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OFFSHORE WIND POWER INTEGRATION INTO THE SOUTH CAROLINA POWER SYSTEM

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OFFSHORE WIND POWER INTEGRATION INTO THE SOUTH CAROLINA POWER SYSTEM

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by

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ABSTRACT

The steady state analysis of the impact of offshore wind on the South Carolina power transmission was conducted in three phases of incremental wind energy injection into the system using forecasted base power flow. The simulation of Phase I involved the generation capacity of 80 MW projected for 2014 in state water. The modeling Phases II and III, which will distribute the energy among neighboring utilities, involve a supplementary capacity of 1000 MW projected for 2020 and 2000 MW for 2030 in federal water. In addition to this steady state investigation, a contingency analysis was performed on the power system after successfully simulating Phase II of the project to evaluate its robustness during outages. Based on the experience of the Europeans in the implementation of offshore wind farms, recommendations were made for designing the transmission system to deliver wind power efficiently to the grid.

Next, the wind power and the load demand historical data obtained from the Electric Reliability Council of Texas (ERCOT) power system were analyzed to confirm known wind patterns and its relation to the load. The hourly unpredictability of wind means it functions as a load modifier given that conventional generation is committed based on the wind availability. As a result, a probabilistic approach was developed to help predict the portion of the load covered by wind power during two periods of the day on a monthly, seasonal and annual basis using a given annual hourly wind power to load ratio.

DEDICATION

Dedicated to my parents,

my sister Sira,

my brother Mamadou,

and all those whom I had the pleasure to meet through my graduate study at Clemson University.

ACKNOWLEDGMENTS

I would like to thank my advisor Dr. Elham B. Makram, for all of her patience and assistance. I would also like to thank Dr. Aldy A. Girgis and Dr. Xiao-Bang Xu for serving on my committee and for providing many hours of insightful discussion in the classroom. I would like acknowledge ERCOT for providing me the wind power and load data and Clemson University Electric Power Research Association (CUEPRA) for giving me the wonderful opportunity to work on this project.

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CHAPTER ONE

INTRODUCTION

The first electric wind turbine was constructed in 1891 by the Dane Poul Lacour [1].Then during World War I and II, the Danish broke new grounds by including the enhanced contemporary aerodynamic knowledge in their design. During the same period in the US, Palmer Putman fabricated a large wind turbine incorporating an upwind rotor with stall regulation, while the Danish design was based on a downwind rotor with variable pitch regulation, with the latter design prevailing. Even though great progress was made in this technology, the interest in wind energy faded after WWII.

With the oil crisis of 1970, wind power technology re-appeared as solution to provide electricity to a grid while reducing foreign dependency on oil. Financial support from the governments in Europe and US led to a renaissance in wind turbine technology. Although Europeans continued the research in wind turbines, development slowed downed again due to unsuccesful prototype implementation in the US. As a result, the US is currently basing its offshore wind farm implemnetation on the European experience.

In power system operation, the intermttency of wind raises the following issues concerning its integration into the network: maintaining adequate voltage level and constantly matching generation to load. Similar concerns were raised during the integration of nuclear power into the power grid due its constant output and the variability of the load. In some cases, the flexiblity of the electric network was increased by adding hydro-pump storage generation near the nuclear station. During the peak-hours of the day , the pump storage generates electricity to meet the high demand, while during the off-peak hours at night, it pumps the water back to the upper storage basin. A similar approach could be used for high wind penetration levels (over 10%) or consumer habits could be influenced through incentives. Another approach is to maintain a geographical diversity of the wind farms and their turbines, which has a smoothing effect on their aggregated output since the wind speed is not the same in all locations at the same time, thereby improving the predictibility and redducing the chances for periods of zero and peak output.

Furthermore, the type of wind turbine generators (WTGs)available online affect the operation of the system; most WTGs are fabricated at either fixed or variable speeds. The fixed speed WTG, which is sturdy, simple in design and directly connected to the grid, has a predetermined rotor speed which sets the output frequency. Its primary disadvantages are its poor power quality, its reactive power consumption and the transfer of the wind intermittancy to the electric network.

The variable speed WTG operates with better efficiency within a given window of wind speed with the output staying constant between the tip and the cut-off speed at which the safe operation of the turbine is not possible. This type of WTGs, which usually maintains a steady output under variable wind speed conditions, is interfaced with the power system through a power converter controlling the rotor speed. Although vaaiable speed WTGs improve the power quality and mechanical stress, the cost and losses due to the power electronics are not negligible. Since 1998, the market share of the fixed speed WTGs has gradually decreased, while the one for the variable speed has increased.

The variable speed WTGs consist primarily of two models: the partial scale and the full-scale frequency converter. The variable speed with a partial scale frequency converter, also known as the doubly fed induction generator (DFIG), consists of a wound rotor induction generator (WRIG) with a partial scale frequency converter interfacing with the rotor and the grid for reactive power compensation and a direct connection between the stator and the power grid. The converter includes a birectional IGBT-based voltage-source-converter which is comprised of two independent converters on each side: the grid-side converter and the rotor-side converter. By adjusting the rotor circuit current, the rotor-side converter controls the active and the reactive power indepently so that voltage control can be implemented. The reactive power is supplied to the grid through the rotor-side converter. The grid-side converter oversees the converter DC voltage for the operation at the unity power factor. During normal operation at a speed below synchronous, the subsychronous speed, the rotor consumes reactive power from the grid and *vice-versa* for oversynchronous speed. Due to its economical small converter which allows the generation or consumption of reactive power for voltage support, the DFIG is the fastest growing model of variable speed turbines. According to the research reported in [2], the variable speed WTGs with reactive power compensation have better electric performance and are more suitable for large capacity wind farms than the one without it.

The full-scale frequency converter variable speed wind turbine is interfaced with the power system through a full-scale frequency converter, which handles the reactive power compensation [1]. This turbine drives directly or through a gearbox a wound rotor induction, a synchronous generator (WRIG or WRSG) or a permanent magnet synchronous generator (PMSG). It also offers the following advantages: high efficiency, the absence of a slip ring, load control, a direct-drive option (gearless), lower nuisance at low speeds. The market share of the expensive full-scale converter WTGs has grown slower than the DFIG even though it offers more operational benefits. As their price goes down in the future, their share will match that of the DFIG.

In Europe, the primary standards for connecting wind farms to the power grid have been developed by Eltra, a Danish transmission system operator in Western Denmark [1]. Some of these standards include the ability to ride through a fault and to reduce the generation from full output to 0% or 20% within seconds, the control of both active and reactive power for frequency and voltage regulation, respectively and the control over the rate of wind energy production increase, also referred to as the ramp rate, in order to allow for generation adjustment. Among the these standards, the most important is the ability to ride through a fault, meaning the WTGs should stay online and remain stable during a fault lasting approximately 100 ms or 6 cycles.

The integration of wind energy into the network changes its operational configuration and power flow. As a result, contingency analysis pre-screening the power system for potential weakness due to component failure is required. The contingency N-1 criterion, which is a failure of a single component in a power system, should not result in a power outage [1]. Consequently, the power reserve must match the largest generator in the network. A second type of contingency analysis based on the Z-bus matrix can be used to solve the overloads in a power system by line switching [3], [4]. A pre-defined list of limiting and sensitive lines is made available to the operators to facilitate the handling of unplanned system overloads. These limiting lines are ones that can be opened or closed, while the sensitive lines are not to be switched.

Another component of the wind power integration is its transmission system to the power grid. The transmission of offshore wind energy to the network connection points consists of three specific options: medium voltage, HVAC and HVDC links. These transmission choices depend on the size and the capacity of the wind farm. For a wind farm capacity of less than 200 MW [5] and located at a short distance from the shore, multiple medium voltage connections are appropriate. From studies, the cutoff distance for using the medium voltage is 9.32 [6] to 12.43 [5] miles depending on the project specifications. As the size and the capacity increase, the option changes from HVAC to HVDC with 31.07 miles [7], [8], being the break-point distance between them depending on the project. To address the limitation of HVAC, which are the high transmission losses over distance, W. L. King et al. [9] suggest the use of gas-insulated line (GIL) as a submarine cable instead Cross Link Poly-Ethylene (XPLE) since it has lower self-capacitance. They also believe that successful laying of offshore pipe can help pioneer the implementation GIL in the submarine environment.

Finally, the incorporation of wind energy into the power system also requires some means of predicting the wind similar to the load. Wind energy forecasts for short-term up to 48 hours in the future were initiated by the Risø National Laboratory and the Technical University of Denmark using numerical weather model predictions (NWP) [1]. The development of these new forecast tools incorporated the online reading of WTGs output, the application Artificial Neural Networks and Fuzzy Logic to determine relationship between input and forecast through training using large historical data.

Unlike in Denmark and Germany, the wind energy in the US and Spain is forecasted for every wind farm since each country has fewer and larger wind farms. A good forecast increases the system stability and reduces the operation costs incurred due to the purchase of unscheduled extra power. As a result, there is a higher power reserve requirement for a system with wind turbines than one without them. In a network including a 10% wind power penetration, the reserve required is approximately 2 to 8% of the installed capacity of the turbines.

Even though Eltra used a sophisticated short-term forecasting tool, Wind Power Prediction Tool (WPPT), a forecast error of 31% for the yearly generation of 1095 GWh resulted in the addition of millions of dollars to operation costs in 2002,. The WPPT employs statistical methods using online data collected from a representative sample of the farms, and local and meteorological forecasts of wind speeds and directions to predict wind power generation for a short period of up to 36 hours. The errors were attributed to the poor quality of the meteorological data.

Through experience, it has been observed that accurate short-term forecast of 0.5 to 6 hours are obtained from tools incorporating both the NWP and the online data collection such as Zephyr, e-wind™, Sipreolico and Advance Wind Power Prediction Tool (AWPPT). On the other hand, the forecast tools that are NWP-based only, provide more accurate predictions for longer periods of 6 to 48 hours.

The intermittent nature wind means it behaves as a load modifier in power systems. If the portion of the load covered by wind energy could be determined, the effect of the wind variation could be neglected. Compared to wind, load forecasting is much more accurate since variations in loads are usually due to planned and known activities. Depending on the location, the next day load can be estimated with a maximum error of approximately 3% [10]. Load can be predicted for short, medium and long terms representing an hour to a week, a week to a year and longer than a year respectively. Short-term forecasting takes into account the time, the weather and the customer classes. The medium and long-term are based on the historical, weather and appliance data; the customer classes, age, economic and other demographic data. Q. Ashan and Moin Uddin [11] proposed a probabilistic approach for long-term load forecasting based on historical data collected from the power system of the Bangladesh Power Development Board. This method predicted the daily, monthly and yearly load demand with a maximum percent deviation of 3.82%, 1% and 0.5%, respectively.

Using past load data and analytically-derived wind power data for the ERCOT system, Reigh Walling and Gary Jordan [12] showed that wind patterns are nearly the opposite of the load, with high wind speeds generally during off-peak load hours. As a result, a high wind penetration level is expected during off-peak hours and *vice versa*. Thus a long-term prediction of the monthly, seasonal and annual wind penetration level during two periods of the day can be estimated based on a curtailed wind power output using an appropriate capacity factor for the US [13] and the available forecasted annual hourly load demand [14]. The monthly and seasonal hourly load and wind output range can be estimated using the approach in [11].

CHAPTER TWO

COASTAL CLEAN ENERGY IMPACT ON THE SOUTH CAROLINA POWER SYSTEM

As a result of the increasing demand world-wide for energy, utilities are advocating renewable energy sources such as wind and solar farms. Although both of these sources depend on uncontrollable natural phenomena, the energy produced by wind farms is currently much more efficient and economical than that from solar cells. Denmark, Spain and Portugal have successfully implemented offshore wind farms, producing 13% to 19% of their total electricity [24]. Consequently, many utilities in the United States are planning to build similar offshore wind farms. These proposed farms create the necessity for investigating the effect of the wind-generated electricity on the power grid.

This research analyzes the South Carolina power transmission system after the incremental addition of 3080 MW of offshore wind energy based on voltage and branch power flow violations. This energy injection into the grid, which is to be realized in three phases over a period of 16 years, is simulated using the software: PSS/E and PowerWorld. The results of the power flow simulation for each step are analyzed for its feasibility.

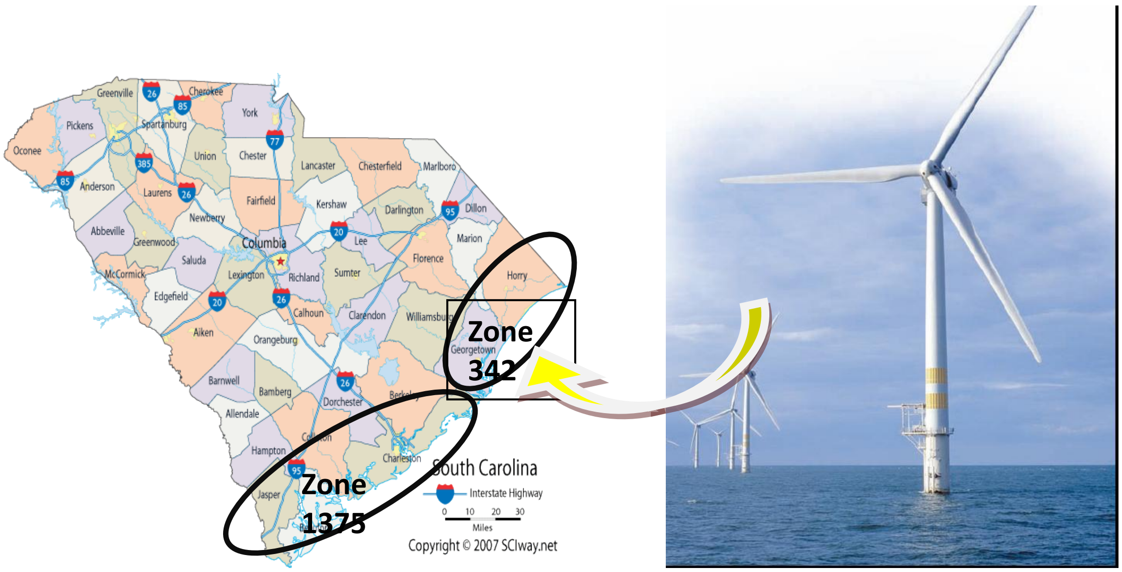
During the initial phase, 80 MW of offshore wind energy will be generated by 2014 in state water within 13.67 miles [22] of the shore line. This energy will be consumed by Santee Cooper, an electric utility in South Carolina. During the second phase, an additional 1 GW of wind power will be produced by 2020 in the federal water beyond the state water line. Different from Phase I, this 1 GW will be distributed among the four neighboring electric utilities, Duke, Progress Energy, Santee Cooper and SCE&G, based on their load ratios in the Summer 2009 base case power flow.

Similar to the previous phase, the energy from the third phase, an additional 2 GW by 2030, will be distributed among five utility companies based on their load ratio in the Summer 2009 base case power flow: 22% for Duke, 14% for Progress Energy, 5% for Santee Cooper, 6% for SCE&G and 53% for Southern Company. As a first step in the development of this renewable energy project, the research reported here discusses the simulation results including the identification of the best locations for grid connection and the various transmission issues associated with offshore wind farms.

2.1 Phase I: 80 MW in state water by 2014

During the first phase, 80 MW of electricity will be produced by two offshore wind farms of 12 generators each located in North Myrtle Beach and Winyah Bay. Half of the wind power (40 MW) will be applied at a bus at each of the two locations. To compensate for the wind energy, the generation will be reduced at the steam plants from the smallest to the largest generators.

Five cases were simulated using three forecast base case power flows (Summer 2010, 2014 and 2019) to investigate the impact of the renewable energy on the transmission system based on voltage violation and branch overload. Each case consisted of two 115 KV buses assigned to each wind farm as an interface bus connecting the wind energy to the power grid. In Figure 1, Zone 342 displays the potential locations for the interface buses.



[26] [28]

Figure 2.1 Map of South Carolina with wind penetration in zone 342

2.1.1 Simulation parameters and designs

For the simulation, an interface bus is used at each location: North Myrtle Beach and Winyah Bay. The choice at Winyah Bay location is easy since there is only one possible interface bus. On the other hand, North Myrtle Beach has five possible interface buses for the wind farm i.e. 5 cases for connecting the two wind farms simultaneously to the Santee Cooper Power System. Tables 2.1 and 2.2 below illustrate the possible interface buses for the wind farms and the corresponding case list. Figures 2.3 and 2.4 display the potential location of the interface buses for each wind farm:

Table 2.1 List of coastal 115 KV buses

Bus No.	Bus Name	Bus location
312811	'3NIX XRD'	Nixons Crossroads
312764	'3DUNES'	Dunes
312807	'3MYRT BC'	Myrtle Beach
311322	'3ARCADI'	Arcadia
312766	'3GRDN C'	Garden City
312845	'3WINYAH'	Winyah 115 kV

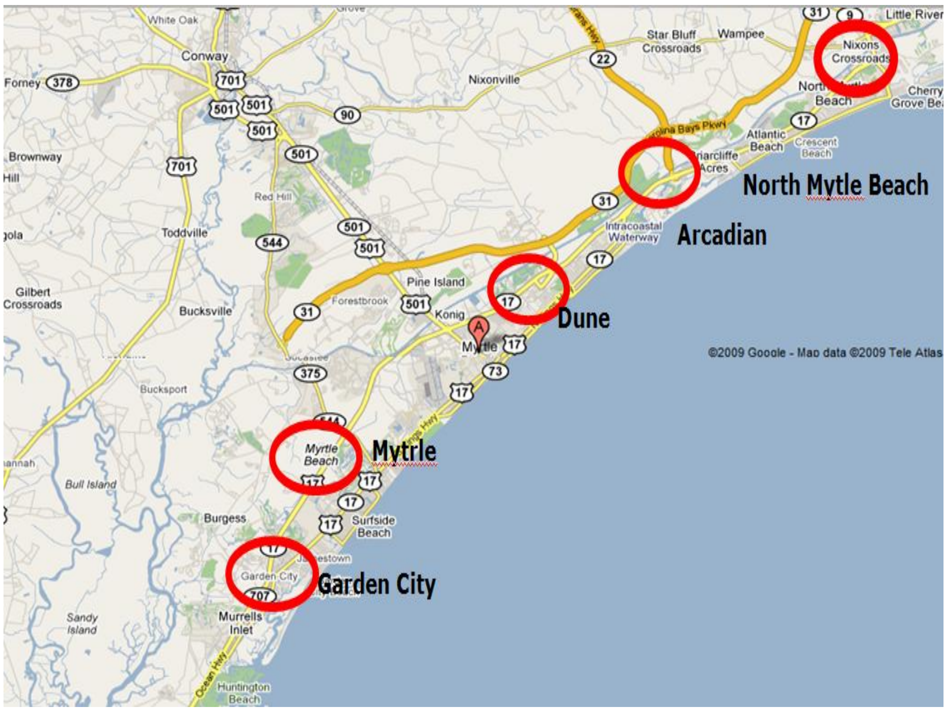


Figure 2.2 Possible location of the North Myrtle Beach wind farm interface bus (location indicated by balloon) [27]

Figure 2.3 Possible location of the Winyah Bay wind farm interface bus (location indicated by balloon) [27]

The 5 cases seen in table 2.2 were simulated using the three forecast base cases (Summer 2010, 2014 and 2019) to observe the effect of 80 MW injection into the South Carolina power transmission system:

Table 2.2 Case list used for each of the 3 base case power flow

Case list	**Interface Bus#**	
	North Myrtle Beach	**Winyah bay**
Case 1	312811	312845
Case 2	312764	312845
Case 3	312807	312845
Case 4	311322	312845
Case 5	312766	312845

Eeach wind farm supplied 40 MW to the interface bus, resulting in a total 80 MW. An interface bus received power from 12 GE 3.6 MW DFIG models. Each of the 12 wind turbines were connected in parallel through a step-up transformer (4.16/34.5 KV) to a common bus, which, in turn, was connected to the interface bus through another step-up transformer (34.5/115 KV). The standard transfomer parameters are listed in Table 3, while Figure 2 illustrates the wind farm connection for Phase I.

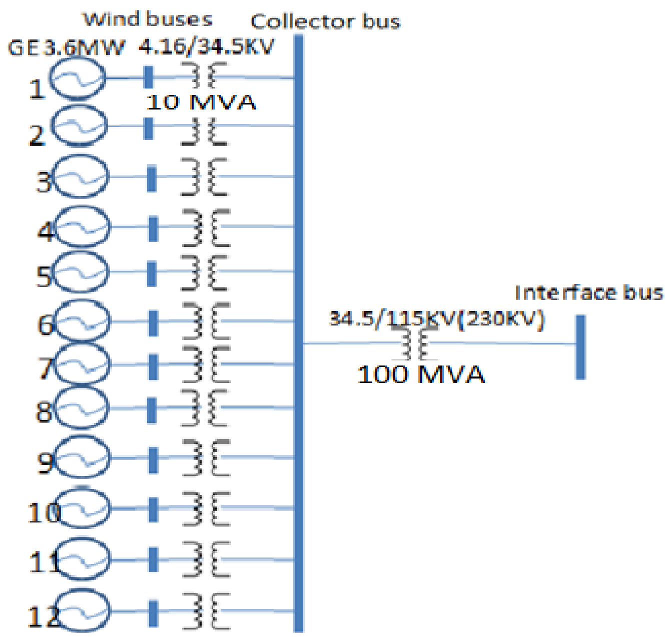


Figure 2.4 Wind farm connection for phase I (12 generators)

Table 2.3 Transformers specification

Transformer index	Wind turbine transformer (4.16/34.5 KV)	Wind farm transformer (34.5/115 KV)
Winding MVA	10	100
Winding 1 Nominal KV	34.5	115
Tap position	33	153
Specified R	0	0.0108
Specified X	0.05	0.3304
Rate A	10	50.4
Rate B	10	51.8
Rate C	10	52.2
Impedance	0.5	0

The table below lists the parameters for the GE 3.6 MW wind turbine utilized in the simulation:

Table 2.4 Data for the GE 3.6 MW wind turbine

GE 3.6 Wind tubine	value
Qmax	1.74MVAR
Qmin	-1.74 MVAR
Rating capacity	4MW
Pmax	3.6MW
Pmin	0.5MW
ZR	0
ZX	0.302
Power factor	0.9

The generation within Santee Cooper was reduced at the following plants from the smallest to the largest generators: first, Myrtle Beach and Hilton Head, second Rainey and finally the Grainger Power Station. The smallest generators in a plant were shut down since they more expensive to operate than larger generators in the network.

