ELECTRIC POWER RESEARCH INSTITUTE

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DOE: Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets

Final Report

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DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

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Southwest Power Pool
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EXECUTIVE SUMMARY

This DOE-funded project titled "Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets" aims to evaluate the benefits of coordination of scheduling and balancing for Southwest Power Pool (SPP) wind transfers to Southeastern Electric Reliability Council (SERC) Balancing Authorities (BAs). The primary objective of this project is to analyze the benefits of different balancing approaches with increasing levels of inter-regional cooperation. Scenarios were defined, modeled and investigated to address production variability and uncertainty and the associated balancing of large quantities of wind power in SPP and delivery to energy markets in the western regions of SERC.

The study evaluates the scheduling/balancing challenges associated with delivery of sufficient wind generation from within the SPP footprint to support 20% energy from renewable resources across the SPP, Entergy (EES), Southern Company (SoCo), and the Tennessee Valley Authority (TVA) balancing areas for the year 2022. The project team worked closely with staff from each of these companies to develop a model of the possible generation fleets within each BA. Based on the 2022 generation plans identified, specific wind generation sites within the SPP footprint were identified to yield sufficient energy output to allow each of the 4 BAs to meet the net renewable energy requirement beyond the renewable energy from the base generation fleet. As the effort required for transmission planning for increased amounts of wind was outside the scope of the project, transmission constraints were ignored and a transportation model was used. The Eastern Interconnect wind generation data set developed by the National Renewable Energy Laboratory (NREL) was utilized for identifying specific wind plants with SPP for both internal SPP consumption and for delivery to the SERC BAs.

The primary analyses for the project include statistical analysis of wind and load data to determine the impact on reserve requirements for each BA and unit commitment (UC) and economic dispatch (ED) simulations of the SPP-SERC regions as modeled for the year 2022. These evaluations are made for a 14 GW wind generation scenario where SPP wind generation is intended for serving only SPP load and for 4 separate high wind (48 GW) transfer balancing scenarios relative to the coordination between regions within the footprint:

1. Hourly Scheduling: SPP carries all additional within-hour reserves for the wind generation for all SPP and SERC regions. Each BA schedules its own generation day-ahead to meet its own forecast load and reserve requirements based on forecast wind generation from the SPP wind plants assigned to each BA without consideration of generation in neighboring BAs. Note that a variation of the Hourly Scheduling simulation ("Integration Proxy") was conducted where all wind generation was assumed to be perfectly forecast & no additional reserve was required for within-hour variability of wind. This case was conducted as a hypothetical case to provide a measure of the balancing costs associated with the wind generation by comparison to the Hourly Scheduling base case.

2. Dynamic Scheduling: Each SERC BA and SPP individually carries reserves for its wind generation output even though all wind is located in the SPP footprint. As with scenario #1, each BA schedules its own generation day-ahead to meet its own load and reserve requirements without consideration of generation from neighboring areas.

3. Shared Reserve/Scheduling w/Hurdle Rates: The additional reserve requirements are determined based on the aggregate wind generation and load from across the entire SPP/SERC footprint. Generation is scheduled day-ahead from the aggregate SPP-SERC region to meet the aggregate load and reserve requirements such that the most economic units from across the footprint are utilized. Although transmission constraints are ignored, the hurdle rates for transferring energy between regions are considered in the UC and ED of generation across the footprint.

4. Shared Reserve/Scheduling No Hurdle Rates : Reserve requirements and scheduling are the same as in scenario #3 with the only exception being that hurdle rates are not considered in the commitment and dispatch of generation across the footprint.

For each of these scenarios, the impact of the variability and uncertainty of the wind generation output on reserve requirements is determined for three reserve categories: regulation, spin, and non-spin/supplemental. Statistical analyses of the wind generation forecast error relative to load on appropriate time scales are utilized to determine the incremental reserves that are required to maintain reliability at the same levels as without the additional wind generation. The details of the reserve requirement calculation method are provided in the report. The impact on average regulating reserve for each BA and the footprint across each of the balancing scenarios is shown in Figure ES- 1, with the following observations:

- The aggregate footprint regulating reserve requirement increases approximately 650 MW from 1675 MW to 2325 MW when moving from 14 GW of wind to 48 GW of wind. Since SPP carries all of the additional reserves scenario #1, this total 650 MW increase is borne by SPP with no increase in the SERC BAs.
- Distributing the regulating reserve out to each of the BAs according to their own wind requirements (scenario #1 → scenario #2) results in an aggregate footprint decrease of approximately 200 MW. Obviously, SPP's requirement decreases with the SERC BAs increasing.
- Aggregating the reserve requirement across the footprint (scenario #2 → scenario #4) results in an aggregate footprint decrease of approximately 190 MW.

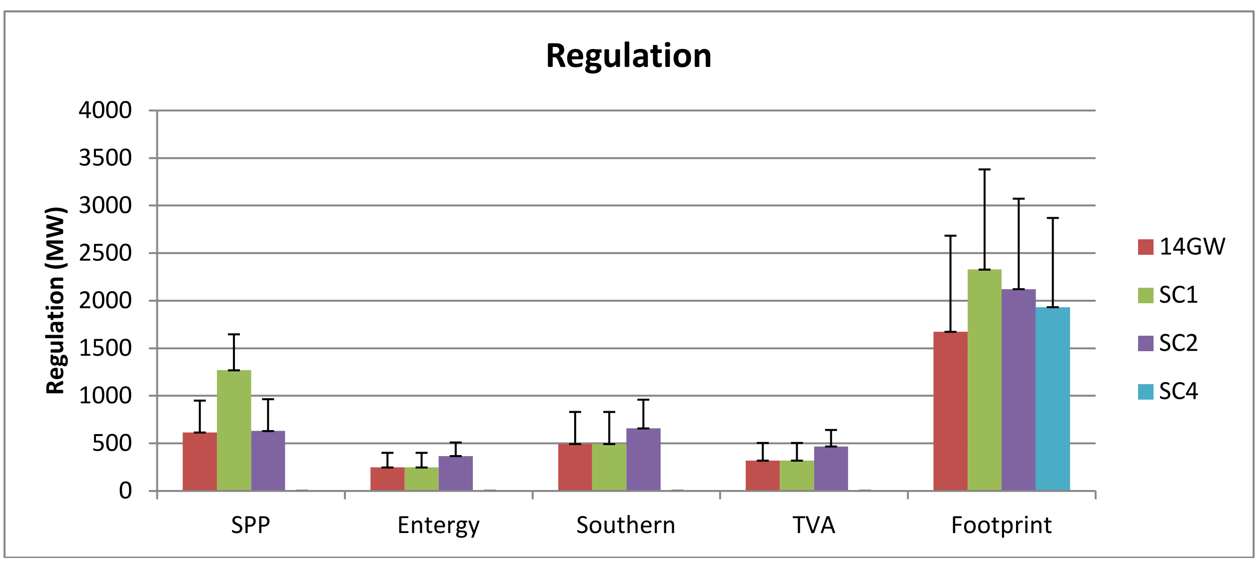

Figure ES- 1

Summary of average regulation requirements for each scenario

The impact on spin and non-spin reserves that are maintained to cover the hour-ahead uncertainty in wind generation forecasts is shown in Figure ES- 2, with the following observations:

