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Carolina Offshore Wind Integration Case Study
Phase 1 Final Technical Report

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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.

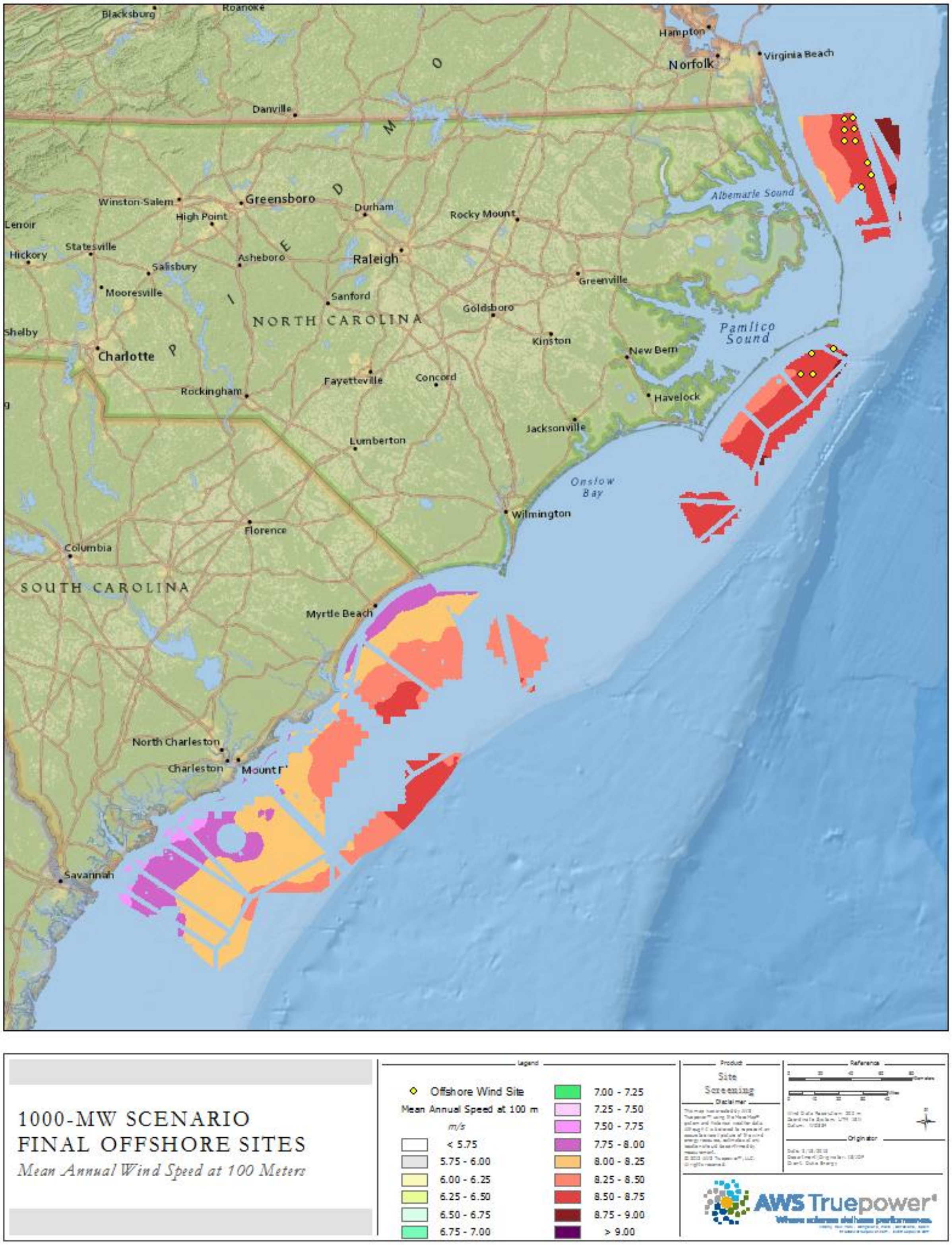

Figure 1. Sites selected for the 1000-MW scenario. Mean annual wind speeds for non-excluded areas are shaded.

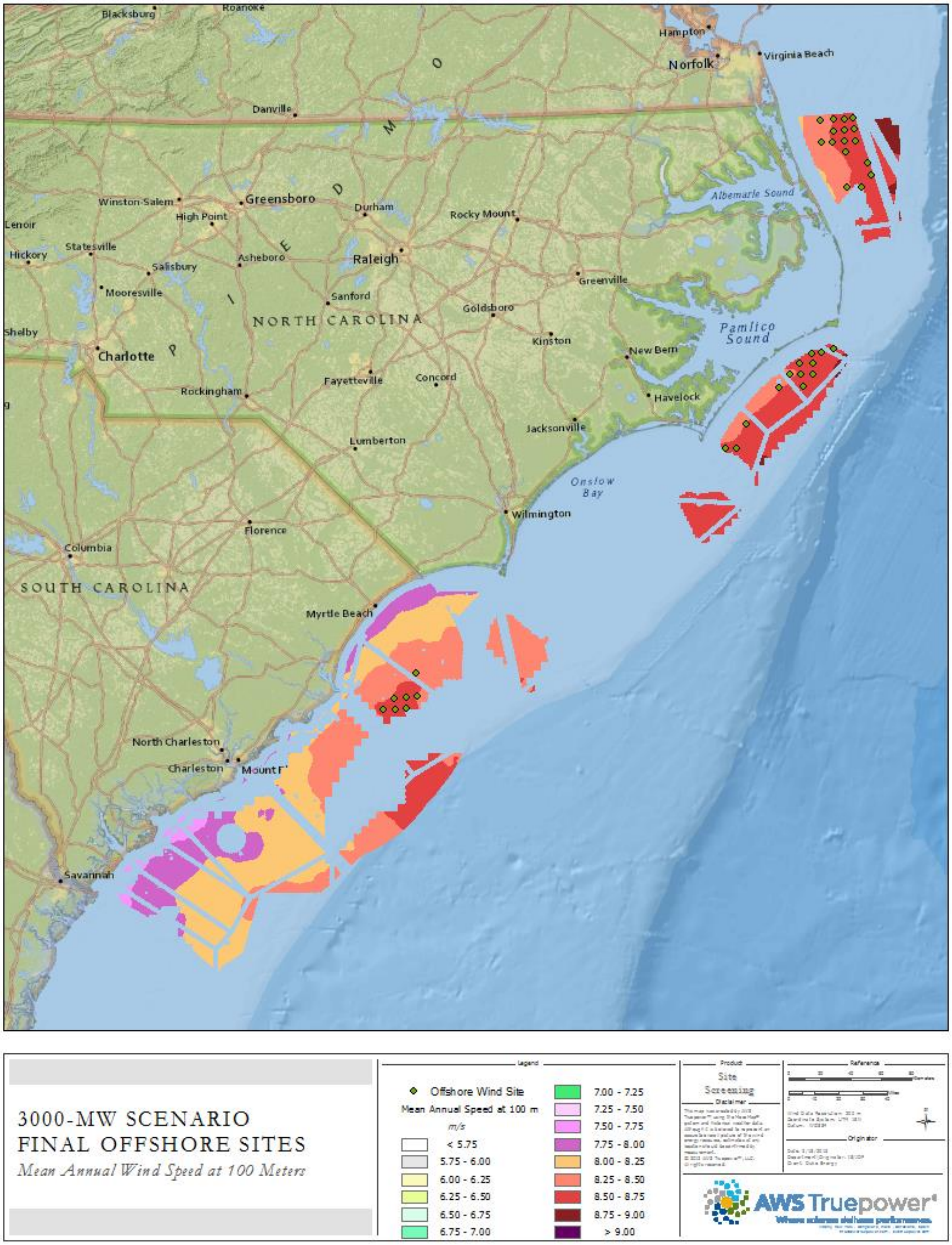

Figure 2. Sites selected for the 3000-MW scenario. Mean annual wind speeds for non-excluded areas are shaded.

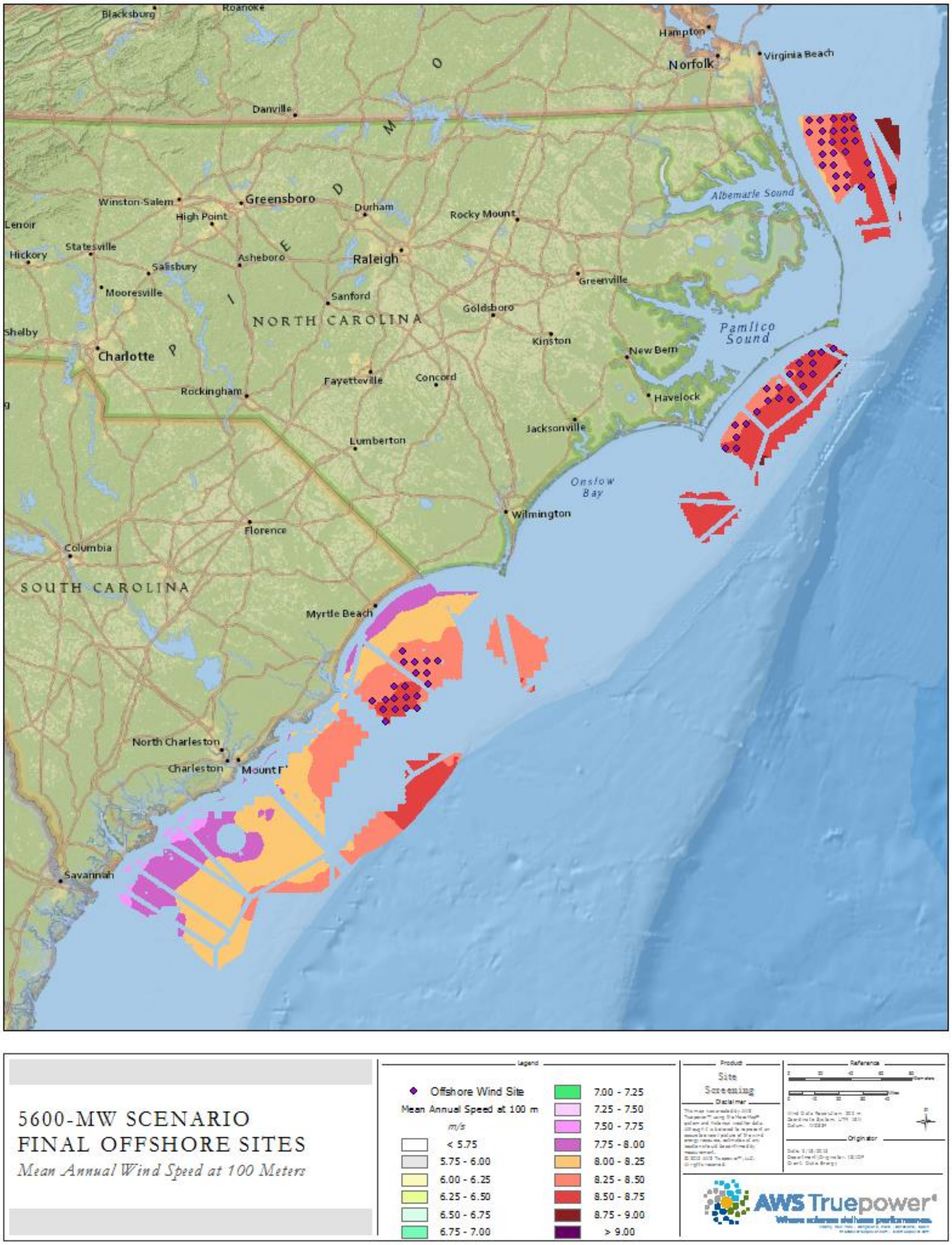

Figure 3. Sites selected for the 5600-MW scenario. Mean annual wind speeds for non-excluded areas are shaded.

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.

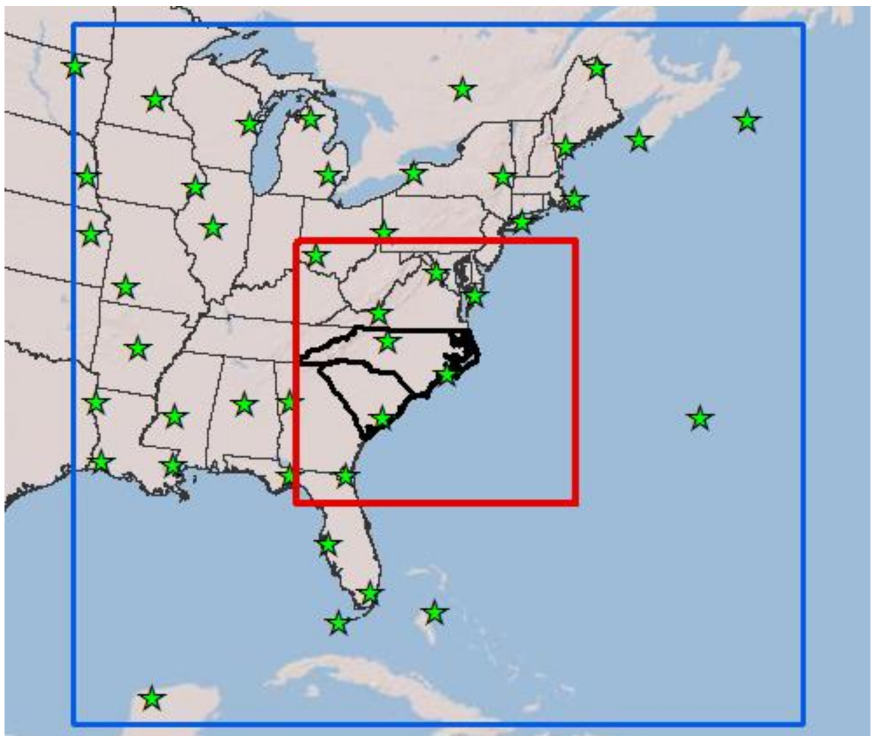

Figure 4. Boundaries of MASS 10-km inner grid (red) and 30-km outer grid (blue). Locations of rawinsondes assimilated in the model are shown by the green stars.

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

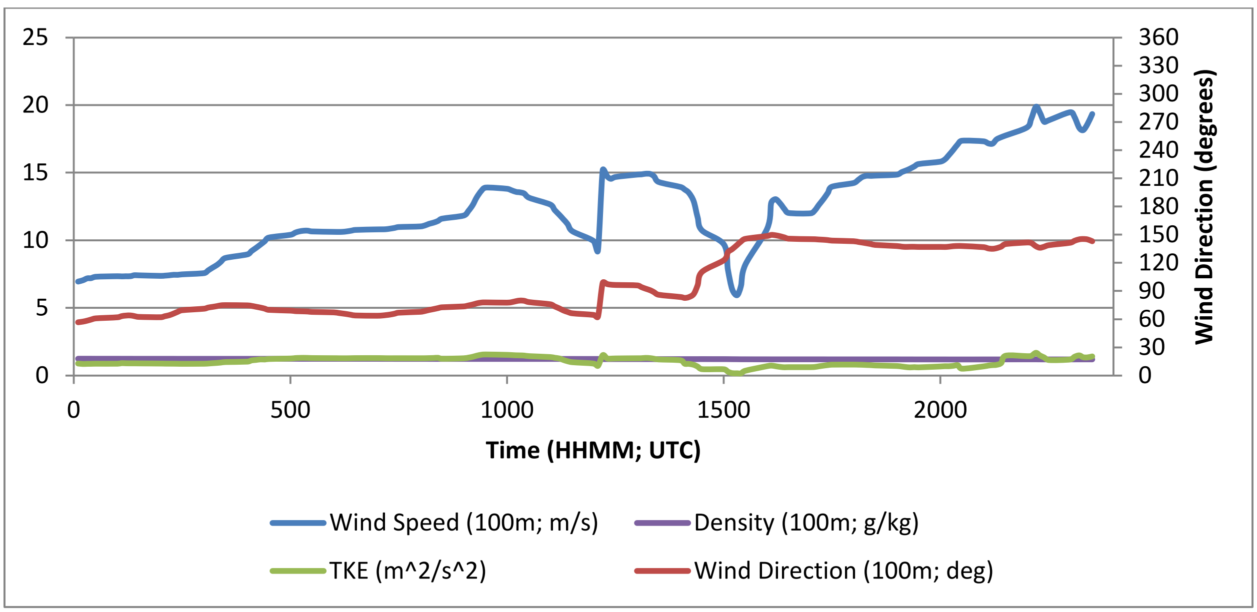

Figure 5. Model output at 100 m hub height for a sample day. Wind speed (m/s), turbulent kinetic energy (m^2/s^2), and density (g/kg) are given by the blue, green, and purple lines, respectively on the primary y-axis. Wind direction (deg.) is given by the red line on the secondary y-axis.

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.

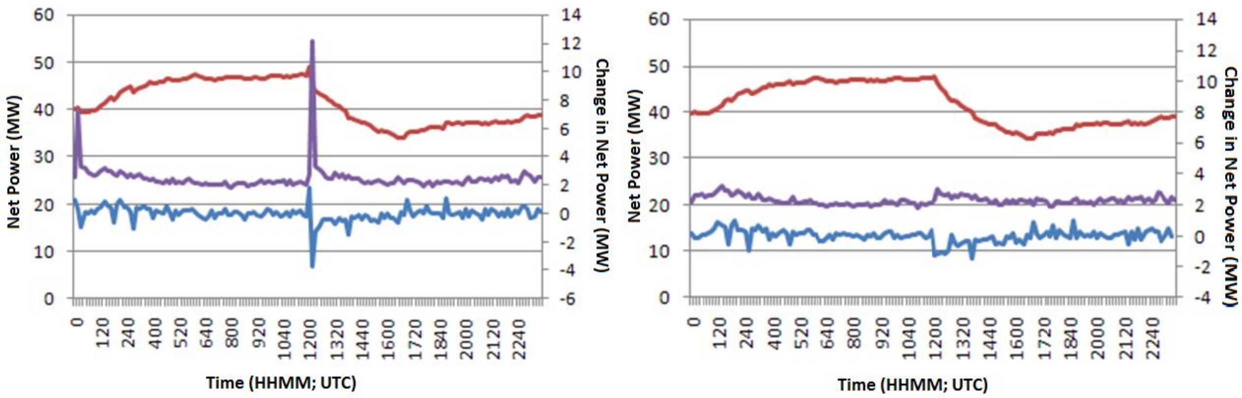

Figure 6. Jumps in power output at one site before (left) and after (right) the correction. The mean output (red) and absolute change in output from one 10-minute record to the next (purple) are shown on the left axis, while the change in output (blue) is shown on the right axis.

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.

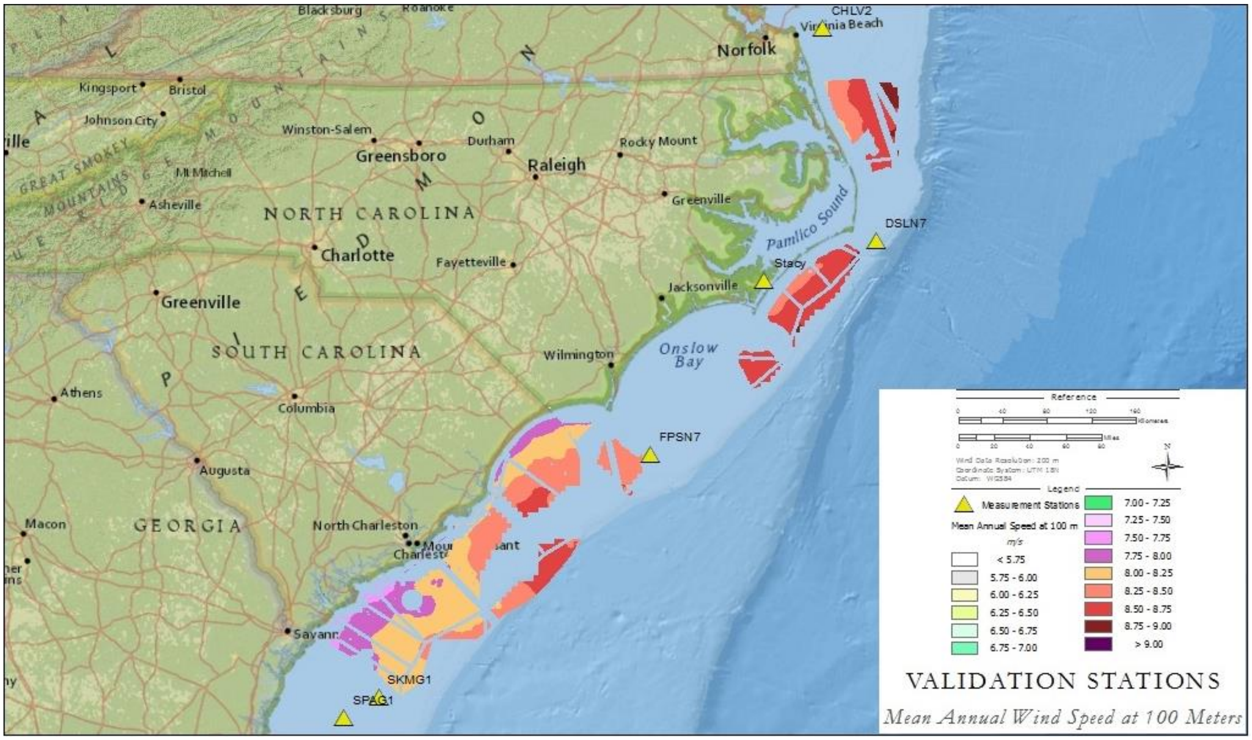

Figure 7. Validation station locations.

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.