2.1.2 Analysis of the simulation results

These simulation results, which include the branch power flow and the voltage violations, can be found in Tables A.1-A.6 in Appendix A. Based on the analysis of the results for all five cases, the power system can successfully absorb 80 MW of wind energy without creating overloaded branches. However, Cases 2 and 5 are recommended based on the voltage limits and the branch power flow distribution.

Table 2.5 The recommended 115 KV interface buses

Recommended cases	**Bus No.**	**Bus Name**	**Bus location**
case 2	312764	'3DUNES'	Dunes
	312845	'3WINYAH'	Winyah 115 kV
case 5	312766	'3GRDN C'	Garden City
	312845	'3WINYAH'	Winyah 115 kV

2.2 Phase II: additional 1 GW generated in federal water by 2020

Phase II will extend the offshore wind farms from the state coastal line to federal water, increasing the potential for wind power generation. Figure 2.5 below shows that the power density in federal water is higher by approximately 100 W/m^2 than of that of state water in the northern coast line of South Carolina:

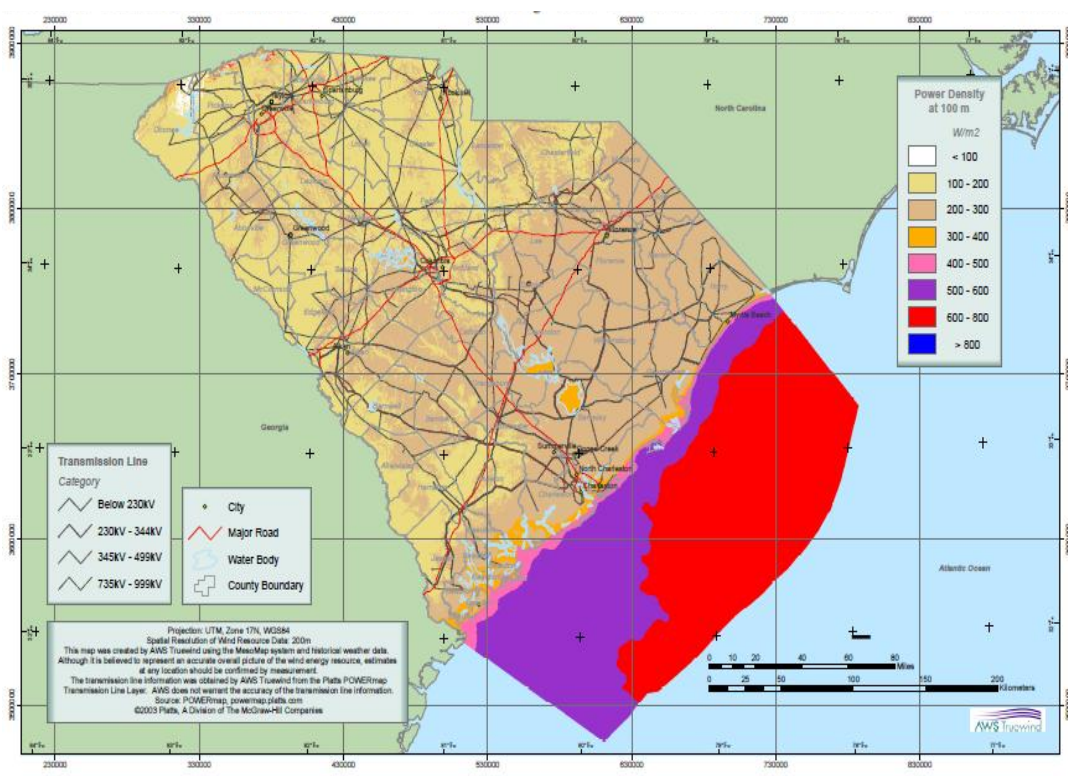


Figure 2.5 Mean annual wind power density of South Carolina at 100 meters [20]

An additional 1 GW of wind energy will be injected into the Santee Cooper power system at the same two locations as in Phase I (80 MW), i.e. with 500 MW at each location at a voltage rating of 115 KV. Thus, the same five cases as for Phase I (Table 2.1) were used in simulating the power injection into the grid to determine the best 115 KV interface buses for the wind farms. Since the forecast base case power flow for 2020 is unavailable, these five cases were analyzed using the forecast for Summer 2019.

The wind energy was distributed among the four electric utilities (Duke, Progress Energy, Santee Cooper and SCE&G) based on the ratio of their loads. The simulated energy distribution was based on the Summer 2009 base case as follows: 46% for Duke, 30% for Progress Energy, 12% for Santee Cooper and 12% for SCE&G. As a result, the generation in the four utilities was reduced based on the same load ratios. Since no guideline was specified for reducing the generation at Duke, Progress Energy and SCE&G, the generators in those three companies near the South Carolina area were adjusted. Table 2.6 presents the detailed active load used in the calculation of the load ratios within the four areas, while Figure 2.6 displays the distribution of the energy for Phase II.

Table 2.6 Wind energy distribution based load ratios in Summer 2009 base case

Area Name	**Area #**	**Zone # Range**	**Bus # Range**	**P Load (MW)**	**Load ratio**	**Load Ratio in (%)**
SCEG	343	1375 - 1384	370000 – 371999	4673.967	0.1158	12%
Santee Cooper	344	340 - 349	311000 – 312999	4774.263	0.1183	12%
Progress	340	315 - 324	304000 – 305999	11961.915	0.2964	30%
DUKE	342	325 - 339	306000 – 309999	18948.089	0.4695	46%
Total				40358.234	1	100%

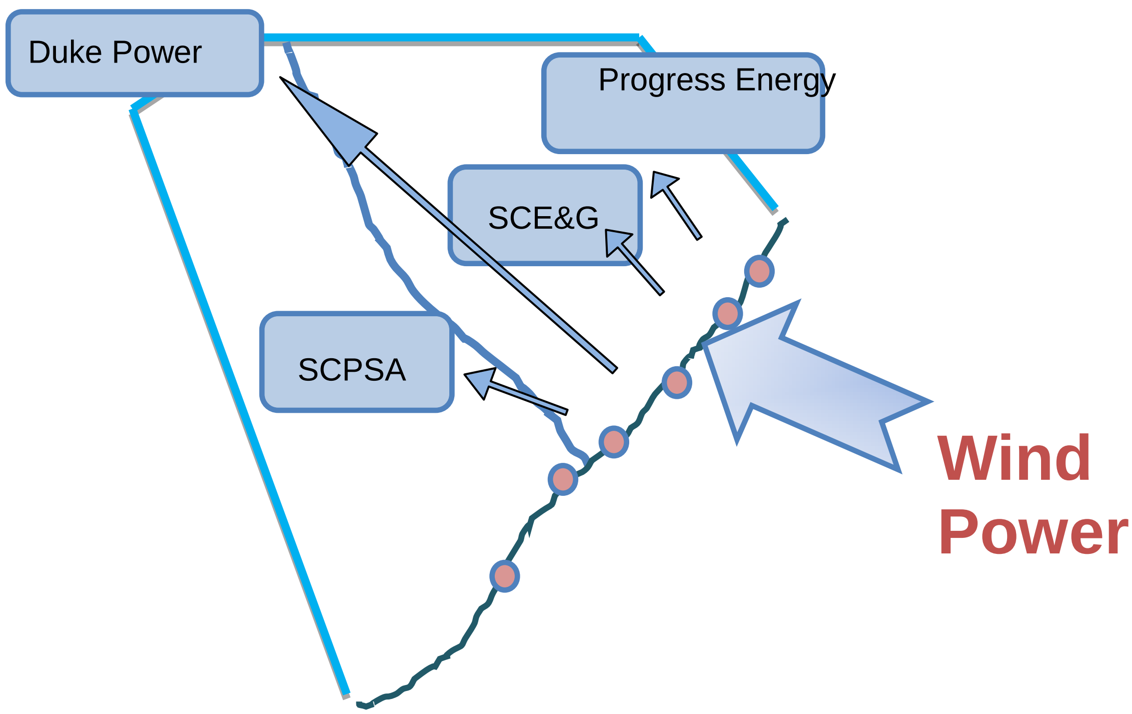


Figure 2.6 Illustration of wind energy distribution for phase II (1000+80 MW)

2.2.1 Wind farm connection and transformer data

Similar to Phase I, the GE 3.6 MW wind turbine was used for this simulation. The turbines were connected in parallel to the collector bus through a step-up transformer, rated 4.16/34.5 KV, and the collector bus was connected to the power system at the interface bus through another step-up transformer of voltage rating 34.5/115 KV. Table 2.7 presents the parameters for the wind farm transformer rated 34.5/115 KV, which has a higher rating than the one used in Phase I.

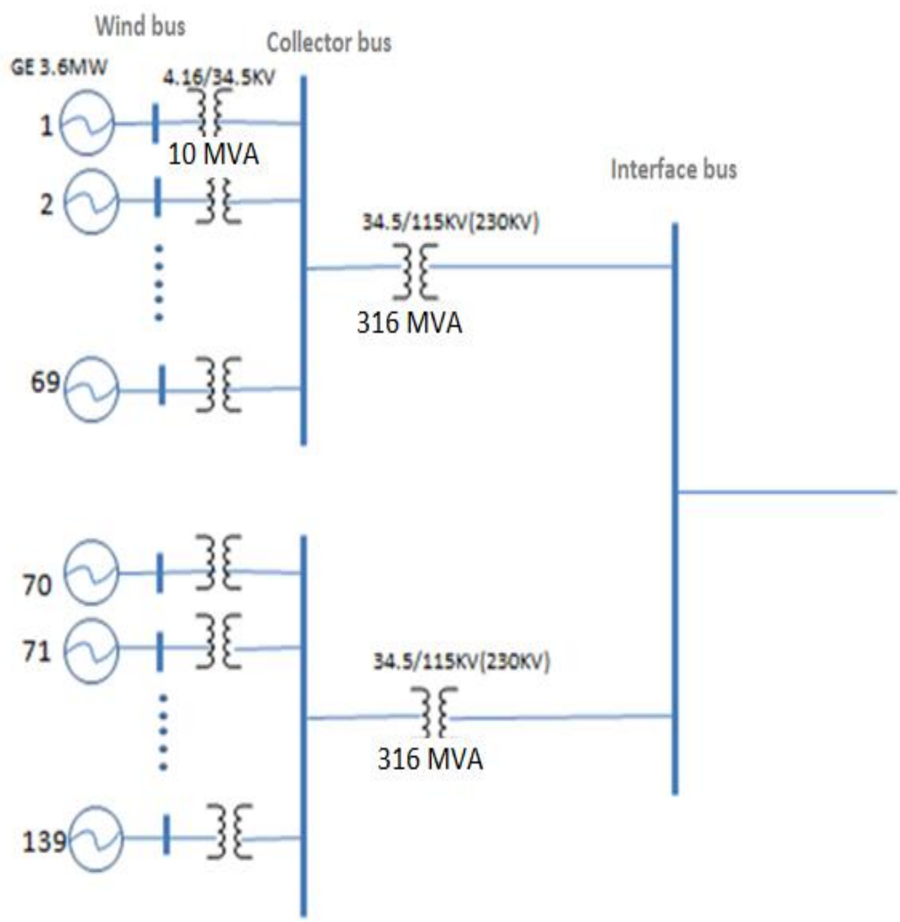


Figure 2.7 Wind farm connection diagram for Phase II

Table 2.7 The transformer (34.5/115 KV) parameters for Phase II

Transformer index	34.5/115KV Wind farm transformer	Transformer index	34.5/115KV Wind farm transformer
Controlled side	No Tapped	**Winding 1 Nominal KV**	115
Tap position	159	**Winding1 Ratio(p.u. KV)**	1.0
Auto adjust	Yes	**Winding 1 Angle**	0
Winding I/O code	Turn ratio	**Winding 2 Nominal KV**	34.5
ImpedanceI/O code	Zp.u(Systembase)	**Winding2 Ratio(p.u. KV)**	1
AdmittanceI/O code	Yp.u.(System base)	**Rmax(p.u.KV or degree)**	1.5
Specified R	0.00036	**Rmind(p.u.KVor degree)**	0.51
Specified X	0.0167	**Vmax(p.u. or KV)**	1.5
Rate A	316	**Vmin(p.u. or KV)**	0.51
Rate B	409	**Load Drop**	0
Rate C	420	**Impedance**	0
Magnetizing G	0	**R(table corrected p.u. or watt)**	0
Magnetizing B	0	**X(table corrected p.u. or watt)**	0

2.2.2 Analysis of the simulation results

2.2.2.1 Injection of wind energy (80 + 1000 MW) at two 115 KV interface buses

The power system in the four utilities was tested using the same five cases as in Phase I, which are the five options for delivery of the wind energy. The branch loading conditions and voltage violations found in Appendix B are analyzed below.

- *Even distribution of 1080 MW between the two wind farms*

In this approach 500 + 40 MW was generated by each of the two wind farms.Tables B.1 and B.2 in Appendix B display the voltage violation (V<0.94 p.u. or

V>1.06 p.u.) and the branch power flow after an additional 1 GW of wind energy was injected into the South Corolina power system.

Table B.2 in Appendix B shows that Case 3 could be mitigated by adding a capacitor bank of 30 MVAR on Bus 312779 or by increasing the existing capacitor bank on Bus 312766 by approximately 50 MVAR (from 30 MVAR to approximately 80 MVAR) to alleviate the overloaded lines. The remaining cases (1, 2, 4 and 5) could not be mitigated if the energy was evenly distributed between the two wind farms (or two interface buses). By reducing the existing generation at Winyah Bay (Bus 311478) to a value of 130 MW, the maximum branch power flow was approximately 98% when using two 115KV interface buses.

- *Uneven distribution of 1080 MW between the two wind farms*

For the case of the uneven distribution of the energy between two interface buses, the wind farm located at Winyah Bay was given a higher installed generation capacity than the one at the North Myrtle Beach location. By adjusting the amount of energy generated at each location, Cases 2 and 3 did not yield an overloaded line after 1080 MW was unevenly drawn from the two wind farms at 115 KV voltage rating. Tables B.3 and B.4 in Appendix B list the simulation results (voltage violation and branch flow).

2.2.2.2 Two additional suggestions for connecting the wind farm to the power grid

• *Using three 115 KV interface buses*

In this scenario, 1080 MW entered the Santee Cooper electrical network at three different 115 KV interface buses with aim of reducing branch power flow. Two of these three interface buses were located at North Myrtle Beach and one in Winyah Bay. Table 2.8 shows a case using three interface buses that has all branches loaded below 96% of their ratings.

Tables B.5 and B.6 in Appendix B display the voltage violation (V<0.94 p.u. or V>1.06 p.u.) and the branch power flow after an additional 1 GW was injected into the South Carolina power system using the three 115 KV interface buses shown in Table 2.8.

Table 2.8 Suggested case using three 115KV interface buses

Interface Bus # and Name	**Bus Location**
312845 '3WINYAH'	Winyah Bay
312764 '3DUNES'	Dunes
312807 '3MYRTBC'	Myrtle Beach

The comparison of these simulation results shows that using three 115 KV interface buses instead of two reduced the branch power flow congestion. This finding is supported by the fact that the highest loadings on a transmission line for the cases using three and two interface buses were approximately 95% and 99% of the line rating, respectively (Appendix B).

• *Using two 230 KV interface buses*

In this last scenario, the 1080 MW entered the Santee Cooper electrical system at two 230 KV interface buses, also with aim of reducing branch loading conditions. In other words, the energy injection at the 230 KV network has the potential to improve the power flow result significantly by reducing line flow. The result of the power flow using two 230 KV buses to inject the energy into the grid (the two interface buses are 312717 and 312719) is presented in Tables B.7 and B.8 in Appendix B.

2.2.2.3 The analysis of the results for Phase II

The simulation results using two 115 KV interface buses show that Case 3 does not produce any overloaded branches for both the even and uneven distribution of the wind energy between the two wind farms (installed capacity). In the scenario with even distribution (500+40 MW at each interface bus), the overloaded lines were mitigated by adding a 30 MVAR capacitor bank on Bus 312779 or by increasing the existing capacitor bank value on Bus 312766 by 50 MVAR (from 30 MVAR to 80 MVAR). Although to keep the maximum power flow on the branches at 97.7% for Case 3, the existing generation at the Winyah Bay plant, on Bus 311478, was reduced to 130 MW.

On the other hand, Case 2 yielded no overloaded line only if the two wind farms have unequal installed capacity (unevenly distribution of wind energy between the two interface buses used in this case). Table 2.9 lists the recommended cases ranked starting from the first choice to the last based on voltage violation and branch power flow. The recommended cases are the ones without any branches loaded at or above 100% of their ratings.

Table 2.9 Recommended interface buses (with most of North Myrtle Beach existing plant shut off and at least 115 MW reduced at existing generation at Winyah Bay plant-Bus 311478)

Ranking (High to Low)	Recommen-ded cases	Interface bus information			Injection amount		
		Bus #	Bus Name	Bus location	Phase I	Phase II Even distribu-tion	Phase II Uneven distribu-tion
1	Case 3	312807	'3MYRT BC'	Garden City	40 MVA	500 MVA	449.6 MVA
		312845	'3WINYAH'	Winyah	40 MVA	500 MVA	550.4MVA
2	Case 2	312764	'3DUNES'	Dunes	40 MVA	N/A	460.4 MVA
		312845	'3WINYAH'	Winyah	40 MVA	N/A	539.6 MVA

2.3 Phase III: Additional 2 GW in Federal water by 2030

During Phase III, an additional 2 GW of wind energy will be injected into the South Carolina power grid in 2030. This additional wind power is distributed among five electric utilities: Southern Company, Duke, Progress Energy, Santee Cooper and SCE&G, based the ratio of their loads. For the simulation, the energy distribution was based on the Summer 2009 base case power flow: 22% for Duke, 14% for Progress Energy, 5% for Santee Cooper, 6% for SCE&G and 53% for Southern Company (see Table 2.10 for further details). The generation within the five utilities was reduced based on their load ratios.

Table 2.10 The wind energy distribution between the five utilities based on the load ratios in Summer 2009 base case

Company	Percent of 3GW	The Wind power(MW)
SCE&G	6%	180
SC	5%	150+80
PROGRESS	14%	420
DUKE	22%	660
SOUTHERN	53%	1590

To fulfill this objective, both the 115 KV and 230 KV coastal buses were considered for delivering the energy to the grid (Table 2.11 lists the 230 KV buses tested as interfaces). Various scenarios from using only one voltage rating or a combination of both to connect the wind farms were developed. Similar to Phase II, the scenarios were simulated using the forecast base case power flow for Summer 2019.

Figure 2.8 presents the coastal bus location zones, orange and green representing the 115 KV and 230 KV buses zones, respectively. It can be seen that the 230 KV coastal substations are located farther inland than the 115 KV.

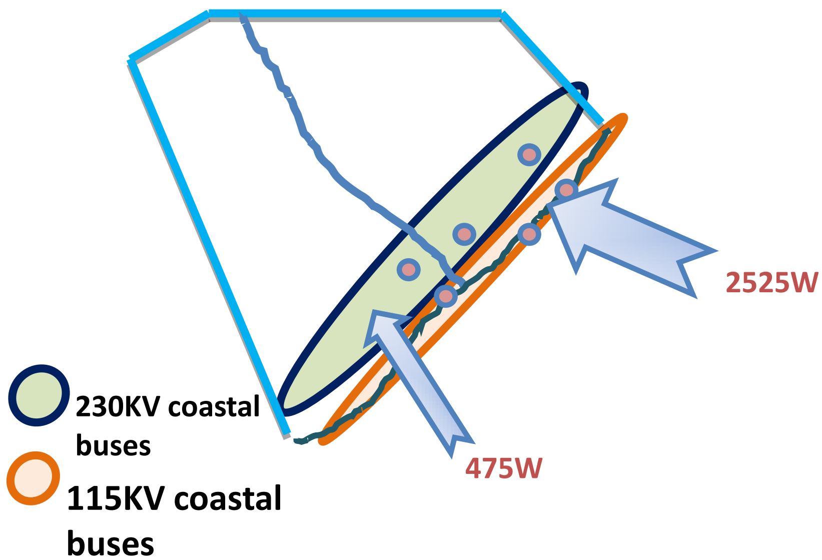


Figure 2.8 3080 MW of wind energy entering the South Carolina system at 115 and 230 KV interface buses

Table 2.11 List of Santa Cooper's 230 KV coastal buses

Bus No.	Bus Name	Bus location
312719	6WINYAH	Winyah
311461	6MYRTLE	Myrtle Beach
312717	6PERRY R	Georgetown
312730	6CAMPFLD	Campfield
312709	6CHARITY	Georgetown
312726	6REDBLUF	Myrtle Beach

2.3.1 Simulation results and analysis

After reducing the existing generation within the five utilities based on their load ratios, the simulation results show that the power system cannot handle the additional 2 GW. The results of the voltage violations (V<0.94 p.u. or V>1.06 p.u.) and the branch power flow displayed in the Appendix C are discussed below.

2.3.1.1 Original system injection capability

• *Simulation results based on the energy distribution criteria*

115 KV interface buses:

To identify the injection capability of the power system using 115 KV buses to connect the wind farm to the power grid, 2 to 5 buses were tested simultaneously. For the scenario using two 115 KV buses as interfaces, the maximum energy injection capacity of the system was approximately 1191.6 MW, achieved by adding 442.8 MW at Winyah Bay (Bus 312845) and 748.8 MW at Dune (Bus 312764). The results of the simulations are shown in Tables C.1 and C.2 in Appendix C, while Table 2.12 below shows the limitations of the scenarios using various combinations of 3, 4 and 5 interface buses:

Table 2.12 Original system injection limit using different sets of 115 KV buses

Number of buses in a set	2 buses	3 buses	4 buses	5 buses
Injection capacity of the original system	1192 MW	1280 MW	1280 MW	1280 MW

230 KV interface buses:

To determine if more power could be injected at higher voltage, two 230 KV interface buses were used, resulting in a maximum injection capacity of approximately 2001.6 MW, 720 MW enter the Santee Cooper network at 6Perry R (Bus 312717) and

1281.6 MW at 6Winyah Bay (Bus 312719). Tables C.3 and C.4 in Appendix C detail the voltage violations and branch loading conditions.