- The aggregate footprint wind-related spin and non-spin reserve requirement increases approximately 3200 MW when moving from 14 GW of wind to 48 GW of wind.
- Distributing the reserve out to each of the BAs according to their own wind requirements (scenario #1 → scenario #2) results in an aggregate footprint increase in spin and non-spin reserve of approximately 350 MW because of the reduced diversity in the wind plant uncertainty with each BA covering only its portion of the wind. Because the aggregated wind is the same in scenarios #1 and #4, the moving from scenarios #2 to #4 results in the same 350 MW reduction of wind-related spin and non-spin reserve.

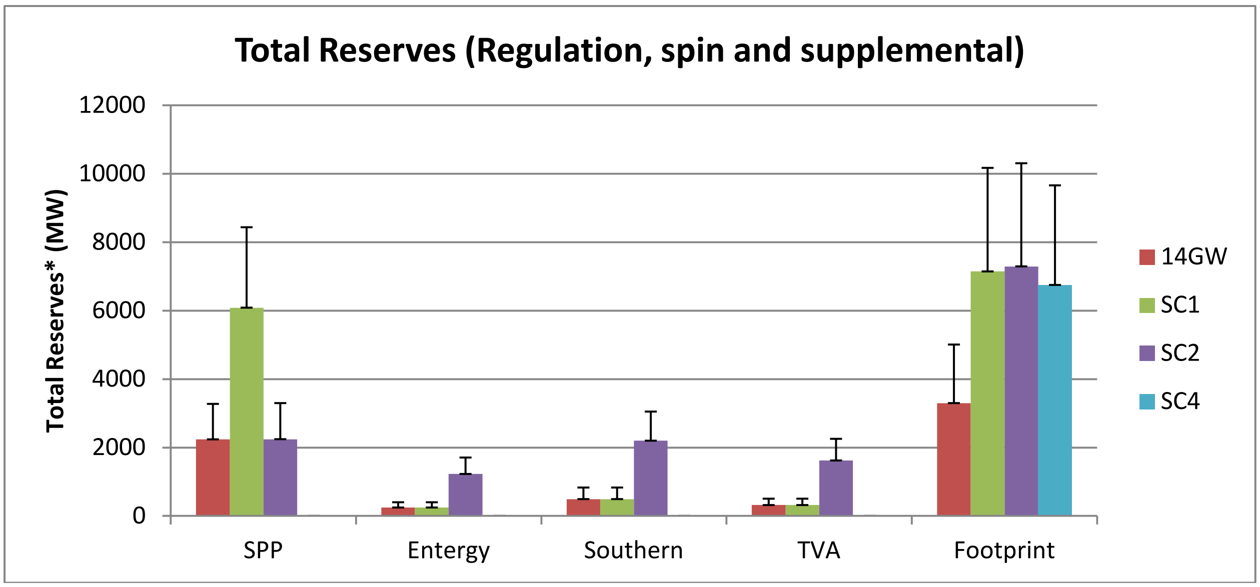

Figure ES- 2
Total reserves (regulation, spin and supplemental but excluding contingency) for each scenario

The study also found large reductions (approximately 5500 MW) in traditional contingency reserve requirements across the footprint when the requirements were aggregated across the full SPP-SERC footprint. This assessment is based on the assumption that for scenarios #3 and #4, the largest single BA spin and non-spin requirement would become the requirements for the aggregate footprint. The utility participants in the project noted that very likely the ability to deliver reserves and other factors would result in an aggregate footprint contingency requirement that would exceed the single largest requirement from any single BA.

The UC/ED models utilized for the project were developed through extensive consultation with the project utility partners, to ensure the various regions and operational practices are represented as accurately as possible realizing that all such future scenario models are quite uncertain. SPP, Entergy, Oglethorpe Power Company (OPC), Southern Company, and the Tennessee Valley Authority (TVA) actively participated in the project providing input data for the models and review of simulation results and conclusions. While other SERC utility systems are modeled, the listed SERC utilities were explicitly included as active participants in the project due to the size of their load and relative proximity to SPP for importing wind energy.

Although the focus of the study was not to conduct an evaluation of all system impacts of 48 GW of wind on the SPP/SERC region, the analysis and modeling does provide some insight as to certain aspects of the impact of increasing wind penetration on the unconstrained system when comparing the results between the 14 GW and 48 GW installed wind cases. The increase of 34 GW of wind in SPP (from 14 GW to 48 GW) results in a total production cost reduction of approximately $5.4 billion or $4/MWh of demand. This cost reduction represents the reduction in fuel costs from the wind generation and does not consider the offsetting cost to purchase the wind energy or the capital/O&M costs to build the wind plants. Comparison of the scenario #1 and Scenario #1 proxy cases show that the costs of the intra-hour variability and uncertainty and the day ahead uncertainty for the total 48 GW of wind in the High Wind Transfer cases are approximately $0.6/MWh of load, or $5/MWh of wind, for scenario 1. It should also be noted that this value does not include any capital costs for the wind generation or transmission to deliver the wind or costs associated with increased cycling of conventional plants due to increased ramping and start/stop operations.

The analysis of the High Wind Transfer scenarios shows that increasing levels of cooperation among SPP, Entergy, Southern, and TVA does result in changes to the operation of the system that produce aggregate system benefits. These result from changes to the amount of reserve required for the different scenarios as presented previously. There is a clear, though possibly small, societal cost benefit to sharing the reserve requirements throughout the region. The difference between scenario 1 where SPP balances all wind and and scenario 2 where each BA balances its own wind is small – only $0.1/MWh. Comparing costs for scenarios 2 where each BA balances their own assigned wind and scenario 3 where balancing requirements are shared across all BAs shows that costs decrease as result of the reduction in aggregate reserve requirement (including contingency reserve) and a more optimal usage of the system generation to meet energy and reserves as scheduling is shared. The cost reduction is approximately $0.7/MWh of demand for the assumed gas prices; removal of hurdle rates impacts this only slightly. Reducing gas prices by approximately 50% reduces this benefit by a factor of 3. This implies that the benefits derived from regional coordination or cooperation are reduced as the diversity in plant mix and fuel costs (coal vs. gas) across regions is reduced.

