selected during the site screening process. Ten years should provide the maximum flexibility for the next steps in this project. The Duke Energy project team converted the mesoscale model wind output to electricity generation time series in the following manner:

(i) Each 10-minute wind speed was reduced by a direction-dependent factor representing the effect of turbine wakes and, secondarily, the effect of blade soiling and environmental factors. The directions of minimum and maximum wake loss were determined by the model-generated wind rose.

(ii) The air density was calculated for each record from the modeled temperature and pressure and corrected to the site elevation.

(iii) A composite 6 MW power curve suitable for use in offshore wind farms was adjusted to the air density. Appropriate cut-out and reset-from-cut-out speeds were assumed to account for high-wind hysteresis.

(iv) The turbine output was scaled to the plant rated capacity and reduced for other losses such as electrical losses and availability.

A frequency distribution of hourly and 10-minute wind and power ramps was examined to characterize the variability of the offshore wind resource and each plant's production.

2.3.3 INTERCONNECTION & DELIVERY

The capacity and energy profiles of the selected sites were used in the transmission system modeling to assess transmission system needs in order to interconnect and deliver the wind energy to load centers. To determine a high-level assessment of the critical reinforcements needed to the transmission system, a Steady State Powerflow Analysis (SSA) was performed. The power system model used for the SSA is based on the Eastern Interconnection Reliability Assessment Group (ERAG) MMWG model, which includes a detailed representation of all of Duke Energy's transmission resources as well as those throughout the Carolinas and the surrounding states. The MMWG maintains a library of transmission system models for ten years into the future.

The method for injecting the wind generation into the system will affect the selection of potential injection locations. Two methods were explored: a) radial lines from the wind plants to shore; and, b) a direct current (DC) grid interconnecting multiple wind plants with radial lines to the shore. For both methods, the most probable locations for the injection of the wind generation into the onshore transmission system will be determined using the wind plant proximity to onshore substations, transmission path ratings in the vicinity of these substations and similar considerations.

Studies will be performed using the appropriate North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Standard Category A, B and C contingencies in order to identify areas prone to transmission loadings and voltage limitation that will hamper the transmission of the high levels of offshore wind. Potential reinforcement measures to deal with any problems observed will be determined, and a preliminary assessment of their capabilities and benefits will be made. Such reinforcements may include additional alternating current (AC) transmission lines, DC transmission paths, reactive compensation (both series and shunt), etc. Upon completion of the SSA, the technical review committee will review the results and a report will be submitted to DOE detailing the team's phase 1 findings. The study team will judge the success of the phase 1 study on the following criteria: whether the study identified sufficient viable sites; whether the capacity and energy profiles suggest the sites could be economically viable; and whether the interconnection and delivery assessment yields multiple feasible solutions. Positive results for such criteria would suggest that further study of the impact of integration is expected to yield significant new information about the system upgrades and operational changes needed to facilitate a given level of wind development. If the study is successful and the technical review committee deems further study is worthwhile, Duke Energy will ask DOE for formal authorization to perform the additional activities necessary to complete the study in phase 2.

3.0 DISCUSSION & RESULTS

3.1 TASK 1 – SITE SELECTION

The site selection process identified likely areas of offshore wind development based on the wind resource, areas excluded from development, and cost of energy. The objective was to identify enough sites to exceed the 5600 MW scenario requirements to allow flexibility in selecting the best sites to represent each scenario. The study team determined that sites should range from 40–100 MW to allow the aggregation of several sites into larger wind farms if larger sites are desirable. This size range is representative of currently planned wind farms in the Atlantic Ocean as well as future larger sites that could be developed through multiple phases.

The first step was to identify and compile areas to be excluded from development. Since a comprehensive site screening was performed as a part of UNC's offshore wind feasibility study,[1] which was reviewed by the Bureau of Ocean Energy Management (BOEM) Task Force, this study began with the areas deemed most suitable for potential development offshore North Carolina based on that analysis. No similar analysis was available for South Carolina at the time of this study, so an effort was made to exclude similar areas from development in South Carolina. The National Oceanic and Atmospheric Administration's (NOAA) ENC® Direct to GIS database,[2] areas excluded from development in NREL's Regional Energy Deployment System (ReEDS),[3] and wind energy exclusion areas from the United States Department of Defense (DoD) South Carolina Outer Continental Shelf Wind Energy Assessment[4] were used to determine buildable areas. A listing of excluded areas and corresponding offsets is provided in Table 1. After consulting with NREL and UNC, it was agreed that the potential contributable area was to extend to 50 nautical miles offshore. Development in state waters within 5 miles from shore was permitted. It should be noted that the list of excluded areas is less thorough than the analysis performed in the UNC study, which may skew development toward South Carolina. It should be noted that visual impact was not a consideration for the selected sites; however, this consideration may be revisited at a later date.

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[1] *Coastal Wind: Energy for North Carolina's Future*, Prepared for the North Carolina General Assembly by the University of North Carolina Chapel Hill, June 2009, 355.

[2] http://ocs-spatial.ncd.noaa.gov/website/encdirect/viewer.htm

[3] W. Short et al., "Regional Energy Deployment System," NREL/TP-6A20-46534, Golden, CO: National Renewable Energy Laboratory, 2011, 94 pp., www.nrel.gov/docs/fy120sti/46534.pdf.

[4] F. Engle, "DoD Assessment of Offshore Military Activities and Wind Energy Development on the Outer Continental Shelf off South Carolina," http://www.boem.gov/uploadedFiles/BOEM/Renewable_Energy_Program/State_Activities/DoD%20SC%20OCS%20Assessment_Engle.pdf

Table 1. Areas excluded from development.

Constraint	Offset	Source
Anchorage Area	300 m	NOAA
Beacon	30 m	NOAA
Buoy	30 m	NOAA
Cables	1100 m	NOAA
Cables (International)	1500 m	NOAA
Coastline	5 km	NOAA
Dumping Ground	300 m	NOAA
Fairway Shipping Channel	1 nm	NOAA
Fog Signal	30 m	NOAA
Lights	30 m	NOAA
Military Practice Area	Layer Extent	NOAA
Obstruction	30 m	NOAA
Offshore Platform	30 m	NOAA
Precautionary Area	Layer Extent	NOAA
Shipping Lane	1 nm	NOAA
Wreck	30 m	NOAA
National Marine Sanctuaries	1 mile	NREL
Marine Protected Areas	1 mile	NREL
Shipping Lane	1 mile	NREL
Sanctuary Preservation Area	1 mile	NREL
Significant Natural Heritage Areas (NC)	1 mile	NREL
Sea Turtle Sanctuaries (NC)	1 mile	NREL
Crab Spawning Sanctuaries (NC)	1 mile	NREL
Refuges (SC)	1 mile	NREL
Ocean & Coastal Resource Management Critical Area (SC)	1 mile	NREL
Wind Energy Exclusion Area	Layer Extent	DoD

The wind resource was defined using AWST's seamless 200-m resolution United States Offshore map. AWST previously developed a method of adjusting its wind maps using a wide array of wind resource measurements to ensure accuracy[5]. The seamless wind speed map and speed-frequency distributions compiled from 15-years of historical mesoscale model runs previously performed by AWST at a 20-km resolution were used to generate a gross capacity factor (CF) map using a composite International Electrotechnical Commission (IEC) Class II wind turbine. Although IEC Class II turbines may not be suitable for every site, the use of a single curve allows an objective ranking of resource potential. The composite power curve was created by averaging several commercial megawatt-class wind turbine power curves (Alstom 6 MW, GE 4.1 MW, Siemens 6 MW, and Siemens 3.6 MW) which were normalized to their rated capacity. The normalized average curve was rescaled to a rated capacity of 6 MW and

[5] The mean bias of the AWS Truepower 200-m United States wind map is found to be virtually zero, while the standard error (after accounting for uncertainty in the data) is 0.35 m s^{-1}.

assumed to have a rotor diameter of 150 m. Losses due to wakes and other factors were estimated for offshore areas based on environmental considerations to generate a net CF map.

A GIS-based site screening algorithm was then used to ensure that all quantifiable factors affecting a site's suitability were considered in a systematic fashion. An energy density of 3.36 MW/km^2 was assumed, which spaces the turbines approximately 10 rotor diameters apart, consistent with AWST's typical offshore turbine spacing. It is assumed that the increased energy production from decreased wakes will offset the increased interconnection costs of this spacing plan. Additionally, sites were placed no closer than 2 km from any neighboring site to reduce wake effects from neighboring wind farms. The algorithm uses the net CF map overlaid with the exclusion map and seeks to identify near-contiguous ocean areas to support the 40–100 MW project size, minimizing the cost of energy. A randomization feature allows the program to select sites with a range of rated capacities, even in areas where very large sites could be supported.

Resulting sites were ranked by cost of energy based on capacity factor, distance to shore, and water depth, using the following equation:

$$COE = \frac{FCR \times (CC + IC)}{8760 \times CF \times P} + OM$$

Where,
FCR = fixed rate charge (12.8%)
CC = capital cost ($4604/kW shallow; $5677/kW deep)
IC = interconnection cost ($2570.5/MW-mile)
CF = net average plant capacity factor
P = plant nameplate capacity
OM = operations and maintenance ($0.06/kWh)

For the purposes of this study, the cutoff between "shallow" and "deep" installations was set at 30 m, consistent with the ReEDS model. As can be discerned from the cost of energy equation above there is a significant increase in capital cost in going from a "shallow" depth installation (i.e. less than or equal to 30 m.) to a "deep" depth installation (i.e. greater than 30 m.). The difference is about $1M/MW ($5.677M - $4.604M). Additionally the offshore interconnection cost of $2570.5/MW-mile increases as the length of the offshore to onshore interconnection increases to access deeper installations. In order to minimize the cost of energy production objective and given the extended shallow nature of the Carolinas offshore continental shelf, the high quality wind in this area (i.e. $\geq$ 8.5 m/s), and increased capital cost to access deeper sites, only sites up to 30 m depth were considered in site selection for this study. There are sufficient 30 m sites to satisfy the maximum 5600 MW installed capacity criterion.

Preliminary interconnection studies revealed that six of the southern zone sites selected were too far from the main groupings of sites to be economically feasible. These sites were replaced with six sites of the next lowest cost of energy nearer the main groupings of sites. Maps of the final sites fulfilling the 1000-MW, 3000-MW, and 5600-MW scenarios are included in Figure 1, Figure 2, and Figure 3, respectively, and a listing of the 66 selected sites is provided in the Appendix Table A17. The distribution of nameplate capacity by state is shown for each scenario in Table 2. Site nameplate capacity ranges from 40–100 MW, and all sites are within 58 km (32 n mi) of the coast in water depths less than 30 m. These are the final sites that were used for all subsequent tasks in the study.

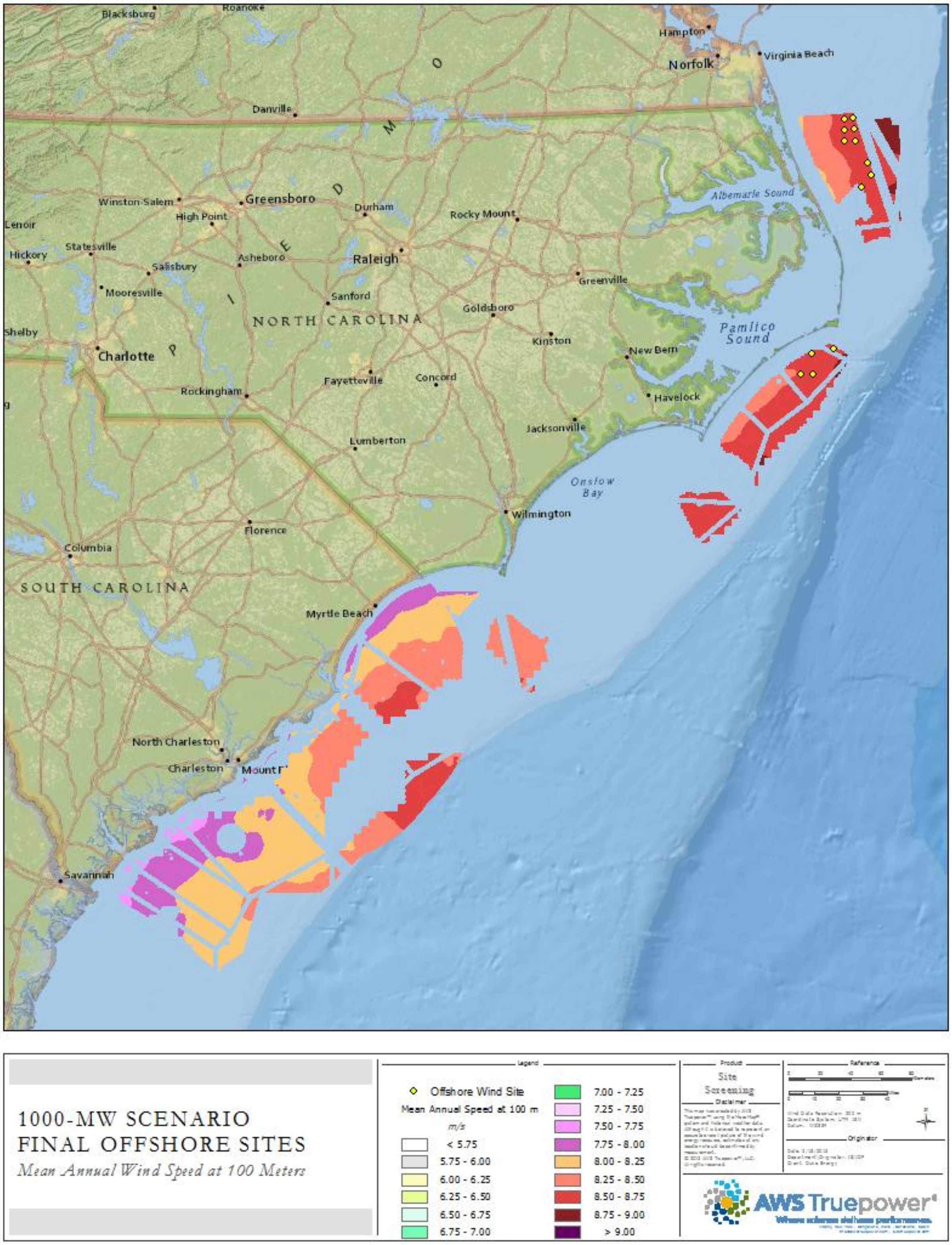

Figure 1. Sites selected for the 1000-MW scenario. Mean annual wind speeds for non-excluded areas are shaded.