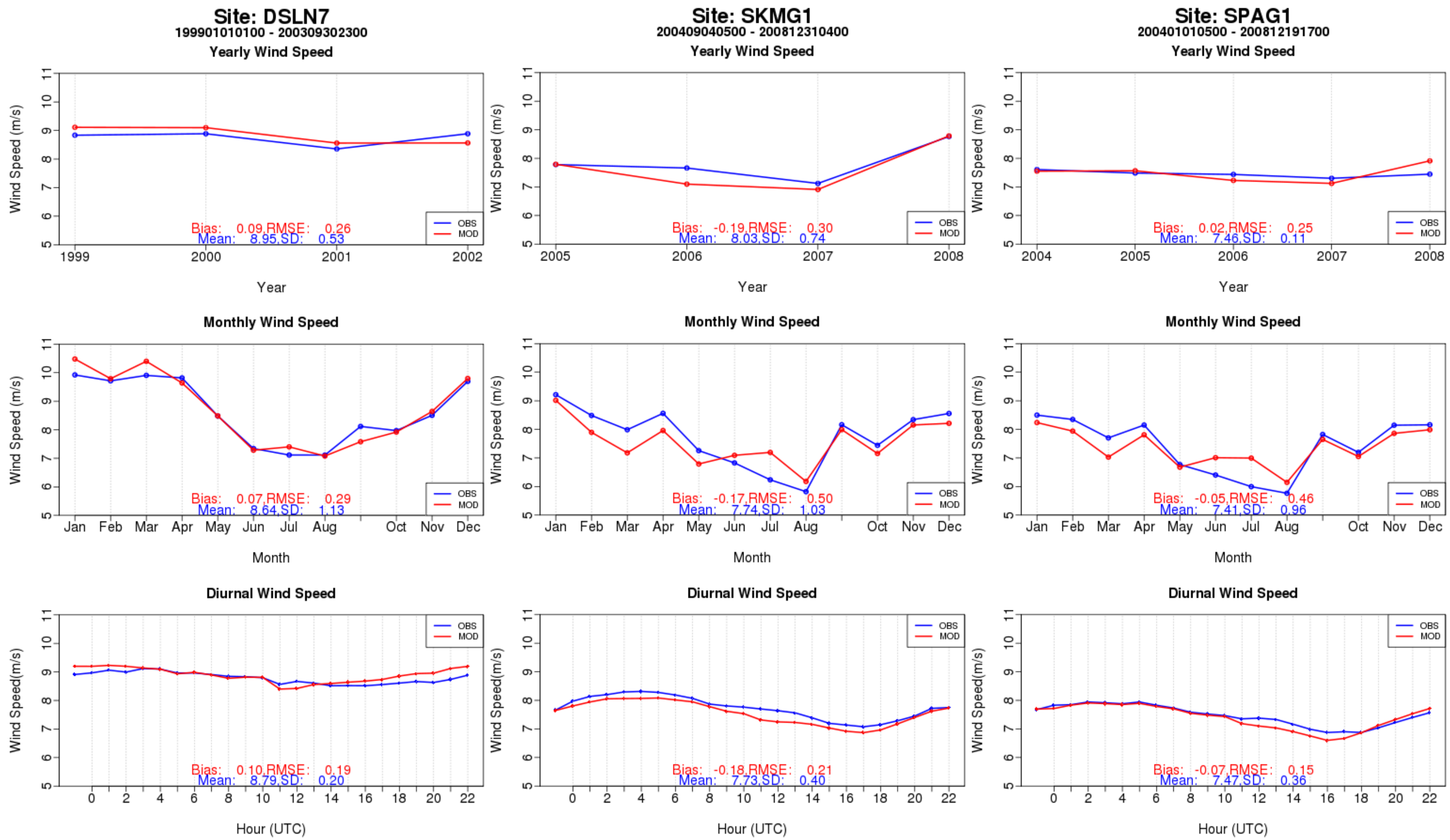

Figure 8. Comparison of modeled (red) and observed (blue) wind speeds for DSLN7 (46.6 m; left), SKMG1 (50.0 m; middle), and SPAG1 (50.0 m; right) and the closest model grid point and level (50 m). Annual, monthly, and diurnal means are shown in the top, middle, and bottom panels, respectively.

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.

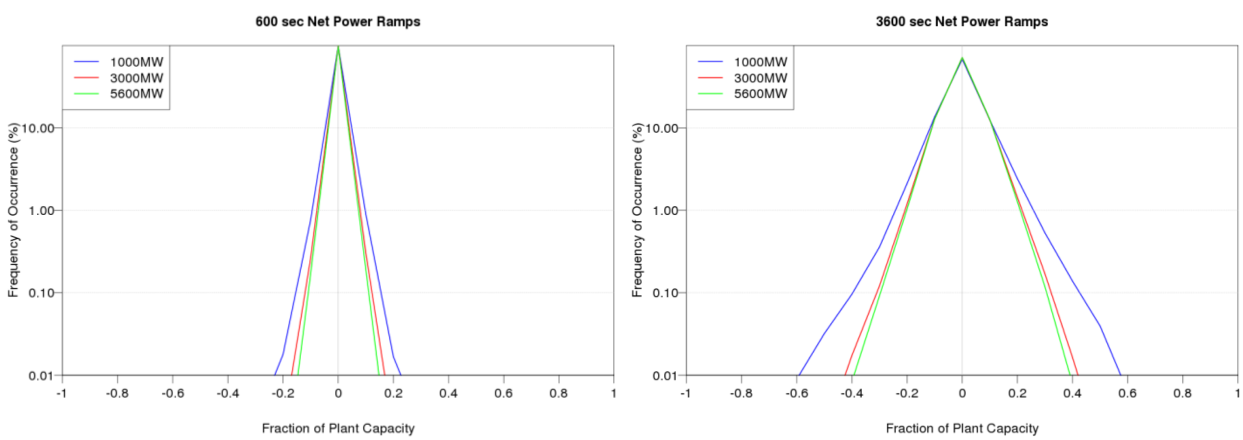

Figure 9. Frequency distribution of net power ramps as a fraction of plant nameplate capacity for 10-minute (left) and 60-minute (right) intervals. Results for the 1000-, 3000-, and 5600-MW scenarios are shown in blue, red, and green, respectively. The y-axis is shown on a logarithmic scale to emphasize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

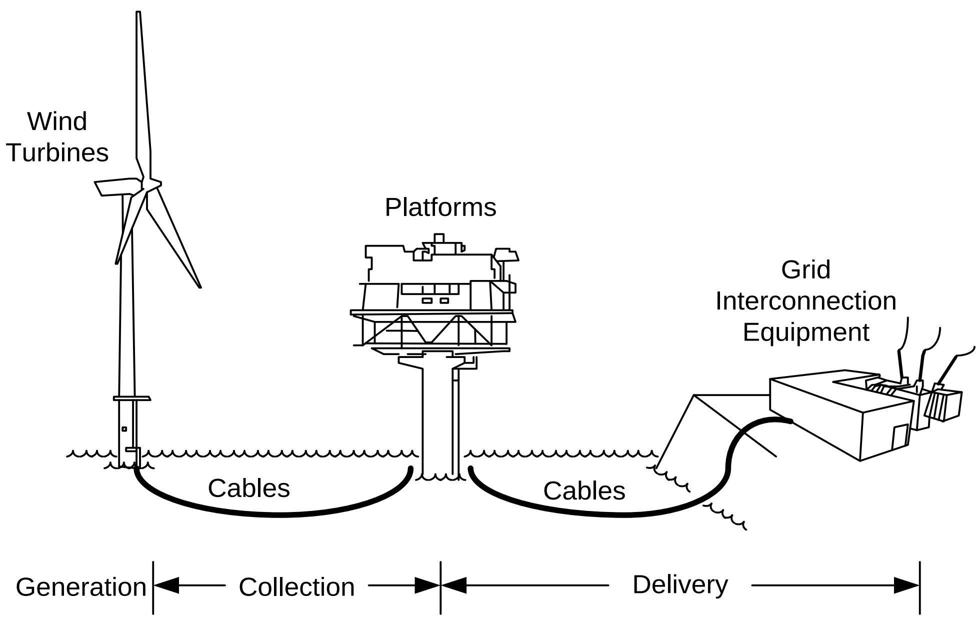

Figure 10. Generalized concept for an offshore wind energy system

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.

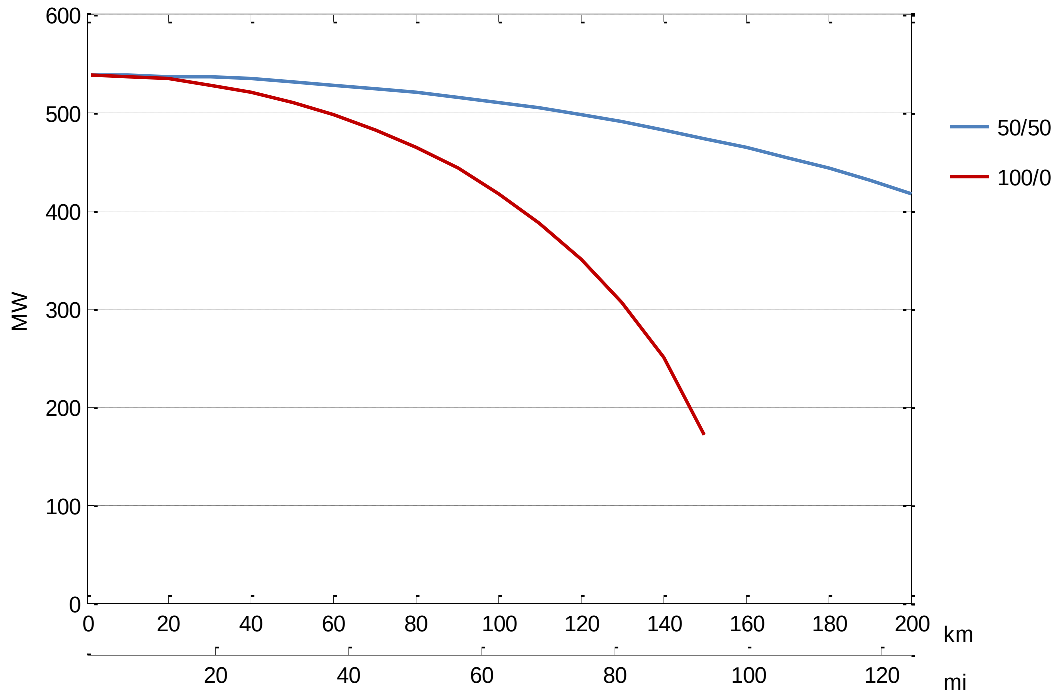

Figure 11. Maximum, real power transfer for 230 kV cables with onshore/offshore reactive compensation splits of 100/0 and 50/50 (2000 kcmil copper cross section)

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

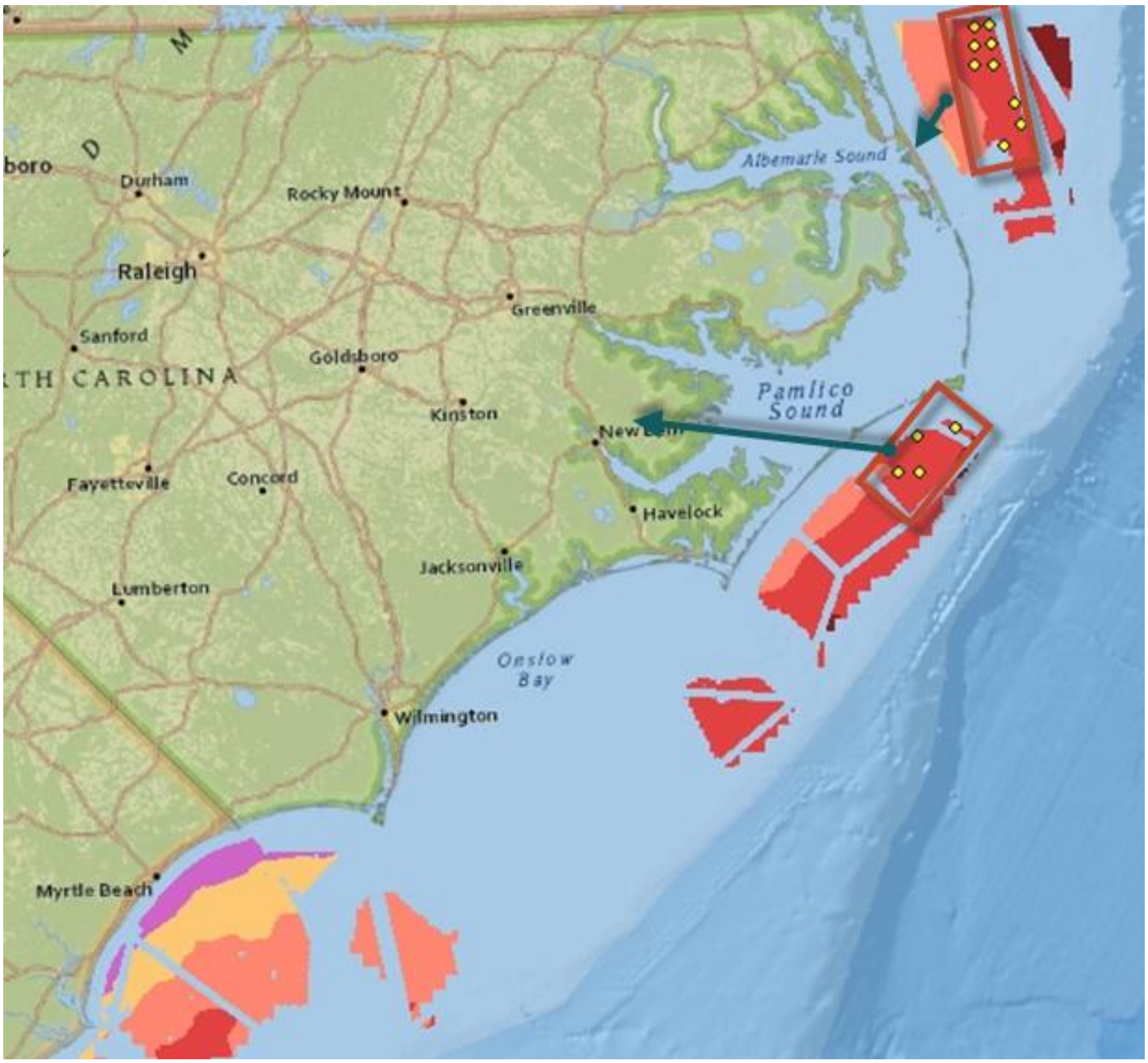

Figure 12. Onshore interconnection station locations, 1000 MW scenario

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**

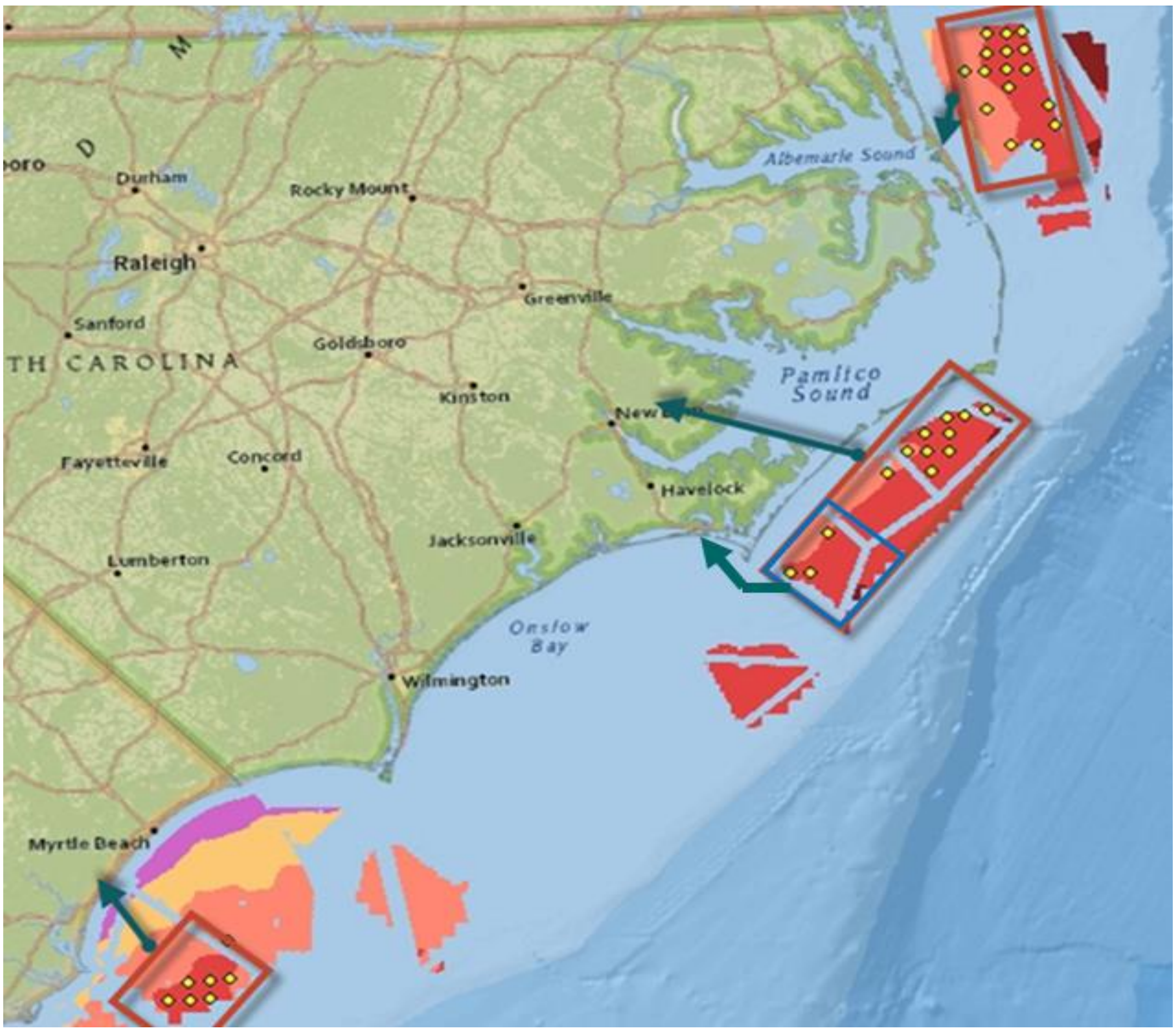

Figure 13. Onshore interconnection station locations, 3000 MW scenario

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

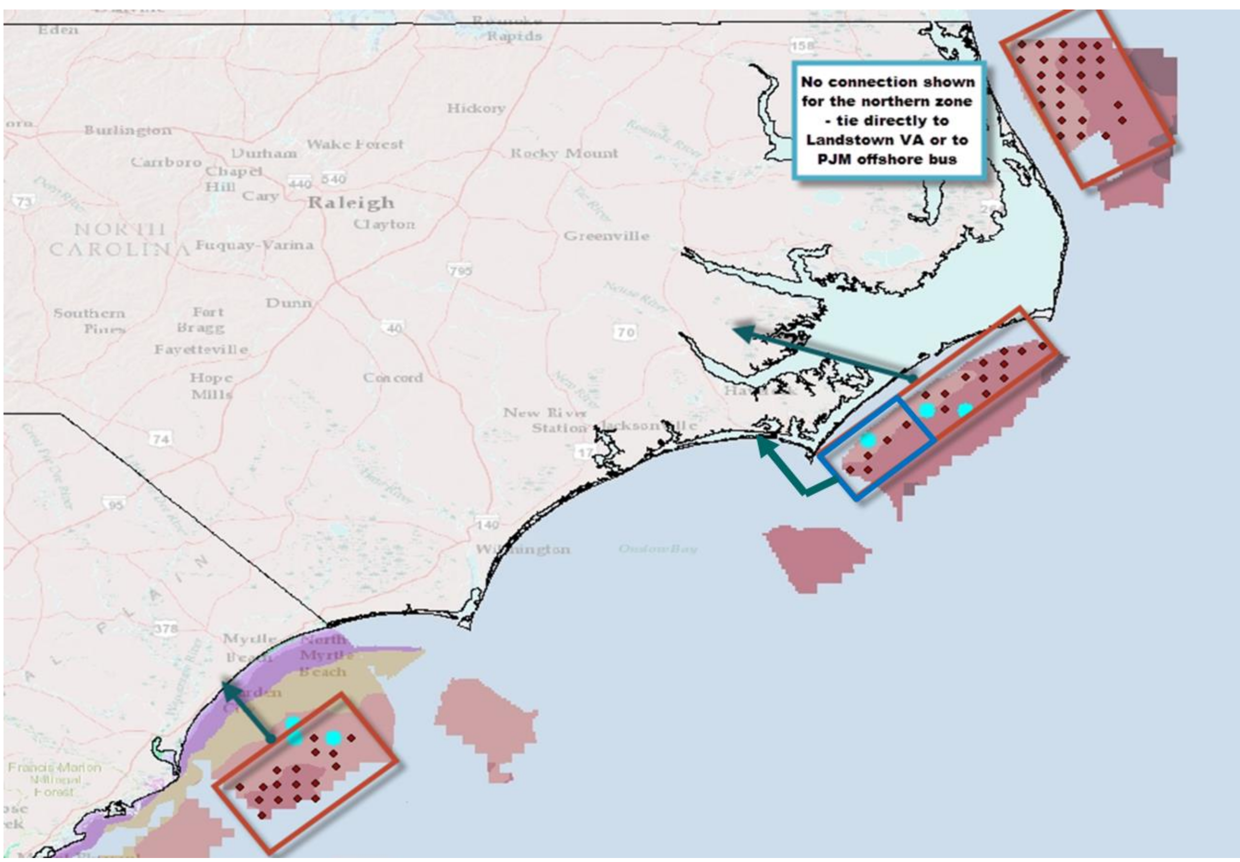

Figure 14. **Onshore interconnection station locations, 5600 MW scenario**

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)

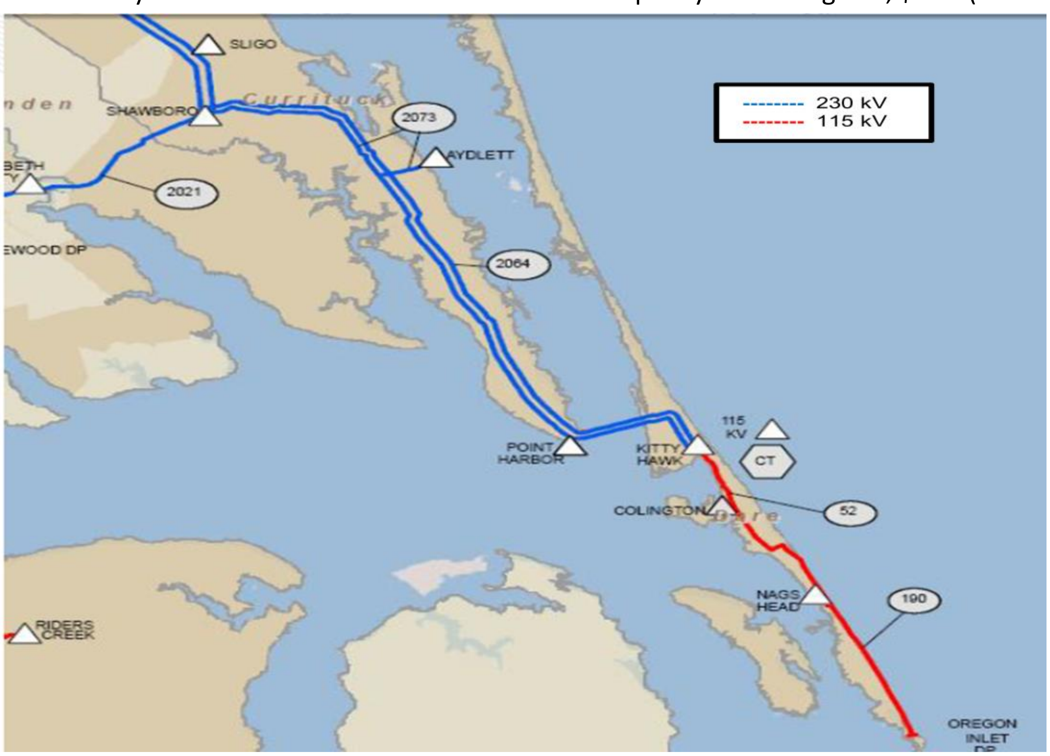

Figure 15. **Northern Zone transmission**

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.

[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.