As with any future scenario production cost model based study, the modeling and data input assumptions have a significant impact on results. Several assumptions made as part of the production cost model analyses for this project significantly impact the results and conclusions presented. While all of the assumptions are discussed in detail in the report, the following most crucial assumptions provide context for the results and conclusions:

- *Unconstrained transmission.* Thermal constraints are removed and losses ignored for the SPP/SERC network in the UC/ED model for which results are presented.
- *Gas and emission prices.* Only a single set of future fuel prices and carbon price was studied in detail. The fuel price was shown to be important with a single gas price sensitivity that was conducted.
- *Reserve margin and conventional generation plant mix.* The additional 40 GW of wind was added to the High Wind Transfer cases without removing any of the conventional

generation in the 2022 Non-RES case resulting in a reserve margin in the model which would likely be higher than that which would be seen in reality if this much wind was present.

Despite these assumptions, the results of the study provide insights as to the balancing impacts associated with the high wind build-out in SPP and as to the benefits of increasing levels of coordination across SPP and SERC BAs in responding to those balancing impacts. Given the assumptions and the nature of future scenario production cost modeling, the insights tend to be based more on the order of magnitude and trends between results than the absolute value of the results presented.

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1 INTRODUCTION AND BACKGROUND

Project Overview

Wind power development in the United States is outpacing previous estimates for many regions, particularly those with good wind resources. The pace of wind power deployment may soon outstrip regional capabilities to provide transmission and integration services to achieve the most economic power system operation. Conversely, regions such as the Southeastern United States do not have good wind resources and will have difficulty meeting proposed federal Renewable Portfolio Standards with local supply. There is a growing need to explore innovative solutions for collaborating between regions to achieve the least cost solution for meeting such a renewable energy mandate.

The DOE-funded project "Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets" aims to evaluate the benefits of coordination of scheduling and balancing for Southwest Power Pool (SPP) wind transfers to Southeastern Electric Reliability Council (SERC) Balancing Authorities (BAs). The primary objective of this project is to analyze the benefits of different balancing approaches with increasing levels of inter-regional cooperation. Scenarios were defined, modeled and investigated to address production variability and uncertainty and the associated balancing of large quantities of wind power in SPP and delivery to energy markets in the southern regions of the SERC.

The primary analysis of the project is based on unit commitment (UC) and economic dispatch (ED) simulations of the SPP-SERC regions as modeled for the year 2022. The UC/ED models utilized for the project were developed through extensive consultation with the project utility partners, to ensure the various regions and operational practices are represented as accurately as possible realizing that all such future scenario models are quite uncertain. SPP, Entergy, Oglethorpe Power Company (OPC), Southern Company, and the Tennessee Valley Authority (TVA) actively participated in the project providing input data for the models and review of simulation results and conclusions. While other SERC utility systems are modeled, the listed SERC utilities were explicitly included as active participants in the project due to the size of their load and relative proximity to SPP for importing wind energy.

The analysis aspects of the project comprised 4 primary tasks:

1. Development of SCUC/SCED model of the SPP-SERC footprint for the year 2022 with only 7 GW of installed wind capacity in SPP for internal SPP consumption with no intended wind exports to SERC. This model is referred to as the "Non-RES" model as it does not reflect the need for the SPP or SERC BAs to meet a federal Renewable Energy Standard (RES).

2. Analysis of hourly-resolution simulation results of the Non-RES model for the year 2022 to provide project stakeholders with confidence in the model and analytical framework for a scenario that is similar to the existing system and more easily evaluated than the high-wind transfer scenarios that are analyzed subsequently.

3. Development of SCUC/SCED model of the SPP-SERC footprint for the year 2022 with sufficient installed wind capacity in SPP (approximately 48 GW) for both SPP and the participating SERC BAs to meet an RES of 20% energy. This model is referred to as the "High-Wind Transfer" model with several different scenarios represented. The development of the High-Wind Transfer model not only included identification and allocation of SPP wind to individual SERC BAs, but also included the evaluation of various methods to allow the model to export the SPP wind to SERC without developing an actual transmission plan to support the transfers.

4. Analysis of hourly-resolution simulation results of several different High-Wind Transfer model scenarios for the year 2022 to determine balancing costs and potential benefits of collaboration among SPP and SERC BAs to provide the required balancing.

Report Structure and Relation to Previous Project Reports

This report summarizes the High-Wind Transfer model development (analysis task #3 above) and associated simulation results from the model (analysis task #4 above). The High Wind Transfer model development activities covered include:

- Chapter 2 summarizes the evaluation of the impacts of limited transmission transfer capability in the 2022 model on export of high levels of wind energy from SPP to SERC, including evaluation of modeling/simulation options that allow analysis of the balancing impacts of the wind despite limited transfer capability.

- Chapter 3 summarizes the allocation of SPP wind plants' energy to SERC BAs, calculation of associated reserve requirements for each BA based on allocated wind plant output over time, and analysis of wind ramping events experienced for each BA.

- Chapter 4 summarizes the High Wind Transfer scenarios/assumptions simulated in order to evaluate the impacts/benefits of coordinated scheduling/balancing among SPP and SERC BAs to address wind variability and uncertainty.

It should be noted that the High Wind Transfer SCUC/SCED model summarized in this report is based on the Non-RES model that is summarized in the separate report titled "Task 1 Deliverable: Non-RES Case Model Development and Analysis Framework" (subsequently referenced as the Task 1 Report). Further, the simulation results for the Non-RES model are summarized in a third report titled "Task 3 Deliverable: Non-RES Case Results". While an attempt is made to restate basic model assumptions that impact the results identified for the High Wind Transfer scenarios, the Task 1 and Task 3 reports should be reviewed to find additional model information.