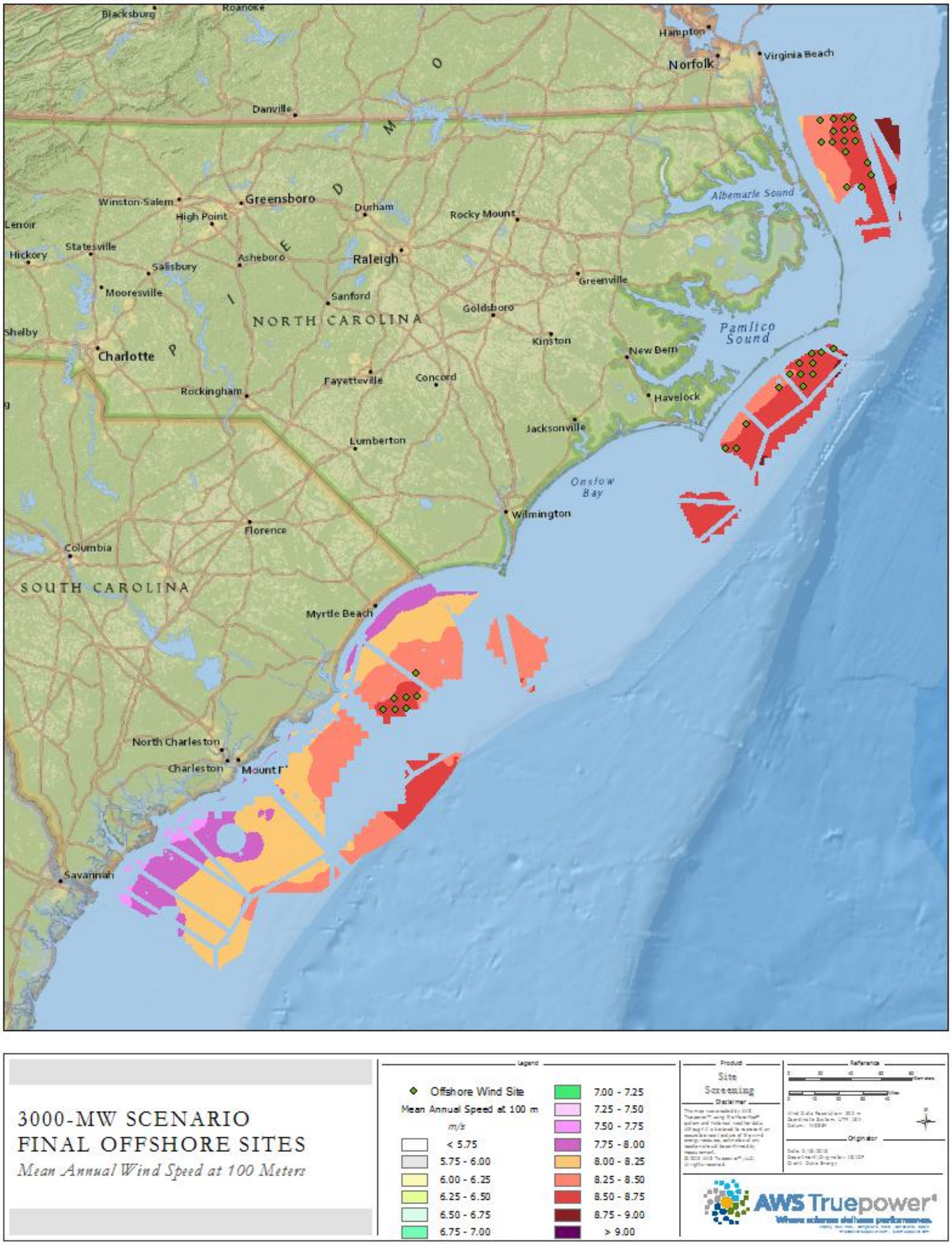

Figure 2. Sites selected for the 3000-MW scenario. Mean annual wind speeds for non-excluded areas are shaded.

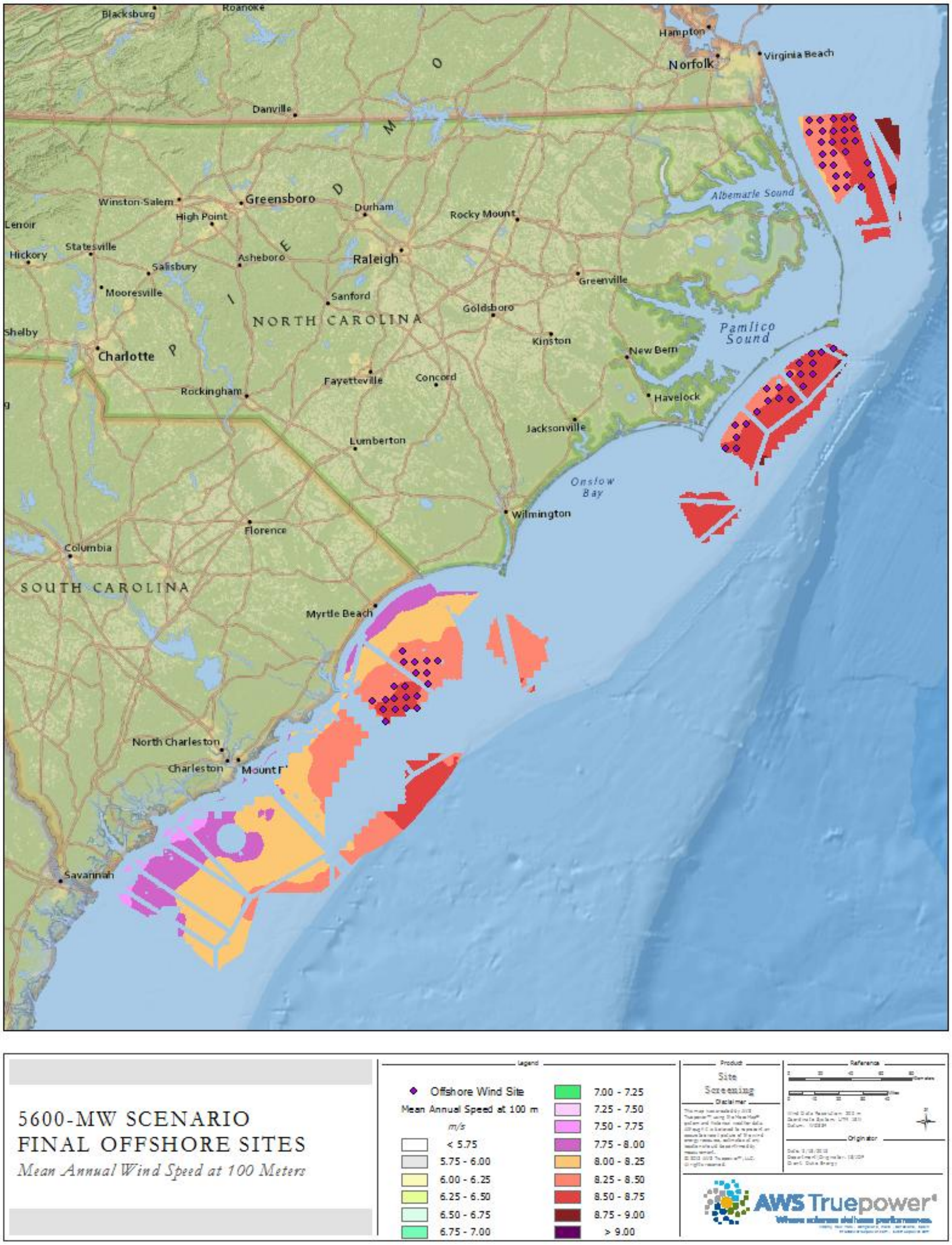

Figure 3. Sites selected for the 5600-MW scenario. Mean annual wind speeds for non-excluded areas are shaded.

Table 2. Percentage of nameplate capacity by state for each scenario.

	NC	SC
1000 MW	100%	0%
3000 MW	78%	22%
5600 MW	69%	31%

3.2 TASK 2 – CAPACITY & ENERGY PROFILE

Ten-minute energy output profiles for the period 1999–2008 were provided for each of the selected sites. These profiles were derived from numerical simulations of weather conditions offshore North and South Carolina and validated using available measurements. The simulation of offshore wind speeds, conversion to energy output profiles, and validation process is described in the following sections.

3.2.1 SIMULATION OF WIND SPEED

AWST employed the Mesoscale Atmospheric Simulation System (MASS)[6], a proprietary mesoscale numerical weather prediction (NWP) model, to simulate time series of wind speed and direction, air density, and turbulent kinetic energy at 100-m above mean sea level for the locations of the hypothetical offshore wind farms. MASS was initialized using the National Centers for Environmental Prediction/National Center for Atmospheric Research Global Reanalysis (NNGR) data.[7] The NNGR data include meteorological observations (e.g. surface observations, rawinsondes, and buoy data) and NWP model output to provide a snapshot of atmospheric conditions around the world every six hours at 28 vertical levels. The reanalysis data are provided on a relatively coarse grid (about 190-km spacing). To avoid generating noise at the boundaries that can result from large jumps in grid cell size, MASS was run using a nested grid configuration with horizontal resolutions of 30 km and 10 km (Figure 4). The inner grid was set to cover the waters offshore North and South Carolina with a 15-grid cell buffer (150 km) to minimize the impact of the grid boundaries. The outer 30 km grid was drawn 750 km from the inner grid to absorb boundary conditions before they could propagate into the inner grid. The vertical grid structure features unevenly spaced levels from the surface up through the lower stratosphere with the highest resolution (tens of meters) in the atmospheric boundary layer below one kilometer. The MASS simulations for this project were run in a hydrostatic mode for 10 years from 1999–2008. The hydrostatic mode simplifies the vertical wind calculations, which decreases computational time. This mode is a reasonable assumption for the 10-km model grid spacing over open ocean.

MASS was initialized from the NNGR data on the first and fifteenth of each month, followed by a 15- or 16-day sequence of 12-hour simulations. Rawinsonde observations of temperature, dew point, wind velocity, and pressure were assimilated into both grids every 12 hours using an objective analysis procedure. Except for the initial run, all subsequent simulations used the previous MASS fields as the

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[6] Manobianco, J., J. W. Zack, and G. E. Taylor, 1996: Workstation-based real-time mesoscale modeling designed for weather support to operations at the Kennedy Space Center and Cape Canaveral Air Station. Bull. Amer. Meteor. Soc., 77, 653-672. Available online at http://science.ksc.nasa.gov/amu/journals/bams-1996.pdf.

[7] Kalnay, Eugenia, et al. "The NCEP/NCAR 40-year reanalysis project." Bulletin of the American meteorological Society 77.3 (1996): 437-471.

starting point for the objective analysis. The NNGR provided lateral boundary conditions for the outer grid throughout all of the simulations, with the inner grid incorporating boundary conditions from the outer MASS grid. The sea surface temperatures for MASS were updated monthly and derived from Moderate Resolution Imaging Spectrometer satellite data at 1-km resolution. The terrain and land cover fields were specified using United States Geological Survey digital elevation and land use/land cover data at 30-m resolution. The run configuration is summarized in Table 3. The wind components, temperature, and turbulent kinetic energy (TKE) are stored at several heights above ground. From these variables, wind speed, wind direction, and density are computed. Results for a sample day are shown in Figure 5. The abrupt change in wind speed and direction is due to the assimilation of observations into the NWP model which is discussed further in Section 3.3.2 – Conversion to Power.

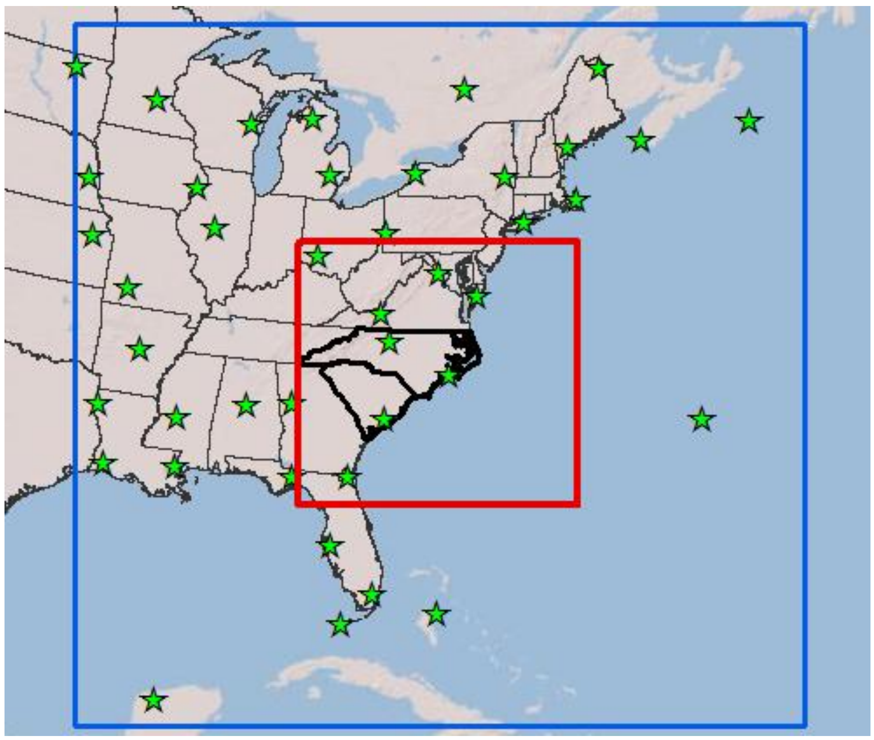

Figure 4. Boundaries of MASS 10-km inner grid (red) and 30-km outer grid (blue). Locations of rawinsondes assimilated in the model are shown by the green stars.

Table 3. MASS model configuration.