- *Simulation results when the energy distribution is not based load ratio*

Although it may not be feasible, the simulation found that the absorption capacity of the power system can be significantly improved if most of the generation reduction was done within the Santee Cooper network, specifically at Winyah Bay. In other words, a large portion of the wind energy was consumed by Santee Cooper. To implement this idea successfully, the generation at the power plants listed in Table 2.13 was reduced to their minimum. Then 3080 MW was added to the original power grid, using two 115 KV buses for Phase I and II (80 + 1000 MW) and two 230 KV buses for Phase III (2000 MW), without overloading the network. The amount of energy entering the system at each bus is listed in Table 2.14 below (the voltage violation is displayed in Table C.6 of Appendix C):

Table 2.13 Critical generators for solving the power flow congestion

Bus #	**Bus name**	**Pg**	**Pmax**	**Pmin**	**Qg**	**Qmax**	**Qmin**	**Sbase**	**R**	**X**
311452	1WINY2 21.000	285	285	100	73.96	130	-175	350	0	0.21
311453	1WINY3 21.000	285	285	100	73.96	130	-175	350	0	0.21
311454	1WINY4 21.000	285	285	100	73.96	157	-184	350	0	0.2513
311653	1PEEDEE 21.000	609	682	200	237.1	250	-155	750	0	0.18

Table 2.14 The distribution of wind power between the four interface buses

Interface Bus	**Bus name and voltage**	**Bus location**	**Area**	**Wind turbine**	**Wind injection**
312717 (230 KV)	6Perry R	Myrtle Beach	Santee Cooper	266	957.6 MW
312719 (230 KV)	6Winyah	Winyah Bay	Santee Cooper	295	1062 MW
312764 (115KV)	Dune	Myrtle Beach	Santee Cooper	121	435.6 MW
312845 (115 KV)	Winyah	Winyah Bay	Santee Cooper	151	542 MW
312764 (115 KV)	Dune	Myrtle Beach	Santee Cooper	12	43.2 MW
312845 (115KV)	Winyah	Winyah Bay	Santee Cooper	11	39.6 MW
Total					3080MW

2.3.2 Adding new transmission lines to the original system

To maintain the wind energy distribution among the five the utilities, the power system transmission was improved by adding new lines to accommodate for an additional 3080 MW of wind energy. The number of new transmission line required depends on the interface bus connections. The study below was conducted using voltage ratings: 115 KV, 230 KV, and a combination of both

- *115 KV interface buses*

Adding new transmission lines to the power system improved its injection capability only when four or more 115 KV interface buses were implemented. By doubling the capacity of the transmission line connecting 6Peedee to 6Marion (Line 1 in Table 2.16), the injection limit of the system was increased to 2080 MW (see Table 2.15 below for more details):

Table 2.15 System injection limit using different sets of 115 KV buses after adding new transmission line# 1

System	3 interface buses	4 interface buses	5 interface buses
Original + 1 New Line(Line1 :PD to Marion)	1280 MW	2080 MW	2080 MW

Table 2.16 Suggested new transmission lines

Line #	New Transmission line information								
	From #	To #	CK #	Resistance (p.u.)	Reactance (p.u.)	Capacitance (p.u.)	Lim A MVA	Lim B MVA	Lim C MVA
1	311650	312729	2	0.00171	0.02274	0.08939	797	797	1100
2	304632	304654	2	0.03251	0.08671	0.0106	97	97	97
3	312845	312770	10	0.0035	0.0309	0.0043	239	275	275

- *230 KV interface buses*

The 3080 MW of wind energy could enter the power grid at two 230 KV buses without any overloaded transmission lines if new Lines 1 and 2 seen in Table 16 were added to the network. Even though three transformers were loaded at approximately 105% of their ratings, this is acceptable value for a transformer loading conditions. Although the improved system resulted in more buses experiencing under-voltages than the original, this situation was resolved by using capacitors. The lowest (0.91 p.u.) and the highest (1.11 p.u.) values of the voltage were approximately the same for both the original and the improved systems. The line power flow of the improved power system after adding the 3080 MW at two 230 KV buses within Santee Cooper is shown in Table C.7 of Appendix C.

- *Both voltage ratings: two 115 KV and two 230 KV buses as interface buses:*

This last design of the wind farm connection to the grid used two 115 KV buses (1080 MW) and two 230 KV buses (2000 MW). It required three new transmission lines (Lines 1, 2 and 3 in Table 2.16) for the system to handle the entire 3080 MW without any overloaded branches. The case list and branch flow are displayed in Tables C.8 and C.9 in Appendix C (for Case 2, a capacitor bank of 30 MVAR was connected to Bus 312799 to correct the overload on the transmission line).

2.3.3 Testing of the 2009 Light Load base case power flow

Using the only light load base case power flow available, Light Load 2009, 3080 MW of wind energy was injected into the power grid to evaluate its absorption capability during off-peak hours. The results of the simulation indicated that the system can take approximately 2150 MW without overloading any branches. The presence of wind energy in the power network reduced the number of buses experiencing overvoltage violations by one third. The table below compares the voltage violations in the original with the system integrating the wind energy at two 230 KV interface buses (Buses 312719 and 312709).

Table 2.17 Voltage violations within the 5 utilities under light load (2009 base case)

System	# of buses with voltage below 0.94 p.u.	# of buses with voltage above 1.06 p.u.	# of buses with voltage above 1.08 p.u.	Lowest voltage (p.u.)	Highest voltage (p.u.)
Original system (2009 Light Load) only	11 buses	262 buses	18 buses	0.916086	1.15422
Original system with 2150 MW of wind energy	11 buses	76 buses	9 buses	0.916777	1.13879

Table 18 below lists the recommended interface buses for successfully adding 3080 MW into the South Carolina power system:

Table 2.18 Recommended interface buses for injecting 3080 MW of wind energy

Buses information			**Three recommended options**		
Interface bus voltage rating	**Interface bus#**	**Bus Name**	**Original power system**	**Power system with improved Transmission capability**	
				Scenario I	**scenario II**
115 KV	312764	Dune	435.6 + 43.2 MW	N/A	N/A
	312807	3MYRT BC	N/A	540 MW	N/A
	312845	Winyah	534.6 + 39.6 MW	540 MW	N/A
230 KV	312717	6Perry R	957.6 MW	N/A	N/A
	312719	6Winyah	1062 MW	1000 MW	1540 MW
	312726	6REDBLUF	N/A	1000 MW	1540 MW
New transmission lines	Line 1: 6PEEDEE to 6Mariom		N/A	Yes	Yes
	Line 2: 3MARION1 to 3DILLN T		N/A	Yes	Yes
	Line 3: 3WINYAH to 3GTWN s		N/A	Yes	No
Wind energy distributed based on the 5 utilities load ratio			No	Yes	Yes
Total wind energy injection			3080 MW	3080 MW	3080 MW

2.3 Conclusion

The investigation of the wind energy penetration in the South Carolina power system was accomplished in three phases. During the Phase I, 80 MW was successfully absorbed and consumed by the Santee Cooper network without any overloaded branches at 115 KV voltage rating.

In Phase II, an additional 1 GW was absorbed by Santee Cooper and distributed among four utilities (Duke, Progress Energy, Santee Cooper and SCE&G) based on their load ratios for the Summer 2009 base case power flow. The power system was overloaded except when most of the existing Myrtle Beach plant was turned off and at least 115 MW was reduced from the existing generation at Winyah Bay (Bus 311478). Furthermore, to expand the options, both two and three 115 KV buses as well as two 230 KV buses were tested separately as interfaces for the wind farms. Using three 115 KV as interface buses is the best suggestion since it reduced the maximum line flow to 96% when 1080 MW was injected into the grid (compared to 97.7% for both scenarios using a set of two 115 KV or 230 KV buses).

In Phase III, an additional 2 GW indicated that the South Carolina transmission system cannot absorb 3080 MW when distributed among the five utility companies (Southern Company, Duke, Progress Energy, Santee Cooper and SCE&G) based on the load ratio criteria. This situation could be mitigated using two approaches. The first did not involve the use of the wind energy distribution criteria, i.e. a large amount of the wind generated power was consumed by Santee Cooper. Specific generators within the Santee Cooper area (Table 2.13) were reduced to their minimum. However, this approach may not be feasible from the system operation standpoint since wind is an unreliable source of energy.

The second approach added new lines to increase the transmission capability of the system. Depending on the different wind farm interface bus connections, the number of new transmission line varies from two to three. Since the investigation of Phase III planned for the year 2030 was simulated using the load forecasting data for 2019, it assumed that the transmission capability by 2030 will be far greater than the one forecasted for 2019. In other words, no new transmission lines might be needed to implement Phase III successfully by 2030.

CHAPTER 3:

CONTINGENCY ANALYSIS

Contingency analysis is the pre-screening process that provides steps for the system operator to follow during an outage. It consists of removing a specific component such as a transmission line or a generator before simulating the power flow from the base case. The results of these simulations are monitored to account for any overloads and out-of-limit voltages.

In this chapter, using the power simulation software PowerWorld, the contingency analysis is applied to the base case power flow of Phase II, after the addition of 1080 MW. First, the approach is used to increase the absorption capacity of the power system, referred here as the Alleviating Contingency. Second, the effect of line, generation bus and plant bus outages is investigated, followed by an analysis of the usability of the spinning reserve.

3.1 Alleviating contingency

Alleviating Contingency increases the system absorption capacity by removing one or more transmission lines from service in order to alleviate any overloads in the system. The opening of lines changes the power system impedance; consequently, the power flow in the neighborhood of the opened line is affected. According to [3], the removal of a line can reduce the overload of the power system by redirecting the power flow.

For illustration, the Alleviating Contingency was applied to the power grid by increasing the wind energy injection by 200 MW from 1080 MW to 1280 MW. This increase created six overloaded lines, three lines located near each of the two wind farms, Winyah Bay and North Myrtle Beach. The goal of this analysis is to redirect the power from heavily loaded branches to less loaded ones with the aim of alleviating the overloading conditions. Different transmission lines near the overloaded branches were opened to observe the effect on the power flow with a trial and error process being followed until the situation is mitigated.

The opening of a transmission line in vicinity of each wind farm was required to correct the overloads. For the North Myrtle Beach location, the option was to open the line connecting 3RNGRG T (Bus 311300) to 3Conway (Bus 312758). In Winyah Bay, the options were to open either line 3DUNBRDP (Bus 311217) to 3GTWN S (Bus 312770) or 3CMPFLD (Bus 311323) to 3GTWN S (Bus 312770) to eliminate the overload on three lines. However, the second option near the Winyah Bay wind farm (opening of line 3CMPFLD to 3GTWN S) necessitated the addition of 120 MVAR capacitor banks to the existing one on Bus 312766 to reduce a line loading to below 100% of its rating (power factor correction). Table 3.1 presents the two options for a successful use of the Alleviating Contingency, while Figures 3.1 and 3.2 exhibit the power flow at the Winyah Bay wind farm interface bus before and after the removal of the line 3DUNBRDP to 3GTWN S, respectively. In those two figures, blue represents a line loaded below 80% of its rating, orange for loading between 80-100% and red for loading above 100%.

Table 3.1 The two options for mitigating branch congestion (Lines to be opened)

Option #	From #	From Name	To #	To Name	Circuit #	Branch Type	Location
1	311217	3DUNBRDP	312770	3GTWN S	1	Line	Winyah
	311300	3RNGRG T	312758	3Conway	1	Line	North Myrtle Beach
2	311300	3RNGRG T	312758	3Conway	1	Line	North Myrtle Beach
	311323	3CMPFLD	312770	3GTWN S	1	Line	Winyah

Table 3.2 Loading of monitored Transmission lines before and after alleviating contingency

Branch information						**Percent of branch MVA Limit (%) after injecting 1280 MW of wind energy**		
						Before Mitigation	**Mitigated (after Alleviating contingency)**	
From #	**From Name**	**To #**	**To Name**	**CKT #**	**MVA Limit**		**Option 1**	**Option 2**
311213	33VCH T	312770	3GTWN S	1	239	100.6	96.1	92.4
311213	33VCH T	312845	3WINYAH	1	239	104.2	99.1	95.8
312770	3GTWN S	312845	3WINYAH	1	239	102.5	97.9	94.1
311402	3SPYB2 T	312807	3MYRT BC	1	179	102.4	99.2	98.1
311402	3SPYB2 T	312815	3OIL PL	1	179	101.8	99.2	98.1
312807	3MYRT BC	312824	3RACEPT	1	179	103.2	98.9	99.5

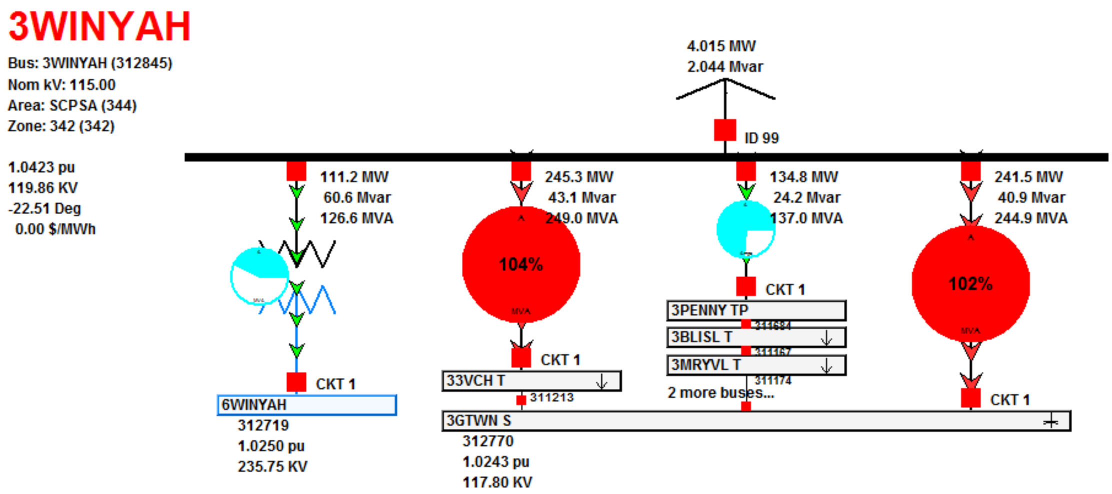


Figure 3.1 Power flow in the congested area near Winyah Bay before opening line 3DUNBRDP to 3GTWN S

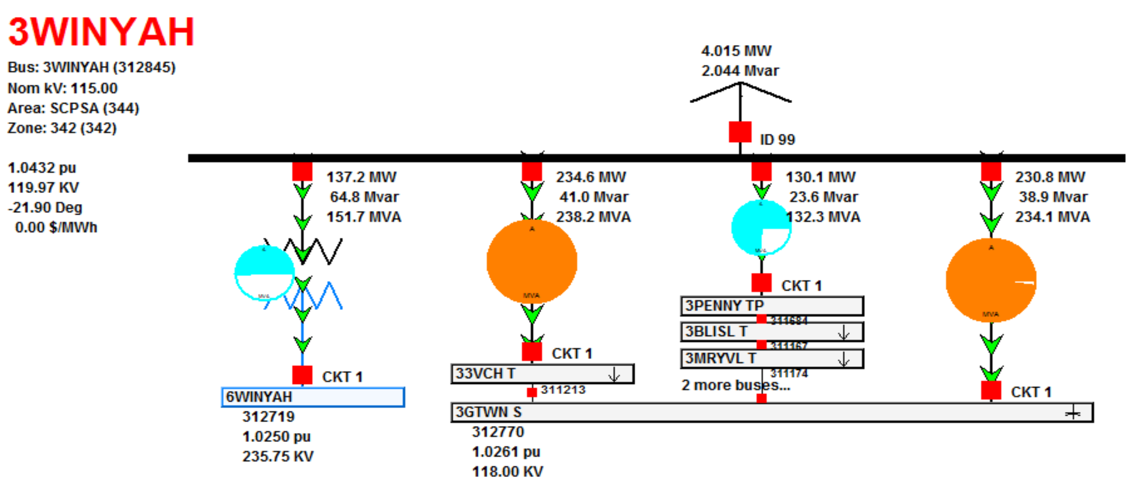


Figure 3.2 Power flow in the congested area near Winyah Bay after opening line 3DUNBRDP

3.2 Line outage

3.2.1 Single line contingency study (N-1)

An N-1 contingency analysis is the removal of a single transmission line (115 KV) to monitor its effect on the power flow. After injecting 1080 MW of wind energy into the grid during Phase II, a 115 KV transmission line within Santee Cooper area was removed to determine if this line outage overloads the system. Listed below in Table 3.3 are the lines in the Santee Cooper power systems that led to an overload of the grid when removed:

Table 3.3 List of lines that caused some overloads (N-1)

Branches that create overloads for N-1			
From Number	**From Name**	**To Name**	**To Number**
311167	3BLISLT	311174	3MRYVLTC1
311167	3BLISLT	311684	3PENNYTPC1
311168	3LONGS	311625	3BAYTREETAPC1
311168	3LONGS	312868	3REDBLUFC1
311174	3MRYVLT	312859	3GTNCTC1
311178	3MCES	311368	3BIGGNTC1
311201	3QUAIL	311380	3ECONWTC1
311201	3QUAIL	311617	3PRTAPC1
311213	33VCHT	312770	3GTWNSC1
311213	33VCHT	312845	3WINYAHC1
311289	3FORSBK	312807	3MYRTBCC1
311289	3FORSBK	312820	3PINEIC1
311305	321ST	311429	3RIVOAKC1
311305	321ST	312764	3DUNESC1
311306	3WAMPEE	311569	3BFTLNDGC1
311307	3GLENNS	312766	3GRDNCC1
311320	3JONESRD	311668	LKRIDGETAPC1
311320	3JONESRD	312829	3SOCASTC1
311322	3ARCADI	311323	3CAMPFLDC1
311322	3ARCADI	311618	3PRKRSVLC1
311322	3ARCADI	312806	3MURRELC99
311323	3CAMPFLD	312770	3GTWNSC1
311323	3CAMPFLD	312776	GREENFTC1
311325	3ISGRT	311372	3DPONDTC1
311325	3ISGRT	312829	3SOCASTC1
311329	3STJAME	311645	3PRINCKTC1
311329	3STJAME	312796	3LITCHFC1
311337	3INDIGO	312803	3MARKETC1
311337	3INDIGO	312863	3BUCKINC1
311368	3BIGGNT	312789	3JEFFC1
311380	3ECONWT	312775	3GRAINGRC1
311402	3SPYB2T	312807	3MYRTBCC1
311402	3SPYB2T	312815	3OILPLC1
311429	3RIVOAK	311617	3PRTAPC1
311556	3GRNDUNE	311715	3TWNCTRTC1
311556	3GRNDUNE	312764	3DUNESC1
311556	3GRNDUNE	312866	3SPRONGC1
311569	3BFTLNDG	312813	3NIXNVTC1

311618	3PRKRSVL	312796	3LITCHFC1
311621	3HMWDT	312853	3NCNWYC1
311625	3BAYTREETAP	312811	3NIXXRDC1
311645	3PRINCKT	312766	3GRDNCC1
311659	3AVALON_SC	311715	3TWNCTRTC1
311659	3AVALON_SC	312866	3SPRONGC1
311668	LKRIDGETAP	312819	3PERRYRC1
311676	3CANEBYT	312750	3CARNESC1
311676	3CANEBYT	312849	3SANGATC1
311684	3PENNYTP	312845	3WINYAHC1
311696	3BEACHWOOD	312811	3NIXXRDC1
311702	3CANEPATCH	312764	3DUNESC1
311702	3CANEPATCH	312848	348THAC1
312747	3BLUFFTN	312779	3HHGTC1
312747	3BLUFFTN	312860	3HHEADC1
312747	3BLUFFTN	312863	3BUCKINC1
312750	3CARNES	312790	3JWALTC1
312750	3CARNES	312844	3WHITSVC1
312752	3CHSTNT	312764	3DUNESC1
312758	3CONWAY	312853	3NCNWYC1
312766	3GRDNC	312806	3MURRELC1
312766	3GRDNC	312861	3CAROPNC1
312767	3GTNREA	312770	3GTWNSC1
312767	3GTNREA	312859	3GTNCTC1
312770	3GTWNS	312785	3IPCOPMPC1
312770	3GTWNS	312845	3WINYAHC1
312776	GREENFT	312785	3IPCOPMPC1
312779	3HHGT	312797	3LGCOVC1
312789	3JEFF	312804	3MCWSC1
312797	3LGCOV	312803	3MARKETC1
312799	3WDLPT	312824	3RACEPTC1
312799	3WDLPT	312836	3SURFSDC1
312804	3MCWS	312844	3WHITSVC1
312807	3MYRTBC	312819	3PERRYRC1
312807	3MYRTBC	312824	3RACEPTC1
312813	3NIXNVT	312819	3PERRYRC1
312815	3OILPL	312843	3WASHPC1
312819	3PERRYR	312820	3PINEIC1
312819	3PERRYR	312866	3SPRONGC1
312835	3STGEORG	370009	3STGEOC1
312843	3WASHP	312848	348THAC1

3.2.2 Double line contingency (N-1-1)

After generating a list of 115 KV transmission lines producing overloaded branches for N-1 contingency (Table 3.3), the power infrastructure was further investigated by opening a second line to alleviate the existing overloaded branches (N-1-1). Similar to the Alleviating Contingency, a line (N-1-1) was removed so that the power flow is redirected towards less loaded branches. Table 3.4 displays the cases of single line contingency (N-1) in Table 3.3 that were now mitigated by a double line contingency.