It should be further noted that the High Wind Transfer SCUC/SCED models and associated simulation results presented in this report are to be used to compare different methods of balancing high penetrations of wind being moved from SPP to the relevant SERC areas. The model's purpose is not to give absolute answers on the operation of such systems with high amounts of wind, but rather to be used as a tool to compare strategies, based on certain input assumptions on wind, demand, unit parameters, reserve provision, etc. Therefore, the absolute answers are meaningful only within the specific context of a particular study and can be misleading if applied outside the context of a given study

2
REPRESENTATION OF TRANSMISSION NETWORK FOR HIGH WIND CASES

As noted in detail in the Task 1 Report, the transmission network included in the SCUC/SCED model for the Non-RES case was a slightly modified version of a model developed by SPP and Entergy (with input from Southern, TVA, et. al.) for a FERC filing. This modeled transmission network was planned to support only 7 GW of installed wind generation interconnected within SPP for consumption within SPP. As such, the transmission network in the non-RES model is not designed to support high wind transfers from SPP to SERC. Further, the primary focus of the DOE funded work is not to evaluate transmission investments for supporting such transfers, but rather to evaluate the balancing challenges associated with such high level of wind in SPP and the potential benefits of coordination among SPP and SERC BAs in addressing those balancing challenges. This section summarizes limited analysis of the capability of the modeled transmission network to deliver wind energy from wind plants located in the SPP region. Further, this section summarizes the modeling/simulation approach that was utilized to enable analysis of the balancing cooperation benefits for the high wind transfer cases despite the transmission delivery limitations and the implications of the associated assumptions.

Transmission Delivery Limitations

While the focus of the project was not to assess capability of the modeled transmission to deliver wind from SPP, a simplified analysis was conducted to obtain an idea of the limits. This analysis was based on including an additional 7 GW of wind in the Non-RES model in the SPP region for an aggregate SPP wind generation capacity of 14 GW with all other model parameters maintained as in the 7 GW Non-RES case. First, the 14 GW case SCUC/SCED simulation was conducted and compared to the 7 GW Non-RES case results to evaluate how much of the additional wind generation in SPP appears to flow to SERC BAs. Second, the transmission network in the 14 GW case was then modeled as being unconstrained – no thermal flow limits – to determine how much wind generation is being curtailed by the transmission thermal limits.

Table 2-1 shows the changes in average generation per BA per generation type between the 14 GW and 7 GW cases. The table shows the following general trends:

- The additional approximately 7 GW of wind capacity in SPP results in an additional average wind generation output of 2131 MW.
- The additional 2131 MW of wind in SPP is consumed as follows
  - increase in average system losses of 282MW
  - reduction in average external net generation of 791 MW
  - reduction in average SPP coal generation output of 794 MW
  - small reduction in average SERC generation, mostly impacting CC output

Table 2-1

Changes In Average Generation Per BA Between 14 GW vs 7 GW

	EES	SoCo	TVA	SPP	SERC_E	SERC_W	External	Total
CC	120	116	3	97	68	19		286
GT	3	12	18	33	70	14		54
Hydro	1	0	0	0	0	0		1
Nuclear	0	1	0	0	0	0		1
Steam Coal	1	24	80	794	47	9		795
Steam GasOil	59	0	0	25	1	1		32
Wind	0	0	0	2,131	0	2		2,128
Other	0	1	5	12	0	21	791	787
Total	183	105	70	1,220	186	24	791	282

The sensitivity case shows that increasing the SPP wind generation capacity from approximately 7 GW to 14 GW results in little impact on SERC generation primarily reducing combined cycle generation output. Instead, most of the additional SPP wind displaces SPP coal, flows to the external regions primarily MISO, and is consumed as additional system losses.

One additional comparison was made to understand the impacts of the modeled Non-RES transmission thermal limits on the deliverability of wind generation. The 14 GW constrained case was re-run with the transmission thermal limits and losses removed to yield a 14 GW unconstrained case that is compared with the previous 14 GW case (with thermal limits and losses) to determine the transmission-related curtailment of SPP wind. The results show that an average of 453 MW of wind generation is curtailed in the 14 GW case due to transmission thermal limits, or roughly 18% of the incremental average 2583 MW of wind generation that would be available when increasing the SPP wind capacity from 7 to 14 GW.

Although somewhat intuitive, the 18% curtailment when moving from 7 to 14 GW can be extrapolated to show that the wind curtailment for 48 GW of wind in SPP with the modeled transmission would be unreasonably high and would not allow for the primary investigation of coordinated scheduling/balancing benefits to be achieved. This analysis would be meaningless if most of the wind in SPP is curtailed such that balancing isn't needed.

Impact of Unconstrained Transmission Assumption for High Wind Transfer Cases

As such, the 48 GW High Wind Transfer cases require that the transmission be treated differently than the Non-RES modeled transmission. Two options were considered for modeling the transmission for the High Wind Transfer Cases:

1. *Develop a conceptual transmission plan to support the high wind transfers associated with the 48 GW cases.* The DOE project did not include funding for the development of transmission alternatives to support large wind transfers from SPP to SERC. While a simplified plan for point-to-point transfers between the two regions might solve the inter-regional congestion issues, it would not alleviate the within SPP collection or within SERC regions distribution congestion issues. EPRI discussed with DOE and the project

participants the possibility of a related, but separately funded project to develop a reasonable transmission network for 2022 that would provide for high wind transfers. Funding and man-power resources for the partner study were not available.

2. *Unconstrain the transmission in the 2022 Non-RES model by removing the thermal rating limits and associated losses.* While a complete "copper sheet" type analysis is quite simplistic and unrealistic, it does approximate a scenario where sufficient transmission would be built to deliver wind energy from SPP to SERC if 48 GW of wind capacity were developed in SPP. This approach has some obvious implications for the results of the SCUC/SCED simulations that must be considered when interpreting the results. Additional analysis was performed to better understand the implications of the "unconstrained" assumption.

As described in detail in the Task 1 Report, UPLAN is the SCUC/SCED simulation platform used for this study. UPLAN has three different internal algorithms for integrating power flow within its Unit Commitment and Economic Dispatch: AC-OPF; DC-OPF; and Transportation. In AC, a non-linear problem is developed to describe the energy flow through each element of the system which considers Kirchoff's laws, voltage and losses directly within the formulation. DC is a linear approximation of the AC power flow which, in the case of UPLAN, can consider losses but not voltage. The transportation method does not model the losses, the voltage, or Kirchoff's laws. It does, however, consider all the physical connections as though they were pipelines. Power can flow anywhere without exceeding specified line capacity, in much the same that way water or gas pipelines are constrained. The transportation model also does consider hurdle rates or wheeling charges.

For the "Constrained" 7 GW and 14 GW scenarios discussed in the Task 1 Report and thus far in this report, the DC model was utilized. As noted above, in order to ascertain the impact of utilizing the UPLAN Transportation mode for the High Wind Transfer cases, a quantitative analysis was conducted for the following 14 GW scenarios to isolate the impact of removing losses and removing thermal constraints:

1. 14 GW constrained w/losses (14 GW) – 14 GW scenario solved with DC OPF representing both losses and thermal constraints (scenario already described and summarized in previous section).
2. 14 GW constrained no losses (14 GW-NL) – 14 GW scenario solved with DC OPF respecting thermal constraints as in #1, but with the losses not calculated.
3. 14 GW unconstrained no losses (14 GW-UC) – 14 GW scenario solved in Transportation mode ignoring both thermal constraints and losses.