Model	**MASS v. 6.8**
Initialization data source	NCEP/NCAR Global Reanalysis (NNGR; ~1.9° resolution)
Data assimilated	Rawinsonde, METAR surface observations (temperature, dew point, wind direction and speed, pressure)
Sea-surface temperatures	MODIS (1-km satellite-based)
High-resolution terrain and land cover (10-km grid only)	Terrain: Shuttle Radar Topography Mission (30 m) Land Cover: GeoCover (30 m)
Cumulus scheme	Kain-Fritsch
Spin-up	12 hours before start of valid run
Length of run	15- to 16-day series (e.g., 1–15 Jan, 16–31 Jan)
Frequency of data sampling	Hourly and 10 minutes
Data stored	Surface pressure; U and V wind components, temperature, turbulent kinetic energy (TKE) at 10, 50, 80, 100, and 200m

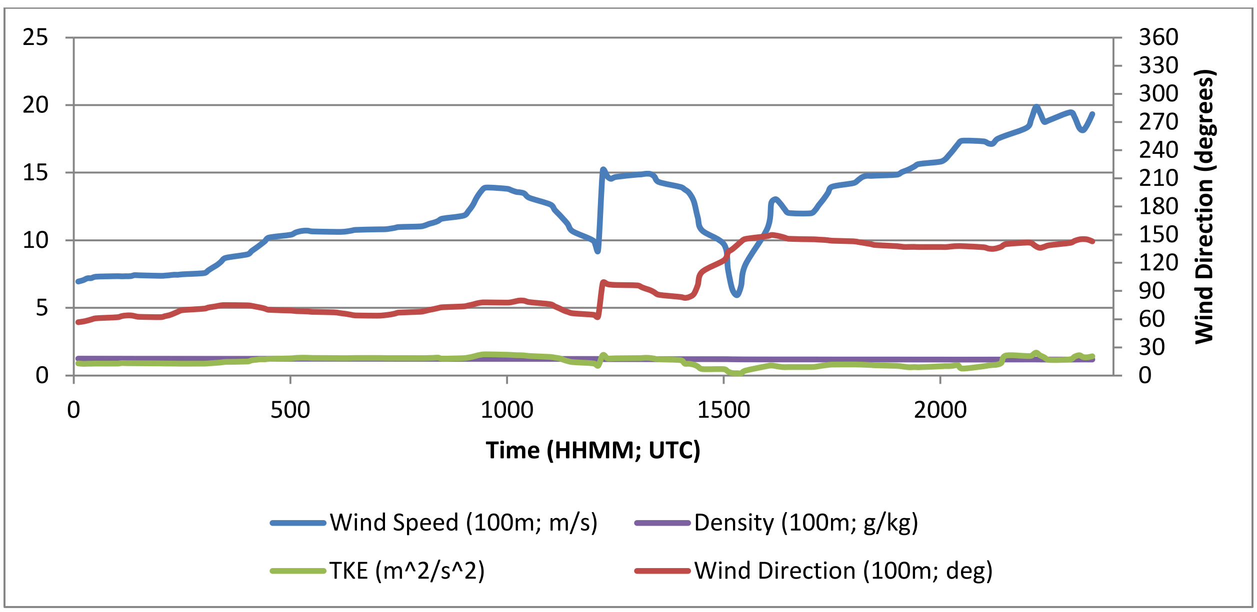

Figure 5. Model output at 100 m hub height for a sample day. Wind speed (m/s), turbulent kinetic energy (m^2/s^2), and density (g/kg) are given by the blue, green, and purple lines, respectively on the primary y-axis. Wind direction (deg.) is given by the red line on the secondary y-axis.

3.2.2 CONVERSION TO POWER

The historical model runs were used to synthesize wind power production. Wind speed and direction, temperature, and turbulent kinetic energy modeled at 100 m were extracted from the model at every grid point corresponding to a selected site. An algorithm written by AWST reads a list of grid cells, latitude and longitude, expected mean speed of the part occupied by, and relative proportion of the site's total rated capacity associated with that cell. The modeled wind speeds were scaled to match the expected mean speed from AWST's 200-m resolution wind map and summed for all grid cells associated with a site. Each cell's speeds were weighted according to the proportion of the site area associated with that cell. The result was a time series of simulated wind speeds for the site as a whole at 100 m.

The wind speed at each grid point was then adjusted for wake losses in a manner that depends on the simulated wind direction relative to the prevailing (most frequent) direction. The loss is given by $w = w_{\min} + (w_{\max} - w_{\min})\sin^2(\theta - \theta_{\max})$, where $w_{\min}$ is the minimum loss (assumed to be 4%) when the wind is aligned with or opposite to the prevailing direction $\theta_{\max}$, and $w_{\max}$ is the maximum loss (9%) when the wind is perpendicular to the prevailing direction. The loss factors accounted both for wake losses and implicitly for other losses such as blade soiling that can affect the efficiency of power conversion for a given free-stream speed without reducing the maximum output. These losses were determined by trial and error to conform to AWST estimates determined from existing onshore wind projects. The method does not account for sites where there is more than one prevailing wind direction or where the prevailing energy-producing direction differs from the most frequent direction. In these cases, only the most prevalent wind direction was used.

The speed was further adjusted by adding a random factor (from -1 to +1) multiplied by the predicted TKE. This adjustment was intended to reflect the impact of gusts on the speeds experienced by the turbines in the offshore wind project. The frequency and intensity of such simulated gusts is dependent to a degree on time of day, as TKE is generally higher in the day when the planetary boundary layer is thermally unstable or neutral than at night when it is thermally stable. The modeled TKE was much lower offshore than onshore due to differences in surface roughness, so the resulting gust factor was also reduced for this study.

The next step in the power conversion process is to import the composite turbine power curve that is valid for the standard sea-level air density of 1.225 kg/m^3. Density at 100-m hub height was determined based on the modeled temperature and air pressure, and the power curve was adjusted accordingly. High-wind hysteresis was accounted for using the composite turbine cut-out and reset-from-cut-out speeds of 25 and 22 m/s, respectively. A loss was applied to account for turbine and plant availability. Based on data obtained by AWST for onshore operating wind projects, the wind turbine availability was assumed to follow a normal distribution with a mean of 94.8% and a standard deviation of 2.3%. To avoid unrealistic rapid fluctuations in output, the availability was allowed to change at random intervals averaging only once per hour. An additional loss of 3% was subtracted from the output to represent electrical losses, regardless of distance to shore. This electrical loss accounts for the collection system from the turbines to the offshore collector substation.

To smooth over discontinuities in wind speed caused by the abrupt assimilation of rawinsonde and surface observations every 12 hours in the mesoscale runs as well as impacts from the model restart every 15 days, wind speeds spanning the affected times were replaced with a linear interpolation plus Gaussian fluctuation with a standard deviation equal to that of the observed data just before and after the jump (Figure 6). In all, about 10% of the data were modified with this method. A small correlated component of the variability was then removed from each site, resulting in a more realistic, consistent diurnal variability when all simulated sites are aggregated across the system. These adjustments were deemed acceptable for the Eastern Wind Integration and Transmission Study,[8] the PJM Renewable Integration Study,[9] and the Eastern Renewable Generation Integration Study,[10] and were thus used here.

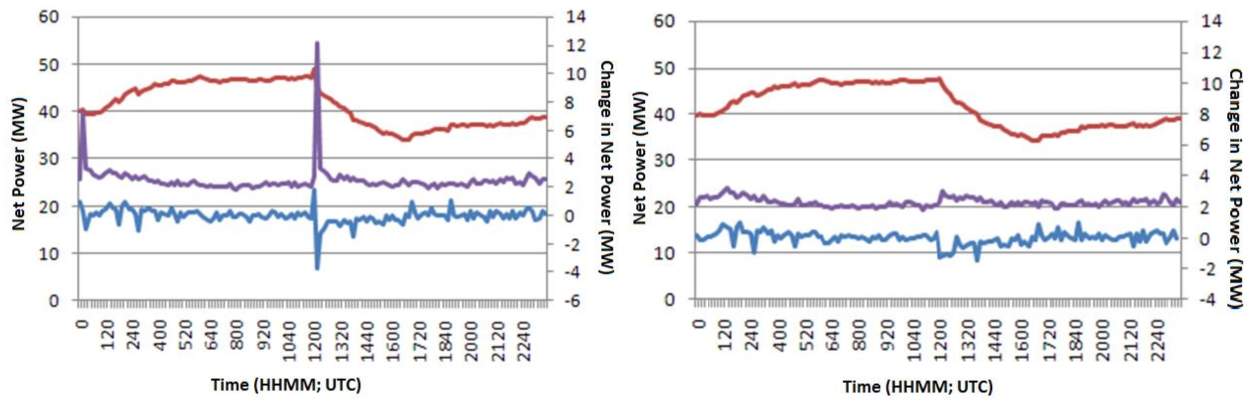

Figure 6. Jumps in power output at one site before (left) and after (right) the correction. The mean output (red) and absolute change in output from one 10-minute record to the next (purple) are shown on the left axis, while the change in output (blue) is shown on the right axis.

A 10-year time series of 10-minute wind speed and power output was simulated at each site. A sample text file is given in Table 4. The header includes the site number, rated capacity, and IEC class of the site,[11] along with the site average losses over the period.

[8] M. Brower, 2009. *Development of Eastern Regional Wind Resource and Wind Plant Output Datasets*. Prepared under Subcontract No. ACO-8-88500-01. NREL/SR-550-46764. Golden, CO: National Renewable Energy Laboratory.

[9] AWS Truepower, 2012. *PJM Renewable Integration Study (PRIS) – Task 1: Wind and Solar Power Profiles*. Available online at http://www.offshorewindhub.org/sites/default/files/resources/pjm_2-17-2012_pristask1_0.pdf.

[10] AWS Truepower, 2012. *Updated Eastern Interconnect Wind Power Output and Forecasts for ERGIS*. Prepared under Subcontract No. DE-AC36-08GO28308. NREL/SR-5500-56616. Golden, CO: National Renewable Energy Laboratory.

[11] Although an appropriate IEC class based on wind characteristics was selected for each site, the same offshore composite power curve was used for all sites.

Table 4. Sample plant output file.

SITE NUMBER: 00012 RATED CAP: 100.0 IEC CLASS: 1 LOSSES (%): 16.3			
SITE LATITUDE: 36.36206 LONGITUDE: -75.29724			
DATE	TIME(UTC)	SPEED100M(M/S)	NETPOWER(MW)
19990101	10	11.897	84.8
19990101	20	11.893	79.7
19990101	30	11.827	86.09
19990101	40	11.679	80.45
19990101	50	11.519	67.59
19990101	100	11.394	66.94
19990101	110	11.231	67.76

3.2.3 VALIDATION

It is important to ensure that the modeled profiles capture annual, monthly, and diurnal mean patterns as accurately as possible. In the absence of offshore wind farm data, measured wind speeds were used to validate the simulated wind speeds. The main source of observed measurements was from NOAA's National Data Buoy Center. Since the focus of the study is 100-m wind speeds during the period 1999–2008, stations with measurements greater than 40 m above sea level during the study period were considered. Stations outside the study area but within the model domain (e.g. Georgia, Virginia) were included in the analysis to increase confidence in the results. Measurement sources include the Coastal-Marine Automated Network (C-MAN), Skidaway Institute of Oceanography, and NREL's onshore tall tower near Stacy, NC. Measurement stations used for validation are shown in Figure 7, and relevant characteristics are given in Table 5. Although none of the measurements are within the non-excluded areas (shaded), validation results at these stations should be representative of results at the hypothetical wind farms.

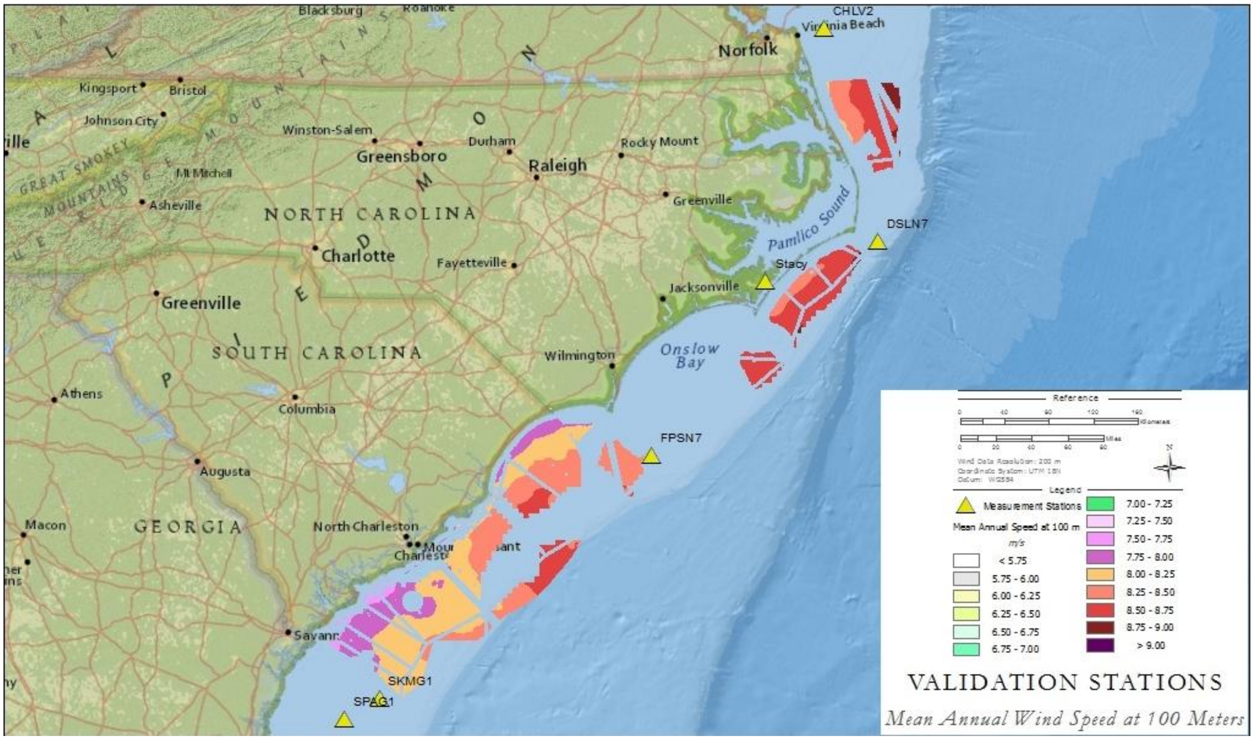

Figure 7. Validation station locations.

Table 5. Validation station characteristics.