Table 3.4 Unsuccessful N-1 cases Mitigated at N-1-1

Branch information							
Branch opened at N-1 for contingency				Branch opened at N-1-1 to alleviate overloads			
From #	**From Name**	**To Name**	**To #**	**From #**	**From Name**	**To Name**	**To #**
311178	3MCES	311368	3BIGGNTC1	312789	3JEFF	312804	3MCWS
311289	3FORSBK	312820	3PINEIC1	311300	3SNGRGT	312758	3CONWAY
311305	321ST	312764	3DUNESC1	311303	3WINDYH	312760	3CRCNTB
311306	3WAMPEE	311569	3BFTLNDGC1	311300	3SNGRGT	312758	3CONWAY
311323	3CAMPFLD	312770	3GTWNSC1	311300	3SNGRGT	312758	3CONWAY
311323	3CAMPFLD	312776	GREENFTC1	311323	3CAMPFLD	312758	3CONWAY
311368	3BIGGNT	312789	3JEFFC1	312789	3JEFF	312804	3MCWS
311569	3BFTLNDG	312813	3NIXNVTC1	311300	3SNGRGT	312758	3CONWAY
311621	3HMWDT	312853	3NCNWYC1	311300	3SNGRGT	312758	3CONWAY
311645	3PRINCKT	312766	3GRDNCC1	311300	3SNGRGT	312758	3CONWAY
311659	3AVALON_SC	311715	3TWNCTRTC1	311300	3SNGRGT	312758	3CONWAY
311696	3BEACHWOOD	312811	3NIXXRDC1	311300	3SNGRGT	312758	3CONWAY
311702	3CANEPATCH	312764	3DUNESC1	311556	3GRNDUNE	311715	3TWNCTRT
311702	3CANEPATCH	312848	348THAC1	311556	3GRNDUNE	311715	3TWNCTRT
312750	3CARNES	312844	3WHITSVC1	311368	3BIGGNT	312789	3JEFF
312758	3CONWAY	312853	3NCNWYC1	311300	3SNGRGT	312758	3CONWAY
312767	3GTNREA	312770	3GTWNSC1	311217	3DUNBRDP	312770	3GTWNS
312789	3JEFF	312804	3MCWSC1	311368	3BIGGNT	312789	3JEFF
312804	3MCWS	312844	3WHITSVC1	311368	3BIGGNT	312789	3JEFF
312813	3NIXNVT	312819	3PERRYRC1	311303	3WINDYH	312760	3CRCNTB

In summary, among the 274 -115 KV transmission lines in the Santa Cooper system, 79 of them resulted in overloaded branches for N-1contingency. Through the application of the Alleviating Contingency process, removal of a line to correct an existing overload, 20 out the aforementioned 79 were mitigated by N-1-1.

3.3 Plant and generation bus outages

3.3.1 Generator bus

The outage of any single generator in Santee Cooper power system, except for Peedee, did not overload the power network.

3.3.2 Plant bus

The removal of any plant bus resulted in the overloading of the branches in the power system. Through the application the Alleviating Contingency (opening of a line) after a power plant outage in the Santee Cooper area, the power flow congestion was corrected for some cases. A list of successful cases can be seen in the Table 5 below:

Table 3.5 List of power plant outage sustainable by the grid

Plant outage information		**Line opened to alleviate overloads**			
Plant name	**Plant bus #**	**From Number**	**From Name**	**To Name**	**To Number**
Cross	312710	312757	3COLUMB	312817	3OWEN S
Jeffries	312789	311217	3DUNBRDP	312770	3GTWN S
St. Stephens	312858	311217	3DUNBRDP	312770	3GTWN S
Rainey	312735	311217	3DUNBRDP	312770	3GTWN S
Peedee	311650	311217	3DUNBRDP	312770	3GTWN S

3.4 Spinning reserve and Wind Power Variability

The Santee Cooper power system has a spinning reserve of approximately 254 MW after 1080 MW of wind energy is injected into its network; thus, the power grid should ride through a net generation loss of 254 MW from the wind power. This scenario was successfully simulated by increasing all conventional generators to their maximum (+254 MW) and reducing the wind energy input to the grid by the same amount. The result of the simulation indicated no branch violation, meaning that spinning reserve is usable in the absence of wind.

3.5 Conclusion

The result of the N-1 contingency analysis showed that after Phase II, the failure of either the Peedee generation or any of 79 transmission lines listed in Table 3.3 will overload the network, potentially requiring load shedding to maintain the stability. Consequently, additional measures must be taken to improve the South Carolina transmission system near the wind farms interface buses since most of the previously mentioned overloads were in the same location.

The integration of wind energy into the network changes its operational configuration and power flow through the branches. As a result, the contingency analysis pre-screening the power system for any potential weakness due to component failure is re-required. The contingency N-1 criterion, which is a failure of single component in a power system, should not result in the consumer outage [1]. Consequently, the power reserve must match the largest generator in the network. Another type of contingency based on the Z-bus matrix can be used to alleviate the overloads in a power system by line switching [3], [4]. A pre-defined list of limiting and sensitive line is made available to the operators to facilitate the handling of unplanned system overloads. The limiting lines are the one that can be opened or closed, while the sensitive lines are not to be switched.

CHAPTER 4

OFFSHORE WIND FARMS TRANSMISSION SYSTEM

In the past, most offshore wind farms were small in capacity and located near the shore line, so they required only a medium Alternating Current (AC) voltage transmission system. As the size and distance of the wind farm from the shore increased, high voltage transmission, requiring an offshore substation, were implemented with the WTGs still connected in a redial network as shown in Figure 4.1. At high voltages, the power can be transferred to the grid through Alternating or Direct Current (AC or DC). The electric losses for the AC application, as opposed to DC, are proportional to distance, which is a limiting factor. On the other hand, the electric losses for the DC application are approximately the same for any distances. The bulk of losses occur at the converter stations located both offshore and onshore.

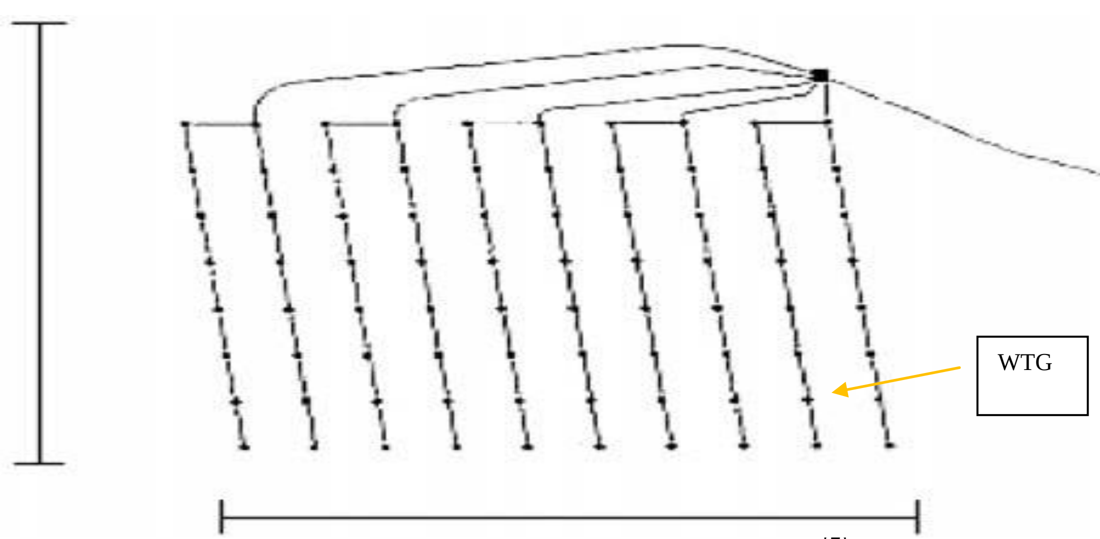


Figure 4.1 Redial connections for WTGs [7]

4.1 Multiple medium voltage connections (up to 36 KV and 200 MW)

The multiple medium voltage connections are suitable for small wind farms with a capacity of up to 200 MW [5], which are located at a short distance from the shore. Since this design doesn't require an offshore substation, the energy is collected from specific groups of WTGs using a medium voltage submarine cable per grouping.

4.2 High Voltage Alternating Current (HVAC)

HVAC technology is appropriate for higher capacity wind farms located at greater distance from the shore. The medium voltage is stepped-up from the collection point at an offshore substation to a higher voltage to minimize the transmission losses and the number of subsea cables needed. For illustration, Figure 4.2 displays a picture of an European offshore substation. The Danish Horns Rev wind farm [7], the first to include an offshore transformer substation, built in 2002, has a capacity of 160 MW. The voltage within the wind farm vicinity is maintained at 36 KV, the maximum voltage allowed due to switchgear cost, before being raised to 150 KV at the substation located approximately at 9.32 miles from the shore.

Figure 4.2 Picture of offshore substations [10]

However, the HVAC technology is limited as the self-capacitance of the AC line increases with distance. The capacitance of the line, which depends on the cable type, generates charging currents that uses most of the line capacity, leading to a poor power factor. As a result, reactor compensation is usually required at each end of the cable to correct the situation. Among the submarine cables used currently, the cross-linked polyethylene, which can be used for both AC and DC applications, is the preferred because of it has lower capacitance than the low-pressure fluid-filled cable (LLFF) and the ethylene propylene rubber (EPR).

4.3 High Voltage Direct Current (HVDC)

An alternative to HVAC for long distance application is HVDC to reduce electric losses. From the studies, for wind farms located beyond 31.07 miles [8] from the shore, it is economically more feasible to use this option for the energy transmission to the grid than AC since the break-even point when comparing the costs of submarine cable is this distance.

In addition to having lower transmission losses, the HVDC offers the following advantages [17]:

- Operation at different frequencies and voltages at either end of the link
- Negligible transmission losses over distance
- Elimination cable capacitance, which could potentially resonant with network inductance in HVAC applications
- Electric isolation of the wind farm during faults
- Increase amount of useful power carried by the cable
- control of the active and reactive power

The prime disadvantage of HVDC is the need for large and expensive AC/DC converter stations at both offshore and onshore locations. The HVDC technology offers two choices: the conventional direct current source converter (DCS) based on thyristors and the voltage source converter (VSC) based on the Insulated Gate Bipolar Transistor (IGBT). The main difference between these two technologies is that the current source converter based HVDC requires a strong voltage source at both ends of the connection for line commutation. As result, an auxiliary offshore power supply, usually a diesel generator is mandatory for the application of HVDC DCS during periods of low wind. This technology may not be suitable for offshore applications. In most studies, the break-even point when compared to HVAC is approximately about 24.85-31.07 miles [7].

On the other hand, the VSC-based HVDC, developed by ABB as HVDC Light and by Siemens as HVDC Plus, is the better choice for offshore applications because it allows for the independent control of both active and reactive power from the wind farm i.e. provides voltage support, a key component for power system operation and stability. The break-even point for the VSC-based HVDC compared to HVAC is approximately 18.64-31.07 miles [7].

4.4 Design Recommendations

Using a standard of 12 nautical miles (13.67 miles) [22] from the shore as the state water limit, HVAC is a good candidate for the South Carolina wind energy project assuming that the collection point is not beyond 31.07 miles from the shore. The break-even point between HVAC and VSC-based HVDC is approximately 18.64-31.07 miles depending on the project. The distance from the shore to the grid connection point is neglected in this comparison between HVAC and HVDC, assuming overhead lines are used for onshore transmission. The break-even distance for cost of these two technologies for overhead transmission lines is about 497.1-621.37 miles [8].

The implementation of HVAC for all three phases of this project requires the installation of an offshore substation for each phase. The medium voltage should be raised to 115 KV at substation for Phases I and II, and to 230 KV for Phase III before being transmitted to the grid. However, if the substation for Phase III is placed beyond 31.07 miles from the shore, VSC-based HVDC, which reinforces the network through independent reactive power control, should be considered instead of HVAC.

Tables 1 and 2 below present the different options for transmitting the offshore wind energy to the Santee Cooper power System:

Table 4.1 Recommended transmission option 1: If the WTGs for Phase I are located far the shore (Phases II and III also being in the range of HVAC)

Phase	Voltage
I	115 KV AC
II	115 KV AC
III	230 KV AC

Table 4.2 Recommended transmission option 2: If WTGs for Phase I is close to the shore (Phase II is located within the HVAC range) and the offshore substation for III is located beyond the range of HVAC

Phase	Voltage
I	Medium Voltage Up to 36 KV AC (standard voltage of 34.5 KV in the US)
II	115 KV AC
III	230 KV DC

4.5 Conclusion

At the light of these analyses on offshore transmission design, the WTGs for Phase I and the offshore substations for Phases II and III should be located as close as possible to shore to reduce transmission. In other words, Medium voltage is to be used for phase I and HVAC for the last two phases. Economically, this design is the most effective since it does involve any DC links or expensive converter stations.

CHAPTER 5

ANALYSIS OF HISTORICAL WIND POWER AND LOAD DATA

More than 8500 MW [12] of wind generation installed in the US during 2008 indicates that this is currently emerging as the most efficient form of the renewable energy. As a result, wind speed patterns are of increasing interest to power engineers who are eager to validate them using historical data. For example, Reigh Walling and Gary Jordan [12], studied the wind hourly and seasonal behavior and the relationship to hourly load demand based on actual load and analytically-derived wind power data for the Electric Reliability Council of Texas (ERCOT) system. Their results indicated that the wind is high during the night and early in the morning, which is nearly the opposite of the load demand. It was also found that the wind is strong during winter and spring, but weak during summer and unpredictable in fall. The state reported data were analyzed to identify these patterns pertaining to these hourly and seasonal behaviors using the ERCOT‘s actual load and onshore wind power data for a period of three years from 2007 to 2009 of incremental wind generation capacity.

Moreover, due to the unpredictability of the wind speed, the energy from it is non-dispatchable, acting as a negative load which affects the amount of traditional generation being committed to the load. As a result, there is a need for accurately estimating the portion of load demand covered by wind power, also referred to as the ratio of wind energy to load demand. For the purpose of long-term system planning, the distribution of wind power ratio to load over the seasons and months corresponding to a given annual hourly average wind penetration value is investigated using a probabilistic approach based on historical data and a curtailed wind power output.

5.1 Verifying the wind hourly and seasonal behavior and the relationship to hourly load demand

5.1.1 Wind power is high at night and early morning hours

As Figure 1, which shows the average annual hourly output of the wind turbines within the ERCOT power system from 2007 to 2009, indicates that the output of the wind turbine generators (WTGs) is higher than the daily average during the night and the early morning hours (9 PM to 7 AM). This pattern is illustrated by the valley during the afternoon in each of the three graphs. To further justify this pattern, the average hourly outputs of the WTGs for the four seasons of each year are plotted in Figures 5.2 to 5.5. These graphs display the same daily pattern of the wind strength variation.

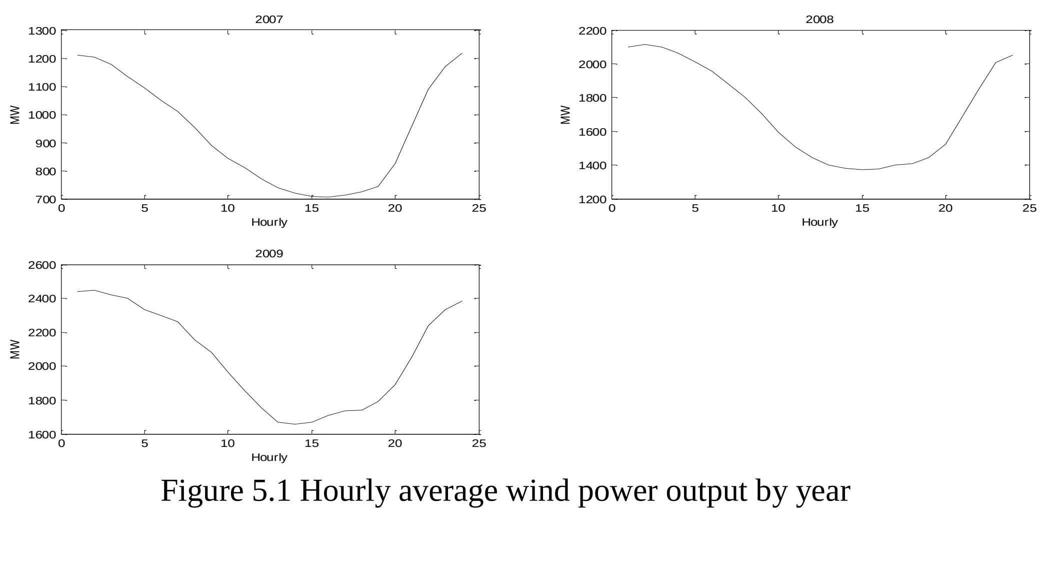


Figure 5.1 Hourly average wind power output by year

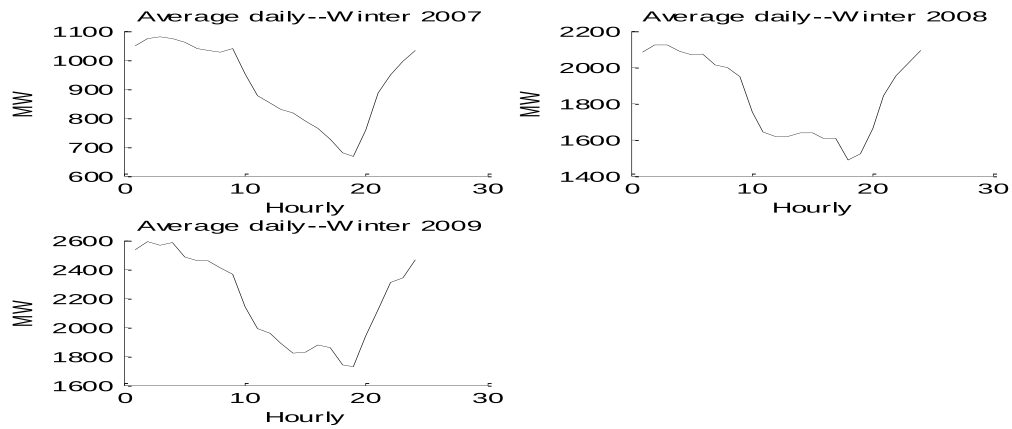


Figure 5.2 Average hourly wind power output over 24 hours for the winter season

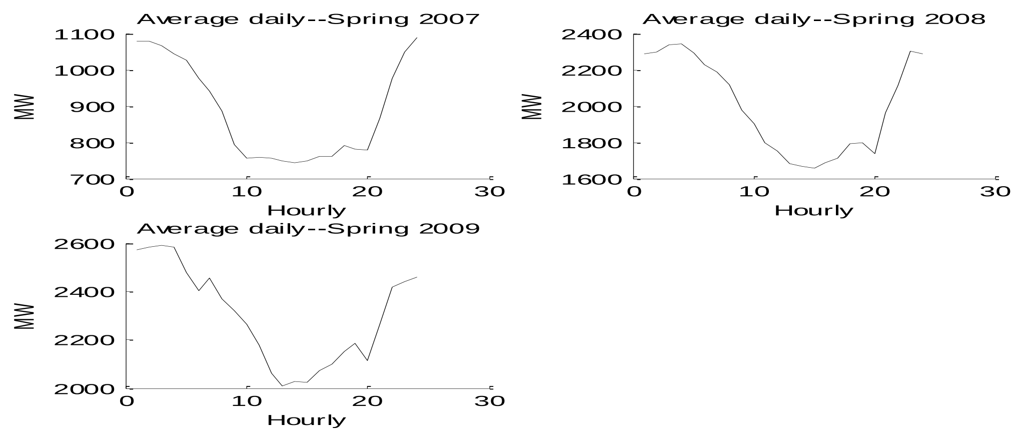


Figure 5.3 Average hourly wind power output over 24 hours for the spring season

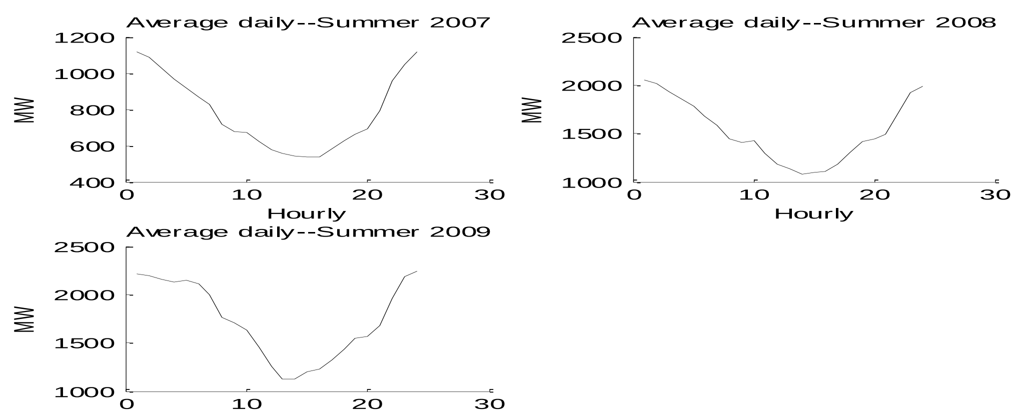


Figure 5.4 Average hourly wind power output over 24 hours for the summer season

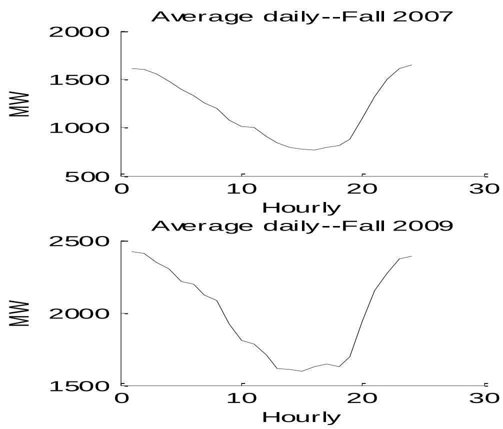


Figure 5.5 Average hourly wind power output over 24 hours for the fall season

5.1.2 Comparing load demand and wind power generation

Figures 5.6 to 5.8 present the average hourly load and the wind output of the WTGs for 2007, 2008 and 2009 respectively, in which the straight line represents the mean value of the plotted curve. It is seen that the wind energy generation is above the daily average at night and during the early morning hours from 9 PM to 7 AM. On the other hand, the load demand is above the average daily demand during the day from 9 AM to 11 PM. An identifiable pattern is the tendency of the wind energy generation to be high during off-peak hours with the exception of the hours from 9 PM to 11 PM for the ERCOT system, nearly the opposite of the load demand. Figures 5.9 to 5.12 illustrate the average hourly load and the WTGs output for all seasons of 2007, 2008 and 2009.