Figure 2-1 shows a comparison of the aggregate average net flow out of each of the SPP and large eastern SERC regions for these three 14 GW cases. Comparison of the 14 GW (red) and 14 GW-NL (purple) data in the bar chart shows that removing losses alone has a small impact on the generation flows between regions suggesting that losses do not play a primary role in restricting economic transfers across the region. Comparison of the 14 GW-NL (purple) and 14 GW-UC (green) data in the bar chart, however, shows that removing thermal constraints significantly changes the flows between regions. This is expected given that removing transmission constraints allows generation to flow between areas based on the relative economics of the generation while being limited only by hurdle rates given that losses were removed in the previous step.

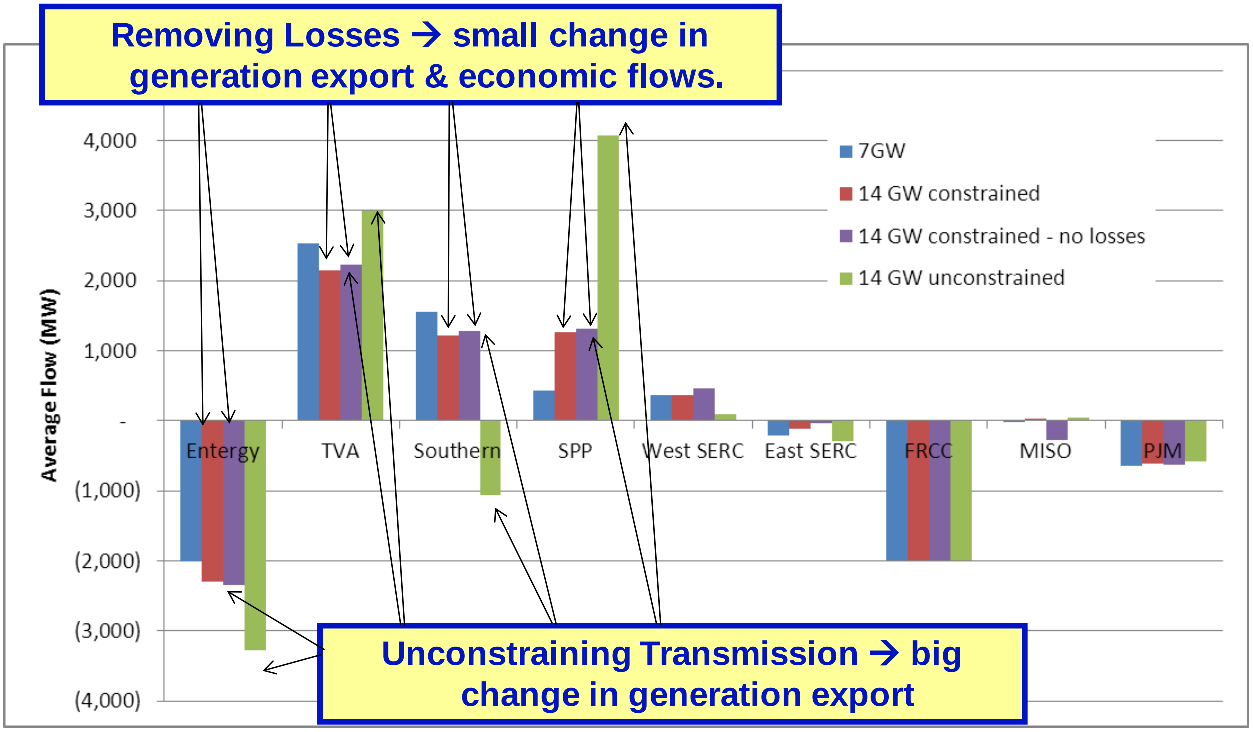

Figure 2-1
Comparison of Average Net Flow Out of Each Region for 7 and 14 GW Cases

Conclusions

In order to effectively investigate the scheduling/balancing challenges of utilizing SPP wind generation to meet a 20% RES across the SPP and SERC footprint and to evaluate the benefits of coordination between regions in meeting this challenge, the modeled transmission system would either have to be expanded or "unconstrained" to allow the new wind generation to be delivered. Developing a reasonable transmission expansion plan that was acceptable to all stakeholders was outside the scope of the project. Test cases simulated to better understand the impacts of removing transmission system losses and thermal constraints show that the primary impact is from removing the constraints. Since the study is not evaluating the capital costs of transmission that would be needed to support wind transfers from SPP to SERC, the gross "unconstrained" assumption is an approximation of the assumption that transmission will exist to support wind transfers in order for the wind to be developed for export. While certainly not a perfect assumption, the project team believes that it does allow for an assessment of the benefits of coordination for scheduling/balancing with some appropriate caveats.

As such, all of the High Wind Transfer cases that are described in detail in the remainder of this report are simulated using the UPLAN Transportation mode solution method where losses and thermal constraints are not respected. As with all of the results of the project, the specific quantitative results obtained from these simulations are less important than the insights that are obtained by comparison between cases as specific scenario parameters are changed. Where appropriate in the presentation of results, it is noted how the "unconstrained" transmission assumption is affecting specific directional differences between cases. As is noted in the Recommended Follow-on Work section at the end of this report, the project team believes that an evaluation utilizing the DC-OPF solution mode with an actual transmission network planned for the wind transfers would be valuable to confirm the conclusions developed from the simplifying assumptions used in this study.

3
HIGH WIND TRANSFER CASE DATA AND ASSUMPTIONS

This chapter describes the wind generation data utilized for the High Wind Transfer cases and the associated operating reserve requirements. The selection of specific wind plants in SPP to yield the wind energy required for supplying 20% RES across the SPP-SERC footprint is summarized, as well as the allocation of those wind plants to specific SERC BAs. In addition, limited analysis of the variability of the wind output and wind forecast uncertainty is presented. Finally, the method for determining appropriate operating reserves to accommodate the wind variability and uncertainty is presented along with the actual reserve requirement values for the various balancing cooperation scenarios.

Wind Data

The wind data used for this study was a subset of the wind data developed by the National Renewable Energy Lab (NREL) for use in the Eastern Wind Integration and Transmission Study (EWITS). The data was developed using numerical weather prediction models to re-create the wind at hub height in a 2 km grid across the eastern interconnection. The wind was calculated at 10 minute intervals for 3 years (2004, 2005 and 2006). The wind speed data was extracted from the model and used to create time series of wind plant output data at each grid point. The data was then processed to account for local terrain effects and some 1400 “wind plants” ranging in capacity from 100MW to 1300MW where created across the interconnection from the individual grid points.