Station ID	Lat	Lon	Anemometer Height (m)	Source	State
CHLV2	36.910	-75.710	43.3	C-MAN	VA
DSLN7	35.153	-75.297	46.6	C-MAN	NC
FPSN7	33.485	-77.590	44.2	C-MAN	NC
SKMG1	31.534	-80.236	50.0	Skidaway	GA
SPAG1	31.375	-80.567	50.0	Skidaway	GA
Stacy	34.867	-76.417	62.0, 92.0, 120.0	NREL	NC

Wind speeds were extracted from historical model runs at the grid point and level closest to measurements (50 m at all locations except for 100 m at Stacy). Care was taken to compare only the overlapping period of record and modeled values were set to missing during periods with missing measured data. The resulting simulated annual, monthly, and diurnal means matched well at all offshore validation stations, with a mean bias of 0.07 m/s. Comparisons at the DSLN7, SKMG1, and SPAG1 stations are shown in Figure 8. These locations were selected because they were closest to the modeled 50 m height and they had the best data recovery during the concurrent period. It was found that the model slightly under-predicted wind speeds in cool months and over-predicted in warm months in the southern part of the domain (SKMG1 and SPAG1). Without data from offshore wind farms, it was not possible to directly validate net power output. However, it is expected that any biases in wind speed will be translated to net power output. Since the wind speed patterns compared well at the locations examined, it is expected that mean net power patterns will compare similarly at the hypothetical wind farms.

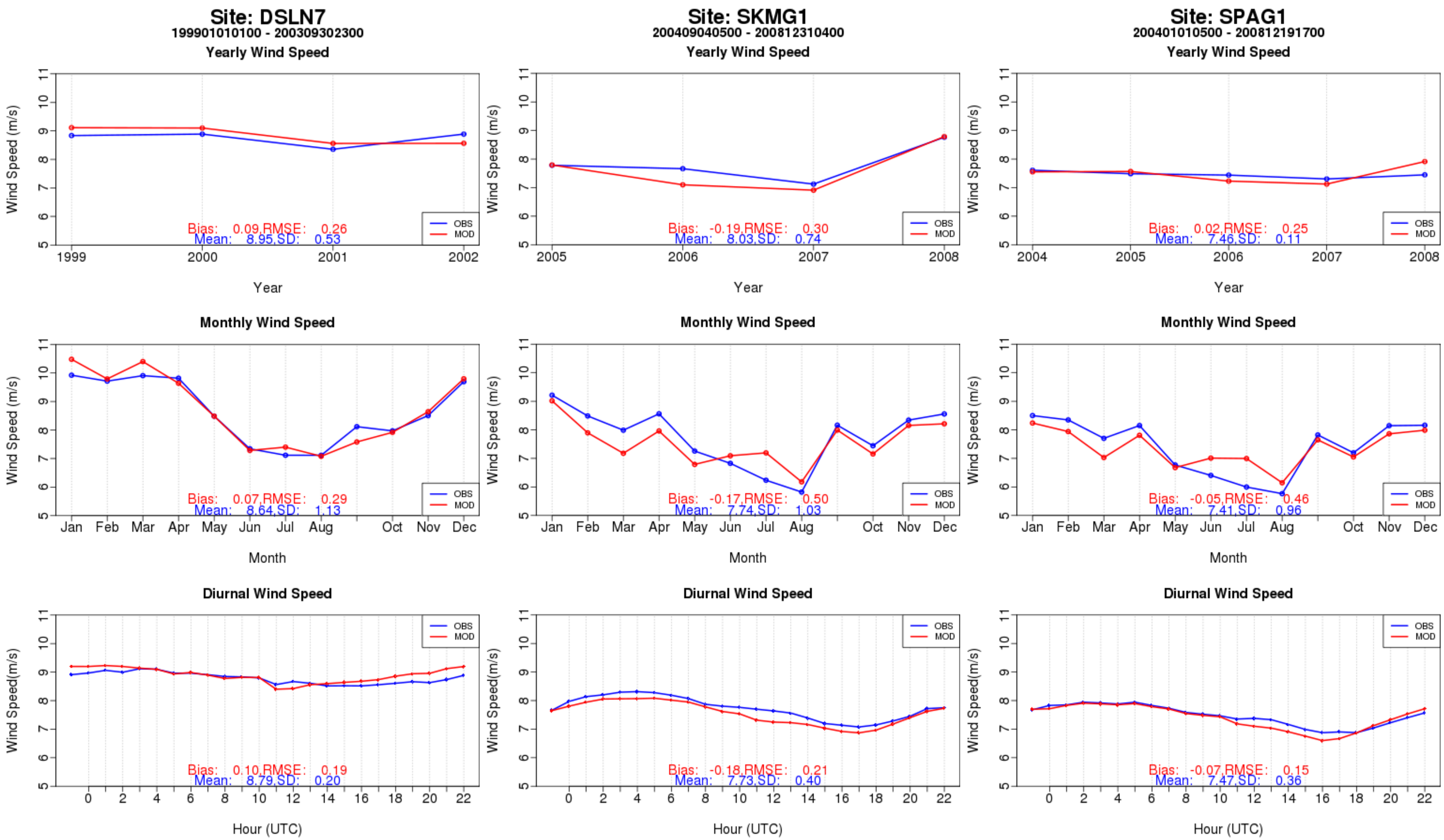

Figure 8. Comparison of modeled (red) and observed (blue) wind speeds for DSLN7 (46.6 m; left), SKMG1 (50.0 m; middle), and SPAG1 (50.0 m; right) and the closest model grid point and level (50 m). Annual, monthly, and diurnal means are shown in the top, middle, and bottom panels, respectively.

3.2.4 RAMP ANALYSIS

The variability of the wind resource was characterized by computing the frequency distribution of 10-minute and 60-minute wind and power ramps for each scenario (1000 MW, 3000 MW, and 5600 MW). The distribution of net power ramps as a function of aggregate capacity is shown for 10-minute and 60-minute intervals in Figure 9. The sizes of the worst ramp, 99.9th, 99th, and 95th percentile up- and down-ramps were also computed for each site and scenario over 10-minute and hourly intervals. It was found that the worst ramps over a 10-minute period at individual sites ranged from 78-97% of plant nameplate capacity, likely due to high wind hysteresis. Approximately 99% of 10-minute ramps were less than 12% of plant capacity. The worst 10-minute ramps decreased when aggregated over the scenarios, with largest 10-minute ramps of 46%, 25%, and 20% of aggregated capacity (459 MW, 741 MW, and 1133 MW), respectively for each scenario. Larger ramps are possible over longer time intervals. The worst hourly ramps at individual sites were 93-97% of plant capacity, while approximately 99% of hourly ramps were less than 34% of plant capacity. The worst hourly ramps were 82%, 60%, and 52% of aggregate capacity (820 MW, 1791 MW, and 2893 MW) when aggregated over the three study scenarios. The ramp statistics are summarized for the aggregate scenarios in Table 6.

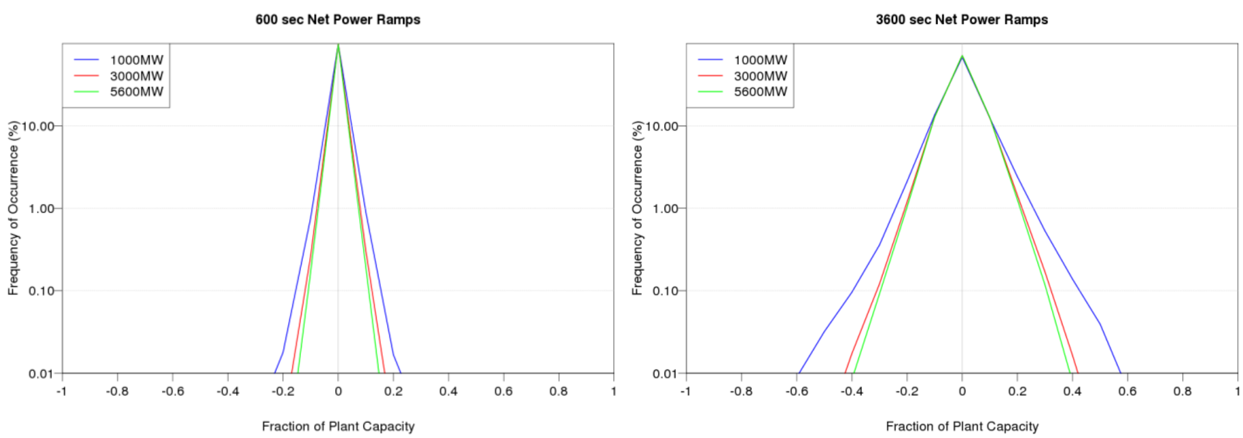

Figure 9. Frequency distribution of net power ramps as a fraction of plant nameplate capacity for 10-minute (left) and 60-minute (right) intervals. Results for the 1000-, 3000-, and 5600-MW scenarios are shown in blue, red, and green, respectively. The y-axis is shown on a logarithmic scale to emphasize large ramps.

Table 6. Size of 10-minute and hourly net power ramps for various quartiles as a fraction of scenario nameplate capacity.

Ramp Interval	Scenario	Capacity (MW)	Worst Down (%)	99.9% Down (%)	99% Down (%)	95% Down (%)	95% Up (%)	99% Up (%)	99.9% Up (%)	Worst Up (%)
10-Minute	1000MW	999.1	-46%	-9%	-5%	-2%	3%	5%	10%	40%
	3000MW	2999.3	-25%	-6%	-3%	-2%	2%	4%	7%	24%
	5600MW	5599.3	-20%	-6%	-3%	-2%	2%	3%	6%	18%
Hourly	1000MW	999.1	-78%	-38%	-20%	-11%	12%	23%	40%	82%
	3000MW	2999.3	-53%	-27%	-16%	-9%	10%	17%	28%	60%
	5600MW	5599.3	-45%	-25%	-16%	-9%	10%	16%	26%	52%

3.2.5 ZONAL PERIOD SELECTION

In addition to the aggregation by scenario (i.e. 1000 MW, 3000 MW, 5600 MW), the sites were analyzed by geographic location or zone. The wind turbine site selection process naturally clustered into three distinct areas or zones based on the site identification input and exclusion criteria. The sites were classified as north, central, or south. The north and central zones are entirely encompassed offshore North Carolina, while sites in the south zone are offshore South Carolina. There was no intentional forced distribution of sites based on state boundaries or any other purpose other than identifying sites that minimize overall cost of energy production.

Because of the relatively small inter-annual variability as shown in the first row of graphs from Figure 8, it was determined that year 2000 data would be used to simulate wind turbine power production. Likewise, because of the relatively large inter-monthly variability as shown in the second row of graphs from Figure 8 and also to evaluate electrical network conditions during peak summer and winter peak load periods and spring/fall shoulder load conditions, the hours of:

- January, 8 am LST
- May, 4 pm LST
- July, 4 pm LST

were selected to model wind turbine power production. The results are given in Table 7.

Table 7. Average output for January 2000 at selected times by scenario and zone.

Scenario/ Zone	Num Sites	Capacity	Jan - 8 AM		May - 4 PM		July - 4 PM	
		MW	MW	% Cap	MW	% Cap	MW	% Cap
1000N	9	701.6	376.13	0.536	308.09	0.439	243.23	0.347
3000N	16	1304.5	688.72	0.528	571.52	0.438	454.82	0.349
5600N	26	2220.4	1151.94	0.519	946.36	0.426	778.11	0.350
1000C	4	297.6	161.35	0.542	163.87	0.551	96.76	0.325
3000C	13	1034.0	559.19	0.541	571.71	0.553	324.25	0.314
5600C	20	1639.4	892.14	0.544	919.09	0.561	512.26	0.312
3000S	7	660.8	371.67	0.562	330.53	0.500	217.84	0.330
5600S	20	1739.5	977.49	0.562	880.69	0.506	573.95	0.330

These data were used as input to Task 3 – Interconnection & Delivery

3.3 TASK 3 – INTERCONNECTION & DELIVERY

3.3.1 INTERCONNECTION POWERFLOW MODELING

Evaluation of the impact of the injection of energy from the three offshore zones on the transmission system was performed. Base powerflow models representing the transmission system of the Eastern Interconnection were created for winter and summer peak conditions, as well as shoulder conditions – 70% to 80% of summer peak load. The winter model and summer model were based on the 2012 series of MWMG models, which provided the furthest out year for which both a summer and winter model existed, namely 2018. The shoulder model was based on the 2011 series of NCTPC models. The 2011 series of NCTPC models included a model for the year 2021 in which the load levels for DEC and Progress Energy Carolinas (PEC) were already scaled to 70% of their expected summer peak load for 2021. The generation in DEC and PEC was economically dispatched to meet the load. In the remaining study areas, DVP and Santee Cooper (SCPSA), the load was uniformly scaled to 70% of its original value in the case. The generation in DVP and SCPSA was uniformly scaled by the corresponding MW value.

A permutation of each model was created with 1000 MW, 3000 MW and 5600 MW of installed offshore wind turbine nameplate capacity. These installations were across three zones that were identified in the site selection task. The appropriate capacity factors for the seasons modeled were applied to each zone based on the average simulated power output for January 2000 at 8 a.m. (winter), May 2000 at 4 p.m. (shoulder), and July 2000 at 4 p.m. (summer). Tables 8-10 show the different scenarios and the corresponding outputs for each zone.

WINTER			
	1000 MW	**3000 MW**	**5600 MW**
North	376	688	1150
Central	161	557	867
South	N/A	368	957

Table 8. **Average simulated power output (MW) for January 2000, 8 a.m.**

SHOULDER			
	1000 MW	**3000 MW**	**5600 MW**
North	308	572	946
Central	164	571	880
South	N/A	329	845

Table 9. Average simulated power output (MW) for May 2000, 4 p.m.

SUMMER			
	1000 MW	**3000 MW**	**5600 MW**
North	243	454	775
Central	97	326	518
South	N/A	219	582

Table 10. Average simulated power output (MW) for July 2000, 4 p.m.

In all scenarios, the offshore wind generated was assumed to sink in the DEC Balancing Authority (BA) area. The DEC BA generation was economically re-dispatched to accommodate the import of the offshore wind energy. The reliability assessment of the offshore wind on the onshore transmission system was performed under base case conditions and under N-1 transmission contingency conditions. Contingencies in Virginia, North Carolina and South Carolina were simulated using Siemens Power Technologies Inc. (PTI) Power System Simulator (PSS®E) software.

The offshore wind was assumed to have the necessary collector station(s) with appropriate connection to onshore facilities and reactive compensation depending on the scenario under evaluation. The characteristics of the three zones would necessitate differing types of connection to the onshore transmission system.