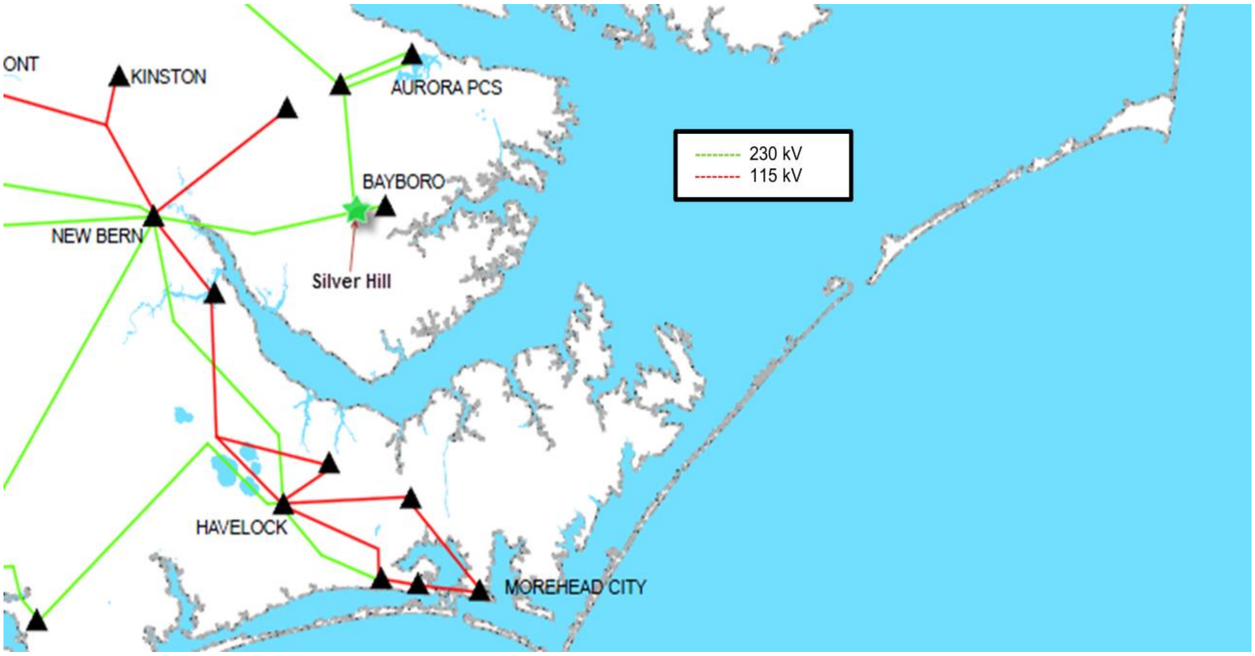

Figure 16. Central Zone transmission

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.

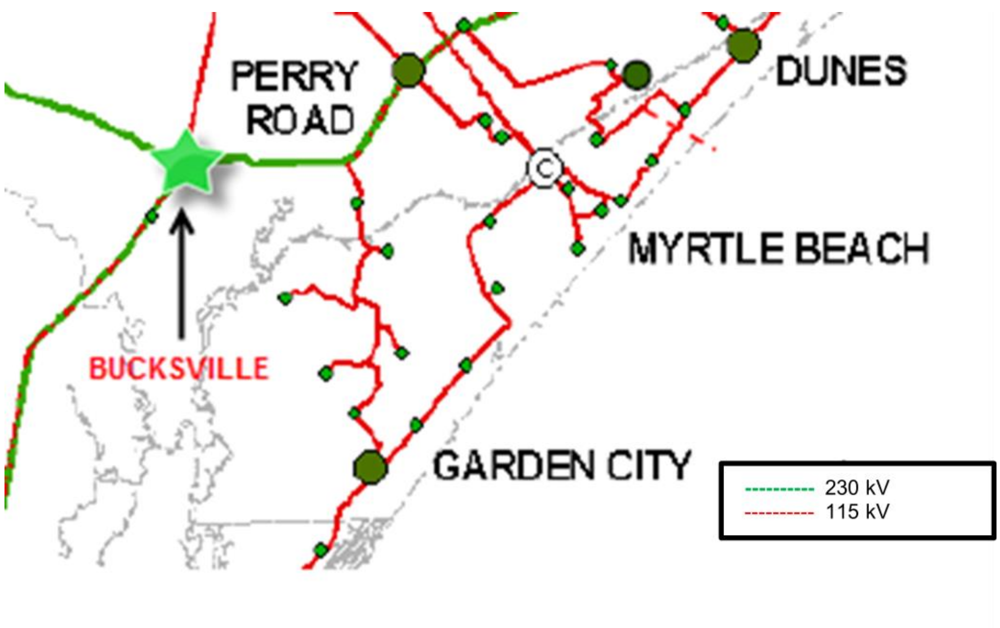

Figure 17. Southern Zone upgrades

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

UNITED STATES DEPARTMENT OF ENERGY

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Carolina Offshore Wind Integration Case Study

Phase 2 Technical Report

April 2015

PHASE 2 DRAFT TECHNICAL REPORT for PROJECT:

CAROLINA OFFSHORE WIND INTEGRATION CASE STUDY (COWICS)

DOE Award No. DE-EE0005368.001

Project Period: 9/30/2012 – 5/30/2015

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1.0 EXECUTIVE SUMMARY

The Carolina Offshore Wind Integration Case Study (COWICS) is a collaborative project led by principle sponsor Duke Energy and contributing investigators ABB, AWS Truepower, the National Renewable Energy Laboratory (NREL), and the University of North Carolina at Chapel Hill. The study evaluates the regional effects of high penetrations of offshore wind energy integrated into the Duke Energy Carolinas (DEC) system. This report complements the report completed for Phase 1 of the project, which was divided into six tasks across the two phases:

- Phase 1
    - Task 1 – Site Selection
    - Task 2 – Capacity and Energy Profile
    - Task 3 – Interconnection and Delivery
- Phase 2 (current document)
    - Task 4 – Dynamic Stability Analysis
    - Task 5 – Operating Reliability Impacts
    - Task 6 – Production Cost Impacts

The analysis focused on the operational impacts to DEC from the development of 1000 MW, 3000 MW, and 5600 MW of offshore wind. The following are the main findings from Phase 2.

For the dynamic stability study (Task 4 – Section 3.0), the most critical contingencies near each offshore wind generation site and within DEC service area were simulated based on the North America Electric Reliability Council (NERC) TPL standard Table 1[1]. The following findings were reported:

- No dynamic stability concern or violation of NERC reliability standards was identified with the interconnection of offshore wind generation.
- All NERC Category B (single contingency) and Category C (loss of multiple elements with normal clearing) faults were stable.
- One NERC Category D2 fault at the northern offshore wind generation neighboring bus caused one close-by generator to trip. This involved a three-phase fault on the transmission circuit with delayed clearing due to the local breaker failure.

The operating reliability impact analysis (Task 5 – Section 4.0) produced the following recommendations for the four types of reserves studied:

- Capacity reserves — Use a summer capacity credit of 39% across all scenarios.
- Contingency reserves — No changes to the requirement. Redundancies in the collection system would be necessary in the North zone for the 5600 MW scenario.
- Regulating reserves — Increase the base requirement of 110 MW to 114 MW, 127 MW, and 155 MW for the 1000 MW, 3000 MW, and 5600 MW scenarios.
- Frequency response reserves — Wind was deemed capable of contributing inertial response and primary frequency response. To do so, it is estimated that power production levels would be de-rated by 0.26% of nameplate capacity for all scenarios to represent these contributions.

[1] http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

The production cost analysis (Task 6 – Section 5.0), demonstrated that offshore wind resources would displace significant amounts of fossil-fueled marginal cost generation in the DEC portfolio along with the following conclusions:

- Annual production cost savings of $120M – $530M (5.7%-24.3%) from the no-wind scenario base conditions were realized in the 1000 MW, 3000 MW, 5600 MW scenarios.
- Emission reductions were significant ranging from 10-44% relative to the base case for the 1000 MW, 3000 MW and 5600 MW scenarios.
- Synergy between pumped storage hydro (PSH) and offshore wind resources produced production cost savings of approximately $50M in the 3000 MW scenario, increased the generation capacity factor of PSH, and reduced the amount of offshore wind curtailment during off-peak periods approximately 19%.
- The integration of such large amounts of offshore wind with existing baseload nuclear and large coal facilities would result in curtailments of wind during off-peak periods. Wind curtailment of 3,000 – 4,000 GWh was required in the 5600 MW scenario. Even with curtailments[2], offshore wind resources contributed approximately 17,000 GWh of energy production to the DEC system in the high wind scenario.

[2] Note that this result assumes no sale of power outside of DEC.

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 DEC 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 and project contributors performed a Phase 1 study to assess the impact of offshore wind development in the waters off the coasts of North and South Carolina [1]. The study analyzed the impacts to the DEC electric power system of multiple wind deployment scenarios. Phase 1 identified the offshore site selection for three levels of wind turbine installations; namely 1000 MW, 3000 MW, and 5600 MW, for years 2018 and 2021. Following site selection the capacity and energy profiles for the various levels of offshore wind were developed and the final task of Phase 1 identified the network upgrade and interconnection facilities needed to integrate the offshore wind into the DEC electrical network.

Study parameters were "frozen" as of the beginning of study Phase 1 initiation (September 2011) and any updates, revised generation/load projections, policy changes, etc. subsequent to the project initiation date were not incorporated into these studies for consistency of results throughout all study phases and tasks.

This Phase 2 study builds on the results of Phase 1 and investigates the dynamic stability of the electrical network in Task 4, the operating characteristics of the wind turbines as they impact operating reserve requirements of the DEC utility in Task 5, and the production cost of integrating the offshore wind resources into the DEC generation fleet making comparisons to future planned operation without the addition of the wind resources in Task 6.

2.3 TASKS TO BE PERFORMED – PHASE 2

2.3.1 DYNAMIC STABILITY

In addition to the steady-state assessment of the system's ability to accept large-scale offshore wind, a dynamic evaluation was also performed. This assessment was made using the NERC Multi-regional Modeling Working Group (MMWG) dynamic models. They include a library of standard wind turbine models which were used to represent the offshore wind plants in the studies. A broad selection of contingencies was studied that include known stability issues as well as anticipated new issues based on the results observed in the steady-state assessment. Wind and thermal generation dispatch scenarios were constructed to allow an assessment of the sensitivity of the dynamic stability of the system to generation dispatch. Dynamic stability cases of particular interest were the high wind generation, low thermal generation scenarios in which the interconnected system loses significant inertia due to the offline thermal generation plants.

2.3.2 OPERATING RELIABILITY IMPACTS

Using the wind production sets in sub-hourly timeframes developed by the capacity and energy profile team and transmission study (both steady state and dynamic) and production costing results, the system operation impacts team assessed the expected reserve requirements and other reliability impacts. The team evaluated the level and types of reserves needed to maintain system balance and account for the variability and technical limitations of the wind developments such as ramping, voltage support, etc. The analytic process was similar to that done for the Eastern Renewable Generation Integration Study (ERGIS) where a statistical analysis of 10 minute variability for the various sites was conducted and reflected to a revised reserve level for production modeling. Potential ramping issues and the means of addressing them were identified.

2.3.3 PRODUCTION COST IMPACTS

Once the system operation team performed its analysis, the production cost team evaluated the impact of offshore wind development on average production cost for the system. The variability of wind generation is known to have significant impacts on the dispatch and operation of the existing generation fleet including unit ramp rates and operating reserve requirements. It is particularly important to assess the impact on baseload (coal and nuclear) units. In order to evaluate that impact and to determine the expected impact on system operation costs, a production cost analysis was performed using the wind variability, reserve changes and other system parameters determined from the wind resource analysis efforts. DEC has a significant amount of PSH generation (2,140 MW) in its portfolio and the production cost analysis identified synergies between the PSH and wind generation. The study also has the ability to analyze the economic, operational, and reliability benefits of storage resources when integrating variable resources such as wind. The production cost analysis used the hourly and sub-hourly wind production data. Two years were evaluated (2018 and 2021) for this analysis.

For each study year and system variation, a production cost analysis was performed for each wind resource assumption used in the system studies. A “no (new) wind development” case was used as a baseline to estimate the differential in production costs on the system due to the wind resources.

As the team analyzed the results from each of the activities performed in Phase 2, it formed decisions regarding specific system design issues including how offshore wind is aggregated and delivered to interconnection points in an attempt to “optimize” the system by adding resources and transmission infrastructure. Each run through the activities produced information about the benefits and trade-offs of wind development and, hence, insight into the total operating costs of integrating varying levels of offshore wind.

3.0 TASK 4 – DYNAMIC STABILITY

For the offshore wind generation interconnection dynamic stability assessment, the analysis was performed based on the measures and requirements set forth in the latest revision of the NERC Reliability Standards TPL-001 through TPL-004. These assessments were based upon system simulations and engineering judgment and addressed any planned upgrades needed to meet the performance requirements of Categories A through D defined in Table 1 (Transmission System Standards – Normal and Emergency Conditions). Dynamic simulations were used to demonstrate compliance with the Table 1 categories and to identify any need for system upgrades, protection system modifications, or dynamic model verification.

This study focused on the dynamic impact at the offshore wind generation site and the critical locations within the DEC service area. This study investigated unit instability or inadequately damped response to system disturbances related to the selected contingencies.

3.1 MODEL OVERVIEW

The study cases were created based on 2012 series of MMWG dynamic stability cases including:

- 2018 Summer peak case
- 2018 Winter peak case
- 2018 Light load case

The power system upgrades identified in the Phase 1 power flow study were incorporated into the study cases.

The offshore wind generation models were composed of several major components:

- Wind Turbine Generator
- Turbine Generator Step Up Transformer
- Collector System
- Main Step Up Transformer (AC Connection)
- AC or DC transmission lines

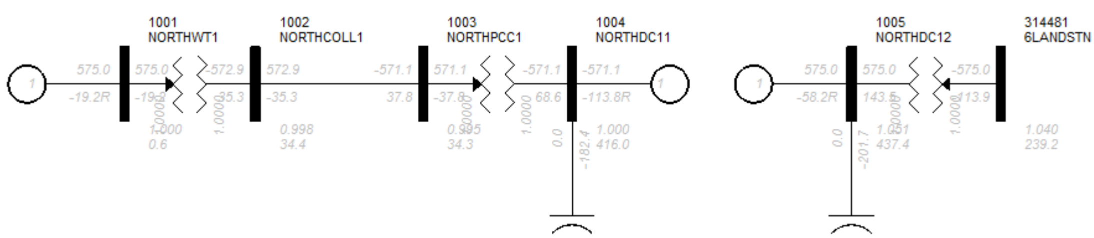


Figure 1. Typical DC Connected Offshore Wind Turbine Generator Model

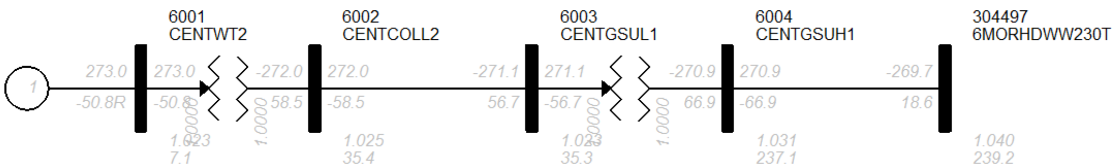


Figure 2. Typical AC Connected Offshore Wind Turbine Generator Model

3.1.1 WIND TURBINE GENERATOR

The offshore wind turbine generators were modeled as full converter type 4 wind turbine generators using the typical data provided in PSSE 32 Application Guide. The wind turbine generators were on voltage control model controlling the generator terminal bus voltage. The wind generation capacity distribution was modeled based on the generation level with the 5600 MW offshore wind scenario option identified in the COWICS Phase 1 report[3]. The maximum size of the ABB HVDC Light system (HVDC Light – M9) is 1163 MW, which is less than the total capacity for northern and southern wind generation sites. Therefore the northern and southern region wind generation sites were modeled as two equally divided generation facilities.

Table 1. Offshore Wind Turbine Generator Capacity

Location	Capacity (MW)
Northern WTDC1	1110
Northern WTDC2	1110
Central WTDC	1123
Central WTAC	517
Southern WTDC1	870
Southen WTDC2	870

3.1.2 TURBINE GENERATOR STEP UP TRANSFORMER

The step up transformers for the individual turbine generators were represented by a large transformer with the same impedance and total MVA capacity of all turbine generator step up transformers combined.

3.1.3 COLLECTOR SYSTEM

The collector cable system connecting each wind turbine generator to the offshore centralized substation was represented by a transmission line between the high voltage side of the turbine step up transformer and the centralized offshore substation.

3.1.4 MAIN STEP UP TRANSFORMER (AC CONNECTION)

The main step up transformer was sized based on the total MVA capacity of the wind turbine generators.

[3] For each offshore wind site, the total installed capacity was based on "Table A17 – Selected Sites" in the COWICS Phase 1 Report

3.1.5 AC UNDERSEA CABLE

The AC undersea cable impedance was calculated based on the typical undersea cable specification provided by ABB. Based on the "Table A17 – Selected Sites" in COWICS Phase 1 Report and being conservative, a cable length of 30 miles was selected.

3.1.6 DC TRANSMISSION SYSTEM

The DC transmission system including the DC substation transformers, inverter/converter, and reactive compensation devices were modeled based on the standard ABB HVDC Light dynamic model library for HVDC Light – M9 model.

3.2 SIMULATION DESCRIPTIONS

Table 1 of the NERC Planning Standards lists contingencies that must be considered in the planning of transmission systems. Based on engineering experience, the most critical stability contingencies for each Category are selected:

NERC TPL-001 Category B2, Fault with normal clearing of a transmission circuit. For the offshore wind generation sites and their neighboring buses, the faults were applied to the strongest transmission circuit connected to the bus. For the DEC service area, based on the engineering experience, the faults were applied to several most critical 230 kV and 500 kV transmission circuits.

NERC TPL-003 Category C1, SLG (single line to ground) Fault with normal clearing of a bus section. For the offshore wind generation sites and their neighboring buses, the faults were applied to the substation bus with normal clearing.

NERC TPL-003 Category C8, SLG Fault with delayed clearing of a transmission circuit due to breaker failure. For the offshore wind generation site and their neighboring buses, the faults were applied at local end of the line and cleared by transmission circuit remote end distance protection, breaker failure detection relay and transformer overcurrent protection for maximum stability impact to the system.

NERC TPL-003 Category D2, 3LG (three phase line to ground) Fault with delayed clearing of a transmission circuit due to breaker failure. For the offshore wind generation site and their neighboring buses, the faults were applied at local end of the line and cleared by transmission circuit remote end distance protection, breaker failure detection relay and transformer overcurrent protection for maximum stability impact to the system.

NERC TPL-003 Category C9, SLG Fault with delayed clearing of a bus section due to bus differential protection failure. For the DEC service area, the faults were simulated at the bus and cleared by the actual clearing time for each protection device including transmission circuit remote end distance protection and transformer overcurrent protection calculated by the protection system simulation software.

NERC TPL-003 Category D4, 3LG Fault with delayed clearing of a bus section due to bus differential protection failure. For the DEC service area, the faults were simulated at the bus and cleared by the actual clearing time for each protection device including transmission circuit remote end distance protection and transformer overcurrent protection calculated by the protection system simulation software.

3.3 RESULTS

Even though the system dynamic responses to each fault between the summer peak, winter peak and light load cases are slightly different, the summarized dynamic stability concerns in the system are the same among all three cases.

The following is a summary of the results arranged by NERC TPL Categories for offshore wind faults and critical locations faults within the DEC service area affected by the new offshore wind generation.

3.3.1 OFFSHORE WIND FAULTS

Faults near offshore wind generation sites and neighbor bus:

Category B2 – No angular stability concern

Category C1 – No angular stability concern

Category C8 – No angular stability concern

Category D2 – There was one contingency on the northern offshore wind site neighbor bus causing one close by generator trip off.

The system dynamic responses for the northern offshore wind site neighbor bus Category D2 fault were plotted below:

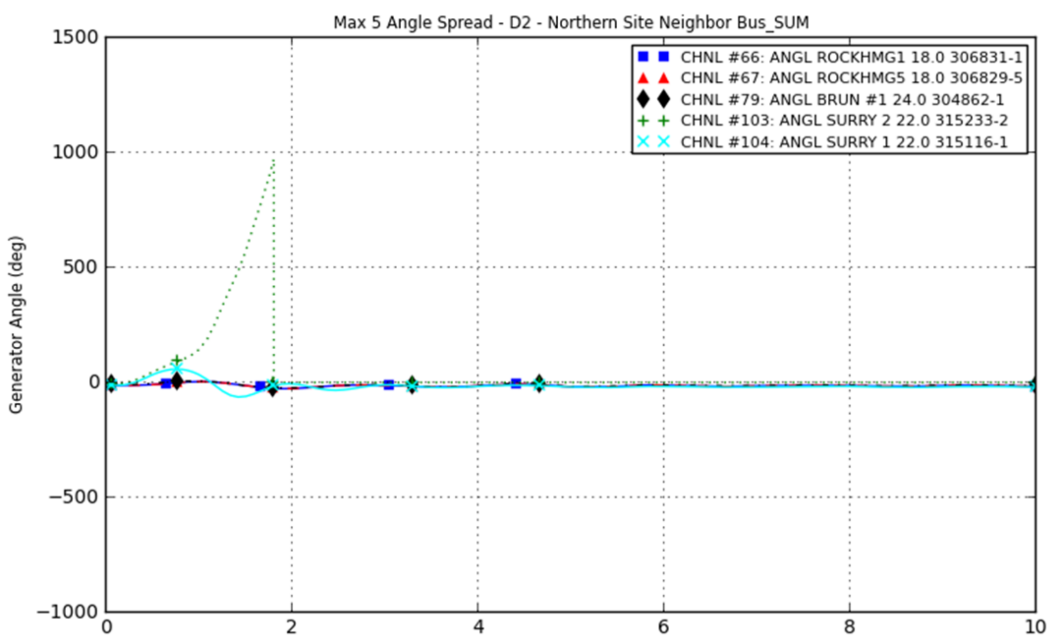


Figure 3. Major generator angular response during Category D2 fault at northern offshore wind generation neighboring bus - 2018 Summer Case

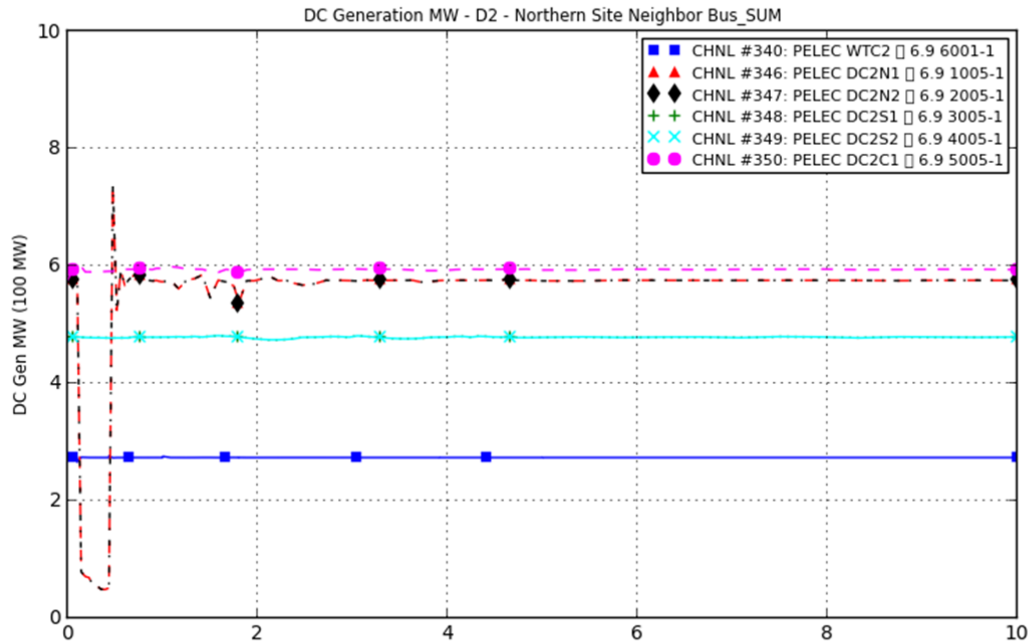


Figure 4. Offshore wind generation real power (MW) generation during Category D2 fault at northern offshore wind generation neighboring bus - 2018 Summer Case