The data that resulted from this process provides a prediction of what the wind production would actually have been at each wind plant every ten minutes over the three years. A separate day-ahead wind generation forecast dataset was also produced for each plant that is designed to behave like an actual forecast with realistic day-ahead mean-absolute-error (MAE) of 15% to 20%.

Site Selection Process

The wind site selection process began by determining the energy targets for each of the regions studied. This was done by determining the load for each region in the study year, 2022. The annual energy was calculated and the gross target was determined as 20% of the totals. Other renewables that were included in the 2022 generation portfolio were netted out of those totals and the net wind targets determined. Existing hydro resources were not counted towards renewable targets. Table 3-1 shows the targets that where calculated.

Table 3-1
Wind energy targets for each region

Region	2022 Load (GWh)	Existing Renewables	Target (GWh)	Wind Requirement (GWh)
Entergy	144,457	533	28,891	28,358
SOCO	287,702	2,608	57,540	54,932
TVA	186,063	104	37,213	37,108
SPP	260,982	177	52,196	52,019
Total	879,204	3,422	175,841	172,418

A subset of the NREL wind plant dataset was selected from the SPP footprint to meet the energy goals for the regions included in the study. The plants were selected based on several criteria beyond simple geography. Plants over 1000 MW were eliminated from the pool as they tend to understate the geographic diversity obtained by combination of smaller plants. The highest capacity factor plants were kept and an effort was made to include significant resources in all states in the SPP footprint.

This reduced the number of plants for selection to 419 totaling 190 GW of nameplate capacity. The locations of these plants can be seen in Figure 3-1.

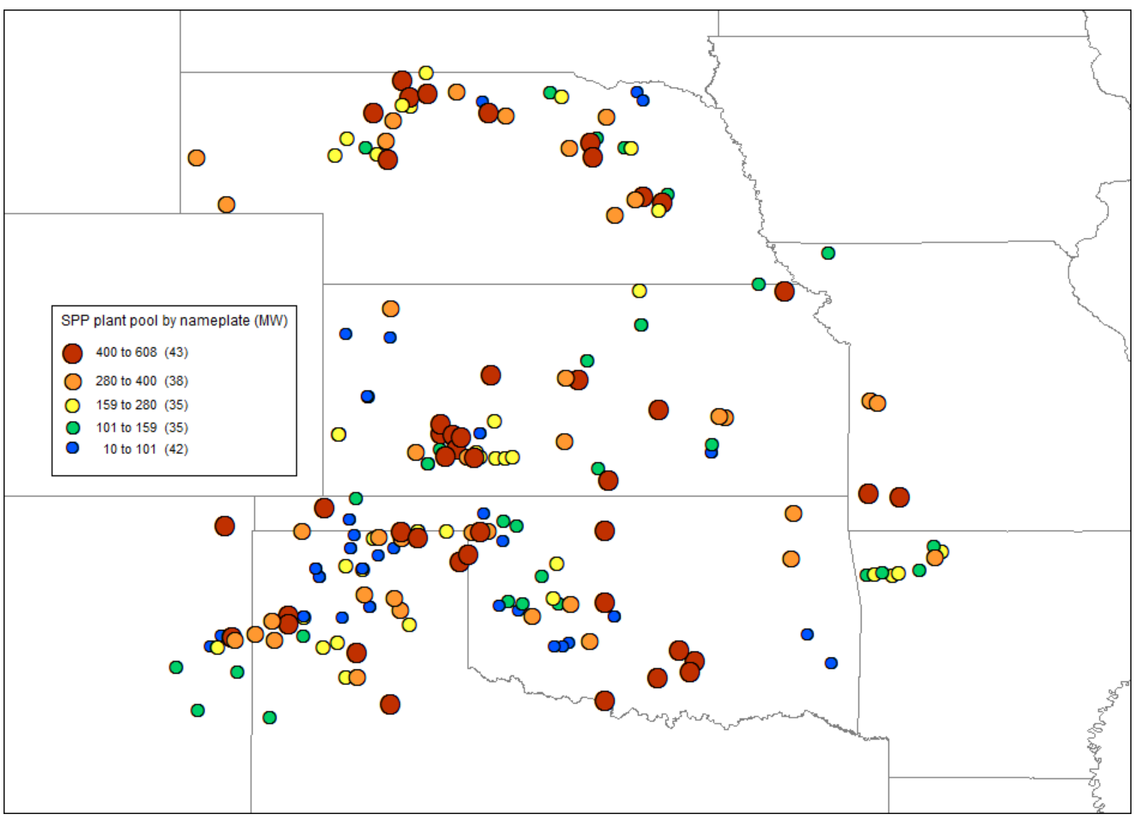

Figure 3-1
Location and size of the wind plant selection pool

The study team determined that any scenario where wind from SPP was moved into the SERC study region would most likely have the wind plants serving each region distributed across the footprint. This served to maximize the aggregation benefits for each region. The effects of aggregation are discussed in the next section.

A prior study performed for SPP selected which plants would be used to meet the 20% energy target for SPP. These same plants were utilized for SPP in this study. To assign plants to Entergy, Southern Company and TVA, random selections were made from the list of plants until each region's energy target was met. The plants were assigned to their respective regions and that assignment was carried through into the production cost modeling. Figure 3-2 shows the results of that process. The aggregate statistics from wind production from these plants is presented in the Wind Characteristics section.