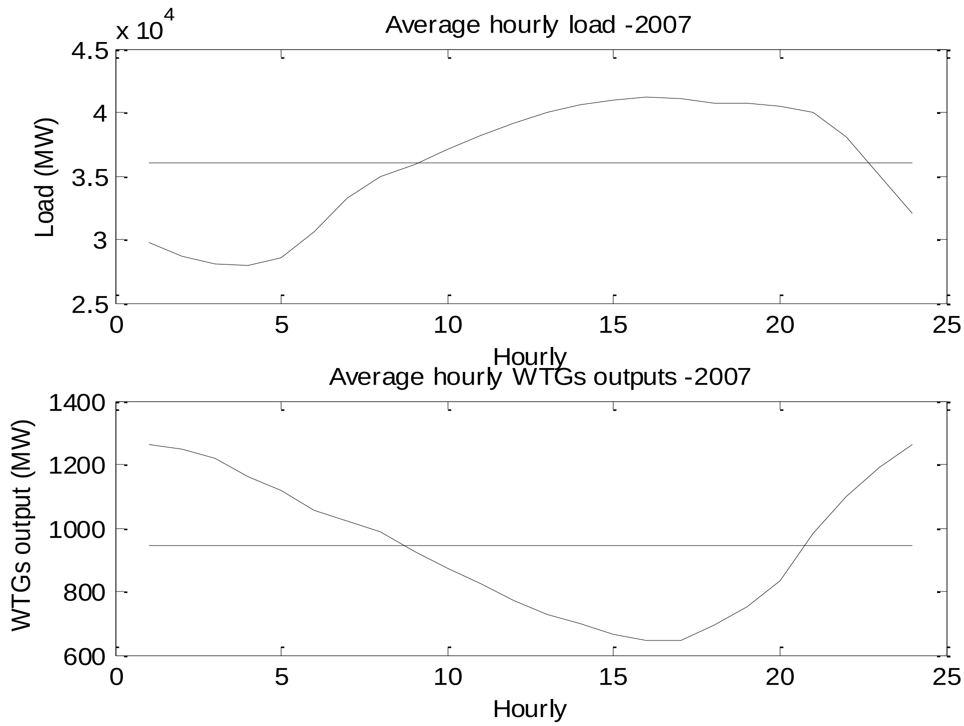


Figure 5.6 Average hourly load and WTGs output for 2007

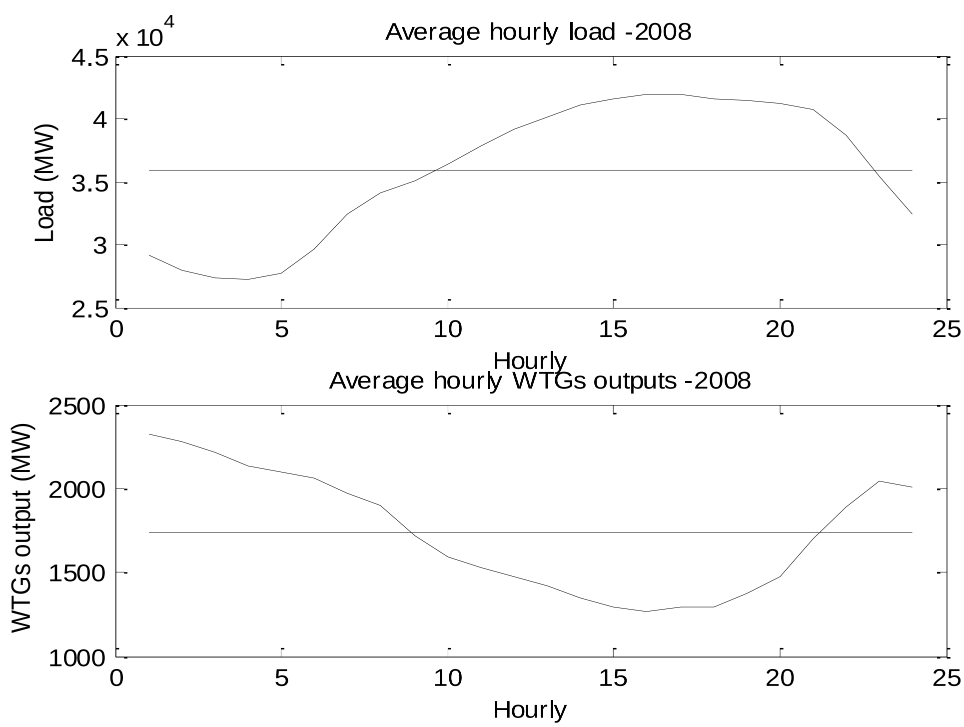


Figure 5.7 Average hourly load and WTGs output for 2008

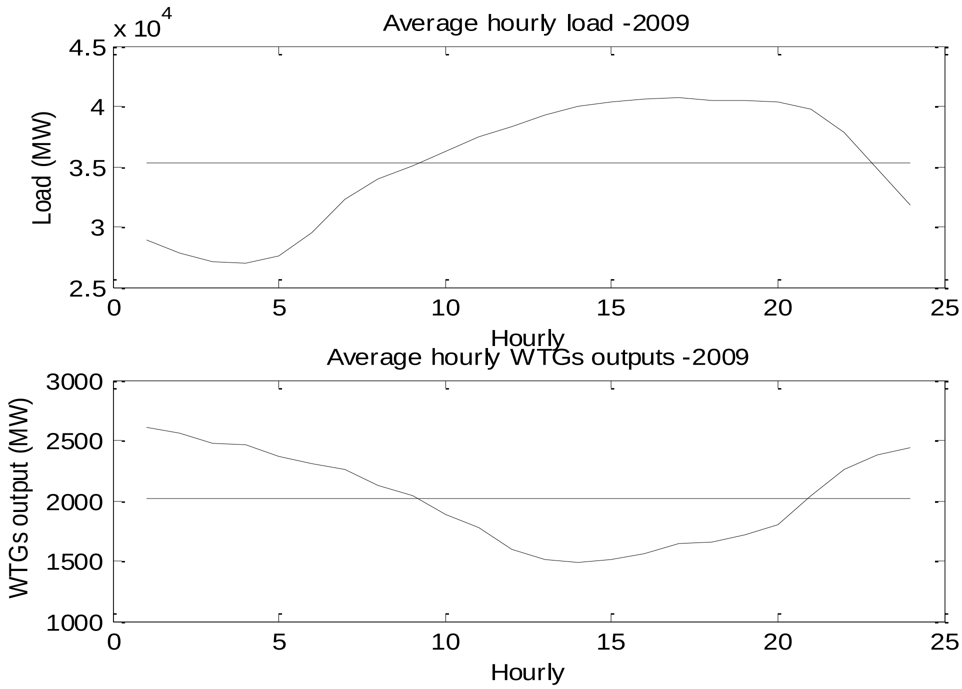


Figure 5.8 Average hourly load and WTGs output for 2009

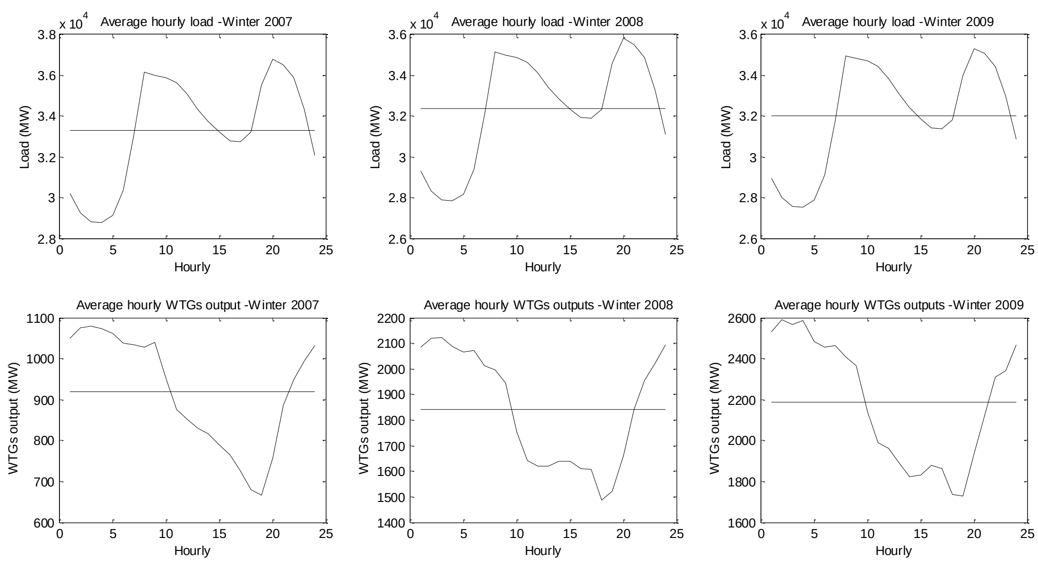


Figure 5.9 Average hourly load and the WTGs output for the winter of 2007, 2008 and 2009

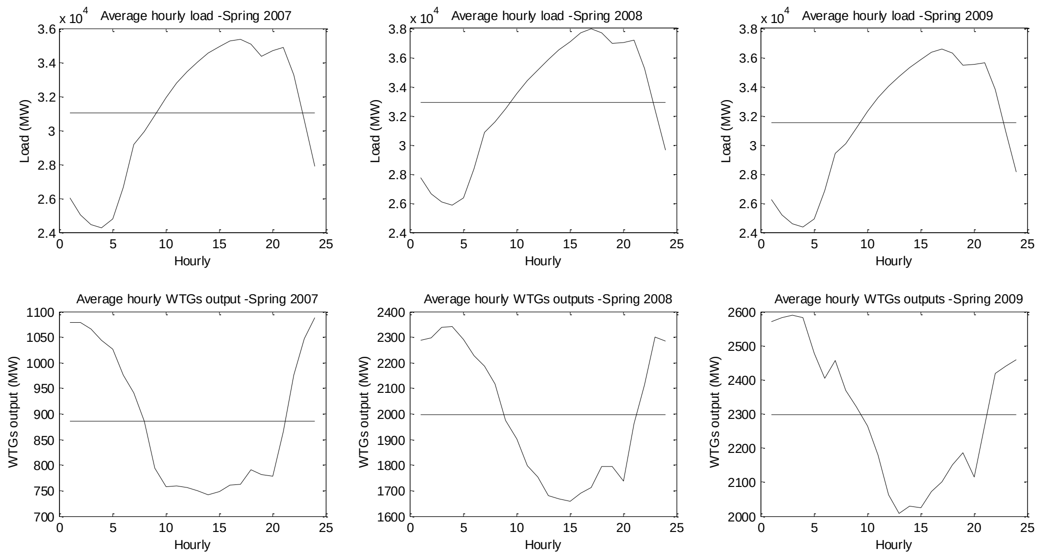


Figure 5.10- Average hourly load and the WTGs output for the spring of 2007, 2008 and 2009

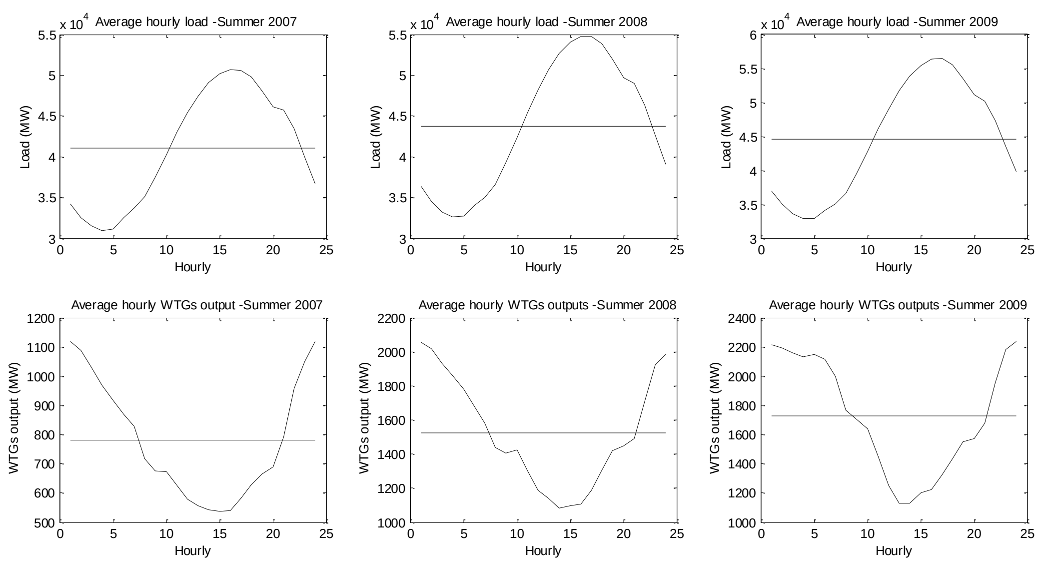


Figure 5.11- Average hourly load and the WTGs output for the summer of 2007, 2008 and 2009

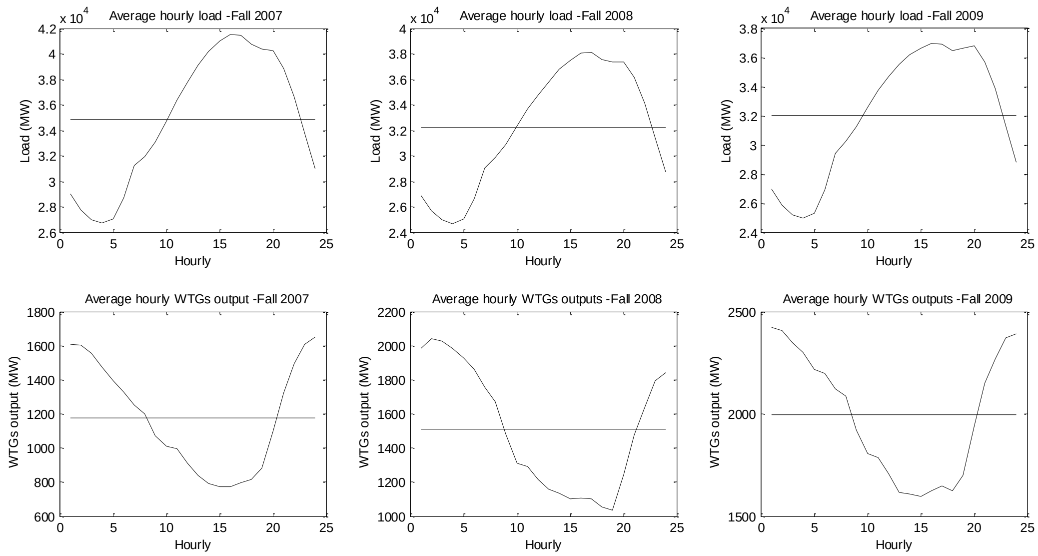


Figure 5.12- Average hourly load and the WTGs output for the fall of 2007, 2008 and 2009

5.1.3 Comparison of wind power by season for all three years

Figure 5.13 displays the annual average hourly wind power generated per season for each year as a percent of the total WTGs capacity installed. The analysis of the three plots shows stronger winds during the spring and the winter, but weaker ones during summer. However, during fall, the availability of high wind is unpredictable as it depends on the yearly weather.

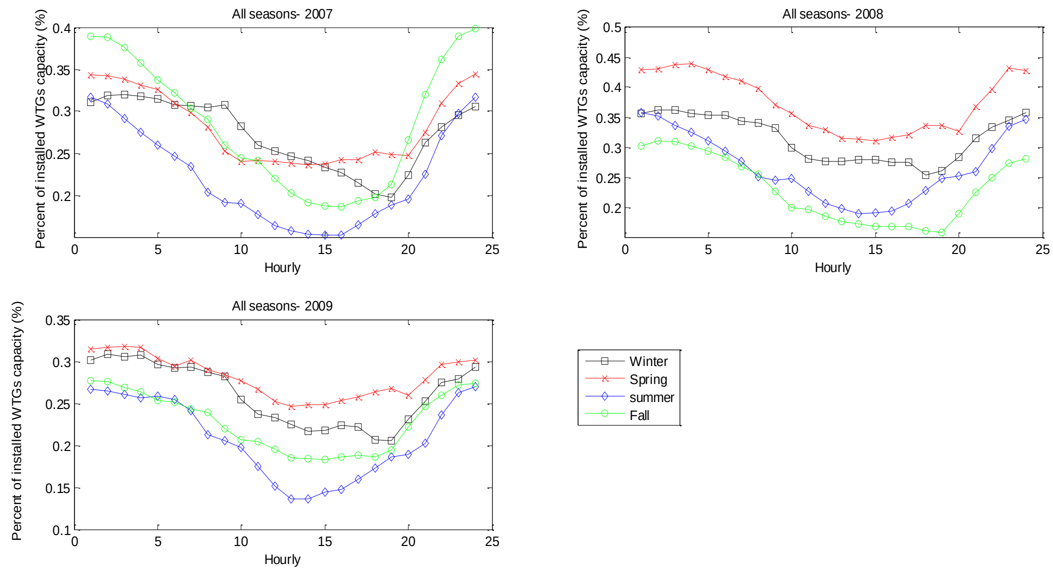


Figure 5.13- Average hourly wind energy produced per season for each year

5.2 Repetitive behavior of wind and load over the years

5.2.1 Repetitive behavior of wind pattern over a year

Although the wind gusts may be different each year, a repetitive behavior of hourly wind patterns for the same month and season of each year was identified. Although, it might be difficult to predict the wind on a daily or a weekly basis, the monthly and seasonal wind power outputs for each year follow the same V-shape pattern with the peak during the night and the trough during the day for each year. Figure 5.14 below shows the average hourly wind power output for 24 hours from 2007 to 2009 as a percentage of the installed capacity. The three plots on the graph have similar V-shaped patterns, although their values are different for each hour.

Another approach to analyzing this data is to normalize the wind power output by dividing the hourly values by the average for the 24 hours (the change in the capacity does not affect the normalized values). It then appears that the hourly values for each of the three years are approximately the same since the curves are more closely aligned as shown in Figure 5.15. The normalized hourly wind power for all the seasons and months showing a similar pattern to that of the yearly are presented in Figures 5.16 and 5.17. Black, red and blue represent the 2007, 2008 and 2009 data respectively.

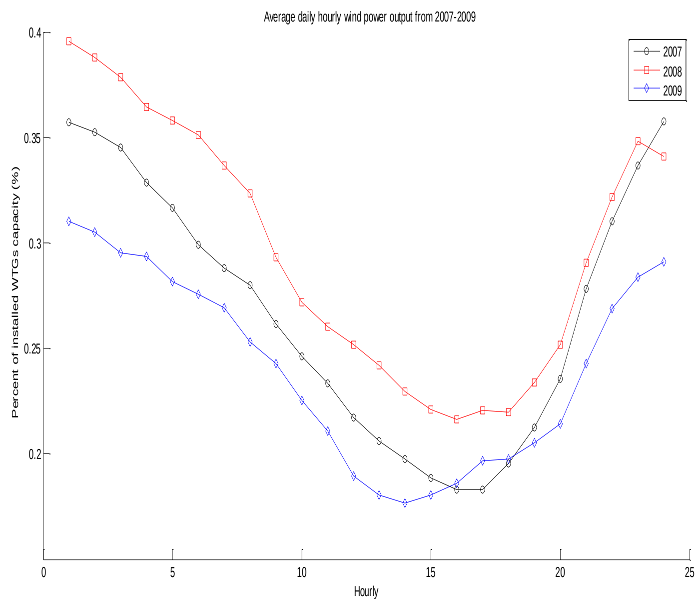


Figure 5.14-Averge output as a percent of installed capacity

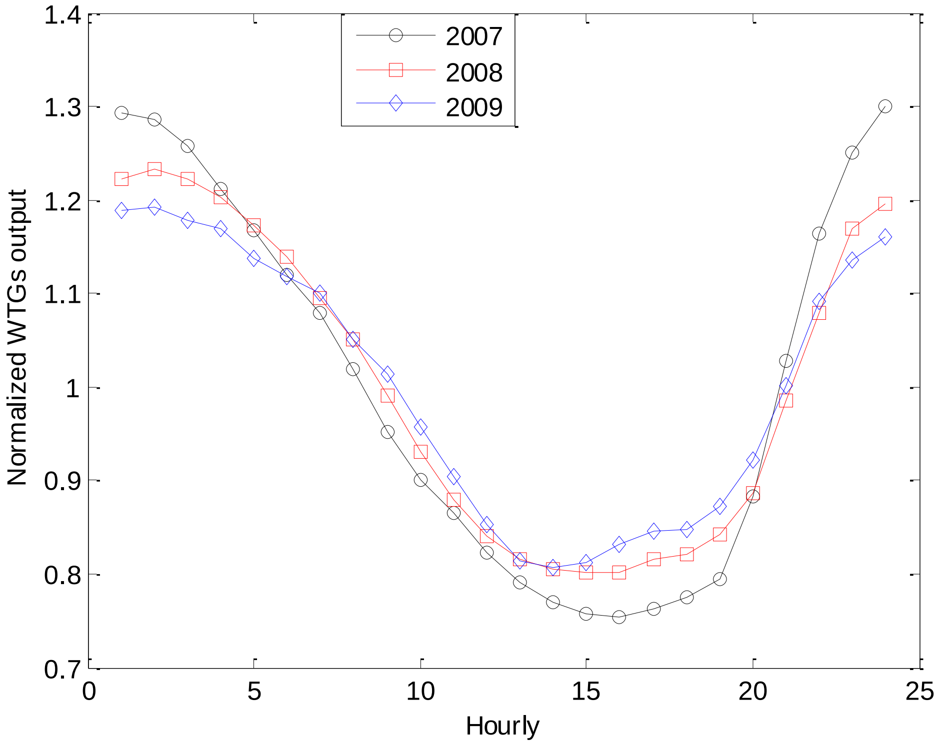


Figure 5.15- Normalized hourly values of the wind power output over 24 hours from 2007-2009.