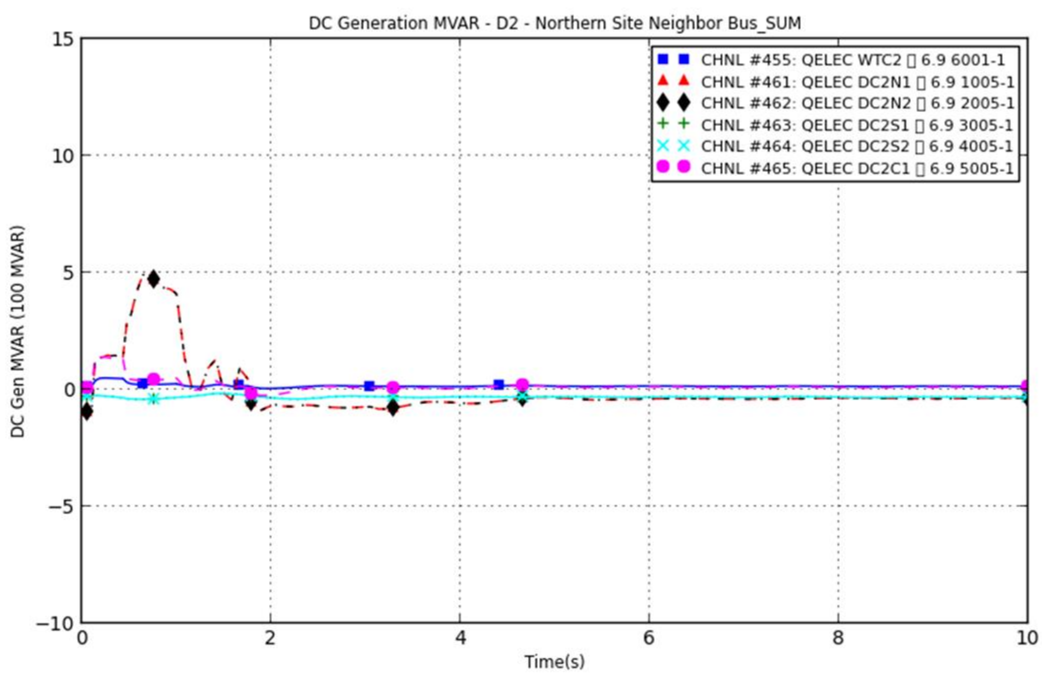


Figure 5. Offshore wind generation reactive power (MVAR) generation during Category D2 fault at northern offshore wind generation neighboring bus - 2018 Summer Case

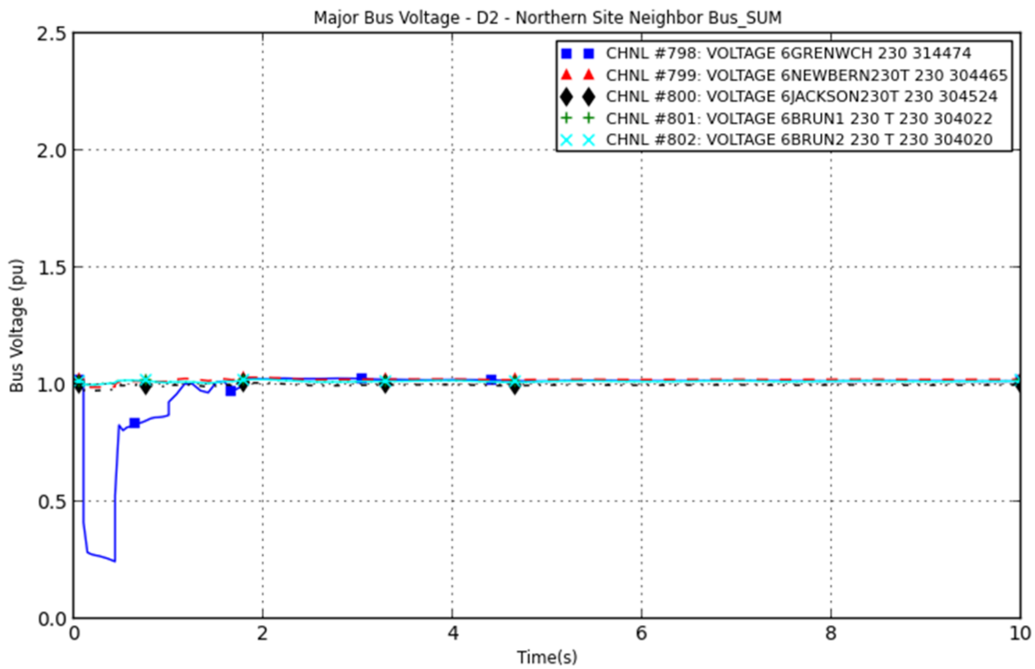


Figure 6. Major 230 kV bus voltage near offshore wind generation site during Category D2 fault at northern offshore wind generation neighboring bus - 2018 Summer Case

3.3.2 DEC ONSHORE FAULTS

Faults in DEC Service Area:

Category B2 – No angular stability concern

Category C9 – No angular stability concern

Category D4 – No angular stability concern

3.4 DYNAMIC STABILITY CONCLUSIONS

For this COWICS dynamic stability study, the most critical contingencies near each offshore wind generation site and within DEC service area were simulated based on the NERC TPL standard Table 1.

All NERC Category B and Category C faults were stable.

One NERC Category D2 fault at the northern offshore wind generation neighboring bus caused one near-by generator to trip. This involved a three-phase fault on the transmission circuit with delayed clearing due to the local breaker failure. The fault is cleared by the remote distance relay on the transmission circuit, breaker failure protection, and transformer overcurrent protection.

Due to the low probability of occurrence for the Category D (extreme events) faults, NERC does not require all generators to maintain stability for these conditions.

No dynamic stability concern was identified with the interconnection of the new offshore wind generation.

4.0 TASK 5 – OPERATING ANALYSIS

This section analyzed the operational impacts to the DEC system from the development of 1000 MW, 3000 MW, and 5600 MW of offshore wind. The energy profiles of each deployment scenario and their relationships to load were analyzed to consider additional reserve requirements on the system.

Reserves were classified into four categories according to their formal definitions from the NERC [2]:

- Capacity reserve (also referred to as installed reserve margin)—The installed capacity above the forecasted peak load required to satisfy a loss-of-load expectation of, on average, 1 day in 10 years.
- Contingency reserve—The provision of capacity deployed by a balancing authority area (BAA) to meet the Disturbance Control Standard (DCS) and other NERC and regional reliability organization contingency requirements.
- Regulating reserve—The amount of reserves responsive to automatic generation control that is sufficient to provide a normal regulating margin.
- Frequency regulation—The ability of a BAA to help an interconnection maintain its scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

In Phase 1 the offshore sites used in each of the three offshore wind deployment scenarios were chosen by evaluating average capacity factors, distance to shore, wind farm size, and other parameters. Three deployment zones were identified: "North" and "Central" (in North Carolina) and "South" (in South Carolina). The Central zone was further divided into two, according to injection points, and the North and South zones had one injection point apiece. Table 2 summarizes the installed capacity by injection point. As shown, installed wind capacity is dominant in the North and Central regions as a result of having more favorable wind areas resulting in higher capacity factors for wind turbines in these areas.

Table 2. Installed Offshore Wind Capacity (MW) by Injection Point

Scenario	North	Central 1	Central 2	South	Total
1,000 MW	702	298	0	0	1,000
3,000 MW	1,305	774	260	661	3,000
5,600 MW	2,220	1,123	517	1,740	5,600

The remainder of this section is organized as follows: Section 4.1 examined the characteristics of the simulated wind profiles and their impact on net load; Sections 4.2 through 4.5 examined the effects of offshore wind on the different types of reserves; and Section 4.6 concludes.

4.1 WIND PROFILES ANALYSIS

This section examined the characteristics of the wind profiles[4] and their relationship with load. The profiles were developed by reproducing the meteorology from the years 1999 through 2008 with numerical weather prediction models, as reported in Phase 1. These profiles have a time resolution of 10 minutes. The analysis included the analysis of 60-minute and 10-minute ramps, which were defined as the change in power between time *t* and time $(t + \Delta t)$. Production simulations performed in COWICS used the time series for the year 2000, so most of the analysis revolves around that particular year. Comparisons of the year 2000 data to the rest of the years in the data set were provided as well.

4.1.1 WIND POWER ANALYSIS

Figure 7 summarizes the power distributions across all 10 years of data. The selected year for the production cost simulations (year 2000) is an average year in terms of wind generation. For all years, wind generation ranged from 0% to 100% of nominal capacity and power output was typically found between 20% and 70% of installed capacity.

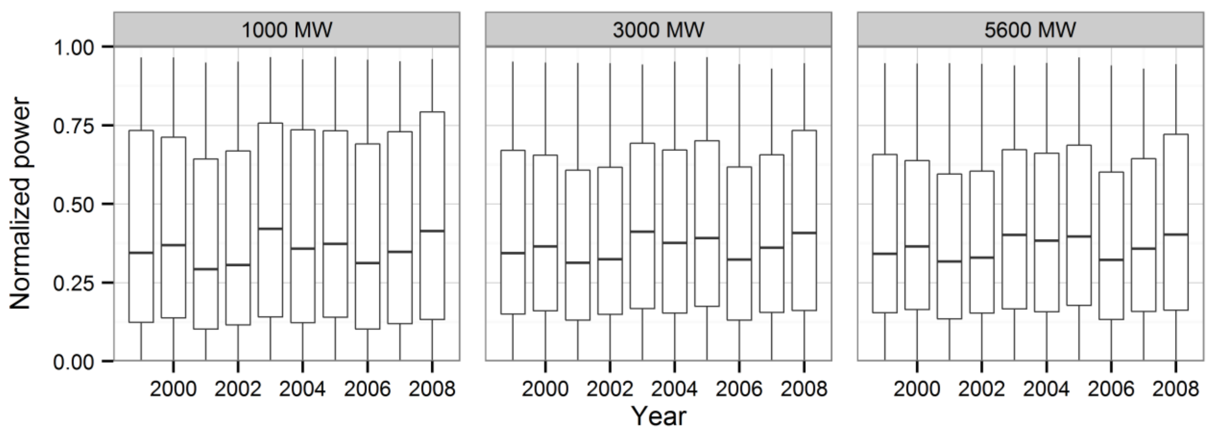


Figure 7. Boxplots showing wind power by year for all scenarios

The graphs shown in Figure 8 depict average power for each scenario by hour of day for all years of data (year 2000 is highlighted with a thick line). There is a clear daily trend for July that shows low offshore wind power during the mornings, but it increases and peaks during the evenings, most likely caused by afternoon breezes. April and October also hint at similar daily patterns, but they are much weaker, and these patterns are nonexistent in January.

[4] Wind power profiles were created as part of Phase 1 of COWICS.

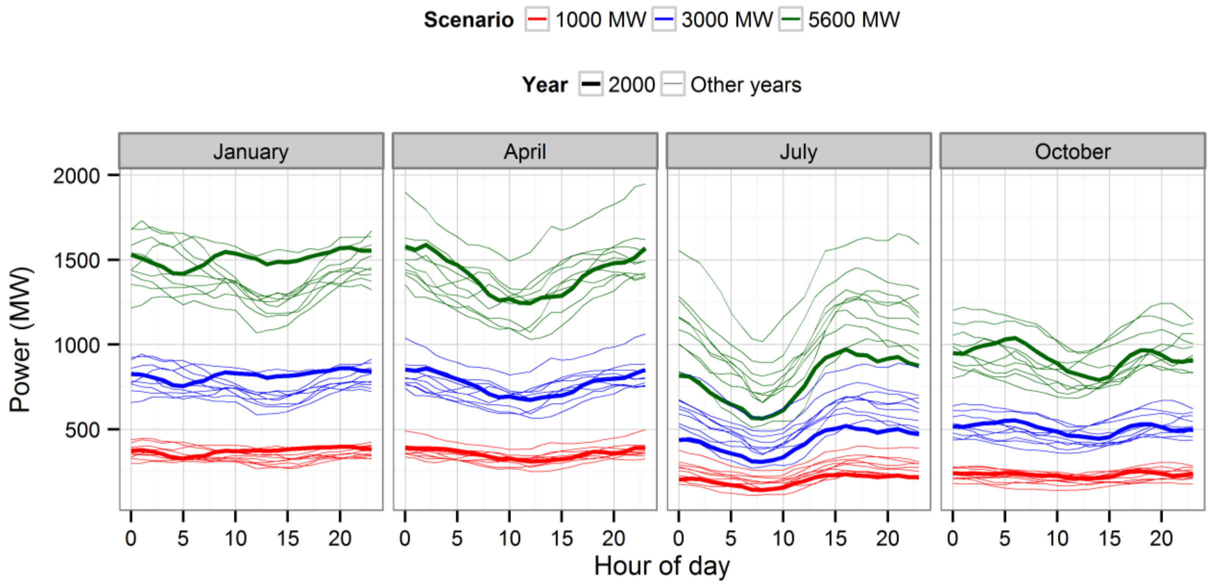


Figure 8. Average power by hour of day across scenarios for selected months

Hourly offshore wind power ramps can affect the ability of a system to perform load-following operations, whereas 10-minute ramps (and shorter timeframes) are most likely to affect system regulation. Figure 9 represents the 60-minute and 10-minute ramp distributions by scenario, normalized to installed capacity. The 60-minute distributions center on zero and the bulk of the ramps are within 10% of nameplate capacity. The distributions look very similar after normalization, although the tails of the 1,000 MW scenario are slightly fatter, especially on the negative end. The shapes of the 10-minute distributions are also very similar, with slightly fatter tails in the lower deployment scenarios. The vast majority of the events are found within 2% percent of nameplate capacity. The shapes of both distributions are similar because there is little geographic diversity, probably due to the small footprint considered in this study.

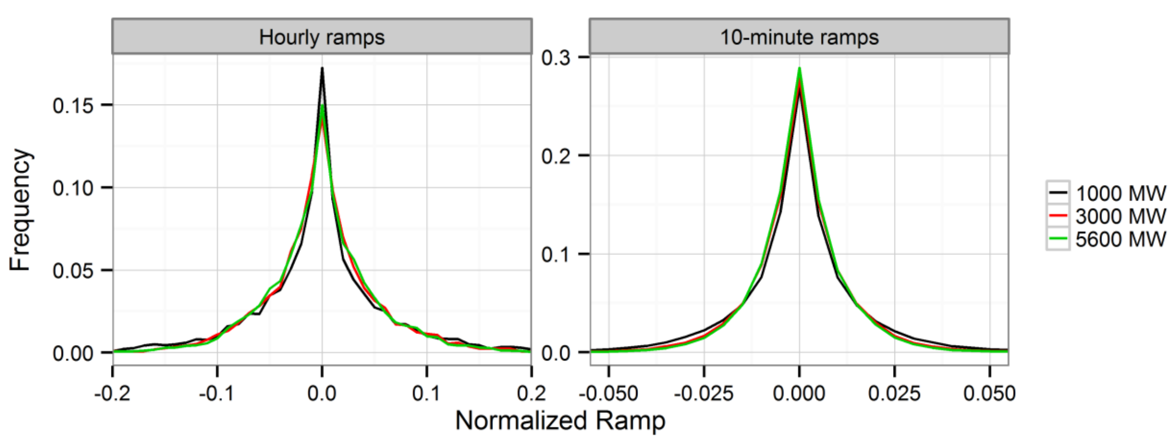


Figure 9. Normalized 60-minute and 10-minute ramp distributions for the year 2000

4.1.2 LOAD AND NET LOAD ANALYSIS

After examining the characteristics of offshore wind for all three deployment scenarios, the analysis of load and net load profiles was performed. Two load profiles were used in the production cost simulations based on Duke Energy's projections: the years 2018 and 2021. Throughout this section the 2018 profile is utilized, although the findings also apply to the 2021 load profile. A methodology developed for the Eastern Renewable Generation Integration Study [3] was used to downscale hourly load data to 10-minute intervals. Offshore wind profiles for the year 2000 were utilized in the production cost simulations and this portion of the study. For the remainder of the document, net load is defined as load minus wind power, i.e., the portion of the load that conventional generators need to balance.

The net load distribution is not affected evenly by the addition of offshore wind. Figure 10 (left) represents the net load distribution across scenarios as duration curves. The curves show that the lower portion of the load distribution shifts downward more prominently and that the ratio of peak to minimum net load value increases with the addition of wind. This phenomenon is a result of higher wind production during the winter and spring months and during nighttime, when lower load levels are experienced. A similar conclusion can be extracted from Figure 10 (right), in which the average net load profiles are represented. Even though the shapes are not drastically different, the peak-to-valley ratio increases.

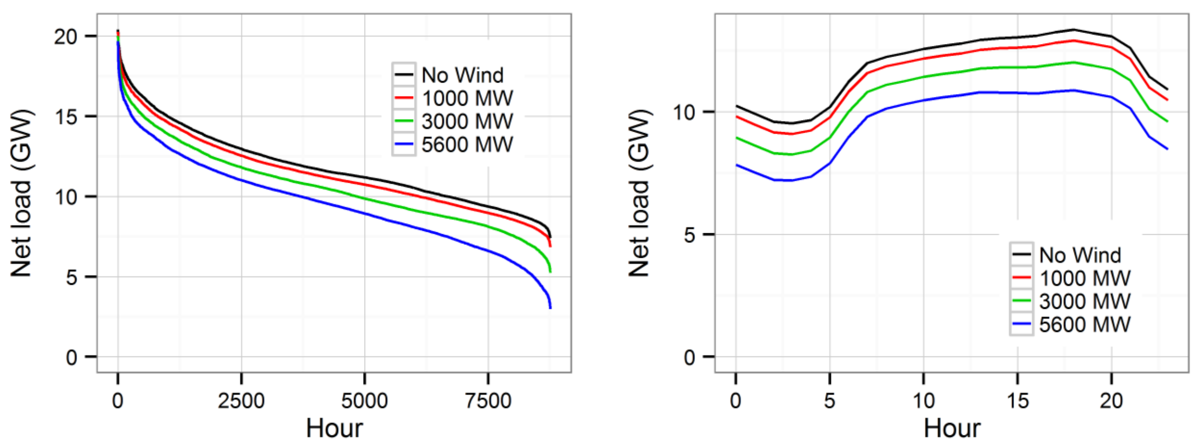


Figure 10. Net load duration curves (left) and Average net load (right) by scenario

Net load ramps are largely unaffected by the addition of offshore wind, as shown in the duration curves in Figure 11. The distributions overlap during most of the hours. The exceptions are a few extreme values, which increase dramatically with the addition of wind power. This increase is much more significant for 10-minute ramps than for hourly ramps. It is unclear if the change in extreme values is due to modeling artifacts in the creation of the offshore wind profiles.

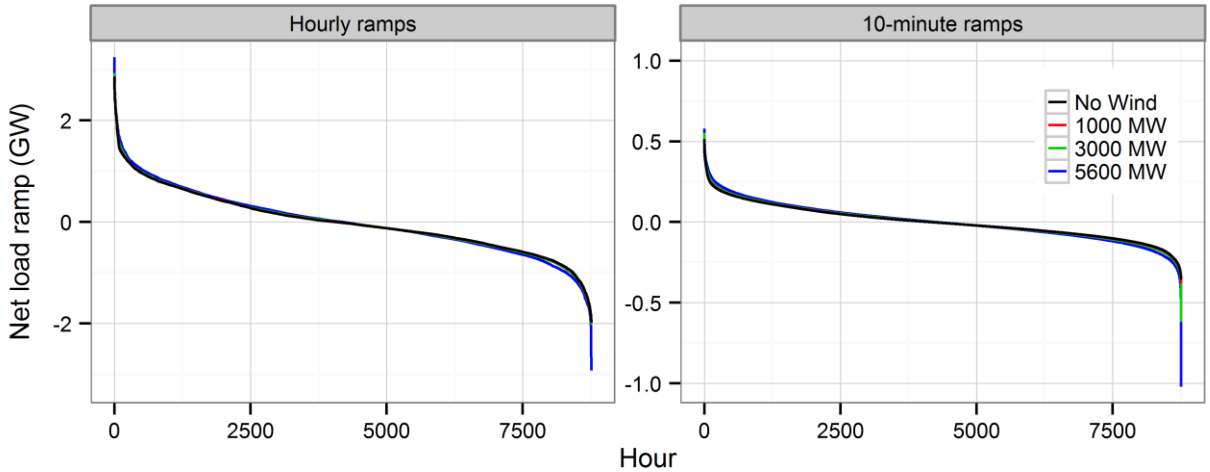


Figure 11. Sixty-minute and 10-minute net load ramp duration curves by scenario

4.1.3 WIND VARIABILITY VS LOAD VARIABILITY

To better understand the effect of wind variability on net load, the relationship between wind and load variability were studied. Figure 12 shows plots that summarize the relationships among 10-minute ramps in load and wind time series. A month per season is represented for all scenarios.

These plots show that wind and load variability are largely uncorrelated. Large outliers for either wind or load are not any more common in the scenario shown in the bottom right quadrant (where load is increasing and wind is decreasing, making net load increase faster than load) than in the others. Similar conclusions are extracted for hourly ramps.