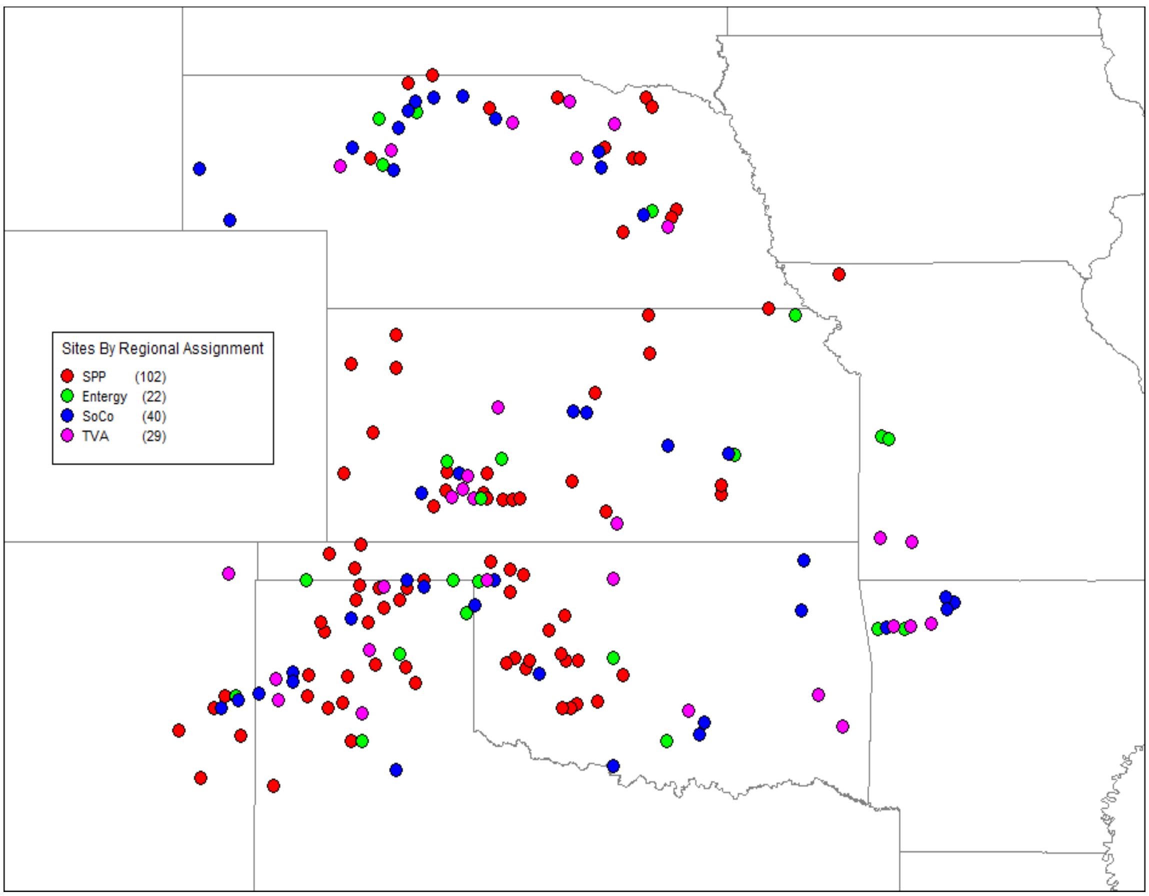

Figure 3-2
Assignment of wind plants to regions

Effect of Aggregation of Wind Plants

As the number of plants and particularly the geographic diversity of those plants increases, the variability of the output of the aggregated plants decreases. As noted, the wind plants selected to comprise the wind generation for each of the regions in the study were selected to provide geographic diversity. This has several consequences. Given the set of wind plants and the geographic area covered, this minimizes the variability seen for each of the regions. A different site selection could have congregated the plants for each of regions in a smaller area, correlating the output to a higher degree and resulting in higher variability. This has direct consequences to the results of the study since the lower the variability, the lower the balancing requirement for wind. This assumption of higher diversity tends to reduce the inter-BA cooperation benefits that are calculated later.

To illustrate, Figure 3-3 shows these diversity effects for an example set of plants from the actual data used in the study. Using the standard deviation of the 10 minute change in aggregate output as a metric, the variability of eight concentric aggregation areas is examined. The smallest is a single 100 WM plant moving in steps to the largest of a 12000 MW regional aggregation.   Note that variability drops from more than 4.5% for the single plant to about 1% for the largest aggregation area.

This aggregation has a direct effect on reserve requirements and ramping duty seen by the entity who balances the wind. If the wind is rising in one portion of the aggregation area, as the size of the area increases, it is much more likely that it is decreasing in another portion to reduce the size of the net change.

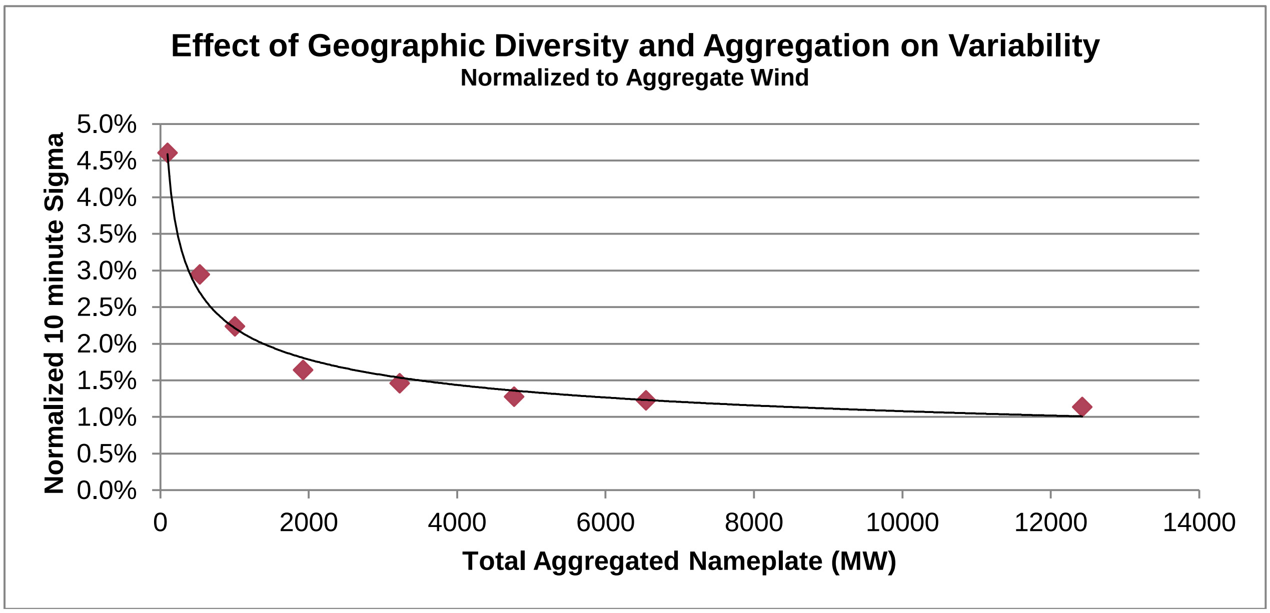

Figure 3-3
Effect of diversity and aggregation on variability

Wind Characteristics

With the wind plants selected and assigned to the four study regions, aggregate wind data can be calculated and characteristics computed. Table 3-2 shows these characteristics tabulated with the coincident total and non-coincident total for the entire footprint.