3.3.2 OFFSHORE COLLECTOR SYSTEM

When considering the offshore wind systems it is convenient to divide them into three primary areas as illustrated in Figure 10 below – namely, the generation, the collection and the delivery. The generation may be comprised of a few or many wind turbine generators which all send power through the collection system to a collector substation, from which the power is shipped in bulk to the onshore grid. With current wind generator technologies, the collector systems will be AC networks typically connecting multiple strings of several generators to the collector substation located at a centralized offshore platform – a hub. Here the voltage will be stepped-up to an appropriate level for delivery to shore. Depending on the distances involved across the wind field, it is possible that several collector systems may connect at medium voltage to a central hub platform for delivery to shore. Studies have suggested that platforms connecting to a central hub should be within approximately 12.5 miles of the hub for it to be advantageous.

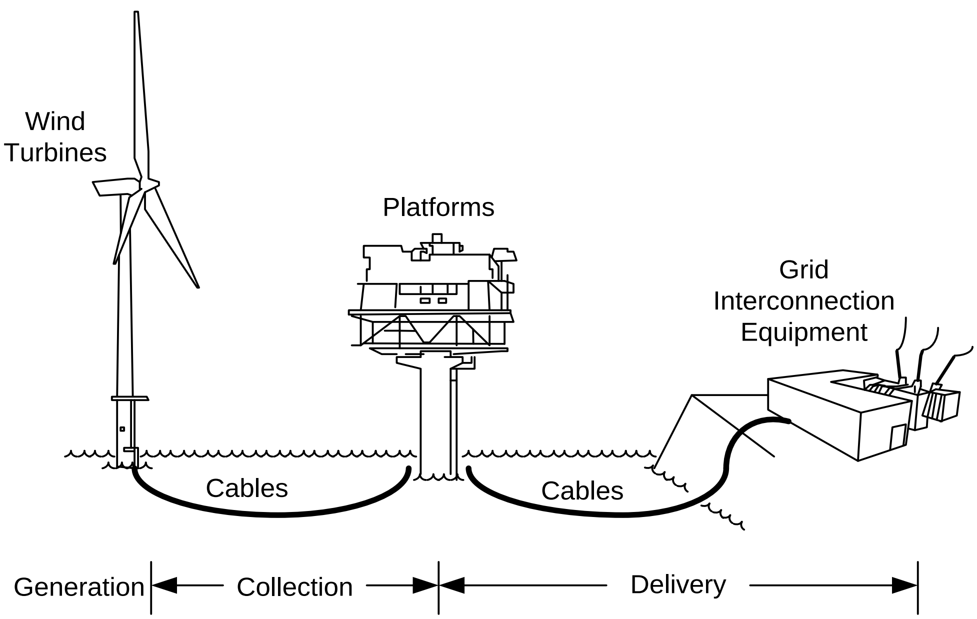

Figure 10. Generalized concept for an offshore wind energy system

Both HVAC and HVDC delivery systems are available with the type of delivery system used being dependent primarily on the economics involved. AC systems are relatively simple and straight forward to design. The AC cables, however, can have significant charging currents that increase as the length of the required cable increases. This charging current has a detrimental impact on the capability to transfer real power and additional cables will be required to move the same amount of power over longer distances. While the charging currents can be compensated to some degree by the use of shunt reactors, these are typically applied only at the onshore end because of the additional platform space and associated costs required for offshore reactors. The impact of cable charging with transmission distance is illustrated in Figure 11 which shows the power transfer capability of a 230 kV copper cable with 2000 kcmil cross-sectional area under two reactive compensation schemes. The first scheme (100/0) has the cable 100% compensated at the on-shore end while the second scheme (50/50) has the cable 50% compensated at each end. As can be seen, there is a significant drop-off in power transfer capacity as the distance increases, with the more common on-shore compensation dropping off more rapidly.

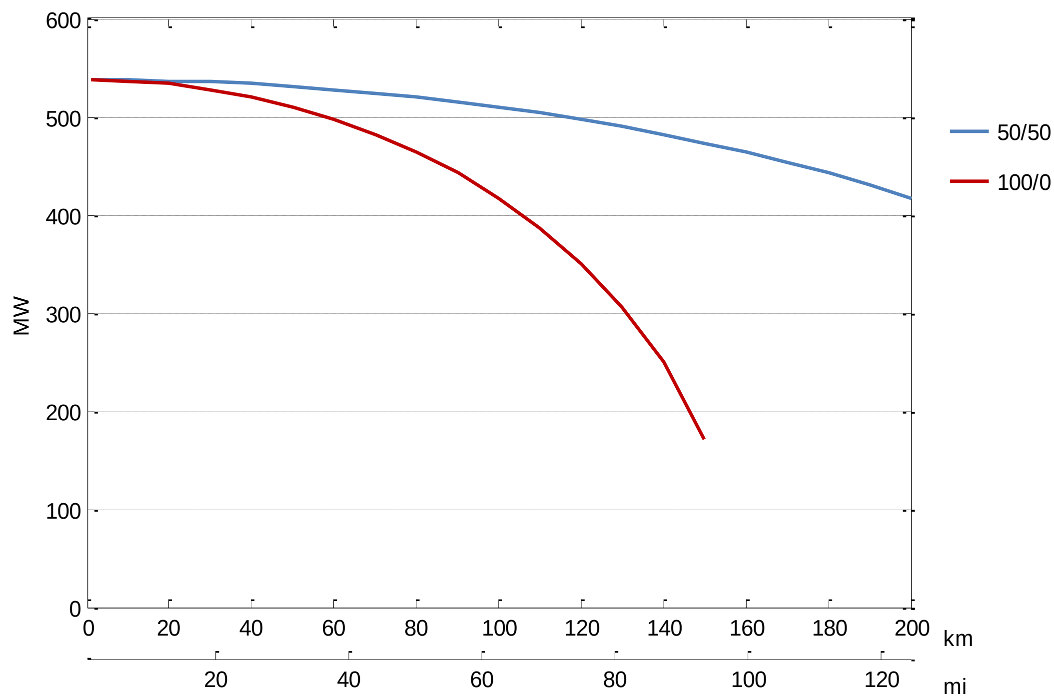

Figure 11. Maximum, real power transfer for 230 kV cables with onshore/offshore reactive compensation splits of 100/0 and 50/50 (2000 kcmil copper cross section)

HVDC delivery systems provide an alternative to the HVAC delivery system. Cable charging – and therefore, distance – is no longer an issue because the cable is charged only once during energization and the voltage on the cable then remains relatively constant. However, HVDC converter stations are required. The space demands for the converters are high, and in the offshore environment, the converters must be enclosed. This increases the size, weight and cost of the platforms. So while cabling and cable compensation costs are reduced, the more complex system with its size, environmental considerations and potential filter requirements increases the cost.

Studies have indicated that the economic cross-over from the HVAC systems to the HVDC system tends to occur at approximately 50 miles. Many aspects of the system design and operation, along with regulatory and environmental issues that may be encountered, may alter the economic cross-over distance. Fifty miles is considered to be an appropriate distance for the preliminary evaluations being made as part of this study.

3.3.3 ONSHORE INTERCONNECTION STATIONS

The following three substation sites were initially identified based on the zonal clustering discussed previously in section 3.2.5, with the approximate locations as indicated:

1) Kitty Hawk, NC (36.0667°N, 75.7006°W)
2) Morehead-Wildwood, NC (34.7277°N, 76.7467°W)
3) Bucksville, SC (33.7186°N, 79.0631°W)

An alternative to the Morehead-Wildwood substation was selected at Silver Hill west of Bayboro, NC (35.1467°N, 76.8397°W) for the 1000 MW & 3000 MW scenarios and New Bern, NC (35.1413°N, 77.1235°W) for the 5600 MW scenario. Although alternative sites were selected, Morehead-Wildwood was utilized as a secondary injection site for the 3000 MW and 5600 MW scenarios.

The wind sites selected as part of the 1000 MW, 3000 MW and 5600 MW scenarios were evaluated for their distances to these substation sites. However, with the options of several substation locations for the central zone, a somewhat more detailed analysis was performed for those sites, with the assumptions adjusted slightly so that small wind capacities (<300 MW) would be economically feasible for distances up to 70 miles. The details of the central zone assessment are provided in Appendix B.

Reactive compensation may be required at the point of interconnection based on the design of the offshore system in some scenarios. From this brief assessment, the following conclusions were made:

- Several of the sites in the North zone were close enough to Kitty Hawk for an AC system to be an alternative. However, for the 5600 MW case, the sites in the North zone would become a part of the AWC bus or make a connection at Landstown, VA. Since the sites will build up over time, it might be practical to consider designing the sites to be integrated to the AWC bus from the start. It should be noted that this assumed connection to AWC is not an endorsement of that project by either the study team or the US Department of Energy. It is simply recognition that discussions regarding the project place it in an optimal position to accommodate the North zone energy production.

- In the Central zone, a few sites totaling 260 MW installed nameplate capacity in the 3000 MW scenario and 517 MW installed nameplate capacity in the 5600 MW scenario are much closer to Morehead City than Bayboro or New Bern and it is expected to be economically attractive to connect those sites to Morehead-Wildwood via an AC delivery system. For the remaining sites, multiple AC collector platforms, additional AC cables or HVDC are possible options to bring the energy in to the Silver Hill or New Bern substations.

- In the South zone, the distance from the sites to Bucksville tended to be at the edge of the 50 mile cross-over point, indicating that at a minimum some reactive compensation would be required. The system offshore of Bucksville would be designed in the most cost effective way depending on the expected build-out and the final location/layout of the wind generation sites.

1000 MW Scenario				
ZONE	**ONSHORE LOCATION**	**ONSHORE DESIGN**	**OFFSHORE DESIGN**	**CHARACTERISTICS**
North	Kitty Hawk	AC connection to 230 kV	34.5 kV AC collector to 230 kV platform	Connects to PJM market.
Central	Silver Hill (Bayboro area)	DC/AC converter to 230 kV	34.5 kV AC collector to AC/DC converter	Bayboro location requires a DC cable across the Pamlico Sound.
South	N/A	N/A	N/A	N/A

Table 11. Onshore interconnection stations, 1000 MW scenario

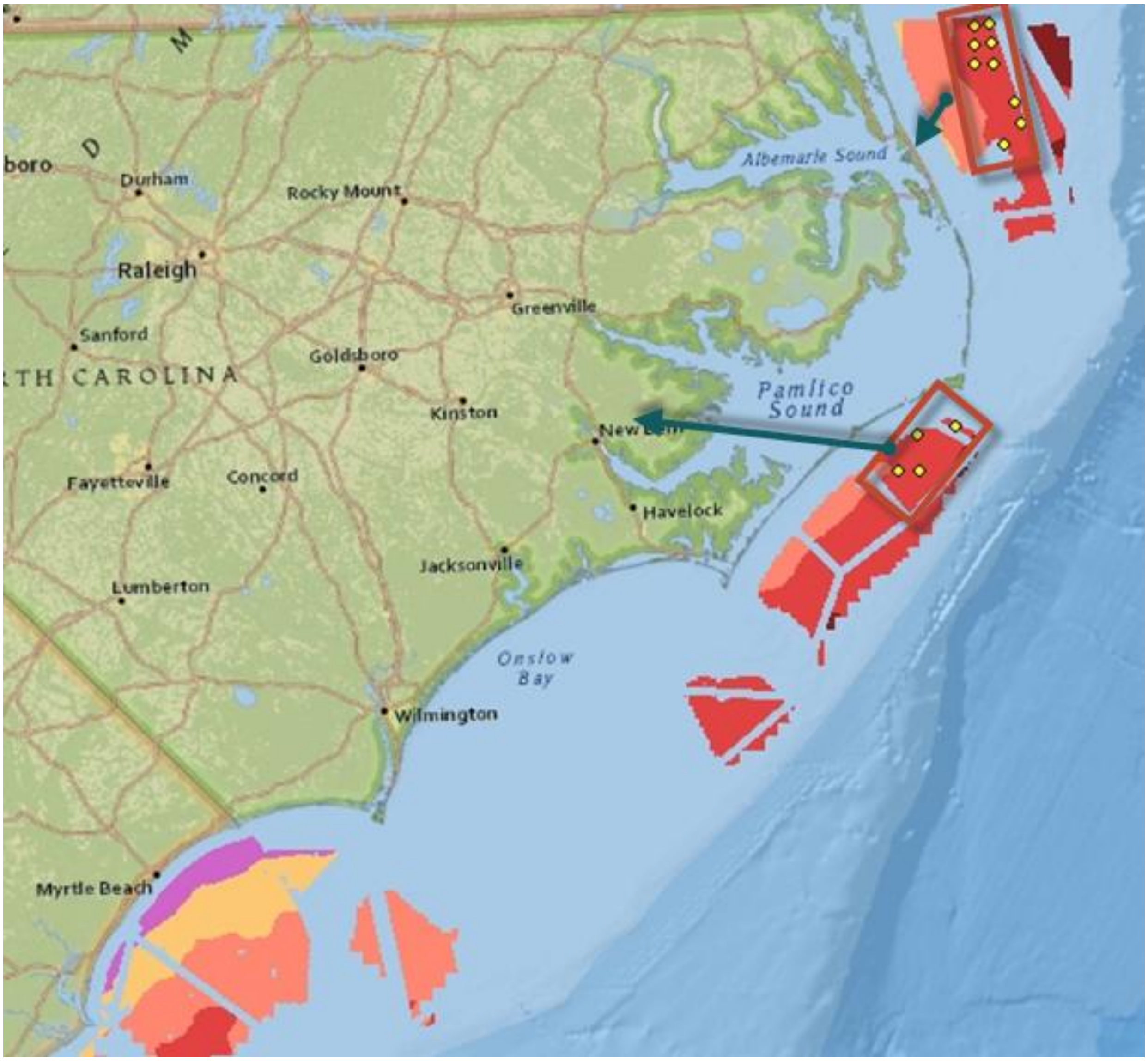

Figure 12. Onshore interconnection station locations, 1000 MW scenario

3000 MW Scenario				
ZONE	**ONSHORE LOCATION**	**ONSHORE DESIGN**	**OFFSHORE DESIGN**	**CHARACTERISTICS**
North	Kitty Hawk	AC connection to 230 kV	34.5 kV AC collector to 230 kV platform	Connects to PJM market.
Central	Silver Hill (Bayboro area)	DC/AC converter to 230 kV	34.5 kV AC collector to AC/DC converter	Bayboro location requires a DC cable across the Pamlico Sound.
Central	Morehead-Wildwood (Morehead City area)	AC connection to 230 kV	34.5 kV AC collector to 230 kV platform	Sites located too far south to connect to Bayboro area.
South	Bucksville	AC connection to 230 kV	34.5 kV AC collector to 230 kV platform	Reactive compensation likely to be required or DC connection to onshore system.