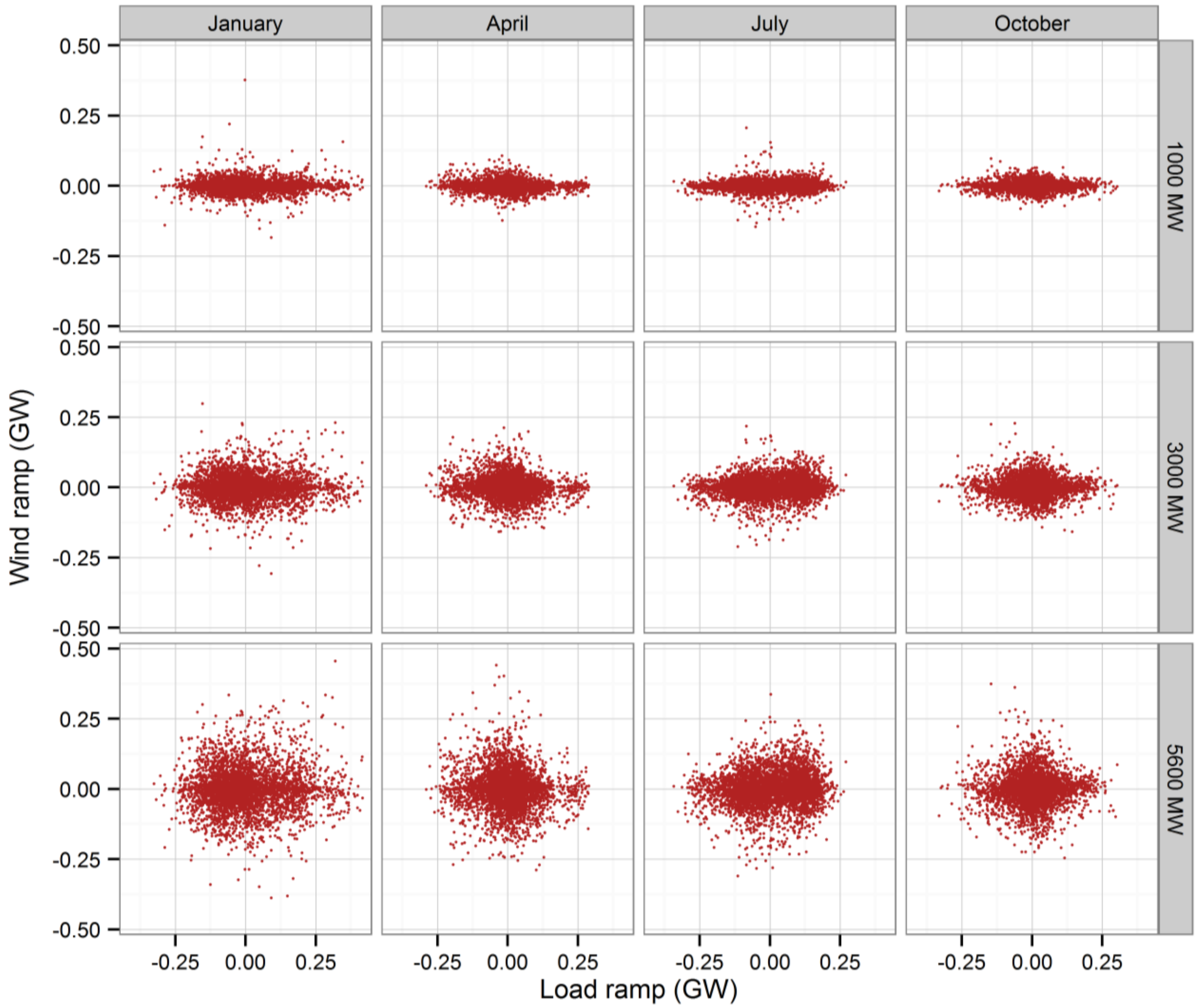


Figure 12. Ten-minute wind power ramps versus load ramps for all scenarios

4.1.4 ANALYSIS OF SAMPLE EVENTS

Two sample weeks were chosen to showcase how load, net load, and wind track during a few selected days. The first week includes the peak load, which occurred in July 17 with a value of 20,386 MW. Figure 13 shows the different time series. A low level of generation from wind is observed during this week. The exception is July 19, when a larger-than-usual differential between peak and valley occurs. Apart from July 19, net load behaves very similarly across scenarios, and integrating wind should be relatively easy.

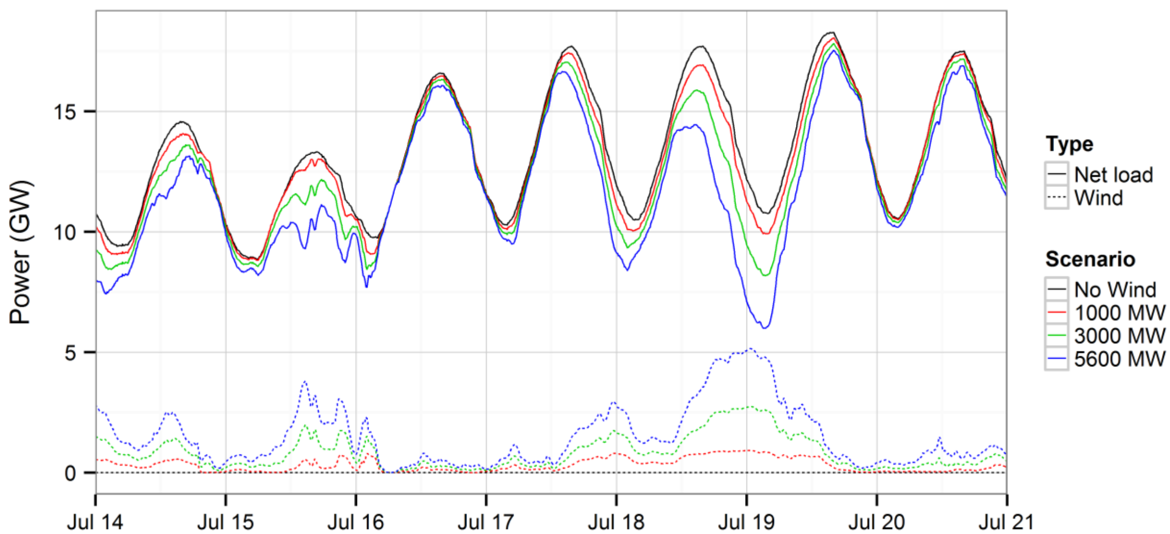


Figure 13. Load, net load, and wind power on the days surrounding the peak load

The second week examined the days with the maximum daily ratio of wind power to load, i.e., the days on which most of the load is served by wind. This maximum occurs on December 2 because of a combination of low load and very high wind. In fact, wind output was steadily close to the maximum for almost two straight days. On December 3, one of the minimum values of instantaneous net load across scenarios is observed. Figure 14 shows that the decline in net load between November 30 and December 2 and the consequent rise through December 4 are exacerbated by the presence of offshore wind.

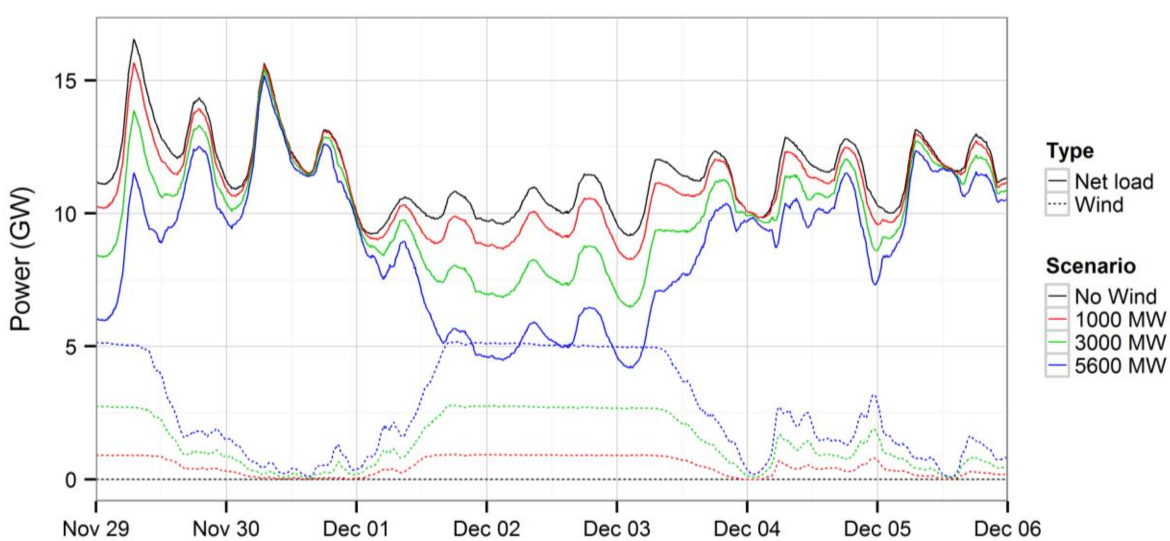


Figure 14. Load, net load, and wind power on the days surrounding the day with the maximum wind-to-load ratio

The DEC footprint is an interesting test bed for offshore wind integration due to the presence of 2,140 MW of PSH facilities with 68 GWh of storage capacity. Currently, PSH generators are scheduled on a weekly basis with the objective of reducing daily load peak and valleys by generating and pumping at those times, respectively. Because load is the main driver of those schedules, they are generally very similar from one week to another and are not changed significantly.

With the addition of significant amounts of offshore wind, conventional units are typically dispatched to the net load profile (i.e., load minus wind), except when excessive wind generation is curtailed. The previous figures show two extreme cases of the effect of offshore wind. These bookends show that there could be an opportunity to improve PSH scheduling procedures to facilitate the integration of wind and minimize the curtailment, e.g., by pumping when there is excess generation. Previous studies [4] have shown that PSH presents an inherent value to the operation of systems with variable renewable energy.

4.2 CAPACITY RESERVES

There exist multitude methods to account for the capacity value of variable generation, as shown in a recent survey [5]. An average capacity factor approach is selected for its simplicity, given that this method is used by different Eastern Interconnection regional transmission organizations (RTOs). Table 3 summarizes how the time window calculations are used to determine capacity values. For reference, the table also includes the default values that the different RTOs use for all new wind plants prior to the availability of generation information.

Table 3. Summary of Capacity Value Calculations Across RTOs

RTO	Season	Months	Time	Default for New Onshore	Default for New Offshore
ISONE	Summer	Jun. 1–Aug. 31	1–6 p.m.	–*	–*
	Winter	Oct. 1–May 31	5–7 p.m.	–*	–*
NYISO	Summer	Jun. 1–Aug. 31	2–6 p.m.	10%	38%
	Winter	Dec. 1–Feb. 28	4–8 p.m.	30%	38%
PJM	Summer	Jun. 1–Aug. 31	2–6 p.m.	13%	13%

*NOTE: ISO-New England requires wind speeds to assign an initial capacity value for a new project.

In this section, 10 years of simulated offshore wind generation (from 1999 to 2008) were used. Figure 15 shows the average wind generation by month and time of day for the 5600 MW deployment scenario; each blue trace represents a year of data. Also in the figure are blocks that graphically represent the windows used by the different methods listed in Table 3. Note that the PJM and New York-ISO (NYISO) windows have the same summary capacity values and hence are calculated only once, along with the values for New England ISO (ISONE).

As previously observed significant daily patterns exist from May to August, probably resulting from the afternoon sea breeze. The increase in power output generally coincides with the summer capacity value calculation windows. During the winter, power profiles are generally flatter, with higher levels of power on average.

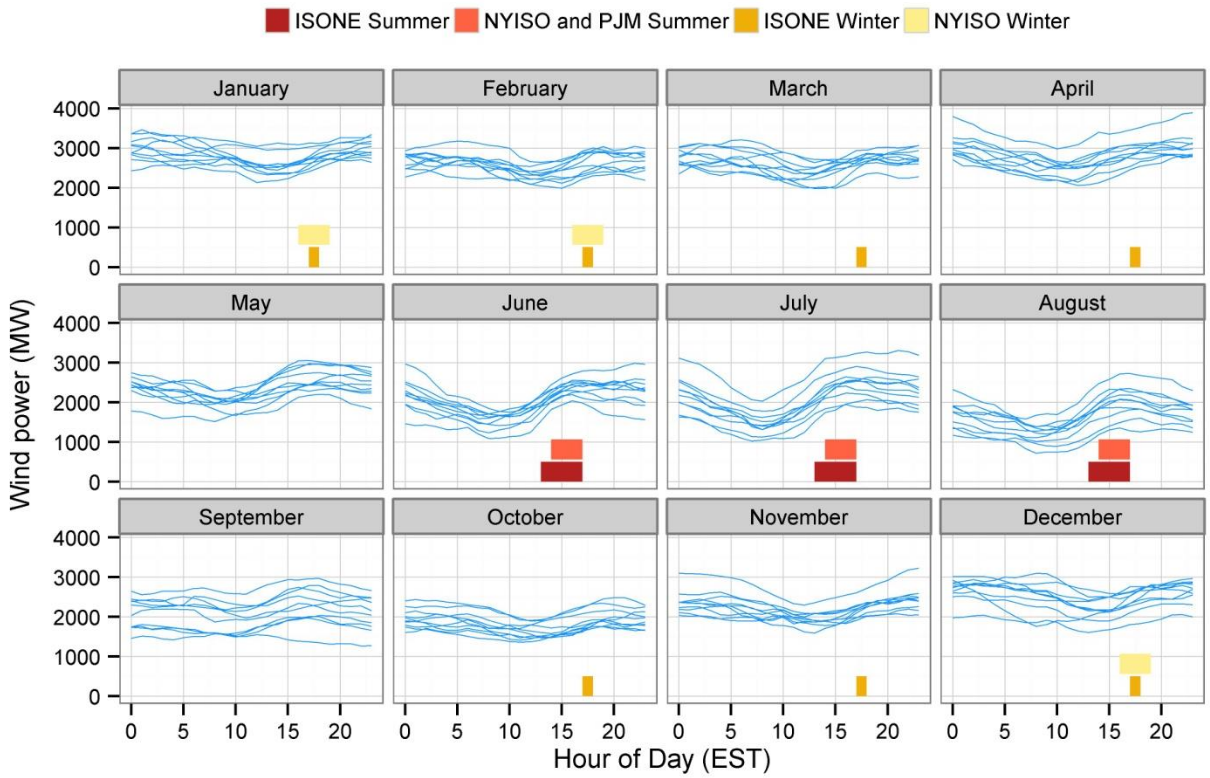


Figure 15. Average wind generation for the 5600-MW scenario with calculation windows

Figure 16 shows the capacity value normalized to nameplate capacity for each year. Summer values are typically found in the 35% to 42% range. Winter values are slightly higher, at 45% to 50%.

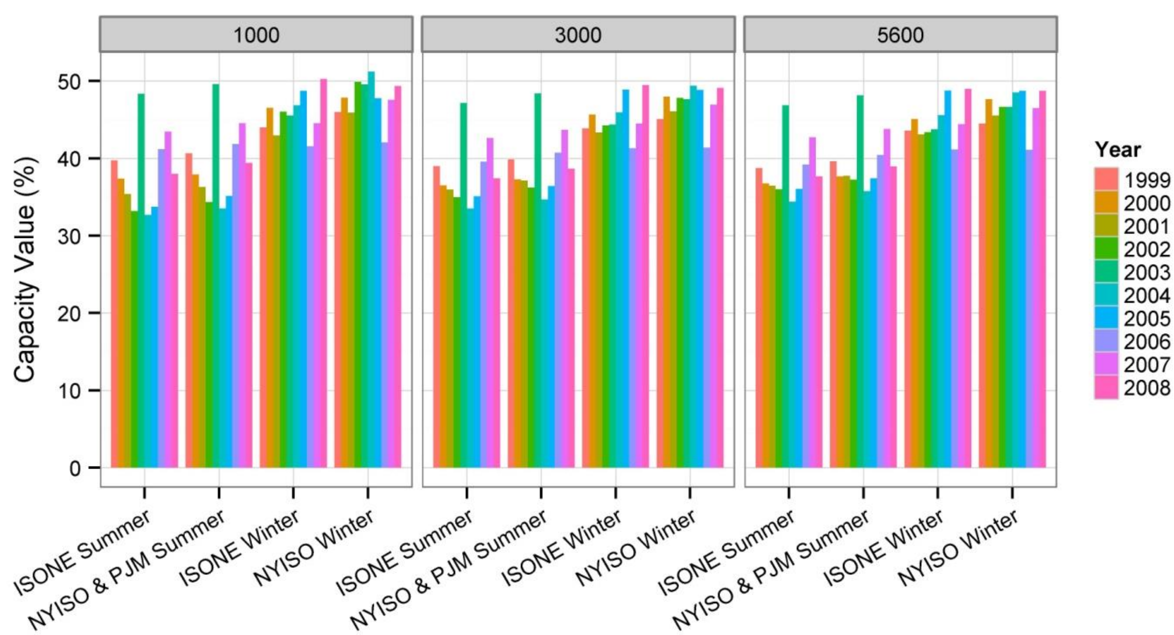


Figure 16. Capacity value (%) by year for all scenarios

Average capacity values are calculated across all 10 years and presented in Table 4. In reality, RTOs use moving averages of different lengths and filter historical data. Capacity values relative to nameplate capacity remain fairly stable across methods and penetrations. Summer capacity values typically average 39%. Winter capacity values average approximately 46%. Because the highest loads in DEC occur during the summer, a capacity value of 39% is recommended for this study.

Table 4. Average Capacity Values Across Scenarios and Methods

	Capacity Value (MW)			Capacity Value (%)		
	1,000 MW	3,000 MW	5,600 MW	1,000 MW	3,000 MW	5,600 MW
ISONE Summer	383.1	1,145.8	2,155.6	38.3%	38.2%	38.5%
NYISO and PJM Summer	393.3	1,179.2	2,222.2	39.3%	39.3%	39.7%
ISONE Winter	457.1	1,355.2	2,508.1	45.7%	45.2%	44.8%
NYISO Winter	477.2	1,410.9	2,601.7	47.7%	47.0%	46.5%

4.3 CONTINGENCY RESERVES

Each BAA is subject to Disturbance Control Standards (DCS) and other NERC and regional reliability organization contingency requirements. To meet the DCS, a BAA should maintain contingency reserves to cover its most severe single contingency (MSSC).[5] To qualify as contingency reserves, resources must respond within 10 minutes, so not all operating reserves can be considered contingency reserves[6]. The following resources can be considered contingency reserves:

- Online, unloaded generation up to the amount the units can increase in 10 minutes
- Offline, quick-start generation that can load in 10 minutes
- Demand resources (load control, interruptible resources, etc.) if they are under central control and capable of responding within 10 minutes

Current MSSC for Duke is 1,360 MW, represented by the loss of the entire Bad Creek plant. Duke participates in a reserve sharing group, so its commitment to support the reserve sharing group MSSC (same as Duke's) is currently 502 MW. If a single resource or single interconnection to a collection of resources were larger than the MSSC, that value would become the new MSSC. Under the current structure of the reserve sharing group, the amount greater than the current MSSC may have to be borne by Duke alone, at least initially.

Thus, the objective of this section is to find whether (and how often) offshore wind generation in the study could become the MSSC. Offshore wind was sited, and four points of interconnection were identified. Table 2 summarizes the nameplate capacity by region. According to the table, only the North and South zones in the largest penetration scenario could exceed the current MSSC (1,360 MW) if wind generators were producing close to 100% capacity. None of the regions in the 1000 MW and 3000 MW scenarios can exceed the MSSC level.

[5] MSSC is not currently defined in the NERC glossary, but a proposed definition is pending.
[6] DCS requires recovery in 15 minutes, but this includes the identification/verification of the loss and communication to respond, so 20 minutes is the time it takes for an actual unit response.

This is confirmed by looking at the simulated wind generation. Figure 17 shows wind power production duration curves for each interconnection point and scenario. Each of the blue traces corresponds to the wind data for a year (from 1999 to 2008). The red dotted line represents the current MSSC. In this plot, only the North and South zones in the 5600 MW scenario exceed the MSSC. Behavior across years is fairly consistent, and the MSSC is surpassed 3,043 to 3,771 hours of the year (that is, 34% to 43% of the time). Maximum power typically peaks at 2,150 MW.

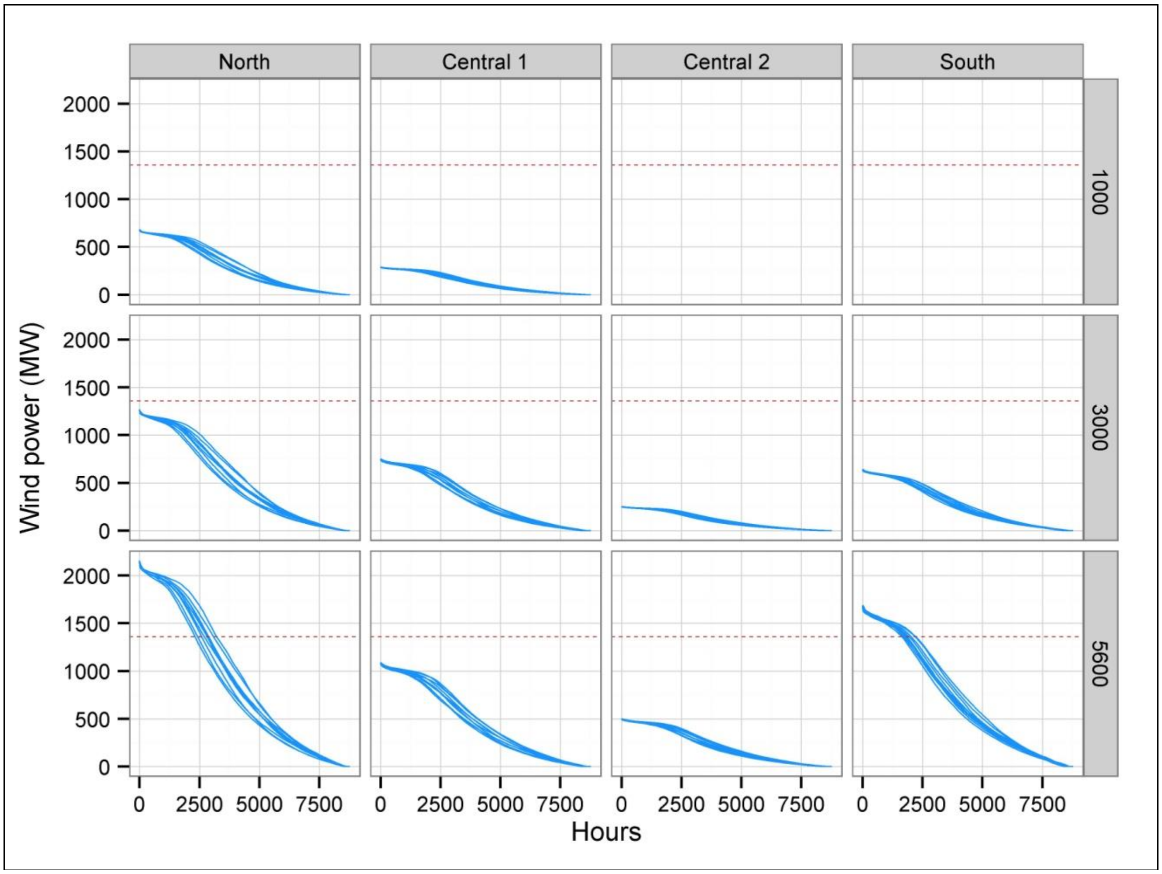


Figure 17. Power duration curves by penetration and point of interconnection

For the 5600 MW scenario, the maximum power injections in the North zone consistently reach 2,150 MW for all the years studied. It is unlikely that this level of capacity would be connected to the grid through one single circuit; instead, it is likely that this involves a configuration of multiple circuits and connections to the onshore substation. If this were the case, no additional contingency reserves would be required, although the additional interconnection cost would need to be considered.

If the 2,150 MW of offshore wind were to become the MSSC, contingency reserves would increase by 790 MW for the DEC footprint. This case is unlikely though because there are incentives for both the BAA and wind developers to build a redundant interconnection to shore for that level of deployment.