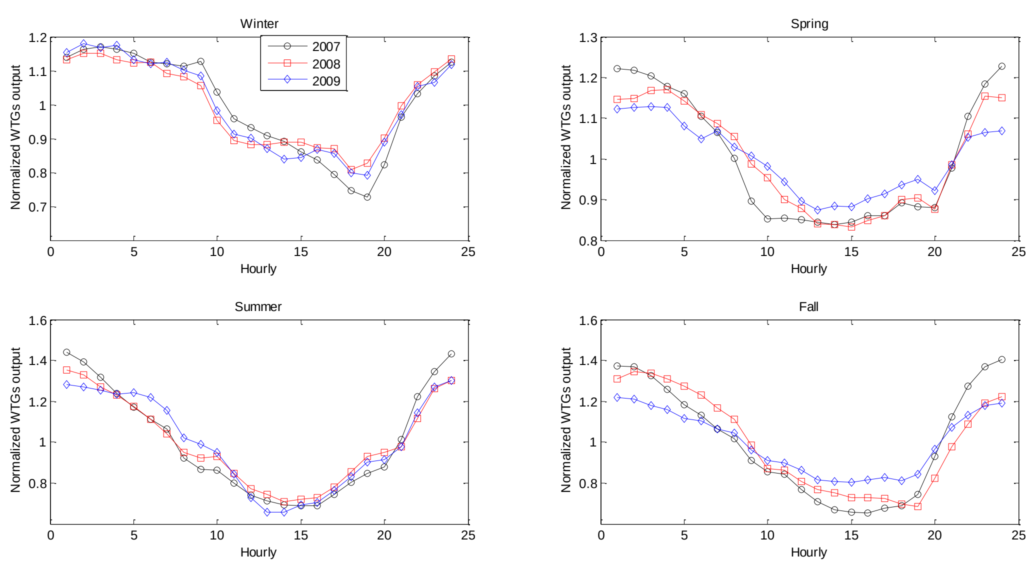


Figure 5.16 Normalized hourly values of the wind power output over 24 hours by season from 2007-2009.

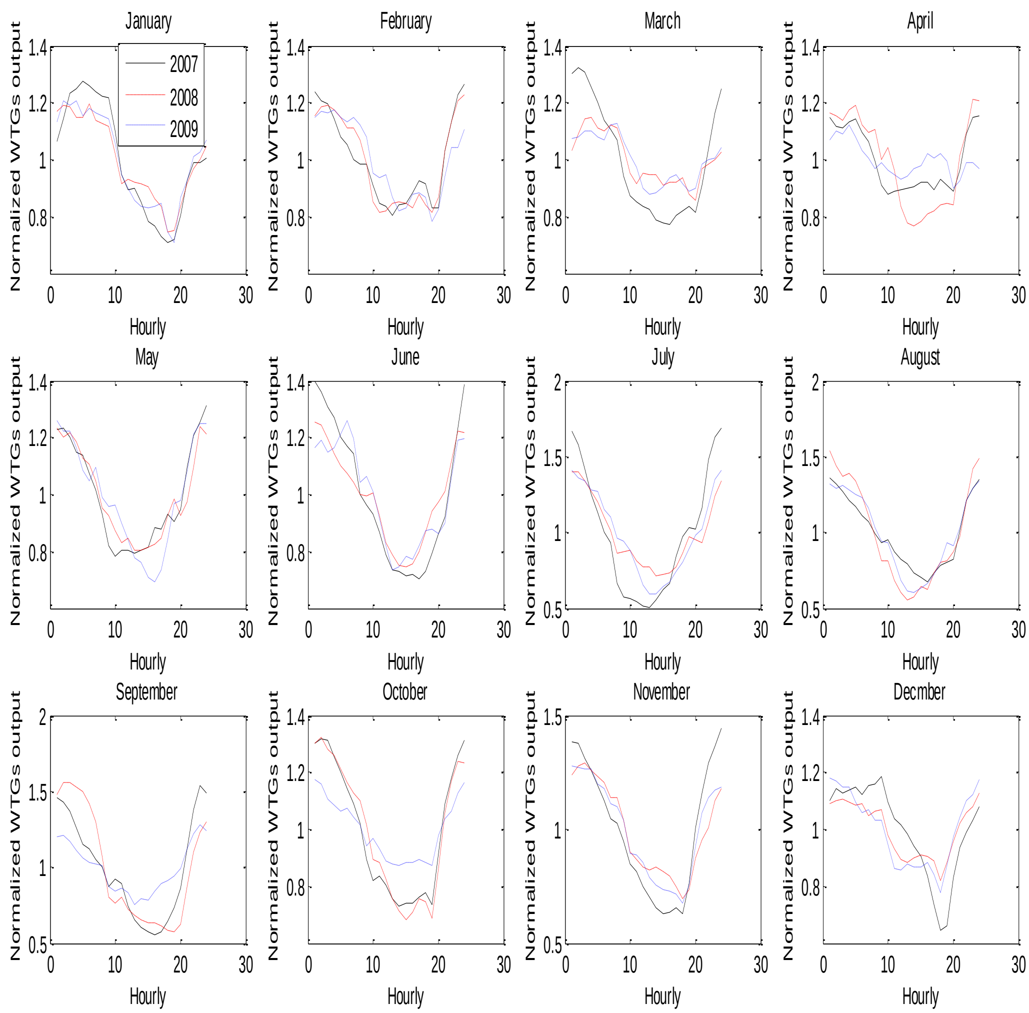


Figure 5.17 Normalized hourly values of the wind power output over 24 hours by month from 2007-2009.

5.2.2 Repetitive behavior of load pattern over a year

Load variation patterns have similar shapes during the same months and seasons regardless of the year. Figures 5.15 to 5.17 show the hourly load average for each of the 24 hours for the year, season and month respectively during the three years from 2007 to 2009. Even though the hourly values are different, the shape of the curves for the three years is the same. To bring the hourly values closer to one another, they are normalized by dividing them by the 24 hours average as shown in Figures 5.8 to 5.10. The next step is using the graphical illustration to establish a mathematical relationship between wind power and load to help determine the wind to load ratio by periods of the day: the high wind penetration hours (11 PM to 7 AM) and the low wind penetration hours (7AM to 11PM). During the high wind penetration period, also referred to as the high wind-to-load ratio period, the wind energy produced is above its 24-hour average and the load demand is below its 24-hour average, and vice versa for the low wind penetration period, also referred as low wind-to-load ratio period.

5.2.3 Ratio of normalized wind power and load

Since the hourly values of the normalized load are more closely aligned for each year than the normalized wind power, the ratio of the normalized wind power to the load will also have an hourly value that is more closely aligned. As a result, it is assumed that the hourly value of the ratio is the same for each of three years:

$$\frac{\left(\dfrac{Wind_{hourly\_2007}}{Wind_{average\_2007}}\right)}{\left(\dfrac{Load_{hourly\_2007}}{Load_{average\_2007}}\right)} = \frac{\left(\dfrac{Wind_{hourly\_2008}}{Wind_{average\_2008}}\right)}{\left(\dfrac{Load_{hourly\_2008}}{Load_{average\_2008}}\right)} = \frac{\left(\dfrac{Wind_{hourly\_2009}}{Wind_{average\_2009}}\right)}{\left(\dfrac{Load_{hourly\_2009}}{Load_{average\_2009}}\right)} \approx ratio_{hourly} \tag{5.1}$$

From Equation (5.1), the expression for the hourly wind penetration is derived as follows:

$$\frac{Wind_{hourly\_2009}}{Wind_{average\_2009}} = ratio_{hourly} * \frac{Load_{hourly\_2009}}{Load_{average\_2009}} \tag{5.2}$$

From equation (5.2) the hourly percent of load cover by the WTGs can be express as:

$$\frac{Wind_{hourly\_2009}}{Load_{hourly\_2009}} = ratio_{hourly} * \frac{Wind_{average\_2009}}{Load_{average\_2009}} \tag{5.3}$$

Equation (5.3) can be used to forecast the average hourly ratio of wind power to the load:

$$\frac{Wind_{hourly\_future}}{Load_{hourly\_future}} = ratio_{hourly\_future} * \frac{Wind_{average\_future}}{Load_{average\_future}} \tag{5.4}$$

The forecasted ratio, $ratio_{hourly\_future}$, is the average $ratio_{hourly}$ from the previously collected data (using equal probability density for each year):

$$ratio_{hourly\_future} = \frac{ratio_{hourly\_2007} + ratio_{hourly\_2008} + ratio_{hourly\_2009}}{3} \tag{5.5}$$

The Equation (5.4) may help predict the average hourly ratio of wind power to the load at the monthly, seasonal and annual basis during the two periods of the day.

5.2.4 Objective of the analysis of historical data

The purpose of this data analysis is the long-term planning of the wind farm expansion to reach a specific penetration ratio of wind energy to load by a given year, and to arrive at an estimated average distribution of the wind power throughout the season and month over a 24-hour period. From a given yearly wind penetration target level, the forecasted WTGs capacity is determined and used to forecast the corresponding seasonal and monthly wind penetration during high and low wind-to-load periods. The only known parameter from Equation (5.4) is the average yearly wind farm output, $Wind_{average\_future}$, and load, $Load_{average\_future}$. Unlike the load, the hourly average wind power output cannot be predicted for nine years from now. However, the yearly wind energy generated is proportional to the installed capacity and the capacity factor, which is the ratio of the hourly output of a wind farm to its installed capacity:

$$Wind_{average\_future} = Capacity\_factor * WTGs_{capacity} \qquad (5.6)$$

According to [13], the wind power capacity factor in the US is at the lower end of the standard range of 20-40 %. The ERCOT data reinforce this assumption with a wind power capacity factor ranging from 24 to 30% from 2007-2009. Thus, in forecasting the wind energy to load ratio in the US, a capacity factor ranging from 20 to 30% should be appropriate in curtailing its true value. The calculation of this forecasted ratio is done for both a minimum of 20% and a maximum of 30% to exemplify the worst and the best situations.

5.2.5 Estimating the average of annual, seasonal and monthly forecasted load and wind output

The Yearly average load is the forecasted load for the ERCOT system found on its website [14], while the yearly average wind power output is based on the installed capacity and the capacity factor chosen for the wind farm (20 to 30%). Similar to the probabilistic approach applied in [11], the following expressions below are developed using the wind power or load forecasted hourly average values of the year to estimate the hourly values over a 24-hour period on a seasonal and monthly basis.

- Season

The seasonal ratio, the $S\_Ratio_{houly(i)}$,is the ratio of the average hourly load or wind output of a season to that of its year:

$$S\_Ratio_{hourly(i)} = \frac{Season(i)}{year(i)} \qquad (5.7)$$

Where i is number of the hour (1-24).

The seasonal average hourly load or wind power output is the $Season\_forecast$:

$$Season\_forecast = \frac{\sum_{1}^{j} S\_Ratio_{hourly(i)}}{j} * AYF \qquad (5.8)$$

Where AYF is the average hourly load or wind power for the forecasted year, i is number of the hour (1-24) and j is the number of yearly data available (using an equal weight for each year).

- Month

The monthly ratio, $M\_Ratio_{houly(i)}$, is the ratio of the average hourly load or wind power of the month to that of its season for each hour is:

$$M\_Ratio_{houly(i)} = \frac{Month(i)}{Season(i)} \qquad (5.9)$$

$$Month\_forecast = \frac{\sum_{1}^{j} M\_Ratio_{hourly(i)}}{j} * \frac{\sum_{1}^{j} S\_Ratio_{hourly(i)}}{j} * AYF \qquad (5.10)$$

5.2.6 Validating the probabilistic method by predicting for 2009 using 2007 and 2008 data

This method is validated by accurately predicting the distribution of the wind energy penetration level for the different seasons and months of the year 2009 based on the annual average hourly wind output and load. In the estimation, the high and low wind-to-load hours periods of the day are considered.

To establish the accuracy of this probabilistic method, the true value of the yearly average load and wind output for 2009 are used in addition to historical data from 2007 and 2008 to forecast the wind to load penetration. The average yearly load and wind output for 2009 are the following: 35022 MW, 0.2407*8394.1=2020.5 MW respectively. Using Matlab, the ratio of wind power to load were predicted and compared to the true data in the tables below:

Table 5.1 Comparison of yearly forecast of wind energy to load ratio to the actual value for 2009

Year	Ratio of wind energy to load					
	High wind penetration period			Low wind penetration period		
	Forecasted value	True value	Error (%)	Forecasted value	True	Error (%)
2009	0.0918	0.0899	2.04	0.0504	0.0528	4.57

Table 5.2 Comparison of seasonal forecast of wind energy to load ratio to the actual value for 2009

Season	Ratio of wind energy to load					
	High wind penetration period			Low wind penetration period		
	Forecasted value	True value	Error (%)	Forecasted value	True	Error (%)
Winter	0.0905	0.0963	6.0556	0.0611	0.0643	5.0146
Spring	0.1108	0.1066	3.9465	0.065	0.068	4.4963
Fall	0.0713	0.0677	5.2644	0.0344	0.0326	5.2813
Summer	0.1005	0.0961	4.6556	0.0486	0.0558	12.8053

Table 5.3 Comparison of monthly forecast of wind energy to load ratio to the actual value for 2009

Month	Ratio of wind energy to load					
	High wind penetration period			Low wind penetration period		
	Forecasted value	True value	Error (%)	Forecasted value	True	Error (%)
January	0.0729	0.0882	17.4005	0.0481	0.0586	17.8799
February	0.1043	0.1132	7.854	0.0669	0.0728	8.1091
March	0.1222	0.1119	9.2058	0.0752	0.0771	2.5129
April	0.1238	0.1251	1.0758	0.0748	0.0859	12.9578
May	0.0906	0.0854	6.1158	0.0494	0.0459	7.5744
June	0.0879	0.0778	12.9689	0.0449	0.0402	11.7072
July	0.0632	0.0567	11.4889	0.0278	0.0258	7.9055
August	0.0661	0.0694	4.7359	0.0296	0.0322	8.2506
September	0.073	0.0624	17.0241	0.0292	0.0354	17.3253
October	0.1173	0.1071	9.5059	0.0589	0.0675	12.8368
November	0.1162	0.1246	6.7322	0.0614	0.0693	11.4571
December	0.0966	0.09	7.2909	0.0681	0.0622	9.5082

As these tables above show, the maximum yearly, seasonal and monthly errors in forecasting the wind energy ratio to load during high wind penetration periods are 2.04%, 6.06% and 17.04% respectively, while during low wind penetration periods, they are 4.57%, 12.81% and 17.88% respectively. In most cases these errors are less than 1% of the load demand. These low error percentages indicates that the method proposed here is valid.

5.2.7 Prediction for the year 2019 with a minimum yearly hourly average penetration of 15%

This method was subsequently applied to 2019:

The first step is to determine the wind energy capacity to be installed by 2019 in order to reach the targeted penetration level of 15%:

$$Wind_{penetration\,2019} = \frac{Wind_{Average-hourly-forecast(2019)}}{Load_{Average-hourly-forecast(2019)}} \qquad (5.11)$$

$$Wind_{penetration2019} = \frac{Capacity\_factor_{\min imum(2019)} * Wind_{installed\_capacity(2019)}}{Load_{Average-hourly-forecast(2019)}} \quad (5.12)$$

$$Wind_{installed\_capacity(2019)} = \frac{Load_{Average-hourly-forecast(2019)} * Wind_{penetration2019}}{Capacity\_factor_{\min imum(2019)}} \quad (5.13)$$

$$Wind_{installed\_capacity(2019)} = \frac{43608 * 0.15}{0.20} = 32706MW$$

In the second step, the Matlab simulation was done using the forecasted hourly average load for 2019 as show in Figure 5.18 below and the values at either ends of the capacity factor range, from 20 to 30%, for the minimum and maximum value. The results of the simulation, consisting of the periodic annual, seasonal and monthly distribution for a goal of 15% yearly penetration, are presented in the tables below:

Table 5.4 Yearly forecast of wind energy to load ratio for 2019

Year	Ratio of wind energy to load			
	High wind penetration period		Low wind penetration period	
	Minimum value	Maximum value	Minimum value	Maximum value
2019	0.2357	0.3536	0.1324	0.1986

Table 5.5 Seasonal forecast of wind energy to load ratio for 2019

Season	Ratio of wind energy to load			
	High wind penetration period		Low wind penetration period	
	Minimum value	Maximum value	Minimum value	Maximum value
Winter	0.2389	0.3583	0.1606	0.2409
Spring	0.2912	0.4369	0.1755	0.2633
Fall	0.1834	0.2751	0.0884	0.1326
Summer	0.2464	0.3697	0.1266	0.1899

Table 5.6 Monthly forecast of wind energy to load ratio for 2019

Month	Ratio of wind energy to load			
	High wind penetration period		Low wind penetration period	
	Minimum value	Maximum value	Minimum value	Maximum value
January	0.2081	0.3122	0.1376	0.2065
February	0.2868	0.4303	0.184	0.2761
March	0.3178	0.4766	0.203	0.3045
April	0.3298	0.4947	0.2078	0.3117
May	0.2361	0.3542	0.1281	0.1922
June	0.224	0.3361	0.1148	0.1723
July	0.1588	0.2382	0.0707	0.106
August	0.174	0.261	0.0789	0.1183
September	0.1768	0.2651	0.0793	0.119
October	0.2849	0.4274	0.154	0.2311
November	0.288	0.432	0.1549	0.2323
December	0.2282	0.3424	0.16	0.24

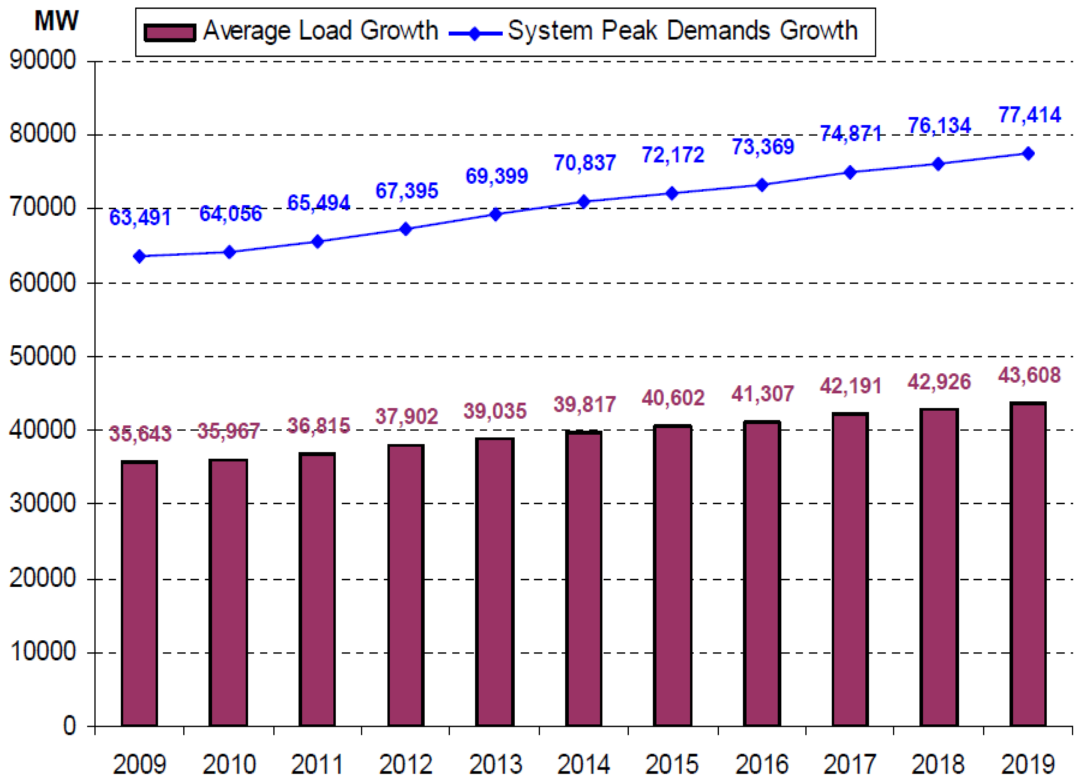


Figure 5.18- ERCOT Forecast Average Load versus System Forecast Growth [14]

5.3 Significance of the proposed method

For the long-term system planning, this method provides the planner an estimation of the average value of the hourly load covered by wind energy on a monthly, seasonal and annual basis. This information may also be used for both the transmission and generation planning since the wind power behaves as a load modifier, so it periodically affects the line power flow and the amount of generation that must be operationally available. For the generation expansion, data collected can be used for the development of both the wind and conventional generation since the wind power behaves as a load modifier, so it periodically affects the amount generation that must be operationally available.

Furthermore, it is observable that the ratio of wind-to-load during period of high wind penetration hours is generally twice the one for low wind penetration hours. Consequently, less generation is needed for covering the load during high wind penetration period as the wind energy implementation keep growing in the US.

5.4 Conclusion

Using the load and wind power historical data from the ERCOT power system, it has been confirmed that the wind tends to be strong during the night and early morning hours, and weak during the day. This pattern is nearly the opposite of the load demand with the exception of a few hours in the early part of the night, which depends on the location. Specific to the ERCOT system, the exception is between 9-11 PM during which both the load demand and wind power generation are usually near their peak values.

Furthermore, for the benefit of system planning, a probabilistic approach estimating the annual, seasonal and monthly distribution of the portion of load demand covered by wind power during periods of high and low wind power penetration of the day was established. This method was validated with the maximum deviation being less than 1.6% of the hourly load demand.

CHAPTER 6

CONCLUSION

The integration of offshore wind energy into the South Carolina power system over a period of 16 years showed that Phase I and II can be implemented at 115 KV with no out-of-limit branch power flow. Using the latest base case power flow available, 2019, Phase III could be successfully completed if only new transmission lines are added. As a result no new transmission lines may be needed to implement Phase III in 2030, assuming an increase in transmission capability from 2019. After Phase II, the contingency analysis on the power system indicated that most of the transmission lines in vicinity of the wind farms interface buses were sensitive since their removal overloaded the network.

The selection of transmission system design for this offshore wind farm project depends on the capacity and the distance of the farm from the coast. An HVAC transmission option requiring an offshore substation is recommended for all three phases of the project based on the assumptions detailed in Table 4.1. If the WTGs for Phase I were located close to the shore, the multiple medium voltage connections are economically more feasible. In addition, if the substation for Phase III was sited extremely far from the shore, a VSC-based HVDC is a better choice than HVAC due to the benefits it offers. A detailed study of this project will provide the cutoff distances for choosing a suitable transmission system.

Finally, the analysis of historical wind power and load demand data confirmed that the wind is strong during the winter and spring, but weak and unpredictable during the summer and fall respectively [12]. It was also corroborated that in general, the wind variation is near the opposite of the load with the exception of few hours, early in the night during which both the wind and the load are high. To predict the portion of load covered by the wind power for the year, seasons and months during periods of high and low wind-to-load ratio, a probabilistic approach was developed based on the forecasted annual average hourly load and a curtail wind energy output. This approach was validated using the true value of the annual average hourly load demand and wind power output for 2009 and the historical data for 2007 and 2008, to estimate the monthly, seasonal and annual wind penetration to load for 2009 with a maximum deviation of less than 1.6% of the hourly load demand.