Table 12. **Onshore interconnection stations, 3000 MW scenario**

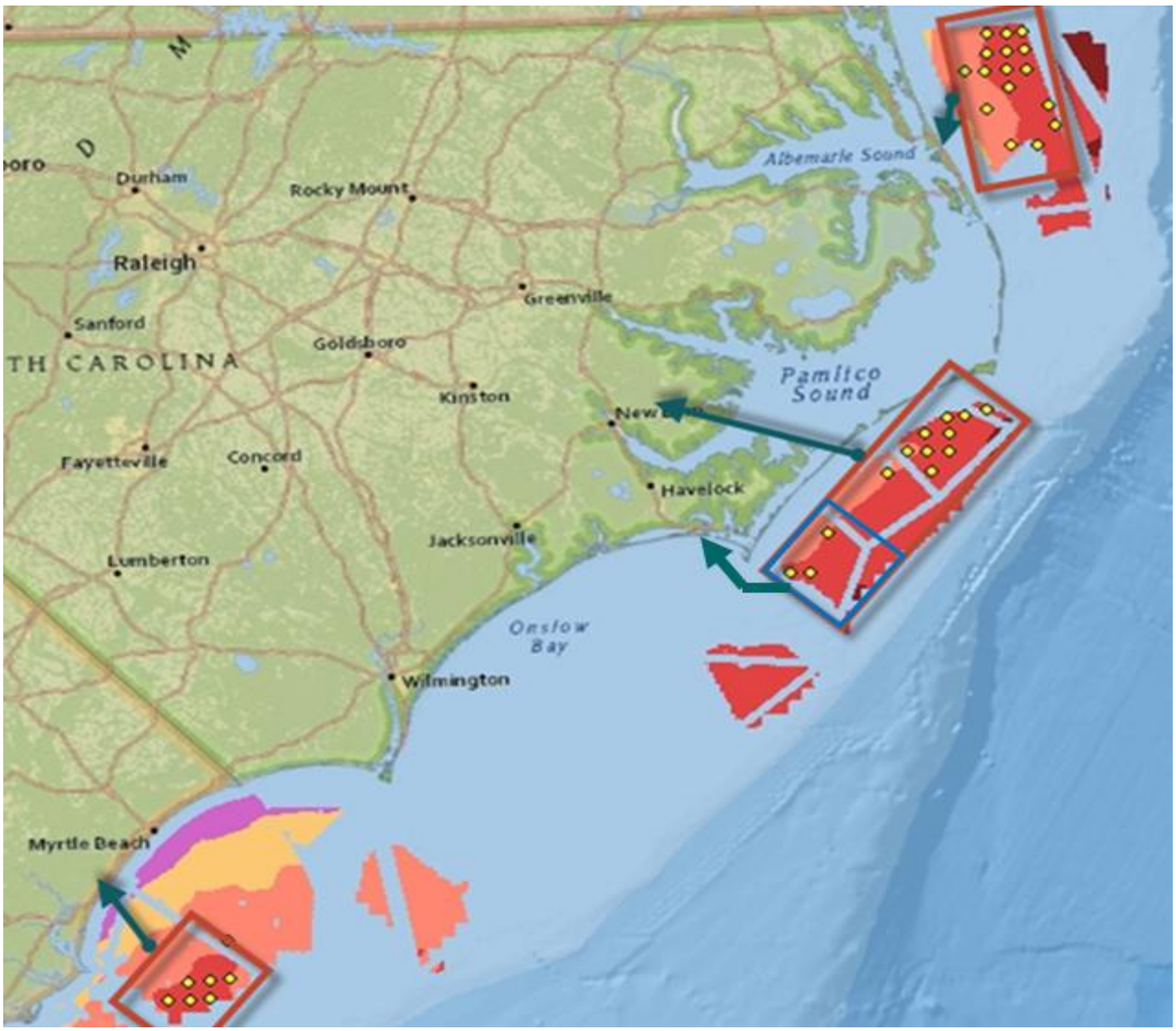

Figure 13. Onshore interconnection station locations, 3000 MW scenario

5600 MW Scenario				
ZONE	**ONSHORE LOCATION**	**ONSHORE DESIGN**	**OFFSHORE DESIGN**	**ISSUES**
North	Landstown (Virginia Beach area)	DC/AC converter to 230 kV	34.5 kV AC collector to AC/DC converter or DC collector to DC bus	Connects to PJM market. Requires connection to Virginia Beach, VA area substation or directly to PJM offshore DC bus.
Central	Morehead-Wildwood (Morehead City area)	AC connection to 230 kV	34.5 kV AC collector to 230 kV platform	Sites located too far south to connect to Bayboro area.
Central	New Bern	DC/AC converter to 230 kV	34.5 kV AC collector to AC/DC converter	New Bern location requires a DC cable across the Pamlico Sound.
South	Bucksville	DC/AC converter to 230 kV	34.5 kV AC collector to AC/DC converter	Required removing 6 outlier wind sites that were too far from the main body of wind sites to reasonably connect. The next 6 "less preferable" sites (blue dots on map) were selected – 3 in the Central zone and 3 in the South zone to reach the full 5600 MW study level.

Table 13. Onshore interconnection stations, 5600 MW scenario

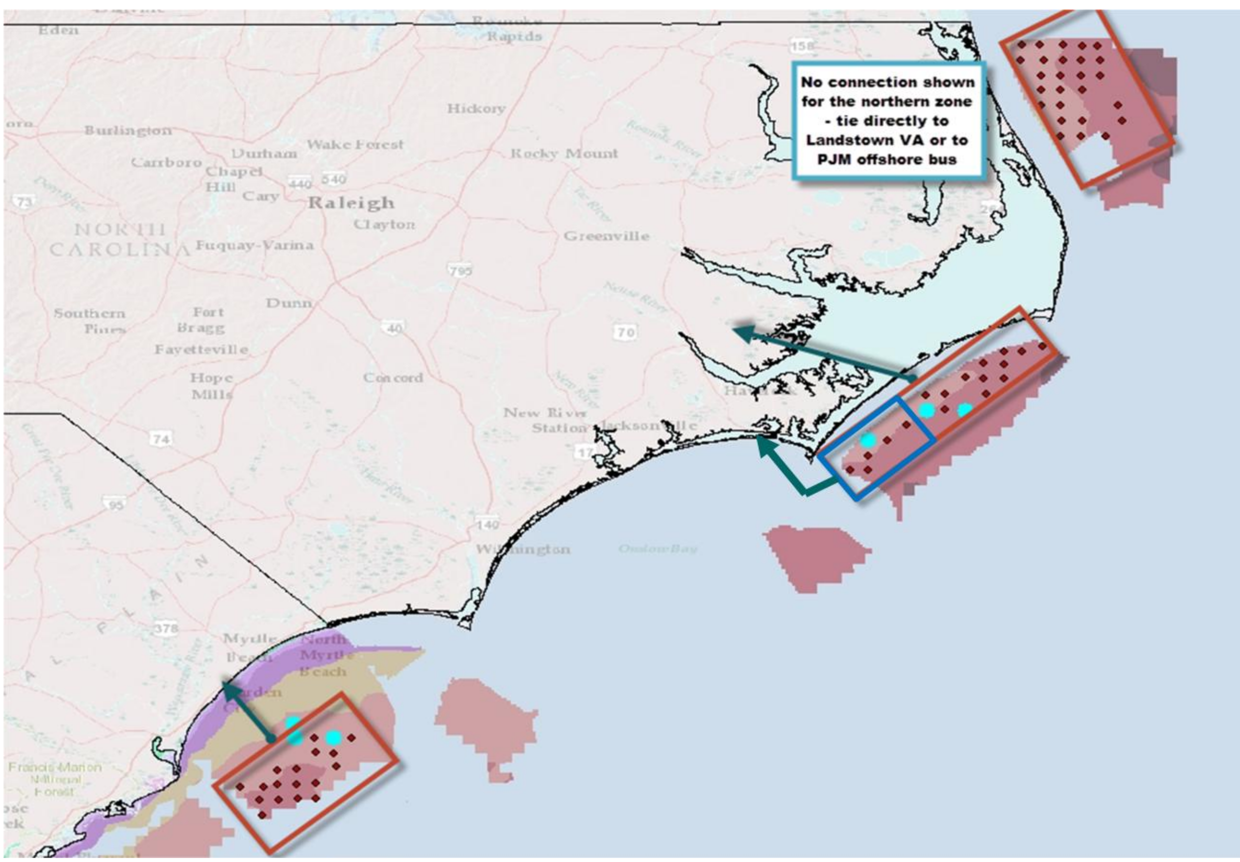

Figure 14. **Onshore interconnection station locations, 5600 MW scenario**

3.3.4 INTERCONNECTION POWERFLOW RESULTS

3.3.4.1 NORTHERN ZONE

The northern zone generation was assumed to connect into the Kitty Hawk, NC area in the 1000 MW and 3000 MW scenarios via a 230 kV AC connection. In the 5600 MW scenario, the northern zone generation terminates into the Virginia Beach, VA area at 230 kV. The assumption was that a DC cable directly from the northern zone or a connection to the proposed DC cable offshore of Virginia would be required. Additionally, there would be a connection through a DC/AC converter station connected to Landstown. Both Kitty Hawk (in North Carolina) and Landstown are part of the DVP transmission system in the PJM market.

The existing transmission infrastructure primarily serving load in the Kitty Hawk area consists of a 230 kV network that is also capable of supporting injection of offshore wind in the 1000 MW and 3000 MW scenarios. The injection of offshore wind serves the load in the radial load pocket south of Kitty Hawk and the remaining energy reverses the existing flow back into the DVP transmission network. The flow back into the system is not significant enough to cause overloads under the contingency conditions studied. If future loads in the Kitty Hawk area are less than forecasted in the models, two transmission upgrades will be required as a result of the increased flow back into the system. The map below shows the area of the potential upgrades.

- Kitty Hawk – Shawboro 230 kV: increase capacity of existing line, \$37 M (assuming \$1M / mile)
- Kitty Hawk – Point Harbor 230 kV: increase capacity of existing line, \$8 M (assuming \$1 M / mile)

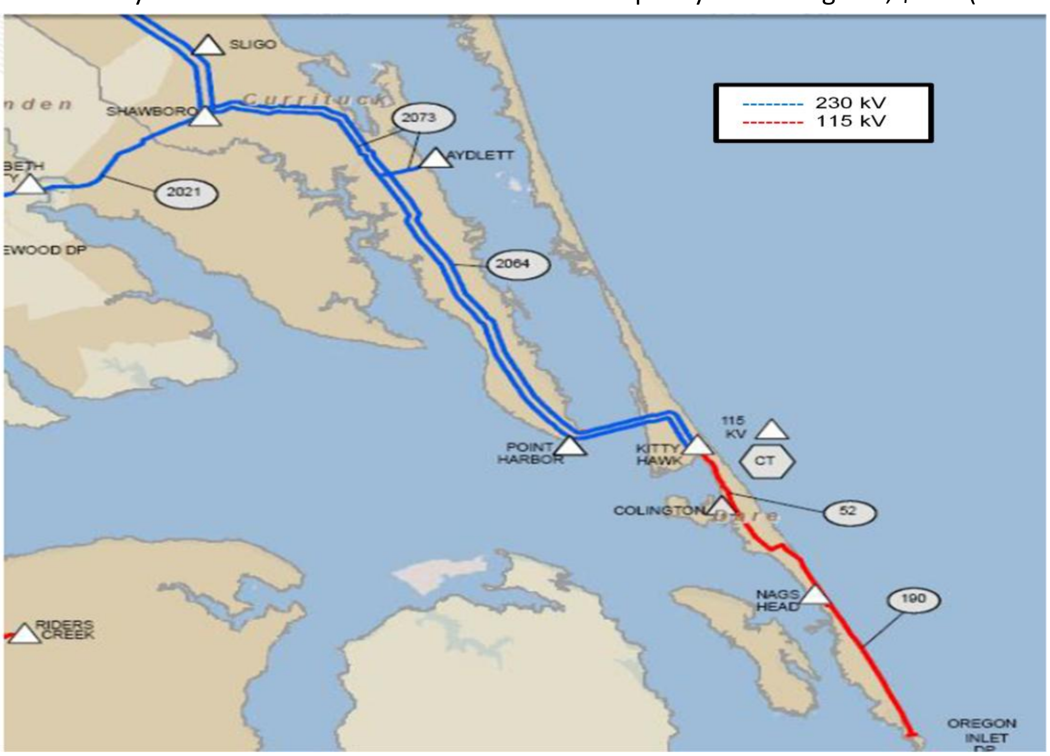

Figure 15. Northern Zone transmission

In the 5600 MW scenario an onshore connection to either DEC or PEC was not recommended because of the lack of any transmission infrastructure near the NC coastline in that area and the wind site's proximity to the proposed AWC project. Integration at Kitty Hawk, NC would require the upgrades that were mentioned previously in discussion of the 3000 MW scenario as upgrades required if the modeled loads were not as high as forecasted. Shawboro, NC could be a potential injection site, however, because it is in the DVP footprint, isn't located on the coast, and would require running transmission across Currituck Sound, it was not studied as a potential injection site. Previous studies performed by DVP identified Landstown (Virginia Beach, VA) as a suitable location for integration of up to 2000 MW which is why it was proposed rather than NC sites. In 2010, DVP's "Virginia Offshore Wind Integration Study" report [12] indicated that Landstown could accommodate up to 1500 MW of offshore wind injection without requiring any upgrades. The "2012 NCTPC – PJM Joint Interregional Reliability Study" report [13] determined that Landstown could accommodate up to 2000 MW of offshore injection if a second 230 kV circuit was added between DVP's Landstown and Stumpy Lake substations. Assuming $1 M/mi., the estimated cost of that project is $4 M.

Therefore in the 5600 MW scenario injection of the offshore wind energy is recommended in the Virginia Beach, VA area of DVP or to the AWC offshore bus which is also planned to connect in the Virginia Beach area. Landstown is a viable location because it is well connected, is in a sizable load pocket and has close proximity to the Virginia coast. No transmission system overloads were observed under the contingency conditions studied.