4.4 REGULATING RESERVES

According to NERC, a regulating reserve is "an amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin." Regulating reserves are limited to online unloaded resources only because the response must be provided in, at most, a few minutes (maximum of 10). It is needed to respond to instantaneous variations in demand and, to the extent supply resources may vary, generation as well. Much analysis has been done industry-wide to determine a probabilistic estimate of this expected variability. The values used in the NERC standards to measure this are ε-1 and ε-10, which describe 1-minute and 10-minute variability, respectively. Current NERC requirements use two measures (based on 1-minute and 10-minute averages of area control error) to determine BAA compliance. To ensure compliance, area control error must be within an established limit (called L_{10} for 10-minute calculations) for at least 90% of the time.

Given that DEC has no significant nonconforming loads to alter the calculation, its regulating reserve requirement is set to L_{10}, which is currently approximately 110 MW. That requirement is maintained for the scenario with no wind in this study.

The following conclusions are extracted from the previous statistical analysis:

- Ten-minute wind variability is fairly consistent across deployment scenarios, with most of the ramps within 0.6% of nameplate capacity.
- The magnitude of extreme ramps increases significantly with the addition of wind, but there are few occurrences of these extreme ramps.
- Wind and load variability are independent in hourly and 10-minute timeframes.
- Net load variability is affected only marginally by increasing amounts of wind energy, except for extreme values (which are rare).

In light of these observations, a simple method to calculate regulating reserves is proposed and it consists of finding a suitable reserve level for the load (representing the current regulation needs) and wind separately. As shown earlier, their variability is independent, so the final reserve is calculated as the root mean square sum of the two:

$$TotalReserve = \sqrt{CurrentReserve^2 + WindReserve^2} =$$
$$= \sqrt{(Current\ L_{10})^2 + (1.65 \times \sigma_{Wind\ 10\ min})^2}$$

The current reserve portion is fixed to L_{10} (110 MW), and the wind reserve portion is determined based on the 10-minute variability. Because the objective is to cover 90% of the events, the wind reserve portion is set to be 1.65 times the standard deviation.[7] The final requirements are summarized in Table 5. The increments in regulating reserve requirements from the No Wind scenario are small and represent less than 1% of nameplate capacity in all deployment scenarios.

[7] This assumes an underlying normal distribution, and although the 10-minute ramp distribution is not normal, a confidence interval of ±1.65σ covers more than 90% of the events.

Table 5. Final Regulating Reserve Requirements

Scenario	10-Minute Wind Std. Dev. (MW)	Regulating Reserve Requirement (MW)
No Wind	–	110
1,000 MW	17	114
3,000 MW	39	127
5,600 MW	66	155

4.5 FREQUENCY RESERVES

The frequency response of the system is the aggregated result of primary frequency response (PFR) and inertia from all resources in the power system, including the natural load response. The frequency response of a power system with high levels of variable generation to sudden large imbalances has been a focal point of many studies both nationally and internationally [6–9]. In the United States, recent studies have suggested that the frequency response has been declining during the last several years [10, 11].

A typical wind power plant is substantially different than a conventional hydro or thermal power plant. Without special controls, a wind power plant does not participate in PFR. Further, inverter-based wind turbine generators (e.g., Type 3 and Type 4 units) do not, without special controls, provide any inherent inertial response. However, if appropriately equipped with the necessary control features, inverter-coupled wind generation technologies are capable of contributing to PFR and inertia. Some examples from industry and research are highlighted in the following sections.

4.5.1 MANUFACTURERS' TECHNOLOGIES

Many researchers have proposed different designs that allow wind power plants to provide capabilities similar to PFR and inertial control [12–14]. Many wind turbine manufacturers have already rolled out products with fast-control capabilities that can provide synthetic inertia and governor-like PFR functionality [15–17]. With further deployments of grid-decoupled wind turbines (Type 3 and Type 4), the flexible control functions are becoming more available for grid support.

4.5.2 OPERATORS' EXPERIENCES

The grid codes of many countries require wind power plants to provide frequency response [17, 18]. Germany requires PFR from wind for system over-frequency. British code requires PFR for both under- and over-frequency control. Rules in the Electric Reliability Council of Texas (ERCOT) require wind power plants to have the capability to provide PFR if they are operating at a point at which they can do so (i.e., only if they were previously curtailed and have head room to provide more energy during under-frequency events) [19].

Many independent system operators and regional transmission organizations in different countries recognize the value of inertial response from wind power and its importance to system reliability. In particular, Red Eléctrica de España (Spain), Hydro-Québec (Canada), the ERCOT, and others in Ireland and Denmark are in different stages of implementing wind inertia requirements in their operations [20–22].

4.5.3 INTERCONNECTION HIGH-WIND PENETRATION SCENARIOS

It was demonstrated in [23] that synthetic inertial control from wind turbine generators, if tuned properly, can significantly improve the frequency nadir during disturbances. PFR from wind turbine generators can be tuned to provide droop-like response and can significantly improve frequency nadir as well as settling (steady-state) frequency.

A frequency response study of the U.S. Eastern Interconnection is described in [24]. The purpose of the study was to create a meaningful baseline model for frequency response in the Eastern Interconnection and to investigate the possible impacts of large amounts of wind generation. Among other useful results, this study demonstrated the benefits of wind power providing PFR.

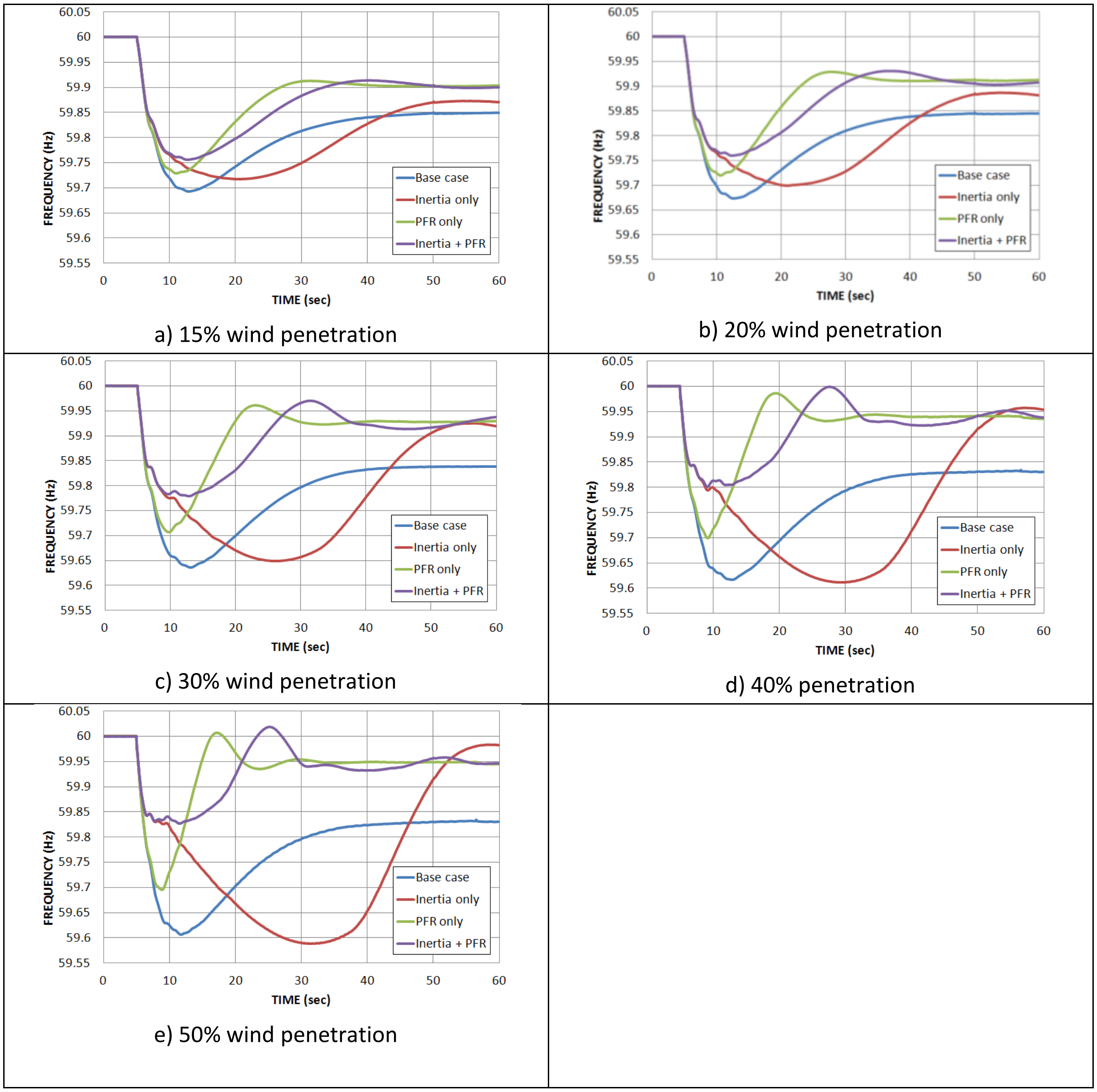
A detailed account of these two control features—PFR and inertial response—is presented in [25, 26]. Impacts of wind power providing inertial and PFR separately were investigated, as well as some of the issues related to applying both of these control strategies and how they might work best together. This work focuses on the different effects that each of these controls has on the large, interconnected system response and how the two controls can complement each other.

Figure 18 shows simulated frequency responses for five different wind power penetration levels (15%, 20%, 30%, 40%, and 50%) in the Western Interconnection and different active power control strategies from the wind power fleet. As shown, the increase in wind power penetration has a visible impact on the performance metrics: the frequency nadir and settling frequency decline with penetration levels for the base case (blue line) as a result of non-frequency responsive wind power replacing the responsive conventional generation.

Further analysis of the graphs in Figure 18 reveals the impact of different active power control strategies. The inertial control by wind power (red trace) shows marginal improvement in frequency nadir compared to the base case for lower penetration levels (Figure 18a–c). At higher penetration levels, the frequency nadir is essentially the same as the base case at 40% penetration (Figure 18d), and lower than the base case at 50% penetration (Figure 18e). Also, the nadir transition time shifts farther and farther right with penetration level. This is because inertial control alone helps reduce only the initial rate of decline of the frequency, which comes at the expense of slowing down the wind turbine rotors. Because of this slowdown, the wind turbines depart from their maximum power point, thus creating a deficiency of active power (a period of underproduction relative to the initial pre-fault operating point) and resulting in a slower frequency recovery time. In addition, as shown in Figure 18, the recovery is of oscillatory nature, with overshoots, and takes longer to settle at a steady-state frequency (i.e., there is a longer transition to Point B).

On the other hand, enabling the PFR feature creates a visible improvement in frequency response, resulting in a better nadir and higher steady-state frequency, as shown in Figure 18 (green trace). The frequency nadir of the PFR-only case does not change significantly with penetration level because of the same 5% head room in all of the simulation scenarios. However, it is consistently higher than the base case nadir for all penetration cases. The recovery of frequency is almost as fast as in the base case, with some oscillatory behavior, depending on penetration level. The biggest improvement is in the settling frequency level, which in the 50% case increases from 59.84 to 59.95.

Combining inertial and PFR controls gives the best performance (purple trace on Figure 18). This control strategy results in a significantly higher frequency nadir with somewhat slower recovery time compared to the PFR-only case.



a) 15% wind penetration

b) 20% wind penetration

c) 30% wind penetration

d) 40% penetration

e) 50% wind penetration

Figure 18. Western Interconnection frequency responses for increasing wind power penetrations

4.5.4 CALCULATIONS

The survey in the previous sections indicates that current wind power technologies can provide inertial response and PFR and that some grid codes already require these features. To provide governor-like controls, wind turbines must be allowed some head room. This section presents a simple estimation of the head room necessary for each deployment scenario.

The current Interconnection Frequency Response Obligation (IFRO) for the Eastern Interconnection is -1,002 MW/0.1 Hz (as shown in Table 1 in [27]). The IFRO can be allocated to the different BAAs based on the annual load and generation, using the data from the most recently filed FERC Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011. The following method is used to calculate the frequency response obligation (FRO) for each BAA [27]:

$$FRO_{BAA} = IFRO \times \frac{(Annual\ Gen_{BAA} + Annual\ Load_{BAA})}{(Annual\ Gen_{INT} + Annual\ Load_{INT})}$$

where:

- Annual Gen_{BAA} is the total annual output of generating plants within the BAA, on FERC Form 714, column c of Part II – Schedule 3.
- Annual $Load_{BAA}$ is total annual load within the BAA, on FERC Form 714, column e of Part II – Schedule 3.
- Annual Gen_{INT} is the sum of all Annual Gen_{BAA} values reported in that interconnection.
- Annual $Load_{INT}$ is the sum of all Annual $Load_{BAa}$ values reported in that interconnection.

The net energy for load (NEL) used by NERC to bill its members is a good proxy for the energies referenced above. In most cases, the NEL values reported by members are the same as those reported on FERC Form 714. The most recent NEL data available on the NERC website is in [28]. From page 11 of that report, the NEL by region is summarized in Table 6:

Table 6. Net Energy for Load by NERC Region

Interconnection	Region	2012 Net Energy for Load (GWh)
Eastern	Florida Reliability Coordinating Council	220,684
	Midwest Reliability Organization	284,519
	Northeast Power Coordinating Council[8]	641,382
	ReliabilityFirst Corporation	902,132
	SERC Reliability Corporation	1,018,700
	Southwest Power Pool	217,689
Texas	Texas Regional Entity	324,860
Western	Western Electricity Coordinating Council	866,704

The resultant Eastern Interconnection NEL is 3,100,284 GWh. Using this value for both Annual Gen_{INT} and Annual $Load_{INT}$, the percentages of IFRO and the FRO for the theoretical COWICS generation-only BAA can be calculated using the wind capacity factors for each scenario to determine the Annual Gen_{BAA} values for each scenario. Annual $Load_{BAA}$ is obviously zero for generation-only BAAs.

According to [29], "to determine an initial target (at scheduled frequency) frequency responsive reserve level (in MW) for a given responsible entity, simply multiply 10 times the responsible entity's FRO

[8] Includes the Net Energy for Load for Hydro-Québec, which is 184,822 GWh (page 2 in [29])

(because FRO is in MW/0.1 Hz) by the MDF [maximum delta frequency] for the responsible entity's Interconnection". The following example illustrated these calculations:

- Given a responsible entity is in the Eastern Interconnection with a pro-rata portion of IFRO is 1.5%.
- The key EI parameters are: IFRO = 1002 MW/0.1 Hz and MDF = 0.449 Hz.
- The responsible entity's FRO is {1.5% *1002 MW/0.1 Hz} or 15.2 MW/0.1 Hz.
- The responsible entity's initial frequency responsive reserve target is {10 * 15.2 * 0.449} or 67.48 MW.

Following the same calculations, the estimated FRO and frequency response ratio (FRR) for the offshore wind COWICS generation-only BAA are calculated in Table 7.

Table 7. Calculations of Frequency Response Head Room for Offshore Wind

Scenario (MW)	Wind CF (%)	Annual Gen. (GWh)	Portion of IFRO	COWICS FRO (MW/0.1 Hz)	Wind FRR (MW)	Wind FRR (% Nameplate)
1,000	42.0%	3,679	0.059%	0.59	2.7	0.27%
3,000	41.4%	10,880	0.176%	1.76	7.9	0.26%
5,600	41.0%	20,113	0.324%	3.25	14.6	0.26%

The end result of these calculations provides a conservative estimate of the expected frequency response contribution from COWICS generators. The recommended method to model this contribution in production cost analyses is to de-rate the units' capabilities by the percentage of nameplate shown in the far right column.

4.6 OPERATING ANALYSIS CONCLUSIONS

A thorough analysis of the impact of offshore wind in the different COWICS scenarios was performed. Analysis of wind profiles showed clear seasonal trends with higher wind outputs during the winter and spring months and also during nighttime. During the summer months, a clear daily trend was observed with upward ramps during the early afternoons.

Wind variability increased for higher wind levels, but the differences were not very pronounced when normalizing by installed capacity. The vast majority of the hourly ramps were smaller than 10% of the capacity, and 50% of those ramps were smaller than 3%. Most of the 10-minute ramps were within 2% of nameplate capacity, with 50% of the total smaller than 0.6%. Similar trends were observed across the ten years of data.

The year selected for the production cost simulations (year 2000) presented average power output values and was more variable than average. Because the study area was relatively small, there was not a significant benefit from geographic diversity. Power profile correlations were found to be significant among sites, and ramp correlations diminished much more rapidly with distance, especially for the 10-minute ramps.

On average, the effect on the footprint net load was slight to moderate. The ratio of peaks to valleys increased with wind penetrations because wind output was higher during low-load hours, but no negative net load values were observed. The changes in net load variability were also moderate in the hourly and 10-minute timeframes. The biggest change happened for very rare extreme ramp values, both upward and downward.[9] Load and wind variability were found to be independent for the hourly and 10-minute ramps.

Based on this analysis, the following are the recommendations for the four types of reserves studied:

- Capacity reserves—Use a summer capacity credit of 39% across scenarios.
- Contingency reserves—No changes to the requirement. Redundancies in the collection system would be necessary in the North zone for the 5600-MW scenario.
- Regulating reserves—Increase the base requirement of 110 MW to 114 MW, 127 MW, and 155 MW for the 1000 MW, 3000 MW, and 5600 MW scenarios.
- Frequency response reserves—Wind was deemed capable of contributing inertial response and PFR. To do so, it is estimated that power production levels would be de-rated by 0.26% of nameplate capacity for all scenarios to represent these contributions.

[9] These could be due to artifacts in the production of the wind power profiles.

5.0 TASK 6 – PRODUCTION COST SIMULATION

To assess offshore wind generation impacts to the DEC generation portfolio, a detailed production cost simulation model was developed to mimic the DEC generation fleet operations under the basecase conditions and with different levels of offshore wind penetrations in study years 2018 and 2021. Input assumptions into the production cost model such as peak load and energy forecasts and operating characteristics of the DEC generation fleet were provided and verified under the scrutiny of DEC operation personnel. The production cost base cases were benchmarked against historical DEC results for accuracy before proceeding to future study year simulations. In addition to assessing the economic performance of the DEC generation fleet, with and without offshore wind resources, the production cost simulations also evaluated two other aspects of the DEC system: 1) the economic interaction between offshore wind and energy storage resources that exist in DEC, and 2) contingency reserve economic considerations to integrate large scale offshore wind. Changes in emission levels from the base case to the wind scenarios due to displacement of fossil-fueled resources were also calculated and are reported in this section.

The production cost model used for this analysis was the ABB GridView program, a state of the art commercial production cost modeling tool designed with features to accurately capture the unique characteristics of the DEC system. A detailed description for GridView is provided in APPENDIX A **– PRODUCTION COST SIMULATION MODEL REVIEW**.

In the GridView simulation, spinning reserve, regulation up and regulation down were co-optimized with energy to serve load and ancillary services simultaneously. The program was also modeled to ensure sufficient capacity commitment for all ancillary services during dispatch. The study years were 2018 and 2021.

5.1 BASE CASE DEVELOPMENT

This study focused on production cost only for the DEC footprint[10]. The different levels of wind generation were integrated into the DEC economic dispatch order. Therefore, in the economic study, the DEC net interchanges with neighboring systems were set to zero while the networks of external networks were still available for wheeling through. Offshore wind generation was transmitted through neighboring systems to be delivered to DEC.

The wind profiles for each scenario were developed based on the sites selected in Phase 1 of COWICS and their associated profiles. ABB updated the economic database with the revised power flow cases for each scenario. Generation cycling and ramping constraints were not considered in the production cost study.

The Ventyx Simulation Ready Database in GridView format provided an Eastern Interconnection simulation platform based on public domain information, Ventyx forecasts and MMWG power flow cases. It covers NYISO, ISO-NE, PJM, MISO, SPP, Florida, Southern Company, Carolinas, TVA, and Canadian regions. NERC version 9.5 was used as the starting point to develop the COWIC study database.

[10] Duke Energy Progress was not part of study region.

The economic hourly simulation database was built based on the following data sources:

1. Ventyx Simulation Ready database (Eastern Interconnection version 9.5 (ABB))
2. Updated power flow cases for the 1000 MW, 3000 MW, and 5600 MW scenarios (DEC)
3. Updated DEC load forecast profiles for 2018 and 2021 (DEC)
4. Updated data for PSH plants Bad Creek and Jocassee (DEC)
5. Updated control algorithm to reflect DEC operation for PSH plants (ABB)
6. Built offshore wind farms and associated transmission connections (ABB)
7. Updated generator data for quick start units (DEC)
8. Updated DEC ancillary service requirement results from Task 5 (NREL)
9. Offshore wind farms with day ahead forecast profiles (NREL)

The Ventyx Simulation Ready Database in GridView format provided an Eastern Interconnection simulation platform based on public domain information, Ventyx forecasts and MMWG power flow cases. It covers NYISO, ISO-NE, PJM, MISO, SPP, Florida, Southern Company, Carolinas, TVA, and Canadian regions. NERC version 9.5 was used as the starting point to develop the COWIC study database.

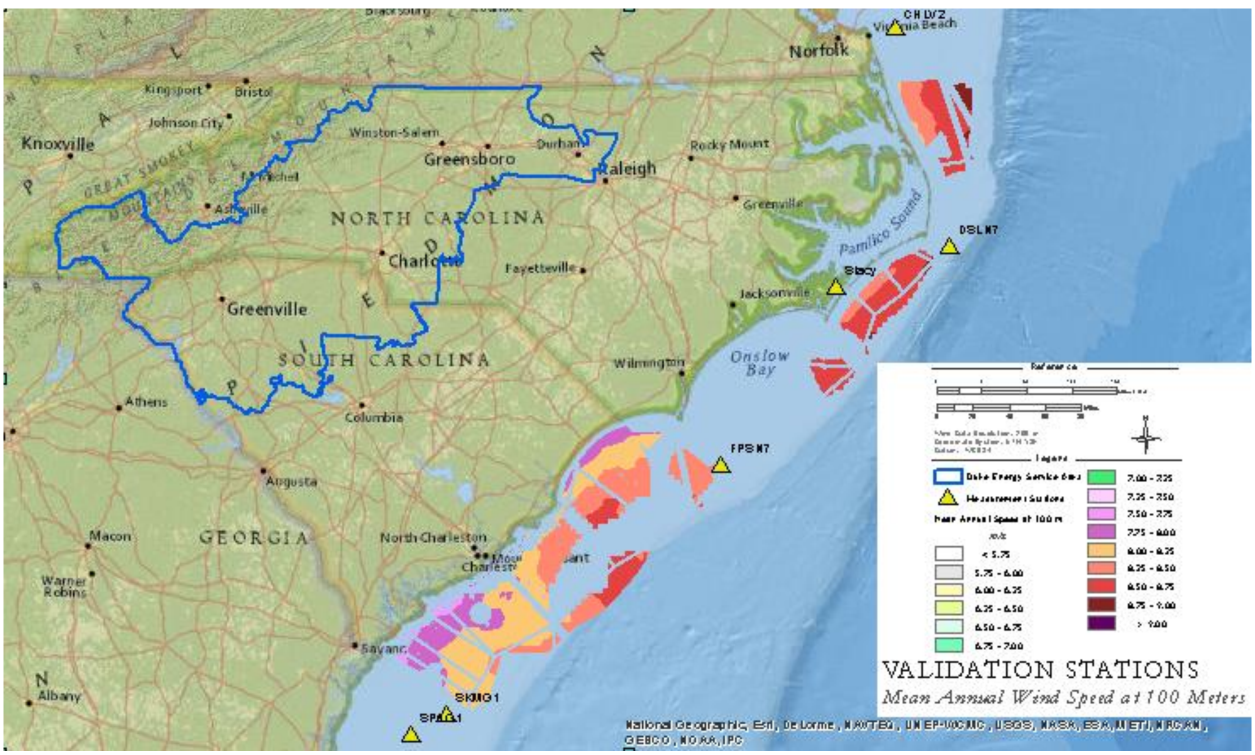


Figure 19. DEC and Potential offshore wind Locations

DEC service territory is located in the western part of the Carolinas removed from the offshore wind farms in the Atlantic Ocean, as shown in Figure 19. Offshore wind will be brought into the DEC service territory through other utility service territories. Since the GridView simulation was performed only for DEC, the paths to bring offshore wind were not monitored in the economic study. Transmission lines, interfaces, and contingency constraints in DEC territory were enforced in the simulations.