Future Research

In addition to the steady state analysis of the wind energy impact on the transmission system in Chapter 2 and the contingency analysis in Chapter 3, the following study will be conducted as a part of the South Carolina wind power integration research:

- Voltage stability study
- Transient study
- Short circuit study

APPENDICES

Appendix A

SIMULATION RESULTS FOR PHASE I

(80 MW of offshore wind energy injected into the grid)

Table A.1 Voltage violation after injecting 80 MW into the summer 2010 base case

BUS#	**NAME – BASE KV**	**AREA**	**Case 1**		**Case 2**		**Case 3**		**Case 4**		**Case 5**	
			V(PU)	**V(KV)**	**V(PU)**	**V(KV)**	**V(PU)**	**V(KV)**	**V(PU)**	**V(KV)**	**V(PU)**	**V(KV)**
304892	1BLEW1-3 4.8000	340	0.931	4.469	0.931	4.469	0.931	4.469	0.931	4.469	0.9311	4.469
304893	1BLEW4-6 4.0000	340	1.1093	4.437	1.1093	4.437	1.1093	4.437	1.1093	4.437	1.1093	4.437
306036	LEE CT7 13.800	342	1.0948	15.108	1.0948	15.108	1.0948	15.108	1.0948	15.108	1.0948	15.108
306072	OXFORD 7.2000	342	0.9397	6.766	0.9397	6.766	0.9397	6.766	0.9397	6.766	0.9397	6.766
306081	1TURN HY 2.4000	342	0.9387	2.253	0.9387	2.253	0.9387	2.253	1.0697	534.83	0.9387	2.253
306101	8BAD CRK 500.00	342	1.0697	534.83	1.0697	534.84	1.0697	534.83	1.069	534.5	1.0697	534.84
306102	8JOCASSE 500.00	342	1.069	534.5	1.069	534.51	1.069	534.5	1.0702	535.11	1.069	534.51
306103	8MCGUIRE 500.00	342	1.0702	535.11	1.0703	535.13	1.0702	535.12			1.0703	535.13
306105	8OCONEE 500.00	342	1.0652	532.58	1.0652	532.59	1.0652	532.58	1.0652	532.58	1.0652	532.59
306168	1TIGER 44.000	342	1.0676	46.974	1.0676	46.974	1.0676	46.974	1.0676	46.974	1.0676	46.974
306177	8WOODLF 500.00	342	1.0708	535.42	1.0709	535.44	1.0709	535.43	1.0709	535.43	1.0709	535.45
306180	4DAN RIV 138.00	342	1.0851	149.74	1.0851	149.74	1.0851	149.74	1.0851	149.74	1.0851	149.74
306181	3BUSH Y 115.00	342	1.0738	123.49	1.0738	123.49	1.0738	123.49	1.0738	123.49	1.0738	123.49

306182	3BUSH R 115.00	342	1.0676	122.78	1.0676	122.78	1.0676	122.78	1.0676	122.78	1.0676	122.78
306195	ANDERSON 100.00	342	1.0639	106.39	1.0639	106.39	1.0639	106.39	1.0639	106.39	1.0639	106.39
306363	ANDER 1 1.0000	342	1.0656	1.066	1.0656	1.066	1.0656	1.066	1.0656	1.066	1.0656	1.066
306411	PISGA 2 1.0000	342	1.0665	1.067	1.0665	1.067	1.0665	1.067	1.0665	1.067	1.0665	1.067
306462	LEE CT8 13.800	342	1.0948	15.108	1.0948	15.108	1.0948	15.108	1.0948	15.108	1.0948	15.108

Table A.2 Branch loaded over 95% after injecting 80 MW into the summer 2010 base case

						Case 1	**Case 2**	**Case 3**	**Case 4**	**Case 5**
BUS#	**NAME – BASE KV**	**AREA**	**BUS#**	**NAME – BASE KV**	**RATING (MVA)**	**PERC**	**PERC**	**PERC**	**PERC**	**PERC**
306063	JOCASSE3 14.400*	342	306132	6JOCASSE 230	215	98.6	98.6	98.6	98.6	98.6
306064	JOCASSE4 14.400*	342	306132	6JOCASSE 230	215	98.5	98.5	98.5	98.5	98.5
306084	5NANTAHA 161.00	342	306175	1NANTAHA 13.200*	27	96.2	96.2	96.2	96.2	96.2
306084	5NANTAHA 161.00	342	306175	1NANTAHA 13.200*	27	96.2	96.2	96.2	96.2	96.2
311451	1CROSS2 22.000*	344	312710	6CROSS 230	584	99.3	99.3	99.3	99.3	99.3

Table A.3 Voltage violation after injecting 80 MW into the summer 2014 base case

BUS#	NAME – BASE KV	AREA	Case 1		Case 2		Case 3		Case 4		Case 5	
			V(PU)	V(KV)	V(PU)	V(KV)	V(PU)	V(KV)	V(PU)	V(KV)	V(PU)	V(KV)
306036	LEE CT7 13.800	342	1.0891	15.03	1.089	15	1.089	15	1.0891	15.03	1.089	15.03
306072	OXFORD 7.2000	342	0.9342	6.727	0.934	6.73	0.934	6.73	0.9343	6.727	0.934	6.727
306079	1RHODHIS 7.2000	342	0.9352	6.733	0.935	6.73	0.935	6.73	0.9352	6.733	0.935	6.734
306081	1TURN HY 2.4000	342	0.9271	2.225	0.927	2.23	0.927	2.23	0.9271	2.225	0.927	2.225
306101	8BAD CRK 500.00	342	1.0681	534.05	1.068	534	1.068	534	1.0681	534.1	1.068	534.06
306103	8MCGUIRE 500.00	342	1.065	532.52	1.065	533	1.065	533	1.065	532.5	1.065	532.54
306105	8OCONEE 500.00	342	1.064	532	1.064	532	1.064	532	1.064	532	1.064	532
306168	1TIGER 44.000	342	1.0613	46.698	1.061	46.7	1.061	46.7	1.0613	46.7	1.061	46.699
306177	8WOODLF 500.00	342	1.0648	532.41	1.065	532	1.065	532	1.0648	532.4	1.065	532.44
306180	4DAN RIV 138.00	342	1.0993	151.71	1.099	152	1.099	152	1.0993	151.7	1.099	151.71
306181	3BUSH Y 115.00	342	1.0702	123.08	1.07	123	1.07	123	1.0702	123.1	1.07	123.08
306182	3BUSH R 115.00	342	1.0644	122.41	1.064	122	1.064	122	1.0644	122.4	1.064	122.41
306195	ANDERSON 100.00	342	1.0605	106.05	1.061	106	1.061	106	1.0605	106.1	1.061	106.05
306363	ANDER 1 1.0000	342	1.0625	1.062	1.063	1.06	1.063	1.06	1.0625	1.062	1.063	1.062
306461	CLFSDTAP 500.00	342	1.0668	533.42	1.067	533	1.067	533	1.0668	533.4	1.067	533.44
306462	LEE CT8 13.800	342	1.0891	15.03	1.089	15	1.089	15	1.0891	15.03	1.089	15.03

311452	1WINY2 21.000	344	1.0625	22.313	1.062	22.3	1.063	22.3	1.0625	22.31	1.061	22.29
311453	1WINY3 21.000	344	1.0612	22.285	1.06	22.3	1.061	22.3	1.0612	22.29	1.06	22.262
311454	1WINY4 21.000	344	1.0606	22.272	0.935	12.9	1.063	22.3	1.0615	22.29		
311465	13HHGT3 13.800	344	0.9357	12.913			0.936	12.9	0.9357	12.91	0.935	12.903
311478	1WINY1 21.000	344	1.0677	22.421	1.068	22.4	1.076	22.6	1.0704	22.48	1.068	22.433
312764	3DUNES 115.00	344	0.9394	108.03			0.938	108				
312811	3NIX XRD 115.00	344	0.935	107.53			0.934	107	0.9358	107.6		

Table A.4 Branch loaded over 95% injecting 80 MW into the summer 2014 base case

BUS#	NAME – BASE KV	AREA	BUS#	NAME – BASE KV	AREA	RATING (MVA)	Case 1 PERC	Case 2 PERC	Case 3 PERC	Case 4 PERC	Case 5 PERC
306061	JOCASSE1 14.400*	342	306132	6JOCASSE 230.00	342	215	99.3	99.3	99.3	99.3	99.3
306062	JOCASSE2 14.400*	342	306132	6JOCASSE 230.00	342	215	99.9	99.9	99.9	99.9	99.9
306063	JOCASSE3 14.400*	342	306132	6JOCASSE 230.00	342	215	99.3	99.3	99.3	99.3	99.3
306064	JOCASSE4 14.400*	342	306132	6JOCASSE 230.00	342	215	99.2	99.2	99.2	99.2	99.2
306084	5NANTAHA 161.00	342	306175	1NANTAHA 13.200*	342	27	96.2	96.2	96.2	96.2	96.2
306084	5NANTAHA 161.00	342	306175	1NANTAHA 13.200*	342	27	96.2	96.2	96.2	96.2	96.2
370406	6CANADYS 230.00	343	370884	1CAN UN1 13.800*	343	160	96.9	96.9	96.9	96.9	96.9
370407	6YEMASSE 230.00	343	370886	1YEM UN2 13.800*	343	160	96.9	96.9	96.9	96.9	96.9
311451	1CROSS2 22.000*	344	312710	6CROSS 230.00	344	584	99.6	99.5	99.6	99.6	99.5
311463	13GRAIN1 13.200*	344	312775	3GRAINGR 115.00	344	584		97.3	97.3	97.3	97.3
311464	13GRAIN2 13.200*	344	312775	3GRAINGR 115.00	344	93		97.3	97.3	97.3	97.3

Table A.5 Voltage violation after injecting 80 MW into the summer 2019 base case

BUS#	NAME – BASE KV	AREA	Case 1		Case 2		Case 3		Case 4		Case 5	
			V(PU)	V(KV)	V(PU)	V(KV)	V(PU)	V(KV)	V(PU)	V(KV)	V(PU)	V(KV)
304881	1CAPE #2 12.000	340	0.9384	11.26	0.938	11.261	0.9384	11.261	0.9384	11.261	0.9384	11.261
304892	1BLEW1-3 4.8000	340	0.9334	4.48	0.933	4.48	0.9334	4.48	0.9334	4.48	0.9334	4.48
304893	1BLEW4-6 4.0000	340	1.1122	4.449	1.112	4.449	1.1122	4.449	1.1122	4.449	1.1122	4.449
304914	1LEE#3SU 4.1600	340	1.0774	4.482	1.077	4.482	1.0774	4.482	1.0774	4.482	1.0774	4.482
306036	LEE CT7 13.800	342	1.0818	14.929	1.082	14.929	1.0819	14.93	1.0819	14.93	1.0818	14.929
306070	FISHNG C 6.6000	342	1.0706	7.066	1.071	7.066	1.0706	7.066	1.0706	7.066	1.0706	7.066
306081	1TURN HY 2.4000	342	0.9172	2.201	0.917	2.201	0.9172	2.201	0.9172	2.201	0.9172	2.201
306101	8BAD CRK 500.00	342	1.0698	534.9	1.07	534.91	1.0698	534.9	1.0698	534.9	1.0698	534.91
306102	8JOCASSE 500.00	342	1.0692	534.59	1.069	534.59	1.0692	534.59	1.0692	534.59	1.0692	534.59
306103	8MCGUIRE 500.00	342	1.0603	530.14	1.06	530.16	1.0603	530.15	1.0603	530.15	1.0603	530.16
306105	8OCONEE 500.00	342	1.0708	535.4	1.071	535.4	1.0708	535.4	1.0708	535.4	1.0708	535.4
306180	4DAN RIV 138.00	342	1.111	153.32	1.111	153.32	1.111	153.32	1.111	153.32	1.111	153.32
306181	3BUSH Y 115.00	342	1.0645	122.42	1.065	122.42	1.0645	122.42	1.0645	122.42	1.0645	122.42
306325	WATEREE 100.00	342	1.0633	106.33	1.063	106.33	1.0633	106.33	1.0633	106.33	1.0633	106.33
306349	1GTFALL2 44.000	342	1.0646	46.844	1.065	46.845	1.0646	46.844	1.0646	46.844	1.0647	46.845
306461	CLFSDTAP 500.00	342	1.0647	532.35	1.065	532.36	1.0647	532.36	1.0647	532.36	1.0647	532.36

306462	LEE CT8 13.800	342	1.0818	14.93	1.082	14.929	1.0819	14.93	1.0819	14.93	1.0818	14.929
311465	13HHGT3 13.800	344	0.9103	12.562	0.909	12.546	0.9102	12.561	0.9103	12.561	0.9091	12.546
312797	3LG COV 115.00	344	0.9392	108.01	0.938	107.88	0.9392	108	0.9392	108.01	0.938	107.88
312803	3MARKET 115.00	344	0.9361	107.65	0.935	107.52	0.9361	107.65	0.9361	107.65	0.935	107.52
312836	3SURFSD 115.00	344	0.9371	107.77	0.939	108.02	0.935	107.52	0.9366	107.71	0.9392	108
312861	3CAROPN 115.00	344	0.9393	108.02			0.9368	107.73	0.9382	107.9		
370855	1SALUDA5 13.200	343	0.9362	12.357	0.936	12.357	0.9362	12.357	0.9362	12.357	0.9362	12.357

Table A.6 Branch loaded over 95% after injecting 80 MW into the summer 2019 base case

BUS#	NAME –BASE KV	AREA	BUS#	NAME –BASE KV	AREA	RAT	Case 1 PERC	Case 2 PERC	Case 3 PERC	Case 4 PERC	Case 5 PERC
306061	JOCASSE1 14.400*	342	306132	6JOCASSE 230.00	342	215	99.5	99.5	99.5	99.5	99.5
306062	JOCASSE2 14.400*	342	306132	6JOCASSE 230.00	342	215	99.9	99.9	99.9	99.9	99.9
306063	JOCASSE3 14.400*	342	306132	6JOCASSE 230.00	342	215	99.5	99.5	99.5	99.5	99.5
306064	JOCASSE4 14.400*	342	306132	6JOCASSE 230.00	342	215	99.4	99.4	99.4	99.4	99.4
306084	5NANTAHA 161.00	342	306175	1NANTAHA 13.200*	342	27	96.2	96.2	96.2	96.2	96.2
306084	5NANTAHA 161.00	342	306175	1NANTAHA 13.200*	342	27	96.2	96.2	96.2	96.2	96.2
306141	6MORN ST 230.00*	342	306144	6NEWPORT 230.00	342	436.9	97.6	97.6	97.6	97.6	97.6
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	102.7	96.1	96.1	96.1	96.1	96.1
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	102.7	96.3	96.3	96.3	96.3	96.3
311322	3ARCADI 115.00	344	311618	3PRKRSVL 115.00*	344	179	97.5				
311380	3ECONW T 115.00*	344	312775	3GRAINGR 115.00	344	142			98.2	99	96.4
311451	1CROSS2 22.000*	344	312710	6CROSS 230.00	344	584	99.8	99.8	99.8	99.8	99.8
312747	3BLUFFTN 115.00	344	312863	3BUCKIN 115.00*	344	179		95.7			95.7

<u>Appendix B</u>

SIMULATION RESULTS PHASE II

(1080 MW of offshore wind energy injected into the grid)

Table B.1 Voltage violation after evenly injection 500+40 MW each of the two wind farm (115 KV)

Bus information				**Original case**	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**
Bus#	**Bus name**	**Area**	**Nominal KV**	**V (PU)**	**V (PU)**	**V (PU)**	**V (PU)**	**V (PU)**	**V (PU)**
304880	1CAPE #1	CPLE	12.00	0.94	0.94	0.94	0.94	0.94	0.94
304881	1CAPE #2	CPLE	12.00	0.94	0.94	0.94	0.94	0.94	0.94
304892	1BLEW1-3	CPLE	4.80	0.93	0.93	0.93	0.93	0.93	0.93
306081	1TURN HY	DUKE	2.40	0.92	0.92	0.92	0.92	0.92	0.92
311465	13HHGT3	SCPSA	13.80	0.91	0.91	0.91	0.91	0.91	0.91
312797	3LG COV	SCPSA	115.00	0.94	N/A	N/A	N/A	N/A	N/A
312803	3MARKET	SCPSA	115.00	0.94	0.94	0.94	0.94	0.94	0.94
312836	3SURFSD	SCPSA	115.00	0.94	N/A	N/A	N/A	0.94	N/A
312861	3CAROPN	SCPSA	115.00	0.94	N/A	N/A	N/A	0.94	N/A
370855	1SALUDA5	SCEG	13.20	0.94	0.94	0.94	0.94	0.94	0.94
304893	1BLEW4-6	CPLE	4.00	1.11	1.11	1.11	1.11	1.11	1.11
304914	1LEE#3SU	CPLE	4.16	1.08	1.08	1.08	1.08	1.08	1.08
306036	LEE CT7	DUKE	13.80	1.08	1.08	1.08	1.08	1.08	1.08
306070	FISHNG C	DUKE	6.60	1.07	1.07	1.07	1.07	1.07	1.07
306101	8BAD CRK	DUKE	500.00	1.07	1.07	1.07	1.07	1.07	1.07
306102	8JOCASSE	DUKE	500.00	1.07	1.07	1.07	1.07	1.07	1.07
306103	8MCGUIRE	DUKE	500.00	1.06	1.06	1.06	1.06	1.06	1.06
306105	8OCONEE	DUKE	500.00	1.07	1.07	1.07	1.07	1.07	1.07
306180	4DAN RIV	DUKE	138.00	1.11	1.11	1.11	1.11	1.11	1.11
306181	3BUSH Y	DUKE	115.00	1.06	1.06	1.06	1.06	1.06	1.06
306325	WATEREE	DUKE	100.00	1.06	1.06	1.06	1.06	1.06	1.06
306349	1GTFALL2	DUKE	44.00	1.06	1.06	1.06	1.06	1.06	1.06
306461	CLFSDTAP	DUKE	500.00	1.06	1.06	1.06	1.06	1.06	1.06
306462	LEE CT8	DUKE	13.80	1.08	1.08	1.08	1.08	1.08	1.08
311478	1WINY1	SCPSA	21	1.07	N/A	N/A	N/A	N/A	N/A

In Table 2, the yellow color indicates the transmission lines loaded over 100% percent their ratings A:

Table B.2 Branch power flow after evenly injection 500 + 40MW each of the two wind farm (115 KV)

Branch information							Percent of branch MVA Limit (%)					
							Before Mitigation					Mitigated
From #	**From Name**	**To Name**	**To #**	**CKT #**	**Branch Type**	**MVA Limit**	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 3**
304615	6BARNARD	3BARNRD	304616	1	Transformer	150	94.75	94.75	94.75	94.75	94.75	94.75
306132	6JOCASSE	JOCASSE1	306061	1	Transformer	215	95.58	95.58	95.58	95.58	95.58	95.58
306132	6JOCASSE	JOCASSE2	306062	2	Transformer	215	96.68	96.68	96.68	96.68	96.68	96.68
306132	6JOCASSE	JOCASSE3	306063	3	Transformer	215	95.57	95.57	95.57	95.58	95.57	95.57
306132	6JOCASSE	JOCASSE4	306064	4	Transformer	215	95.49	95.49	95.49	95.49	95.49	95.49
306084	5NANTAHA	1NANTAHA	306175	1	Transformer	27	94.69	94.69	94.69	94.69	94.69	94.69
306084	5NANTAHA	1NANTAHA	306175	2	Transformer	27	94.69	94.69	94.69	94.69	94.69	94.69
306165	CHEROKEE	GAFFNEY	306240	1	Line	120	97.78	97.78	97.78	97.81	97.79	97.77
306208	BUSH RIV	NEWBERRY	306288	1	Line	87	94.25	94.28	94.25	94.39	94.36	94.24
306261	LAKEWOOD	RIVERBEN	306305	1	Line	103	95.56	95.56	95.56	95.56	95.56	95.56
306261	LAKEWOOD	RIVERBEN	306305	2	Line	103	95.76	95.76	95.76	95.75	95.76	95.76
306289	NEWPORT	WYLIE HY	306333	1	Line	197	97.50	97.50	97.49	97.52	97.51	97.49
306289	NEWPORT	WYLIE HY	306333	2	Line	197	97.36	97.36	97.36	97.39	97.37	97.36
306539	6RIVERVW	6BRECBL2	306564	2	Line	557	94.03	94.03	94.03	94.03	94.03	94.03
306574	FNEWPTG1	FNEWPORT	306573	1	Transformer	220	94.24	94.24	94.24	94.26	94.25	94.24

306575	FNEWPTG2	FNEWPORT	306573	2	Transformer	220	94.24	94.24	94.24	94.26	94.25	94.24
311213	33VCH T	3GTWN S	312770	1	Line	239	97.71	97.21	97.00	N/A	N/A	97.01
311213	33VCH T	3WINYAH	312845	1	Line	239	100.68	100.17	99.95	N/A	95.65	99.96
311303	3WINDYH	3CRCNTB	312760	1	Line	120	146.03	N/A	N/A	N/A	N/A	N/A
311307	3GLENNS	3BURGS T	311539	1	Line	179	N/A	N/A	N/A	N/A	97.71	N/A
311307	3GLENNS	3GRDN C	312766	1	Line	179	N/A	N/A	N/A	N/A	113.97	N/A
311322	3ARCADI	3PRKRSVL	311618	1	Line	179	N/A	N/A	N/A	140.34	N/A	N/A
311322	3ARCADI	3MURREL	312806	99	Line	179	N/A	N/A	N/A	121.33	N/A	N/A
311329	3STJAME	3LITCHF	312796	1	Line	179	N/A	N/A	N/A	108.85	N/A	N/A
311380	3ECONW T	3GRAINGR	312775	1	Line	142	N/A	N/A	N/A	96.11	N/A	N/A
311402	3SPYB2 T	3MYRT BC	312807	1	Line	179	N/A	N/A	97.25	N/A	N/A	97.17
311402	3SPYB2 T	3OIL PL	312815	1	Line	179	N/A	N/A	97.25	N/A	N/A	97.17
312710	6CROSS	1CROSS2	311451	1	Transformer	584	97.76	97.75	97.73	97.85	97.75	97.74
311618	3PRKRSVL	3LITCHF	312796	1	Line	179	N/A	N/A	N/A	127.60	N/A	N/A
311696	3BEACHWOOD	3CRCNTB	312760	1	Line	120	177.87	N/A	N/A	N/A	N/A	N/A
311696	3BEACHWOOD	3NIX XRD	312811	1	Line	120	186.18	N/A	N/A	N/A	N/A	N/A
312752	3CHSTNT	3DUNES	312764	1	Line	179	N/A	105.09	N/A	N/A	N/A	N/A
312766	3GRDN C	3MURREL	312806	1	Line	179	N/A	N/A	N/A	103.71	N/A	N/A
312766	3GRDN C	3CAROPN	312861	1	Line	179	N/A	N/A	N/A	N/A	152.43	N/A
312770	3GTWN S	3WINYAH	312845	1	Line	239	98.03	97.57	97.38	N/A	N/A	97.40
312799	3WDL P T	3RACEPT	312824	1	Line	179	N/A	N/A	95.18	N/A	N/A	N/A
312807	3MYRT BC	3RACEPT	312824	1	Line	179	N/A	N/A	100.16	N/A	N/A	95.82
312836	3SURFSD	3CAROPN	312861	1	Line	179	N/A	N/A	N/A	N/A	120.85	N/A