3.3.4.2 CENTRAL ZONE

Bayboro, NC, near the North Carolina outer banks, is the area where central zone generation was assumed to connect for the 1000 MW and 3000 MW scenarios. These scenarios analyzed offshore wind injections at PEC's Silver Hill 230 kV station, west of Bayboro, NC. The 5600 MW scenario required injection at PEC's New Bern 230 kV station, located in New Bern, NC. This connection would require bypassing the Silver Hill station with a double circuit 230 kV line from the onshore converter station to New Bern. The 3000 MW and 5600 scenarios included several offshore wind sites that were located much farther south in the central zone and were not feasible to connect to either Silver Hill or New Bern, so an additional injection site was selected. These scenarios analyzed an additional offshore wind injection west of Morehead City, NC at PEC's Morehead-Wildwood 230 kV station. Tables 14-16 show how the injections were split for the 3000 MW and 5600 MW scenarios. Because of the generators distance from shore in the central zone, a DC cable with associated converter stations would be required for integration at Silver Hill and New Bern; however, integration at Morehead-Wildwood can be accomplished with a 230 kV AC connection.

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[12] http://offshorewindhub.org/resource/1015/

[13] http://www.nctpc.org/nctpc/document/REF/2013-02-14/2012_NCTPC-PJM_Study_Final_Report.pdf

WINTER			
	1000 MW	**3000 MW**	**5600 MW**
Morehead-Wildwood	N/A	140	273
New Bern	N/A	N/A	594
Silver Hill	161	417	N/A

Table 14. Average simulated power output (MW) for January 2000, 8 a.m.

SHOULDER			
	1000 MW	**3000 MW**	**5600 MW**
Morehead-Wildwood	N/A	143	277
New Bern	N/A	N/A	603
Silver Hill	164	428	N/A

Table 15. Average simulated power output (MW) for May 2000, 4 p.m.

SUMMER			
	1000 MW	**3000 MW**	**5600 MW**
Morehead-Wildwood	N/A	82	163
New Bern	N/A	N/A	355
Silver Hill	97	244	N/A

Table 16. Average simulated power output (MW) for July 2000, 4 p.m.

All injections at Silver Hill required converting the station from a tap station to a switching station in order to increase the flexibility of the local transmission system. The 1000 MW and 3000 MW scenarios did not require additional transmission system modifications. If Morehead-Wildwood was not included as a second injection site in the central zone, the 3000 MW scenario would require construction of a second 230 kV circuit between the Silver Hill and New Bern 230 kV stations. This transmission upgrade would be required to reduce contingency loading on the existing New Bern – Silver Hill 230 kV circuit and to help transfer the power to the New Bern area to serve load. Assuming $2 M per mile, construction of this facility would cost approximately $34 M. Figure 16 below shows the area of the system modifications. No additional upgrades are required in the Morehead-Wildwood area.

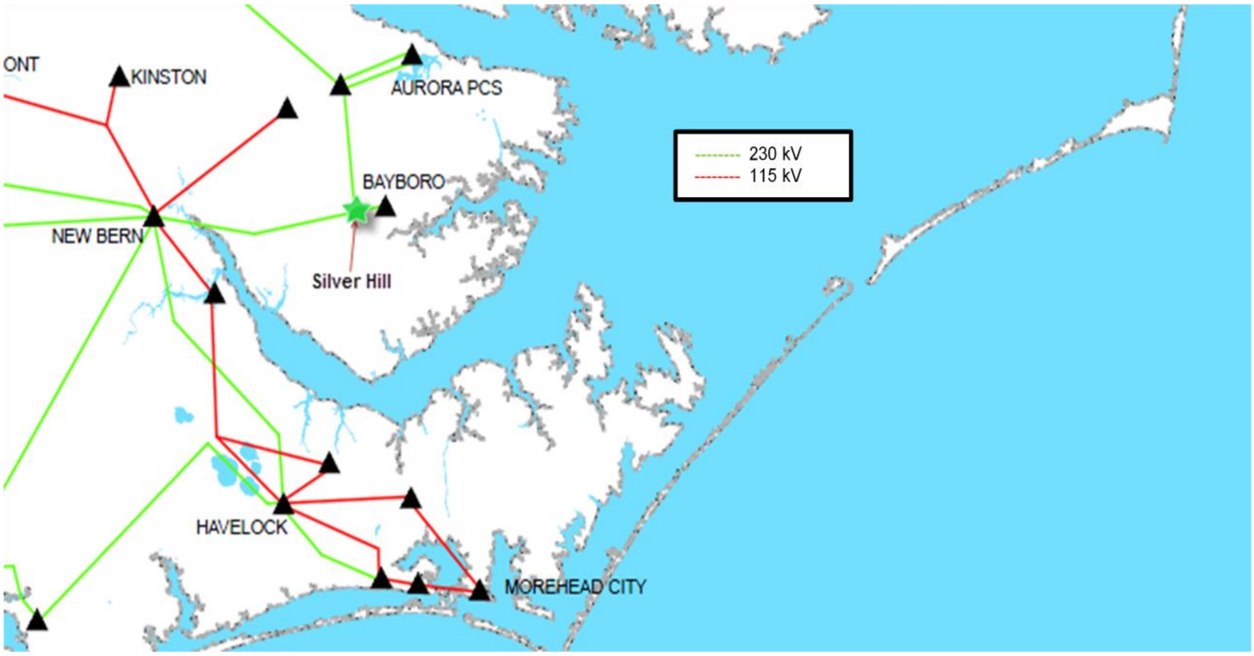

Figure 16. Central Zone transmission

With the connection at New Bern for the 5600 MW scenario, no additional transmission system modifications were necessary to satisfy the contingency conditions studied. Prior to including the second injection site at Morehead-Wildwood, all of the central zone offshore wind generation was integrated at New Bern without requiring any upgrades. This shows that the New Bern area can accommodate an injection of at least 880 MW. In the 5600 MW scenario, no additional upgrades are required in the Morehead-Wildwood area.

3.3.4.3 SOUTHERN ZONE

No offshore generation was identified in the southern zone in the 1000 MW scenario. In the 3000 MW and 5600 MW scenario, southern zone generation was assumed to connect onshore at SCPSA's Bucksville 230 kV station. Bucksville is a new station scheduled to be completed in 2014 in the Myrtle Beach area of South Carolina. The station is network connected and is located in a large load pocket. Bucksville was assumed to connect to the southern zone offshore generation via a 230 kV connection.

Several transmission system upgrades in the area near Bucksville would be necessary to satisfy the contingency conditions studied.

- Bucksville - Perry Road 230 kV Lines: increase capacity of existing lines by adding a second set of conductors per phase (bundling), $12 M (assuming $1.5 M / mile)
- Perry Road 230/115 kV transformer bank #3: replace 150 MVA bank with 250 MVA bank, $4 M
- Perry Road - Myrtle Beach 115 kV Lines: upgrade conductor from 556 ACSR to bundled 556 ACSR, $8 M (assuming $1.5 M / mile)

Figure 17 below shows the area of the upgrades.

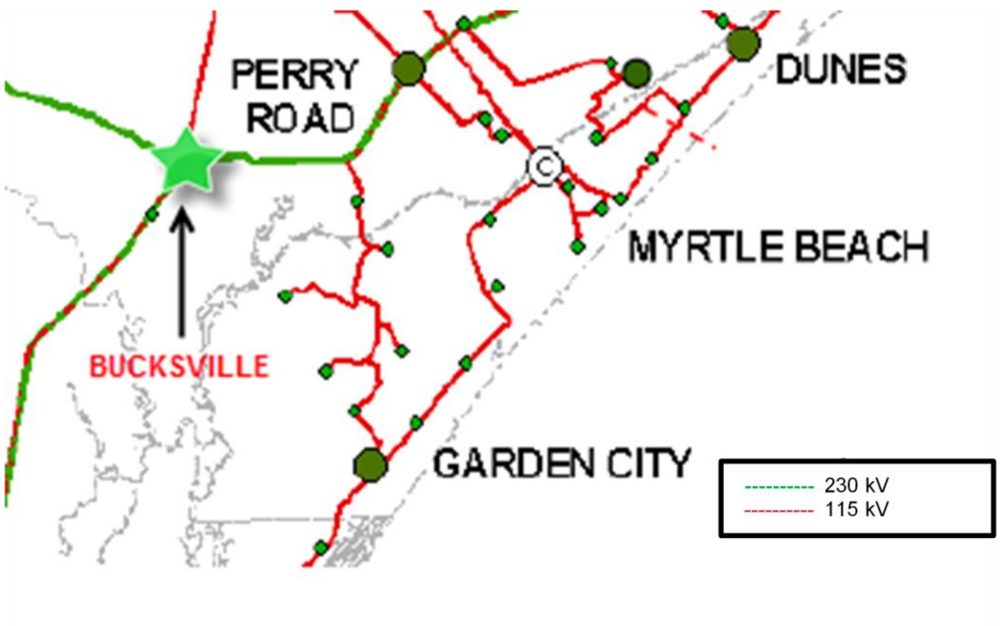

Figure 17. Southern Zone upgrades

These issues and potential solutions have appeared in previous transmission studies in the area. No additional transmission system modifications are necessary to integrate offshore wind generation in the southern zone under N-1 conditions studied.

4.0 CONCLUSIONS & RECOMMENDATIONS

This study has shown that high quality wind sites exist off the Carolinas shore in relatively shallow depths and near shore taking into consideration known exclusion criteria.

Minimal onshore electrical grid infrastructure reinforcements are required to integrate offshore wind generation.

The study should continue to Phase 2 to address the tasks of dynamic stability analysis, operating reliability impacts, and production cost impacts. Exclusion criteria assumptions should be reviewed because some of these criteria are updated as new reports are published. In addition it is suggested to add a new study task to estimate generic offshore collector system costs for the sites identified in Phase 1 in order to provide a comprehensive final study report for potential commercial reference and comparison.

APPENDIX A – SELECTED SITES

Table A17. Selected sites.

SITE	SCENARIO	ZONE	LONGITUDE	LATITUDE	CAPACITY (MW)	WSPD100 (M/S)	DEPTH (M)	COAST DIST (KM)
12	1000 MW	North	-75.322473	36.379735	100.0	8.66	-28.66	43.54
18	1000 MW	North	-75.332178	36.446170	62.4	8.66	-27.52	44.68
30	1000 MW	North	-75.400843	36.378219	93.8	8.61	-27.11	36.77
31	1000 MW	North	-75.226225	36.108237	67.1	8.63	-28.39	39.41
33	1000 MW	North	-75.393807	36.445977	67.9	8.61	-26.70	39.27
34	1000 MW	North	-75.246364	36.177066	68.5	8.61	-28.11	40.96
493	1000 MW	North	-75.320822	36.313780	100.0	8.64	-29.51	41.22
498	1000 MW	North	-75.403253	36.313531	100.0	8.61	-27.66	34.26
507	1000 MW	North	-75.297507	36.040486	41.9	8.56	-29.49	30.46
22	1000 MW	Central	-75.559834	35.101917	57.4	8.66	-26.24	13.01
51	1000 MW	Central	-75.722466	34.958001	95.0	8.59	-27.69	24.65
497	1000 MW	Central	-75.721776	35.081216	45.2	8.57	-23.71	12.07
504	1000 MW	Central	-75.808340	34.959048	100.0	8.53	-24.02	20.91
49	3000 MW	North	-75.397240	36.249940	76.5	8.55	-28.84	32.43
62	3000 MW	North	-75.476749	36.378303	65.2	8.53	-25.19	30.22
69	3000 MW	North	-75.475769	36.449577	61.2	8.51	-25.57	32.14
125	3000 MW	North	-75.571062	36.447882	100.0	8.41	-22.28	23.73
499	3000 MW	North	-75.487912	36.313215	100.0	8.51	-25.18	27.13
501	3000 MW	North	-75.570341	36.312850	100.0	8.43	-21.78	20.10
509	3000 MW	North	-75.402535	36.043622	100.0	8.44	-23.30	22.01
47	3000 MW	Central	-75.648743	35.081732	46.5	8.60	-28.02	14.31
56	3000 MW	Central	-75.721009	35.024780	88.2	8.57	-29.15	17.98
65	3000 MW	Central	-75.797096	34.887699	66.0	8.58	-24.97	27.29
71	3000 MW	Central	-75.808500	35.025334	100.0	8.53	-22.58	14.46
80	3000 MW	Central	-76.293687	34.548181	98.0	8.53	-29.52	22.14
82	3000 MW	Central	-76.369020	34.550295	69.4	8.53	-22.11	15.52
94	3000 MW	Central	-76.213663	34.683173	92.6	8.51	-26.78	19.39
112	3000 MW	Central	-75.971884	34.888877	100.0	8.49	-25.64	18.55
503	3000 MW	Central	-75.882401	34.962746	75.8	8.49	-23.44	15.89
66	3000 MW	South	-78.684368	33.147621	98.0	8.57	-20.61	46.08
72	3000 MW	South	-78.681585	33.081009	98.0	8.56	-23.46	47.96
73	3000 MW	South	-78.762841	33.078613	97.8	8.55	-20.92	40.86
76	3000 MW	South	-78.765687	33.145185	98.0	8.53	-18.74	38.63
87	3000 MW	South	-78.841687	33.076205	97.0	8.53	-18.16	34.07
100	3000 MW	South	-78.607666	33.151540	88.3	8.51	-22.22	53.12
133	3000 MW	South	-78.607853	33.287831	83.7	8.45	-20.07	47.52
81	5600 MW	North	-75.397296	36.111326	87.6	8.48	-25.84	25.59
92	5600 MW	North	-75.484956	36.247146	93.0	8.45	-26.06	24.92
98	5600 MW	North	-75.558808	36.379897	64.6	8.46	-22.16	23.19

139	5600 MW	North	-75.568558	36.245471	99.9	8.39	-23.28	17.72
167	5600 MW	North	-75.482014	36.110466	89.1	8.36	-24.73	18.69
202	5600 MW	North	-75.654326	36.379223	100.0	8.32	-17.04	14.87
212	5600 MW	North	-75.649188	36.446896	81.7	8.32	-20.11	16.85
491	5600 MW	North	-75.569359	36.177623	100.0	8.31	-23.69	15.06
492	5600 MW	North	-75.487072	36.177986	100.0	8.39	-26.05	21.85
508	5600 MW	North	-75.486238	36.042755	100.0	8.30	-23.92	15.12
67	5600 MW	Central	-75.881868	34.818112	74.2	8.57	-28.76	29.62
75	5600 MW	Central	-75.970807	34.822422	100.0	8.53	-29.15	24.02
104	5600 MW	Central	-76.132784	34.753756	97.2	8.50	-27.68	19.28
113	5600 MW	Central	-76.046792	34.817700	76.5	8.49	-28.99	19.64
122	5600 MW	Central	-76.290238	34.611107	70.2	8.50	-26.97	18.59
169	5600 MW	Central	-76.051225	34.887192	98.1	8.42	-23.21	13.76
191	5600 MW	Central	-76.293710	34.681744	89.2	8.42	-22.91	13.66
83	5600 MW	South	-78.686901	33.214891	93.3	8.52	-19.03	45.36
101	5600 MW	South	-78.829018	33.006076	63.0	8.53	-20.70	38.37
109	5600 MW	South	-78.607876	33.083091	79.6	8.51	-24.84	54.53
118	5600 MW	South	-78.826302	33.134864	56.4	8.49	-17.62	33.33
127	5600 MW	South	-78.766353	33.212275	89.5	8.47	-18.43	37.94
128	5600 MW	South	-78.521537	33.226211	69.4	8.47	-24.01	58.03
140	5600 MW	South	-78.529599	33.285092	89.0	8.45	-22.19	53.87
143	5600 MW	South	-78.923234	33.133696	69.1	8.47	-14.72	24.68
195	5600 MW	South	-78.613555	33.353388	98.0	8.37	-19.22	43.39
207	5600 MW	South	-78.453827	33.355379	80.6	8.37	-24.54	54.28
209	5600 MW	South	-78.532029	33.355736	98.0	8.36	-21.45	49.08
219	5600 MW	South	-78.692126	33.351651	94.8	8.34	-16.91	37.07
242	5600 MW	South	-78.695747	33.417657	98.0	8.31	-17.53	33.03

APPENDIX B – CENTRAL ZONE SITE DISTANCE ASSESSMENTS

1000 MW SCENARIO

Table B18 shows the analysis results for COWICS central wind sites for 1000 MW scenario.