DEC is projected in 2018 to have installed generating capacity of 25,012 MW comprised of nuclear, coal, combined cycle, gas turbines, wind, solar, conventional hydro, and pumped storage hydro resources. The capacity by resource type is shown in Figure 20.

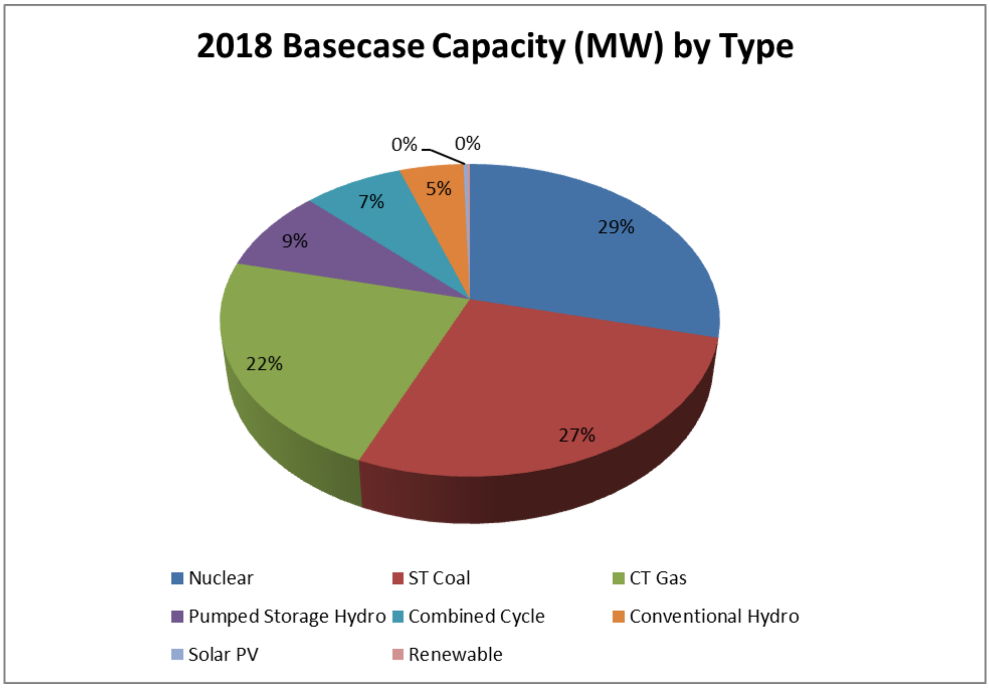


Figure 20. DEC Generation Capacity by Type in 2018

Based on the 2018 GridView simulation, 56% of DEC energy demand is served by nuclear, 30% by coal, 8% by combined cycle plants, 3% by pumped storage hydro, 2% by conventional hydro, and less than 1% by all other resource types as shown in Figure 21.

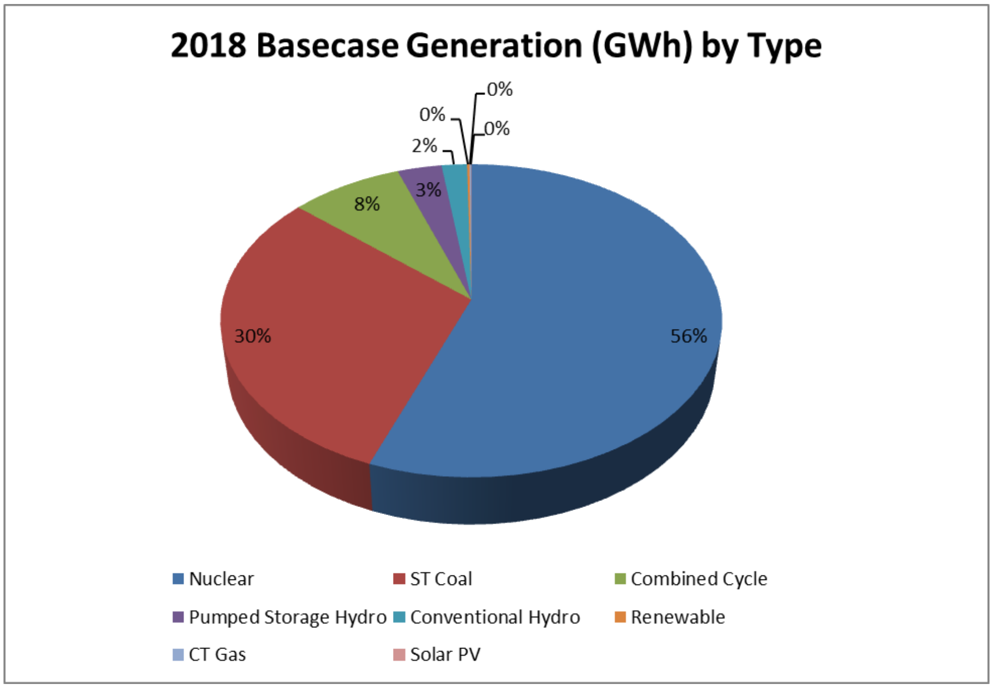


Figure 21. 2018 Basecase DEC Generation by Type

5.2 BENCHMARKING

The 2018 GridView simulation results were benchmarked against DEC 2013 actual performance, as shown in Table 8. The simulation results track closely to actual energy generation thereby validating GridView modeled conditions as predictive of future operation.

In summary, the 2018 simulation dispatched more coal and gas generation than actual 2013 production. The differences are due to (1) 2018 load is higher than 2013; (2) one additional CC plant in-service in 2018; (3) plant maintenance and outages are scheduled differently; (4) DEC has energy interchanges with neighboring systems but no interchange was permitted with neighboring systems in the simulation; (5) fuel prices are slightly different.

Table 8. DEC generation resources capacity, energy, and capacity factor by type

	2018 Basecase Capacity (MW)	2018 Basecase Generation (GWh)	2018 Basecase Average Capacity Factor	2013 Capacity (MW)	2013 Generation (GWh)	2013 Average Capacity Factor
Nuclear	7,233	59,963	95%	7,054	59,085	96%
Combined Cycle	1,844	8,860	55%	1,268	8,224	74%
Renewable	45	195	49%	49	279	65%
Steam Coal	6,877	32,753	54%	7,172	29,371	47%
Conventional Hydro	1,182	2,004	19%	1,118	2,704	28%
Pumped Storage Hydro	2,140	3,490(Gen)	19%	2,140	2,779 (Gen)	15%
Solar PV	74	44.261	7%	46	33	8%
Combustion Turbine	5,617	96	0%	2,856	427	2%
Total	**25,012**	**107,405**	**49%**	**21,703**	**102,900**	**54%**

Fuel prices are shown in Table 9 and Figure 22. Gas prices change monthly while coal plants have the same fuel price for all months of the year.

Table 9. Coal Plant fuel price for 2013 historical and 2018 Forecast

Coal Plant Name	2013 Historical	2018 Forecast
Belews Creek	3.35	3.90
Cliffside	3.53	3.76
Allen	3.23	3.94
Marshall	3.32	3.66

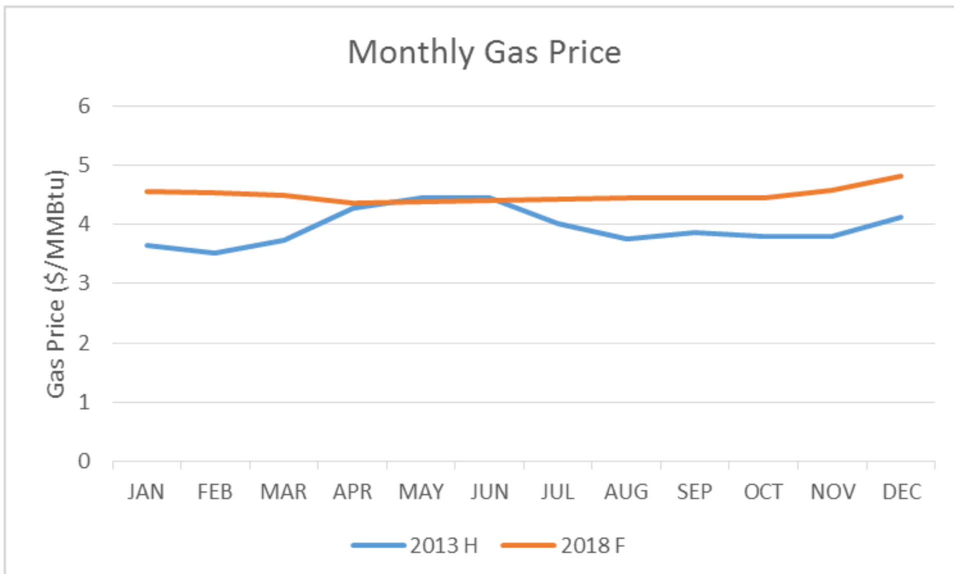


Figure 22. Monthly Gas Price for 2013 Historical and 2018 Forecast

DEC PSH plants (Bad Creek and Jocassee) operate on weekly operator-controlled schedules. The scheduling objective is to start Monday morning, before morning load ramp-up, at full pond levels and through the week use the water during daily on-peak hours and recharge off-peak, ending Friday evening at minimum pond levels to be refilled over the weekend. Bad Creek and Jocassee collectively have average annual capacity factors of approximately 15-19% historically. The GridView simulation utilized these PSH plants at a generating capacity factor of 18% in the 2018 base case, which is within the historical capacity factor typical range. Conventional hydro plants also track very closely between historical and simulated energy production.

There is little transmission congestion in the DEC system historically and GridView simulations reflect this network characteristic. The highest congestion occurs on the McGuire – Riverbend #2-230 kV circuit under normal conditions in the 2018 simulation which is also representative of actual system operation. Lincoln CTs were dispatched when the circuit was constrained in the simulation.

5.3 ECONOMIC STUDY RESULTS

The 2018 and 2021 base cases have no offshore wind resources modeled. Offshore wind development at capacities of 1000 MW, 3000 MW, and 5600 MW were added to the base cases to establish the wind cases. Offshore wind was modeled as hourly resources with hourly profiles. In economic dispatch, offshore wind displaces the marginal priced generation which is typically fossil-fired generation such as coal and gas CT/CC resources on the DEC system, thereby reducing production cost to serve load. Simulation demonstrated coal and CC plants are on margin for over 95% of hours.

Conversely, offshore wind necessitates carrying moderately more operating reserves than the fossil generation it displaces, as discussed in Task 5 Section 3.2, which acts to increase production cost. The net impact of these competing outcomes, by adding offshore wind to the DEC generation portfolio, is to reduce system production cost.

DEC has 7,232 MW of nuclear baseload generation to serve a projected peak load of 20,386 MW in 2018 and minimum load of 7,411 MW. During the off-peak hours nuclear plants will run at their maximum capacity and some coal plants will remain online at minimum loading to be ready for next day peak loads due to longer minimum down times and ramping rates associated with coal-fired generators. As a result, during off-peak hours over-generation conditions may occur when offshore generation plus nuclear generation and coal minimum generation is greater than demand. When over-generation conditions occur, wind resources will be curtailed to maintain generation-load balance.

The annual benefit for wind integration is shown in Table 10, where production cost saving is calculated as base case production cost minus wind scenario production cost. Production cost saving (of approximately 5.7%-24.3%) and wind curtailment both increase as more offshore wind is added.

Table 10. Economic Simulation Results for Wind Integration

Year	Scenario	Production Cost ($M)	Production Cost Savings ($M)	Wind Energy Consumed (TWh)	Wind Curtailment (%)
2018	Basecase	2,179	-	-	-
	1000 MW	2,055	124	3.7	0.5
	3000 MW	1,843	336	10.4	5.4
	5600 MW	1,649	530	16.2	19.8
2021	Basecase	2,378	-	-	-
	1000 MW	2,256	122	3.6	2.2
	3000 MW	2,042	336	10.3	5.8
	5600 MW	1,840	539	16.9	15.4

A graphic depiction of offshore wind displacing fossil-fired generation on the DEC system is shown in Figure 23. DEC generation resources economically separate into four distinct groups based on production cost: Renewables excluding wind ($0/MWh), Nuclear ($12/MWh), Coal & CC ($32-$39/MWh), CT ($49/MWh).

For most hours of the year the hourly DEC system load is in the range of 10,000 MW – 20,000 MW for which the marginal resource type is either coal or CC at a production cost of approximately $32/MWh - $39 MWh. As offshore wind is added to the DEC generation portfolio, the "operating point" on the economic dispatch stack moves from Point A to Point B because coal and CC resources are displaced by wind resources. Although the marginal production cost is relatively flat in this area of the curve (i.e., no change in marginal cost), there is a significant difference in total production cost for the DEC system since wind at near $0/MWh is displacing the coal & CC generation between Point A and B at $32/MWh - $39/MWh, thus producing savings previously shown in Table 10.

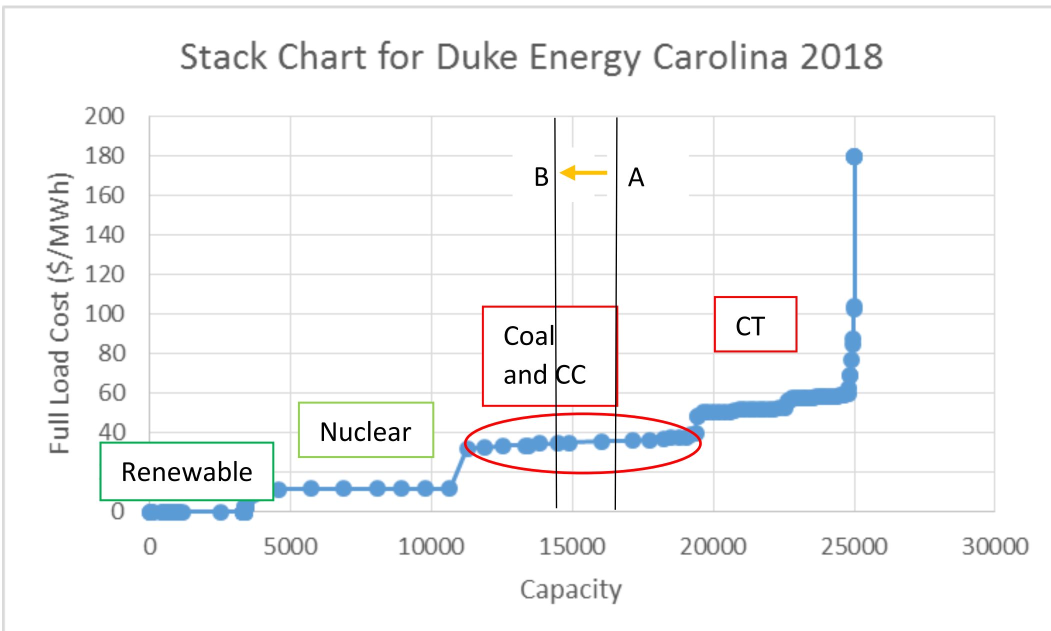


Figure 23. Economic Dispatch Stack for DEC in 2018

While economic dispatch is the primary driver of production cost saving due to wind displacement of fossil-fueled resources there are also other conditions which impact the analysis such as minimum load, minimum downtime/runtime, reserve provisions, etc.

Resource displacement for varying wind penetrations is also shown in Figure 24 which depicts annual energy production changes by resource type due to offshore wind additions. Wind Curtailment is the amount Wind Production would have to be reduced during off-peak over-generation conditions previously discussed for nuclear and baseload coal must run units. 2021 simulations showed similar wind displacement patterns as that for 2018 and as noted previously, these results assume no market for energy sales outside of DEC.

Although barely perceptible in Figure 24, PSH resources on the DEC system are utilized slightly more for higher wind integration levels suggesting a natural synergy between low/no cost renewable resources such as offshore wind and large scale energy storage resources. This unique combination allows capture of the "free energy" produced by renewables during times when it may not be needed or desired to be stored and used during higher load and cost periods when renewable energy may not be able to be produced. This characteristic of the DEC system is discussed more in Section 5.5.

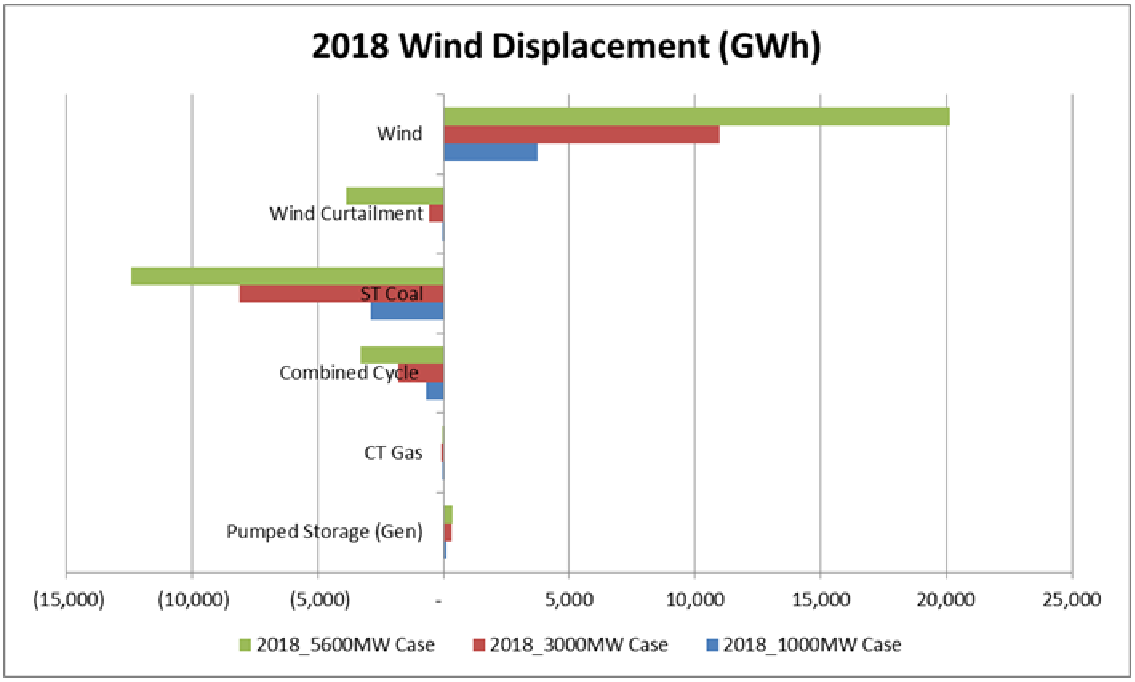


Figure 24. Wind displacement in 2018

Another beneficial effect of adding wind generation and displacing fossil fueled generation is effluent emission reduction. GridView simulation results quantifying emission volumes and rates are shown in Table 11 and Table 12.

Table 11. Emission Results for Wind Integration

Year	Scenario	SO_2 (thousand tons)	NO_x (thousand tons)	CO_2 (million tons)	SO_2 reduction (%)	NO_x reduction (%)	CO_2 reduction (%)
2018	Basecase	6.74	15.6	34.2	-	-	-
	1000 MW	6.07	14.0	31.4	10%	10%	8%
	3000 MW	4.88	11.2	26.4	28%	28%	23%
	5600 MW	3.92	8.7	22.1	42%	44%	35%
2021	Basecase	7.73	17.9	38.9	-	-	-
	1000 MW	7.09	16.4	36.1	8%	8%	7%
	3000 MW	5.94	13.6	31.1	23%	24%	20%
	5600 MW	4.88	11.0	26.4	37%	39%	32%

Table 12. Emission reduction for each MWh of wind added to the system

Year	Scenario	SO_2 (lb/MWh wind)	NO_x (lb/MWh wind)	CO_2 (lb/MWh wind)
2018	1000 MW	0.36	0.83	1,540
	3000 MW	0.36	0.85	1,511
	5600 MW	0.35	0.83	1,507
2021	1000 MW	0.35	0.84	1,547
	3000 MW	0.35	0.84	1,513
	5600 MW	0.34	0.81	1,469

5.3.1 WIND WEEKS

The annual simulation results show that wind generation impacted coal and CC generation. Two extreme weeks were chosen in the 2018 simulation to demonstrate the wind generation impacts to the DEC economic dispatch stack: the summer peak load week and the highest wind penetration week.

5.3.1.1 SUMMER PEAK LOAD WEEK

For summer peak load week, since wind generation is relatively small compared with peak demand, the expected impacts to coal and CC generation were small. The detailed dispatch stack for summer peak week is shown in Figure 25, for the base case, 1000 MW, 3000 MW, and 5600 MW scenarios. PSH resources pumping at off-peak hours help to keep baseload units on line and avoid over generation conditions. There is no wind curtailment during summer peak load week for all wind scenarios.