Table B.3 Voltage violation after unevenly injection 1080 MW at the two wind farm (115 KV)

BUS#	NAME – BASE KV	AREA	Base case V(PU)	Case 1 V(PU)	Case 2 V(PU)	Case 3 V(PU)	Case 4 V(PU)	Case 5 V(PU)
304880	1CAPE #1 12.000	340	0.9384	0.939	0.939	0.939	0.9388	0.939
304881	1CAPE #2 12.000	340	0.9384	0.939	0.939	0.939	0.9388	0.939
304892	1BLEW1-3 4.8000	340	0.9334	0.9338	0.9338	0.9338	0.9335	0.9338
304893	1BLEW4-6 4.0000	340	1.1122	1.1127	1.1127	1.1126	1.1124	1.1127
304914	1LEE#3SU 4.1600	340	1.0774	1.0776	1.0776	1.0776	1.0775	1.0776
306036	LEE CT7 13.800	342	1.0819	1.0817	1.0817	1.0817	1.0817	1.0817
306070	FISHNG C 6.6000	342	1.0706	1.0718	1.0718	1.0718	1.0717	1.0718
306081	1TURN HY 2.4000	342	0.9172	0.918	0.918	0.9181	0.918	0.918
306101	8BAD CRK 500.00	342	1.0698	1.0699	1.0699	1.0699	1.0699	1.0699
306102	8JOCASSE 500.00	342	1.0692	1.0693	1.0693	1.0693	1.0693	1.0693
306103	8MCGUIRE	342	1.0603	1.0615	1.0615	1.0615	1.0614	1.0615
306105	8OCONEE 500.00	342	1.0708	1.0709	1.0709	1.0709	1.0709	1.0709
306180	4DAN RIV 138.00	342	1.111	1.1116	1.1116	1.1117	1.1116	1.1116
306181	3BUSH Y 115.00	342	1.0645	1.0628	1.0628	1.0627	1.0628	1.0628
306325	WATEREE 100.00	342	1.0633	1.064	1.064	1.0641	1.064	1.064
306349	1GTFALL2 44.000	342	1.0646	1.0653	1.0653	1.0653	1.0652	1.0653
306461	CLFSDTAP 500.00	342	1.0647	1.0654	1.0654	1.0654	1.0653	1.0654
306462	LEE CT8 13.800	342	1.0819	1.0817	1.0817	1.0817	1.0817	1.0817
311465	13HHGT3 13.800	344	0.9102	0.9116	0.9116	0.9117	0.9116	0.9116
312803	3MARKET 115.00	344	1.0681	0.9376	0.9376	0.9376	0.9376	0.9376
370855	1SALUDA5 13.200	343	0.9361	0.936	0.936	0.936	0.936	0.936
311478	1WINY1 21.000	344	1.0681					
312797	3LG COV 115.00	344	0.9392					
312836	3SURFSD 115.00	344	0.935					
312861	3CAROPN 115.00	344	0.9368					

Table B.4 Branch loading condition after unevenly injection 1080 MW at the two wind farm (115 KV)

BUS#	NAME – BASE KV	AREA	BUS#	NAME – BASE KV	AREA	RATING	Base Case	case 1	case 2	case 3	case 4	case 5
							PERC	PERC	PERC	PERC	PERC	PERC
306141	6MORN ST 230.00*	342	306144	6NEWPORT 230.00	342	436.9		95.9	96	95.8	96	96
306165	CHEROKEE 100.00	342	306240	GAFFNEY 100.00*	342	120		95.6	95.6	95.7	95.6	95.6
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	102.7		95.5	95.5	95.5	95.5	95.5
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	102.7		95.7	95.7	95.7	95.7	95.7
311213	33VCH T 115.00	344	312770	3GTWN S 115.00	344	239			96.2	97.1		
311213	33VCH T 115.00*	344	312845	3WINYAH 115.00	344	239			99	99.9		
311322	3ARCADI 115.00	344	311618	3PRKRSVL 115.00*	344	179					138.3	
311322	3ARCADI 115.00*	344	312806	3MURREL 115.00	344	179					119.5	
311329	3STJAME 115.00*	344	312796	3LITCHF 115.00	344	179					113	
311303	3WINDYH 115.00*	344	312760	3CRCNTB 115.00	344	120		149.2				
311307	3GLENNS 115.00	344	311539	3BURGS T 115.00	344	179						96.5
311307	3GLENNS 115.00*	344	312766	3GRDN C 115.00	344	179						112.8
311380	3ECONW T 115.00*	344	312775	3GRAINGR 115.00	344	142	98.2				95	
311402	3SPYB2 T 115.00*	344	312807	3MYRT BC 115.00	344	179	99.8			95.4		
311402	3SPYB2 T 115.00	344	312815	3OIL PL 115.00*	344	179				95.4		
311618	3PRKRSVL 115.00	344	312796	3LITCHF 115.00*	344	179					128.5	

311696	3BEACHW OOD 115.00	344	312760	3CRCNTB 115.00*	344	120		180.5				
311696	3BEACHW OOD 115.00*	344	312811	3NIX XRD 115.00	344	120		188.7				
312752	3CHSTNT 115.00*	344	312764	3DUNES 115.00	344	120			99.7			
312766	3GRDN C 115.00*	344	312806	3MURREL 115.00	344	179					107.9	150.8
312770	3GTWN S 115.00*	344	312845	3WINYAH 115.00	344	239			97.4	98.3		
312799	3WDL P T 115.00*	344	312824	3RACEPT 115.00	344	179				96.8		
312807	3MYRT BC 115.00	344	312824	3RACEPT 115.00*	344	179				99.6		
312836	3SURFSD 115.00*	344	312861	3CAROPN 115.00	344	179						121.8

Table B.5 Voltage violation for the case of the three 115 KV interface buses

BUS#	NAME – BASE KV	AREA	V(PU)	V(KV)
304880	1CAPE #1 12.000	340	0.939	11.268
304881	1CAPE #2 12.000	340	0.939	11.268
304892	1BLEW1-3 4.8000	340	0.9338	4.482
304893	1BLEW4-6 4.0000	340	1.1127	4.451
304914	1LEE#3SU 4.1600	340	1.0777	4.483
306036	LEE CT7 13.800	342	1.0817	14.928
306070	FISHNG C 6.6000	342	1.0718	7.074
306081	1TURN HY 2.4000	342	0.918	2.203
306101	8BAD CRK 500.00	342	1.0699	534.94
306102	8JOCASSE 500.00	342	1.0693	534.64
306103	8MCGUIRE 500.00	342	1.0615	530.75
306105	8OCONEE 500.00	342	1.0709	535.46
306180	4DAN RIV 138.00	342	1.1116	153.41
306181	3BUSH Y 115.00	342	1.0628	122.22
306325	WATEREE 100.00	342	1.064	106.4
306349	1GTFALL2 44.000	342	1.0653	46.873
306461	CLFSDTAP 500.00	342	1.0654	532.68
306462	LEE CT8 13.800	342	1.0817	14.928
311465	13HHGT3 13.800	344	0.9116	12.581
312803	3MARKET 115.00	344	0.9376	107.82
370855	1SALUDA5 13.200	343	0.936	12.355

Table B.6 Branches loaded above 95% of their rating for the case of the three 115 KV interface buses

BUS#	NAME – BASE KV	AREA	BUS#	NAME – BASE KV	AREA	CKT	LOADING	RATING	PERCENT
306165	CHEROKEE 100.00	342	306240	GAFFNEY 100.00*	342	1	114.7	120	95.6
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	1	98.1	102.7	95.5
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	2	98.3	102.7	95.7

Table B.7 Voltage violation when a case of 230KV buses is used as interface buses (bus# 312717 and 312719)

BUS#	NAME - BASE KV	AREA	V(PU)	V(KV)
304880	1CAPE #1 12.000	340	0.9385	11.262
304881	1CAPE #2 12.000	340	0.9385	11.262
304892	1BLEW1-3 4.8000	340	0.9333	4.48
304893	1BLEW4-6 4.0000	340	1.1121	4.448
304914	1LEE#3SU 4.1600	340	1.0774	4.482
306036	LEE CT7 13.800	342	1.0813	14.922
306070	FISHNG C 6.6000	342	1.0711	7.069
306081	1TURN HY 2.4000	342	0.9164	2.199
306101	8BAD CRK 500.00	342	1.0698	534.92
306102	8JOCASSE 500.00	342	1.0692	534.61
306103	8MCGUIRE 500.00	342	1.0613	530.64
306105	8OCONEE 500.00	342	1.0709	535.43
306180	4DAN RIV 138.00	342	1.1116	153.4
306181	3BUSH Y 115.00	342	1.0618	122.11
306325	WATEREE 100.00	342	1.0636	106.36
306349	1GTFALL2 44.000	342	1.065	46.858
306461	CLFSDTAP 500.00	342	1.0653	532.67
306462	LEE CT8 13.800	342	1.0813	14.922
311465	13HHGT3 13.800	344	0.9079	12.529
311478	1WINY1 21.000	344	1.0707	22.484
312797	3LG COV 115.00	344	0.9369	107.74
312803	3MARKET 115.00	344	0.9339	107.4
370855	1SALUDA5 13.200	343	0.9361	12.356

Table B.8 Branches loaded above 95% of their rating when a case of 230KV buses is used as interface buses (bus# 312717 and 312719)

BUS#	NAME – BASE KV	AREA	BUS#	NAME - BASE KV	AREA	CKT	LOADING	RATING	PERCENT
306141	6MORN ST 230.00*	342	306144	6NEWPORT 230.00	342	1	419.1	436.9	95.9
306165	CHEROKEE 100.00	342	306240	GAFFNEY 100.00*	342	1	115.1	120	95.9
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	1	98.2	102.7	95.6
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	342	2	98.4	102.7	95.8
312747	3BLUFFTN 115.00	344	312863	3BUCKIN 115.00*	344	1	174.9	179	97.7

Appendix C

SIMULATION RESULTS FOR PHASE III

(3080 MW of offshore wind energy injected into the grid)

Table C.1 The voltage violation at maximum injection when using two 115 KV buses

BUS#	NAME – BASE KV	AREA	V(PU)	V(KV)
311465	13HHGT3 13.800	344	0.9116	12.58
306081	1TURN HY 2.4000	342	0.9163	2.199
304892	1BLEW1-3 4.8000	340	0.9338	4.482
370855	1SALUDA5 13.200	343	0.9361	12.356
312803	3MARKET 115.00	344	0.9375	107.82
304880	1CAPE #1 12.000	340	0.939	11.269
304881	1CAPE #2 12.000	340	0.939	11.269
306103	8MCGUIRE 500.00	342	1.0613	530.66
306181	3BUSH Y 115.00	342	1.0621	122.14
306325	WATEREE 100.00	342	1.0636	106.36
306349	1GTFALL2 44.000	342	1.065	46.859
306461	CLFSDTAP 500.00	342	1.0653	532.66
306102	8JOCASSE 500.00	342	1.0691	534.57
306101	8BAD CRK 500.00	342	1.0698	534.89
306105	8OCONEE 500.00	342	1.0708	535.38
306070	FISHNG C 6.6000	342	1.0711	7.07
304914	1LEE#3SU 4.1600	340	1.0777	4.483
306036	LEE CT7 13.800	342	1.08	14.905
306462	LEE CT8 13.800	342	1.08	14.905
306180	4DAN RIV 138.00	342	1.1116	153.41
304893	1BLEW4-6 4.0000	340	1.1127	4.451

Table C.2 The lines power flow at maximum injection when using two 115 KV buses

BUS#	NAME – BASE KV	AREA	BUS#	NAME – BASE KV	CKT	RATING (MVA)	PERC (%)
306165	CHEROKEE 100.00	342	306240	GAFFNEY 100.00*	1	120	95.8
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	1	102.7	95.6
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	2	102.7	95.8
311213	33VCH T 115.00*	344	312845	3WINYAH 115.00	1	239	95.9
312752	3CHSTNT 115.00*	344	312764	3DUNES 115.00	1	179	98.1

Table C.3 The voltage violations at maximum injection when using two 230 KV buses

BUS#	NAME – BASE KV	AREA	V(PU)	V(KV)
311465	13HHGT3 13.800	344	0.91	12.585
306081	1TURN HY 2.4000	342	0.91	2.191
304892	1BLEW1-3 4.8000	340	0.93	4.472
304880	1CAPE #1 12.000	340	0.94	11.247
304881	1CAPE #2 12.000	340	0.94	11.247
312803	3MARKET 115.00	344	0.94	107.86
306359	1TURNER 44.000	342	0.94	41.308
306103	8MCGUIRE 500.00	342	1.06	530.51
311451	1CROSS2 22.000	344	1.06	23.359
306325	WATEREE 100.00	342	1.06	106.33
306349	1GTFALL2 44.000	342	1.06	46.846
306461	CLFSDTAP 500.00	342	1.06	532.46
306102	8JOCASSE 500.00	342	1.07	534.23
306036	LEE CT7 13.800	342	1.07	14.752
306462	LEE CT8 13.800	342	1.07	14.752
306101	8BAD CRK 500.00	342	1.07	534.62
306105	8OCONEE 500.00	342	1.07	535.03
306070	FISHNG C 6.6000	342	1.07	7.066
311478	1WINY1 21.000	344	1.07	22.522
304914	1LEE#3SU 4.1600	340	1.08	4.479
304893	1BLEW4-6 4.0000	340	1.11	4.44
306180	4DAN RIV 138.00	342	1.11	153.41

Table C.4 The lines power flow at maximum injection when using two 230 KV buses

BUS #	**NAME – BASE KV**	**AREA**	**BUS#**	**NAME – BASE KV**	**CKT**	**RATING (MVA)**	**PERC (%)**
306165	CHEROKEE 100.00*	342	306240	GAFFNEY 100.00	1	120	97.8
306208	BUSH RIV 100.00	342	306288	NEWBERRY 100.00*	1	86.6	100
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	1	102.7	95.2
306261	LAKEWOOD 100.00*	342	306305	RIVERBEN 100.00	2	102.7	95.4
306326	WESTFORK 100.00*	342	306330	WINECOFF 100.00	1	126.4	95.2
306326	WESTFORK 100.00*	342	306330	WINECOFF 100.00	2	126.4	95
312819	3PERRY R 115.00	344	312866	3S PRONG 115.00*	1	179	98.6

Table C.5 The voltage violation at maximum injection (2361.6 MW) into two 230KV

BUS#	NAME – BASE KV	AREA	V(PU)	V(KV)
311465	13HHGT3 13.800	344	0.912	12.585
306081	1TURN HY 2.4000	342	0.9146	2.195
304892	1BLEW1-3 4.8000	340	0.9319	4.473
304880	1CAPE #1 12.000	340	0.9376	11.251
304881	1CAPE #2 12.000	340	0.9376	11.251
312803	3MARKET 115.00	344	0.9379	107.86
306103	8MCGUIRE 500.00	342	1.0609	530.46
311451	1CROSS2 22.000	344	1.062	23.363
306325	WATEREE 100.00	342	1.0633	106.33
306349	1GTFALL2 44.000	342	1.0647	46.846
306461	CLFSDTAP 500.00	342	1.0649	532.44
306102	8JOCASSE 500.00	342	1.0688	534.4
306101	8BAD CRK 500.00	342	1.0695	534.75
306105	8OCONEE 500.00	342	1.0704	535.22
306070	FISHNG C 6.6000	342	1.0706	7.066
311478	1WINY1 21.000	344	1.0708	22.487
304914	1LEE#3SU 4.1600	340	1.0769	4.48
306036	LEE CT7 13.800	342	1.0783	14.88
306462	LEE CT8 13.800	342	1.0783	14.88
304893	1BLEW4-6 4.0000	340	1.1104	4.442
306180	4DAN RIV 138.00	342	1.1116	153.4

Table C.6 The voltage violations when injection 3080 MW into the original grid (using two 115 KV buses and two 230 KV buses)

BUS#	NAME – BASE KV	AREA	V(PU)	V(KV)
311465	13HHGT3 13.800	344	0.9115	12.579
306081	1TURN HY 2.4000	342	0.9146	2.195
304892	1BLEW1-3 4.8000	340	0.9307	4.468
304880	1CAPE #1 12.000	340	0.9363	11.236
304881	1CAPE #2 12.000	340	0.9363	11.236
312803	3MARKET 115.00	344	0.9375	107.81
306103	8MCGUIRE 500.00	342	1.0609	530.43
311451	1CROSS2 22.000	344	1.0609	23.34
306325	WATEREE 100.00	342	1.0633	106.33
306349	1GTFALL2 44.000	342	1.0647	46.848
306461	CLFSDTAP 500.00	342	1.0651	532.54
306102	8JOCASSE 500.00	342	1.0687	534.35
306101	8BAD CRK 500.00	342	1.0694	534.72
306105	8OCONEE 500.00	342	1.0704	535.21
306070	FISHNG C 6.6000	342	1.0706	7.066
304914	1LEE#3SU 4.1600	340	1.0763	4.477
306036	LEE CT7 13.800	342	1.0781	14.877
306462	LEE CT8 13.800	342	1.0781	14.877
304893	1BLEW4-6 4.0000	340	1.109	4.436
306180	4DAN RIV 138.00	342	1.1111	153.34

Table C.7 The lines power flow in the improved system (new line 1 and 2) after injection 3.08 GW at two 230 KV buses

Branch information							Percent of branch MVA Limit (%)
From #	From Name	To Name	To #	CKT #	Branch Type	Branch limit (MVA)	
306208	BUSH RIV	NEWBERRY	306288	1	Line	86.60	99.48
306289	NEWPORT	WYLIE HY	306333	1	Line	196.80	97.49
306289	NEWPORT	WYLIE HY	306333	2	Line	196.80	97.36
311368	3BIGGN T	3JEFF	312789	1	Line	179.00	98.55
312710	6CROSS	1CROSS2	311451	1	Transformer	584.00	98.89
312717	6PERRY R	3PERRY R	312819	1	Transformer	250.00	104.31
312717	6PERRY R	3PERRY R	312819	2	Transformer	250.00	105.08
312719	6WINYAH	3WINYAH	312845	1	Transformer	300.00	105.84
370006	3WHITE R	3SALUDA	370280	1	Line	89.40	99.87
380237	3BENHILLJ	3EPOINT2	380251	1	Line	135.00	98.81
380423	3TOCCOA	3CURRAHEE	380468	1	Line	124.00	98.28
382045	3LICKCRK	3LWHARMNJ	382329	1	Line	130.00	99.08
383001	8RUMBLERD	1RMBLCC1	383723	1	Transformer	250.00	97.34
383001	8RUMBLERD	1RMBLCC2	383726	1	Transformer	250.00	97.34
384356	3BANKHEAD	1BANK GEN	384357	1	Transformer	52.50	98.75
386421	1GADSDEN1	3GADSSTR	384372	1	Transformer	72.00	99.19
386422	1GADSDEN2	3GADSSTR	384461	2	Transformer	72.00	99.25

Table C.8 Case list in Table 9

Case #	Bus voltage rating			
	115 KV		230 KV	
1	bus# 312845	bus# 312807	bus# 312719	bus# 312717
2	bus# 312845	bus# 312807	bus# 312719	bus# 312726

Table C.9 The lines flow in the improved system (new line 1, 2 and 3) after injection 3.08 GW at 4 buses

Branch information							Percent of branch MVA Limit (%)	
From #	From Name	To Name	To #	Circuit #	Branch Type	Branch limit (MVA)	Case 1	Case 2
304448	3FAIRMO	3DILLN T	304654	1	Line	97.00	N/A	97.35
306208	BUSH RIV	NEWBERRY	306288	1	Line	86.60	99.31	99.19
306289	NEWPORT	WYLIE HY	306333	1	Line	196.80	97.47	97.46
306289	NEWPORT	WYLIE HY	306333	2	Line	196.80	97.34	97.32
311368	3BIGGN T	3JEFF	312789	1	Line	179.00	99.55	99.85
311368	3BIGGN T	3JEFF	312789	1	Line	179.00	N/A	99.45
312710	6CROSS	1CROSS2	311451	1	Transformer	584.00	98.58	98.56
312717	6PERRY R	3PERRY R	312819	1	Transformer	250.00	97.82	N/A
312717	6PERRY R	3PERRY R	312819	2	Transformer	250.00	98.54	N/A
312807	3MYRT BC	3RACEPT	312824	1	Line	179.00	97.56	97.71
312819	3PERRY R	3S PRONG	312866	1	Line	179.00	99.73	N/A
370006	3WHITE R	3SALUDA	370280	1	Line	89.40	99.74	99.66
380237	3BENHILLJ	3EPOINT2	380251	1	Line	135.00	98.81	98.81
380423	3TOCCOA	3CURRAHEE	380468	1	Line	124.00	98.31	98.35
382045	3LICKCRK	3LWHARMNJ	382329	1	Line	130.00	99.08	99.08
383001	8RUMBLERD	1RMBLCC1	383723	1	Transformer	250.00	97.34	97.34
383001	8RUMBLERD	1RMBLCC2	383726	1	Transformer	250.00	97.34	97.34
384356	3BANKHEAD	1BANK GEN	384357	1	Transformer	52.50	98.75	98.75
386421	1GADSDEN1	3GADSSTR	384372	1	Transformer	72.00	99.19	99.19
386422	1GADSDEN2	3GADSSTR	384461	2	Transformer	72.00	99.25	99.25

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