Table B18. Analysis Results for 1000 MW Scenario

Site ID	Scenario (MW)	Capacity (MW)	Distance to Interconnection Options			Shortest Distance to	Suggested Location	Distance to Other Sites		
			To MW	To SH	To NB			51	497	504
			mi	mi	mi			mi	mi	mi
51	1000	95	60.6	64.9	80.7	**Morehead**	**Silver Hill**	0.0	8.6	4.9
497	1000	45.2	63.4	63.7	79.8	**Morehead**	**Silver Hill**	8.6	0.0	9.8
504	1000	100	55.9	60.1	75.9	**Morehead**	**Silver Hill**	4.9	9.8	0.0

While each of these three sites is closer to Morehead-Wildwood, the differences to Silver Hill are small. They are also close to each other and have a total capacity of 240 MW installed nameplate capacity so it may be more economical to connect them to a common collector platform and transmit the bulk power to shore using a 230 kV AC system.

3000 MW SCENARIO

Table B19 shows the distances from the wind generator sites to the substation options, while Table B20 shows the distances among the sites.

In this case, sites 80, 82 and 94 (highlighted in yellow) are significantly closer to Morehead-Wildwood than to Silver Hill. These sites are also close to each other, but quite far from the other sites in the Central zone. They have a total capacity of about 260 MW installed nameplate capacity. For these reasons it is recommended that these three sites be connected via a 230 kV AC system to the Morehead-Wildwood site.

The remaining sites have a combined capacity of about 718 MW installed nameplate capacity and are between fifty and seventy miles from both Morehead City and Silver Hill. There are several options for these sites:

1) Multiple collector platforms can be used, each transmitting lower power levels via HVAC cables to Silver Hill;
2) A common collector platform can be used for the entire capacity and a HVAC transmission system using multiple cables per phase can be used; or,
3) A common collector platform can be used and a HVDC transmission system can be used.

Ultimately, a complete economic assessment would be needed to determine the best option, but it is noted that the distances calculated are direct route distances. Experience has shown that it is seldom possible to lay the cable in a direct line between the platforms and the substation. This indirect routing will add distance to the cable, thereby tending toward the HVDC solution considering only distance and cable issues.

Regardless of the transmission method, it is reasonable to plan that the power from the remaining sites will be brought into Silver Hill.

Table B19. 3000 MW Scenario Site Distances to Substation Options

Site ID	Scenario (MW)	Capacity (MW)	Distance to Interconnection Options			Shortest Distance to	Suggested Location
			To MW	To SH	To NB		
			mi	mi	mi		
51	1000	95	60.6	64.9	80.7	Morehead	Silver Hill
497	1000	45.2	63.4	63.7	79.8	Morehead	Silver Hill
504	1000	100	55.9	60.1	75.9	Morehead	Silver Hill
47	3000	46.5	67.2	67.9	83.9	Morehead	Silver Hill
56	3000	88.2	62.0	64.2	80.2	Morehead	Silver Hill
65	3000	66	55.3	62.0	77.5	Morehead	Silver Hill
71	3000	100	57.4	59.2	75.2	Morehead	Silver Hill
80	3000	98	28.8	52.0	62.8	Morehead	Morehead
82	3000	69.4	24.9	49.4	59.5	Morehead	Morehead
94	3000	92.6	30.6	48.1	60.8	Morehead	Morehead
112	3000	100	45.6	52.5	67.9	Morehead	Silver Hill
503	3000	75.8	51.9	55.9	71.7	Morehead	Silver Hill

Table B20. 3000 MW Scenario Distances among Sites

Site ID	Scenario (MW)	Capacity (MW)	Distance to Other Sites											
			51	497	504	47	56	65	71	80	82	94	112	503
			mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	Mi
51	1000	95	0.0	8.6	4.9	9.6	4.6	6.5	6.8	43.3	46.5	33.9	15.0	9.1
497	1000	45.2	8.6	0.0	9.8	4.2	3.9	14.1	6.3	49.4	52.2	39.4	19.5	12.3
504	1000	100	4.9	9.8	0.0	12.5	6.8	5.0	4.6	39.8	42.8	30.0	10.5	4.2
47	3000	46.5	9.6	4.2	12.5	0.0	5.7	15.9	9.9	52.2	55.3	42.5	22.8	15.7
56	3000	88.2	4.6	3.9	6.8	5.7	0.0	10.5	5.0	46.5	49.6	36.8	17.1	10.1
65	3000	66	6.5	14.1	5.0	15.9	10.5	0.0	9.6	36.9	40.2	27.7	10.0	7.1
71	3000	100	6.8	6.3	4.6	9.9	5.0	9.6	0.0	43.2	46.0	33.2	13.3	6.1
80	3000	98	43.3	49.4	39.8	52.2	46.5	36.9	43.2	0.0	4.3	10.4	30.0	37.2
82	3000	69.4	46.5	52.2	42.8	55.3	49.6	40.2	46.0	4.3	0.0	12.8	32.7	39.9
94	3000	92.6	33.9	39.4	30.0	42.5	36.8	27.7	33.2	10.4	12.8	0.0	19.9	27.1
112	3000	100	15.0	19.5	10.5	22.8	17.1	10.0	13.3	30.0	32.7	19.9	0.0	7.2
503	3000	75.8	9.1	12.3	4.2	15.7	10.1	7.1	6.1	37.2	39.9	27.1	7.2	0.0

5600 MW SCENARIO

Table B21 shows the distances from the wind generator sites to the substation options, while Table B22 shows the distances among the sites.

For this scenario the list of recommended sites to Morehead-Wildwood are expanded to include an additional 257 MW installed nameplate capacity (sites are highlighted in yellow). This can be handled either by a larger collector platform with appropriate cabling to shore or by multiple collector platforms.

The sites highlighted in orange are all close to each other and form a natural cluster for either an independent collector platform, or a collector hub to gather the locally generated energy for transmission to a main platform that collects from the remaining sites. The orange sites and the remaining sites are both best transmitted to Silver Hill or New Bern. For the 5600 MW scenario, New Bern is a preferred location because it is closer to larger load centers.

Table B21. 5600 MW Scenario Site Distances to Substation Options

Site ID	Scenario	Capacity (MW)	Distance to Interconnection Options			Shortest Distance to	Suggested Location
			to MW	to SH	to NB		
			mi	mi	mi		
51	1000 MW	95	60.6	64.9	80.7	**Morehead**	**New Bern**
497	1000 MW	45.2	63.4	63.7	79.8	**Morehead**	**New Bern**
504	1000 MW	100	55.9	60.1	75.9	**Morehead**	**New Bern**
47	3000 MW	46.5	67.2	67.9	83.9	**Morehead**	**New Bern**
56	3000 MW	88.2	62.0	64.2	80.2	**Morehead**	**New Bern**
65	3000 MW	66	55.3	62.0	77.5	**Morehead**	**New Bern**
71	3000 MW	100	57.4	59.2	75.2	**Morehead**	**New Bern**
80	3000 MW	98	28.8	52.0	62.8	**Morehead**	**Morehead**
82	3000 MW	69.4	24.9	49.4	59.5	**Morehead**	**Morehead**
94	3000 MW	92.6	30.6	48.1	60.8	**Morehead**	**Morehead**
112	3000 MW	100	45.6	52.5	67.9	**Morehead**	**New Bern**
503	3000 MW	75.8	51.9	55.9	71.7	**Morehead**	**New Bern**
75	5600 MW	100	44.8	54.4	69.3	**Morehead**	**New Bern**
104	5600 MW	97.2	35.1	48.7	62.5	**Morehead**	**Morehead**
122	5600 MW	70.2	27.3	48.6	60.1	**Morehead**	**Morehead**
169	5600 MW	98.1	41.2	48.4	63.5	**Morehead**	**New Bern**
67	5600 MW	74.2	49.8	59.1	74.2	**Morehead**	**New Bern**
113	5600 MW	76.5	40.4	50.6	65.3	**Morehead**	**New Bern**
191	5600 MW	89.2	26.1	44.9	57.1	**Morehead**	**Morehead**

Table B22. 5600 MW Scenario Distances among Sites

Site ID	Scenario	Capacity (MW)	Distance to Other Sites																		
			51	497	504	47	56	65	71	80	82	94	112	503	75	104	122	169	67	113	191
			mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	mi	Mi
51	1000 MW	95	0.0	8.6	4.9	9.6	4.6	6.5	6.8	43.3	46.5	33.9	15.0	9.1	17.0	27.4	40.4	19.4	13.3	20.9	37.8
497	1000 MW	45.2	8.6	0.0	9.8	4.2	3.9	14.1	6.3	49.4	52.2	39.4	19.5	12.3	22.9	32.7	46.0	23.1	20.4	26.0	42.8
504	1000 MW	100	4.9	9.8	0.0	12.5	6.8	5.0	4.6	39.8	42.8	30.0	10.5	4.2	13.3	23.4	36.6	14.7	10.7	16.8	33.7
47	3000 MW	46.5	9.6	4.2	12.5	0.0	5.7	15.9	9.9	52.2	55.3	42.5	22.8	15.7	25.7	35.8	49.1	26.6	22.6	29.2	46.1
56	3000 MW	88.2	4.6	3.9	6.8	5.7	0.0	10.5	5.0	46.5	49.6	36.8	17.1	10.1	20.0	30.1	43.4	21.1	17.0	23.5	40.4
65	3000 MW	66	6.5	14.1	5.0	15.9	10.5	0.0	9.6	36.9	40.2	27.7	10.0	7.1	10.9	21.3	34.1	14.5	6.8	15.0	31.8
71	3000 MW	100	6.8	6.3	4.6	9.9	5.0	9.6	0.0	43.2	46.0	33.2	13.3	6.1	16.9	26.4	39.8	16.8	15.0	19.8	36.5
80	3000 MW	98	43.3	49.4	39.8	52.2	46.5	36.9	43.2	0.0	4.3	10.4	30.0	37.2	26.5	17.0	4.4	27.3	30.1	23.5	9.3
82	3000 MW	69.4	46.5	52.2	42.8	55.3	49.6	40.2	46.0	4.3	0.0	12.8	32.7	39.9	29.6	19.6	6.2	29.6	33.5	26.2	10.1
94	3000 MW	92.6	33.9	39.4	30.0	42.5	36.8	27.7	33.2	10.4	12.8	0.0	19.9	27.1	16.9	6.7	6.7	16.9	21.1	13.3	4.6
112	3000 MW	100	15.0	19.5	10.5	22.8	17.1	10.0	13.3	30.0	32.7	19.9	0.0	7.2	4.6	13.1	26.5	4.5	7.1	6.5	23.3
503	3000 MW	75.8	9.1	12.3	4.2	15.7	10.1	7.1	6.1	37.2	39.9	27.1	7.2	0.0	11.0	20.4	33.8	11.0	10.1	13.8	30.5
75	5600 MW	100	17.0	22.9	13.3	25.7	20.0	10.9	16.9	26.5	29.6	16.9	4.6	11.0	0.0	10.4	23.4	6.4	5.1	4.3	20.9
104	5600 MW	97.2	27.4	32.7	23.4	35.8	30.1	21.3	26.4	17.0	19.6	6.7	13.1	20.4	10.4	0.0	13.4	10.4	15.0	6.6	10.5
122	5600 MW	70.2	40.4	46.0	36.6	49.1	43.4	34.1	39.8	4.4	6.2	6.7	26.5	33.8	23.4	13.4	0.0	23.5	27.4	20.0	4.9
169	5600 MW	98.1	19.4	23.1	14.7	26.6	21.1	14.5	16.8	27.3	29.6	16.9	4.5	11.0	6.4	10.4	23.5	0.0	10.8	4.8	19.9
67	5600 MW	74.2	13.3	20.4	10.7	22.6	17.0	6.8	15.0	30.1	33.5	21.1	7.1	10.1	5.1	15.0	27.4	10.8	0.0	9.4	25.4
113	5600 MW	76.5	20.9	26.0	16.8	29.2	23.5	15.0	19.8	23.5	26.2	13.3	6.5	13.8	4.3	6.6	20.0	4.8	9.4	0.0	17.0
191	5600 MW	89.2	37.8	42.8	33.7	46.1	40.4	31.8	36.5	9.3	10.1	4.6	23.3	30.5	20.9	10.5	4.9	19.9	25.4	17.0	0.0