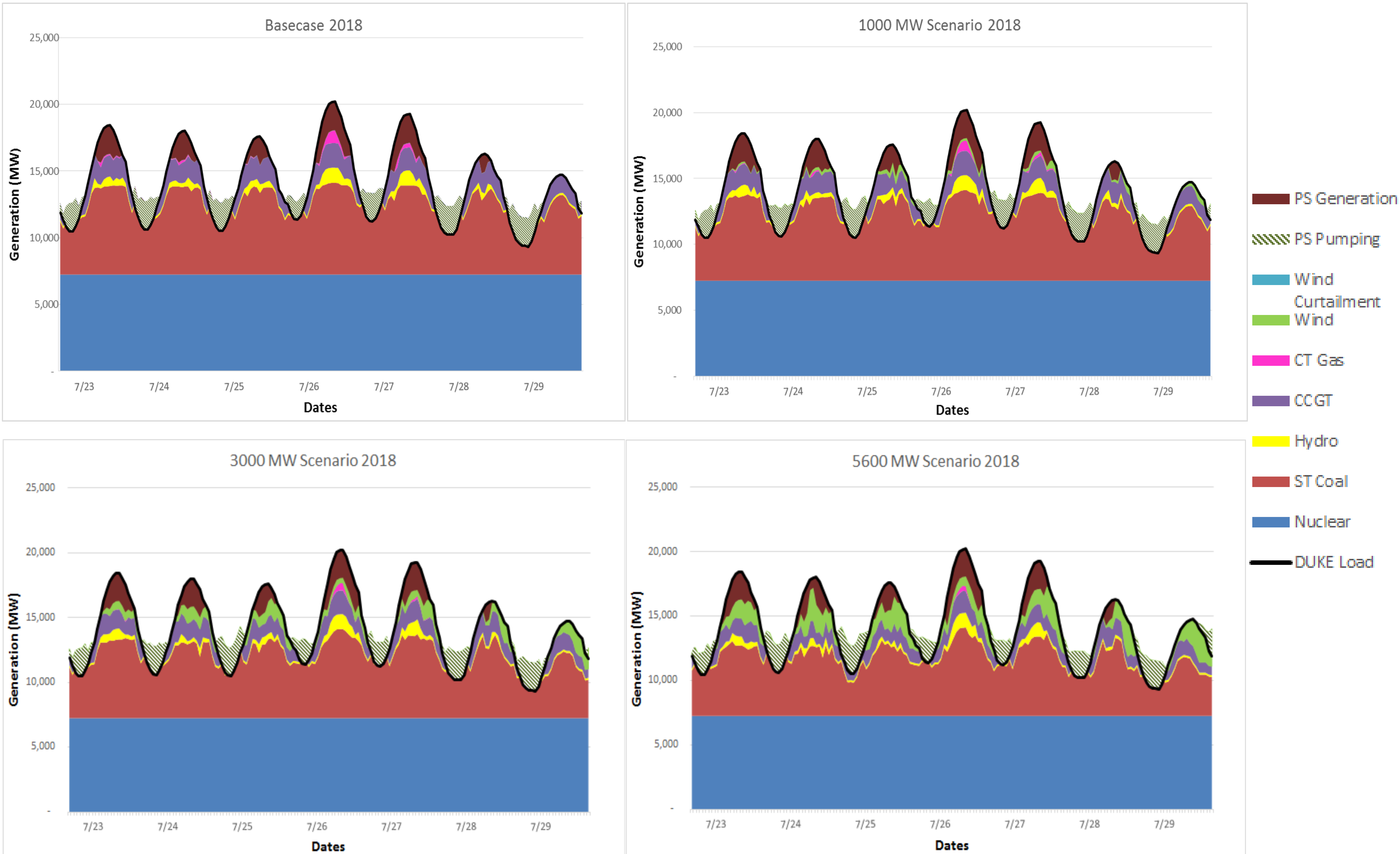


Figure 25. Generation dispatch stack in Summer Peak week for different Wind Scenarios

5.3.1.2 PEAK WIND WEEK

The dispatch stack for the high wind week for all scenarios is shown in Figure 26. During this week a nuclear unit was scheduled off for refueling and a baseload coal unit was assumed to be turned off for routine fall scheduled maintenance. Offshore wind was curtailed during some low load hours at nights and weekends in the 5600 MW scenario and weekends in the 3000 MW scenario. The 5600 MW scenario has wind curtailment of 75.7 GWh during 46 hours in this week while the 3000 MW scenario showed minimal wind curtailment of 0.9 GWh during 2 hours in this week and the 1000 MW scenario had no wind curtailments.

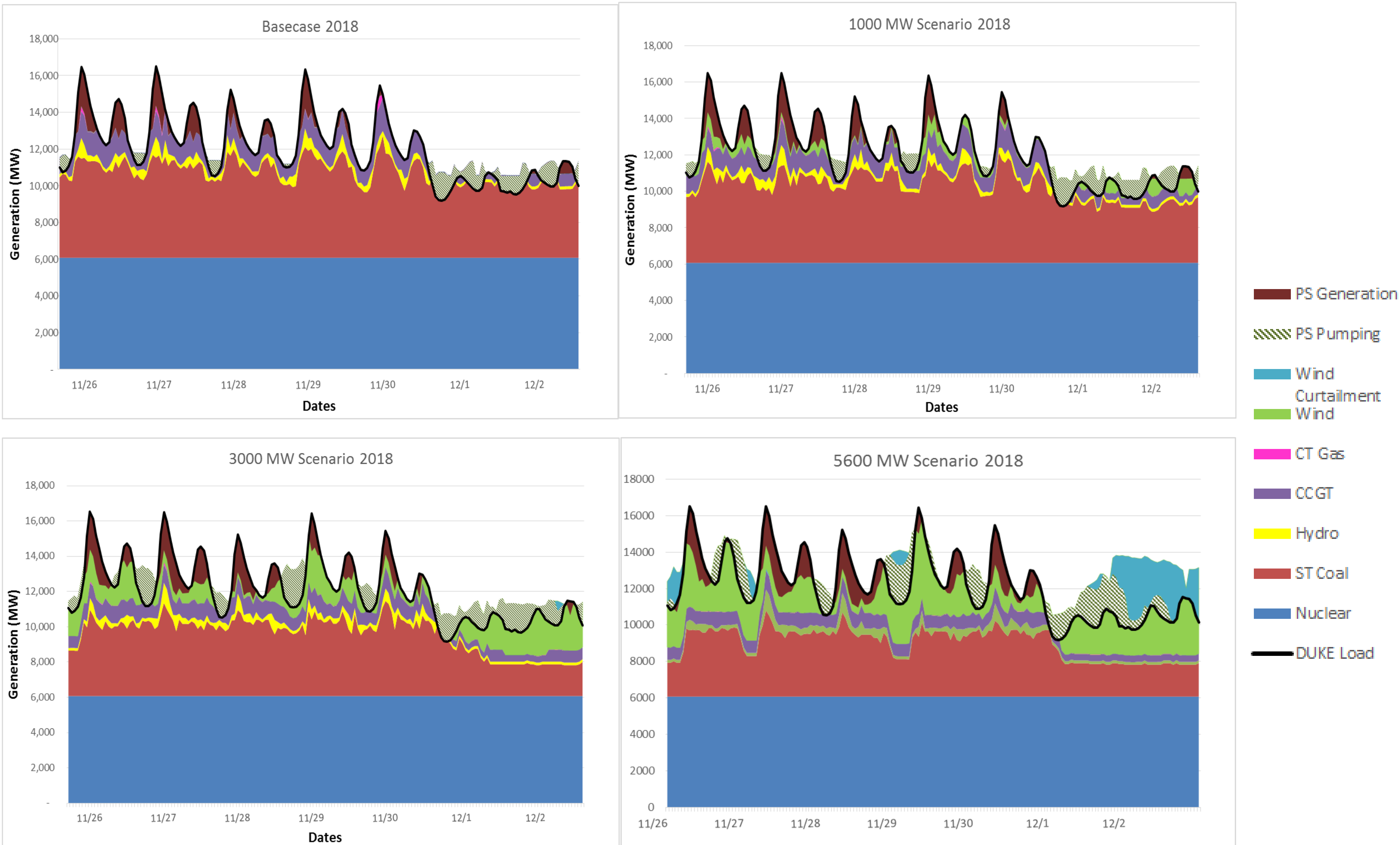


Figure 26. Generation dispatch stack in High Wind week for different Wind Scenarios

5.4 CONTINGENCY RESERVE EVALUATION

Section 4.3 discussed contingency reserves on the DEC system and the concept of most severe single contingency as it relates to future offshore wind integration into DEC. In the 5600 MW wind scenario the offshore wind turbine capacity in the northern zone was modeled as approximately 2,150 MW or 790 MW in excess of the present DEC MSSC amount of 1,360 MW. Additional production cost simulations were performed to quantify the cost of carrying 790 MW more contingency reserves. The results of the simulations are shown in Table 13.

An additional 790 MW of contingency reserves, modeled in the production cost simulations as spinning reserves, increased production cost by approximately $14M and increased wind curtailment/reduced wind energy consumed by 275 - 300 GWh in 2018. Most of these additional contingency reserves were met by PSH based on analysis.

The economic comparison to be made is the increased cost of the additional contingency reserves versus the annual carrying charges associated with a second offshore – onshore interconnection to integrate the offshore wind resources. Construction costs for a second interconnection were not sought but it is estimated the additional production cost of contingency reserves would approximate annual construction carrying charges. Additionally there are reliability considerations to build two connections for the northern zone and incentives for both the BAA and wind developers to build a redundant interconnection to shore for that level of deployment. As such, additional contingency reserves were not modeled in the 5600 MW scenario and two interconnections to the northern zone were assumed in the analysis.

Table 13. Economic Impacts of 790 MW additional Contingency Reserve

Year	Scenario	Production Cost ($M)	Production Cost Saving ($M)	Wind Energy Consumed (TWh)	Wind Curtailment (%)
2018	Basecase	2,179	-	-	-
	5600 MW	1,649	530	16.2	20%
	5600 MW + cont. reserve	1,662	516	15.8	21%
2021	Basecase	2,378	-	-	-
	5600 MW	1,840	539	16.9	15%
	5600 MW + cont. reserve	1,848	530	16.8	16%

5.5 PUMPED STORAGE HYDRO

DEC has 7,232 MW of baseload nuclear generation. In 2018 the projected peak demand is 20,386 MW and minimum load is as low as 7,411 MW. During the off-peak hours, nuclear plants will continue to run at maximum capacity and additionally some coal plants will remain online at minimum loading to be ready for next day peak loads due to minimum down time and ramping rate characteristics of these units. When load is below a certain level, DEC minimum generation can be greater than load and require energy curtailment of the wind resources. The DEC PSH would utilize what otherwise would be curtailed wind energy to refill lake levels during these minimum load/generation periods.

To understand the synergy between PSH and offshore wind resources, additional cases were developed to gradually replace PSH capacity with equivalent CT capacity so that comparison of wind curtailment and production cost saving could be made in the 3000 MW scenario. Incremental blocks of 535 MW replacement of PSH with CTs were modeled to maintain the same DEC installed capacity for resource adequacy requirements.

Simulation results in Table 14 and Table 15 show increased production cost savings of approximately $53M in the 3000 MW wind scenario with and without the PSH resources. Additionally, wind energy utilization increased approximately 2.9 TWh while wind curtailment decreased in the same amount. The combination of variable renewable energy resources such as offshore wind turbines with large scale energy storage resources such as PSH acts to enhance the utilization and efficiency of both technologies.

Table 14. PSH impacts on production cost results for the year 2018

	BaseCase Production Cost ($M)	3000 MW Production Cost ($M)	Wind production cost savings ($M)
With PSH	2,179	1,843	336
Without PSH	2,205	1,922	283
Difference	-26	-79	53

Table 15. PSH impacts on wind generation and curtailment for the 3000 MW scenario in year 2018

PSH Capacity (MW)	Wind Energy Consumed (TWh)	Energy Curtailment (%)
2,140	10.4	5%
1,605	10.1	8%
1,070	9.7	12%
535	8.8	19%
0	7.5	31%

5.6 PRODUCTION COST CONCLUSIONS

Wind turbines located offshore from the Carolinas coast can provide significant energy production cost savings to the DEC generation portfolio by displacing higher marginal cost fossil-fueled resources. The resulting simulated production cost savings were $124 million, $336 million and $530 million for the 1000 MW, 3000 MW and 5600 MW scenarios in the 2018 study year, respectively. The 2021 study year showed similar results (see Table 10. Economic Simulation Results for Wind Integration). Changes to operating reserve considerations were incorporated into the production cost simulations.

Another significant benefit of offshore wind and its displacement of fossil-fueled generation is reduction of effluent emissions (i.e., NO_x and SO_x), carbon capture, and other combustion and scrubber byproducts treatment (see Table 11. Emission Results for Wind Integration). Emissions were reduced from 10% to 44% for the 1000 MW, 3000 MW and 5600 MW scenarios.

Such large quantities of offshore wind do create over-generation conditions during light load off-peak periods. The DEC system has significant baseload resources, namely nuclear and large coal units, which are not cycled. During daily light load periods it may be necessary to curtail offshore wind production to accommodate these baseload resources. In the simulations, such wind curtailment began at the 1000 MW installed generation level and became more pronounced (>3,000 GWh) in the highest 5600 MW scenario (see Table 10. Economic Simulation Results for Wind Integration). Potential DEC off-system economic sales were not modeled in the simulations and it is probable that some of the curtailed offshore wind energy could be sold rather than curtailed.

Pumped storage resources can mitigate offshore wind curtailment created in over-generation conditions. The DEC system has large scale energy storage resources in the form of PSH plants at stations Bad Creek and Jocassee totaling 2,140 MW. The synergy of these pumped storage resources combined with offshore wind demonstrated that energy storage can reduce curtailed energy from the wind resources during off-peak times and also that the renewable wind resources can increase the generation produced by the energy storage resources by providing low/no cost energy for pumping during the same off-peak periods. This study measured the increased production cost savings from the renewable/energy storage combination as providing approximately an additional $50 million in savings from increased utilization of the PSH resources and wind curtailment was reduced approximately 26% (~2.9 TWh) in the 3000 MW offshore wind scenario in 2018 (see Table 15).

Finally, the addition of large quantities of offshore wind can create an issue with contingency reserve levels depending on how the wind is integrated into the electrical network. In this study offshore wind resources were integrated into the network in three distinct areas. The northern zone had the largest concentration of offshore wind resources. In the 5600 MW scenario, loss of the northern zone generation interconnection could exceed the largest single contingency on the DEC system by 790 MW which would require carrying additional contingency reserves. Production cost simulation measured the additional cost of carrying these contingency reserves as approximately $14 million annually. Since this annual charge could approximate the annual carrying charge associated with building a second offshore-onshore interconnection for the northern zone, it was assumed in this analysis that additional contingency resources would not be incorporated into the production cost simulations but rather assumed a second offshore wind interconnection would be built at this high level of offshore wind development.

6.0 PHASE 2 SUMMARY & CONCLUSIONS

This study has demonstrated that high quality wind sites as exist off the Carolinas shore can provide significant benefits to an electric utility system such as DEC in terms of operating reserve benefits, production cost savings, and emission reductions while preserving first priority electric grid reliability as summarized in the following findings and documented in this report.

- No dynamic stability concern or violation of NERC reliability standards was identified with the interconnection of offshore wind generation.
- All NERC Category B (single contingency) and Category C (loss of multiple elements with normal clearing) faults were stable.
- One NERC Category D2 fault at the northern offshore wind generation neighboring bus caused one close-by generator to trip. This involved a three-phase fault on the transmission circuit with delayed clearing due to the local breaker failure.
- Capacity reserves — Use a summer capacity credit of 39% across all scenarios.
- Contingency reserves — No changes to the requirement. Redundancies in the collection system would be necessary in the North zone for the 5600 MW scenario.
- Regulating reserves — Increase the base requirement of 110 MW to 114 MW, 127 MW, and 155 MW for the 1000 MW, 3000 MW, and 5600 MW scenarios.
- Frequency response reserves — Wind was deemed capable of contributing inertial response and primary frequency response. To do so, it is estimated that power production levels would be de-rated by 0.26% of nameplate capacity for all scenarios to represent these contributions.
- Annual production cost savings of \$120M – \$530M (5.7%-24.3%) from the no-wind scenario base conditions were realized in the 1000 MW, 3000 MW, 5600 MW scenarios.
- Emission reductions were significant ranging from 10-44% relative to the base case for the 1000 MW, 3000 MW and 5600 MW scenarios.
- Synergy between pumped storage hydro (PSH) and offshore wind resources produced production cost savings of approximately \$50M in the 3000 MW scenario, increased the generation capacity factor of PSH, and reduced the amount of offshore wind curtailment during off-peak periods approximately 19%.
- The integration of such large amounts of offshore wind with existing baseload nuclear and large coal facilities would result in curtailments of wind during off-peak periods. Wind curtailment of 3,000 – 4,000 GWh was required in the 5600 MW scenario. Even with curtailments, offshore wind resources contributed approximately 17,000 GWh of energy production to the DEC system in the high wind scenario.

APPENDIX A – PRODUCTION COST SIMULATION MODEL REVIEW

The Production Cost Simulations will be based on ABB's commercially available GridView Software. GridView is a powerful yet user's friendly software tool for integrated engineering and economic analysis of electric power grid. It can be used to study the operational and planning issues facing regulated utilities, as well as competitive electric markets. Some typical applications of GridView are listed below.

- Determine the utilization of generators and transmission lines in a regulated and/or deregulated environment.
- Calculate the production cost of generation in a deregulated environment.
- Calculate the location marginal price (LMP) in a deregulated environment.
- Identify transmission bottle necks and congestion in the system.
- Assess the impacts of uncertainties, such as, forced outages of transmission line / generation, fuel price forecasts, load forecasts, wind forecasts, etc.
- Evaluate the operational and economic impacts of renewable energy resources, such as wind and solar systems.
- Allocate / purchase Congestion Revenue Rights (CRR) / Financial Transmission Rights (FTRs) to hedge congestion costs.
- Calculate the resource adequacy indices, LOLE (Loss of Load Expectation) and EENS (Expected Energy Not Served).
- Evaluate the impacts of emission policy compliance.
- Co-optimize energy market with ancillary service markets.
- Coordinate hydro and thermal schedule to best utilize hydro energy.
- Integrated power flow study with economic study, etc.

GridView is a production cost simulation program, developed by Ventyx, an ABB company. It simulates the economic operation of power systems in hourly and sub-hourly intervals for periods ranging from one day to many years. It incorporates detailed supply model, demand model, and transmission system model for large–scale transmission grid. By performing transmission and security constrained unit commitment and economic dispatch for different generating resources to meet the spatially distributed loads, GridView produces a realistic forecast of the utilization levels of power system components and power flow patterns in the transmission grid. It will calculate generation dispatch, generation cost, fuel consumptions, and transmission flows etc. The Locational Marginal Pricing (LMP) can be used to calculate generation revenue and provide investment signals to the energy provider as to the locations of high profit potential. The congestion conditions and the shadow prices for constrained transmission lines or interfaces provide very valuable insight to system planners as to the stressed pathways in the system and the potential economic impact if expansion options are used to alleviate the congestion.

GridView inputs and outputs structure is shown in Figure 27.

Generator Representation: GridView has detailed modeling capability for thermal generation, hydro generation, pumped storage hydro and renewable resources. It can also model compressed air energy storage (CAES), concentrated solar power with thermal storage (CSP), Plug-in hybrid electric vehicle (PHEV), and virtual generator/demand to meet emerging needs in the power industry. Generator has distinct characteristics based on type. All have generating capacity and bus location specified.

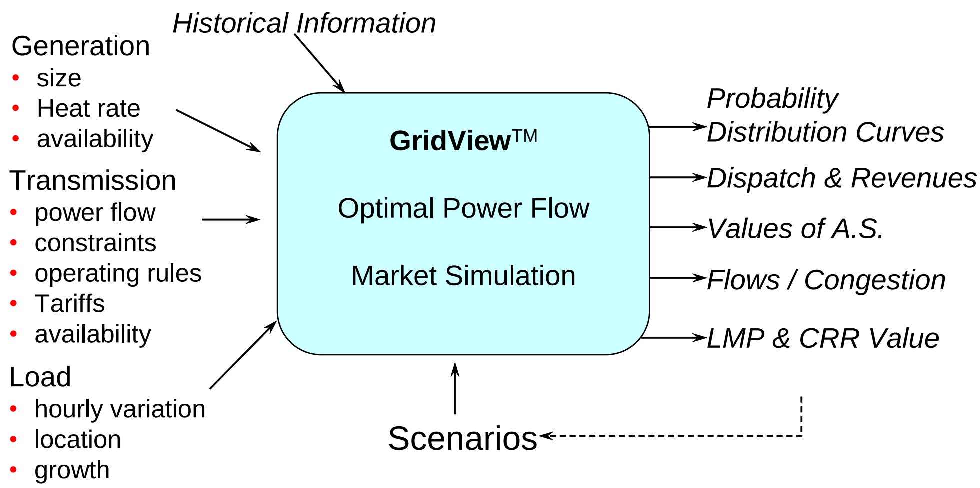


Figure 27. Inputs/Outputs of GridView Software for Power Market Simulation

Transmission Representation: The transmission network can be explicitly modeled with all the details as in the power flow case. Transmission line flow limits under normal and contingency conditions, interface limits and operational nomograms can be modeled to mimic the constraints in the system. The network topology may be subject to changes under forced or maintenance outages of transmission elements.

Load Representation: The load is represented chronologically for all the 8760 hours (8784 for the Leap year) including the starting day of the week for the New Year. Each area will be modeled with historical 8760 hour load profile and forecasted annual peak and energy.

Ancillary Services Representation: Generators can provide energy and ancillary services simultaneously. Ancillary services include regulation up, regulation down, spinning reserve, non-spinning reserve, load following up, and load following down. Regulation down and load following down are downward reserves. Everything else is upward reserve. Higher wind penetration will require higher reserve for load following up and down. Wind generators will not provide upward ancillary services. Unit at maximum rating will not be able to provide upward reserves. Unit at minimum rating will not provide downward reserve. Ancillary service requirement will be defined by area, region or combined areas/regions. To maintain system operation reliably and economically, ancillary services will be co-optimized with energy to minimize cost to serve both energy and ancillary service requirements, subject to ramping rate and capacity limits for generating units. It will calculate ancillary service price for each ancillary service requirement.

The simulation program mimics the operation of electricity markets by performing security constrained unit commitment and economic dispatch. The simulation is usually run sequentially in chronological order for a few days to several years, depending on the application. For each hour, a linearized power flow solution is solved. In order to enforce the various Interface and branch flow limits simultaneously, a Linear Programming algorithm (LP) is used to find the optimal solution. Some units have minimum up time and down time, ramping rates, storage limits will be considered from hour to hour simulation. It will produce the results include hourly generation, hourly generation revenue and cost, load payment, transmission constraint flows, shadow price for binding constraints, and Locational Marginal Price (LMP), etc.

Historical information, such as boundary flows, can be used to study internal regions in details while simplifying external system's contribution by the loop flows only. To forecast future system operation with many uncertainties around load growth, fuel price, public policy, resource expansion plans, and technology development, etc., it will require scenario analysis to capture the impacts to generator owners, consumers, and transmission owners. The following basic attributes are obtained by post-simulation processing of results and tabulated by GridView in comparison forms:

- LMP price
- Load payment and generator energy revenue
- Ancillary service price, generator ancillary service amount and revenue
- Hourly generation and generator cost, wind generation and curtailment
- Transmission flows, congestion cost and transmission losses
- Environmental effects such as $NO_X/SO_2/CO_2$ emission amounts and cost

In summary, GridView has been used for resource adequacy, LOLE reliability study, renewable integration, market analysis, transmission economic expansion planning, and integrated economic and technical studies, etc. GridView provides user a common platform to perform different applications using different modules: transportation model, transmission model, and sub-hourly model. In addition to line limits under normal / contingency constraints, interfaces and nomogram, it models generators' operational constraints, fuel limits, and conditional constraints. It provides database management tools, data sanity checking, standard/customized reports and plots, debug tools, and automatic post processing, etc. It has been widely used by utilities, ISO/RTOs, and regulators to study the operational and planning issues facing regulated utilities and competitive electric markets.

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