Table 3-2
Characteristics of aggregated wind plants

	Entergy	SOCO	SPP	TVA	Total (Coincident)	Total (non-Coincident)
Nameplate (MW)	7850	14999	14692	10368	47909	
Maximum Output (MW)	7170	13541	13229	9366	43067	43306
Total Energy (GWh)	28537	55441	52216	37499	173693	
Average Output (MW)	3231	6277	5912	4246	19666	
Capacity Factor	41%	42%	40%	41%	41%	
Apparent Capacity Factor*	45%	46%	45%	45%	46%	
10 Minute Ramps						
Max Up Ramp (MW)	665	1349	918	899	2588	3830
Average Up Ramp (MW)	68	110	110	85	303	374
Max Down Ramp (MW)	747	1010	866	820	2545	5988
Average Down Ramp (MW)	65	105	106	83	292	650
1 Hour Ramps						
Max Up Ramp (MW)	1565	2781	2768	1912	7457	9025
Average Up Ramp (MW)	255	464	480	342	1438	1540
Max Down Ramp (MW)	1427	2638	2991	2151	8635	17842
Average Down Ramp (MW)	253	448	466	337	1384	2889

*Apparent Capacity Factor is the ratio of the average output to the maximum output as opposed to the nameplate capacity.

The maximum output shown is significantly less that the nameplate for several reasons. First, the wind rarely blows everywhere at once so not all turbines assigned to a region are at full output at the same time. When the wind is blowing at very high speeds, high speed cut-outs of turbines also occur. When the production data was calculated, losses, both electrical and wind related are taken into account further reducing the maximum output from nameplate.

Comparing the energy values in Table 3-2 to the energy requirements in Table 3-1 shows slight variations from the targets. This is due to the granularity of the plants making it impossible to meet the target exactly. The actual total is within about 1% of the target.

Variability of wind plants is a measure of how much and how often the output of the plant changes. While statistics give a high level picture of that variability, it is useful to look at specific examples of how the wind output varies hour to hour. Figure 3-4 shows two separate weeks from the wind output data at an hourly resolution. The first week shows a typical week in the spring. The changes in output can be relatively sudden, with extreme changes typically due to the passage of weather fronts. The second week is from summer where a diurnal pattern can be observed. In both cases, the wind production data for the four regions in the study footprint are highly correlated on timeframes in the tens of minutes to hour. The subject of variability and how it relates to reserves is reviewed in detail in subsequent sections of this chapter.

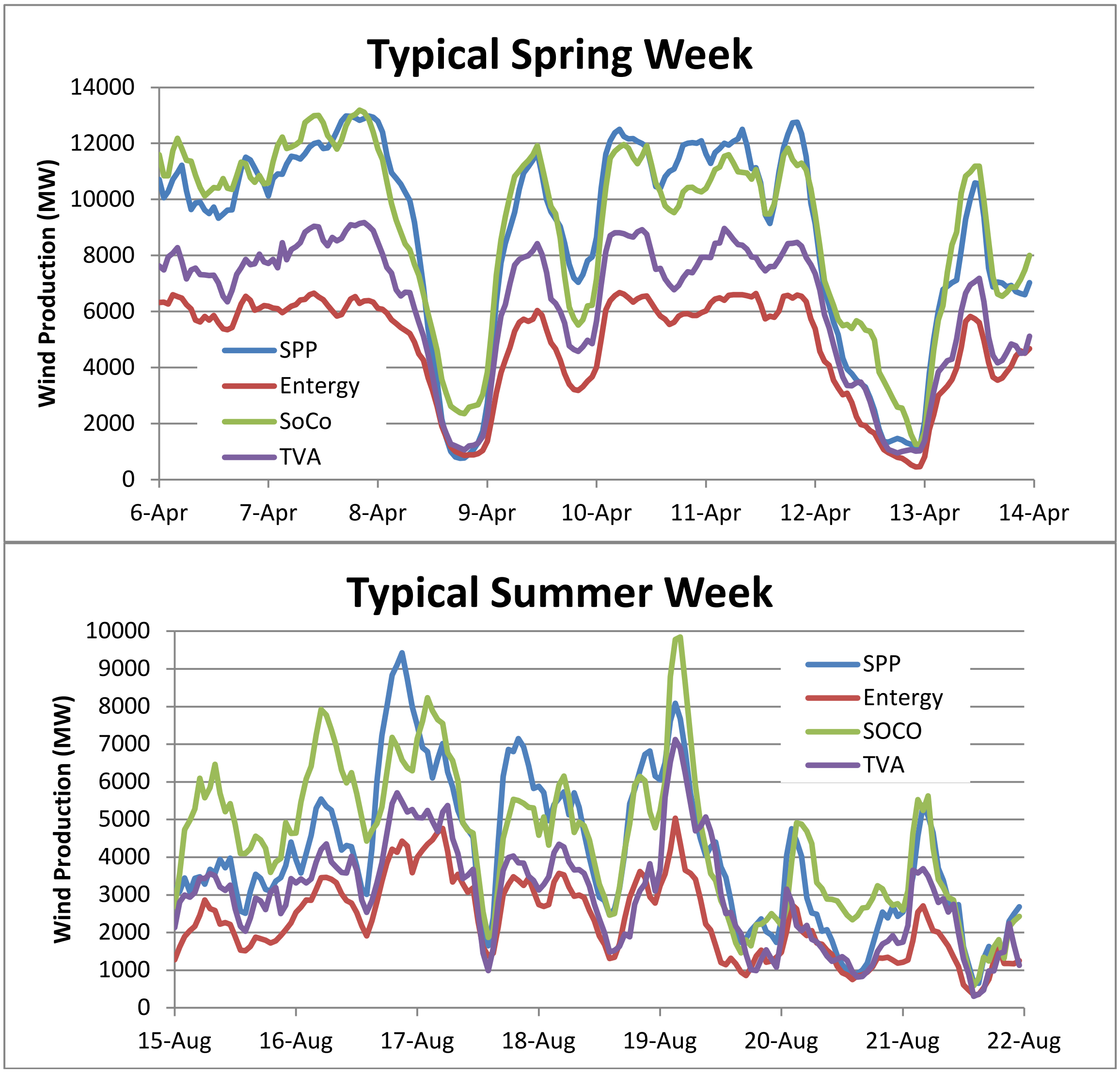

Figure 3-4
Sample weeks of wind output for the study regions

An interesting and important characteristic of wind production is the size and duration of wind ramps that the system will experience. Based upon the one year of data analyzed for this study, Figure 3-5 shows the maximum expected ramp magnitude and duration for each region. The method used to create this data looks at every possible ramp within the data and tabulates the maximum up and down ramp seen at each duration.

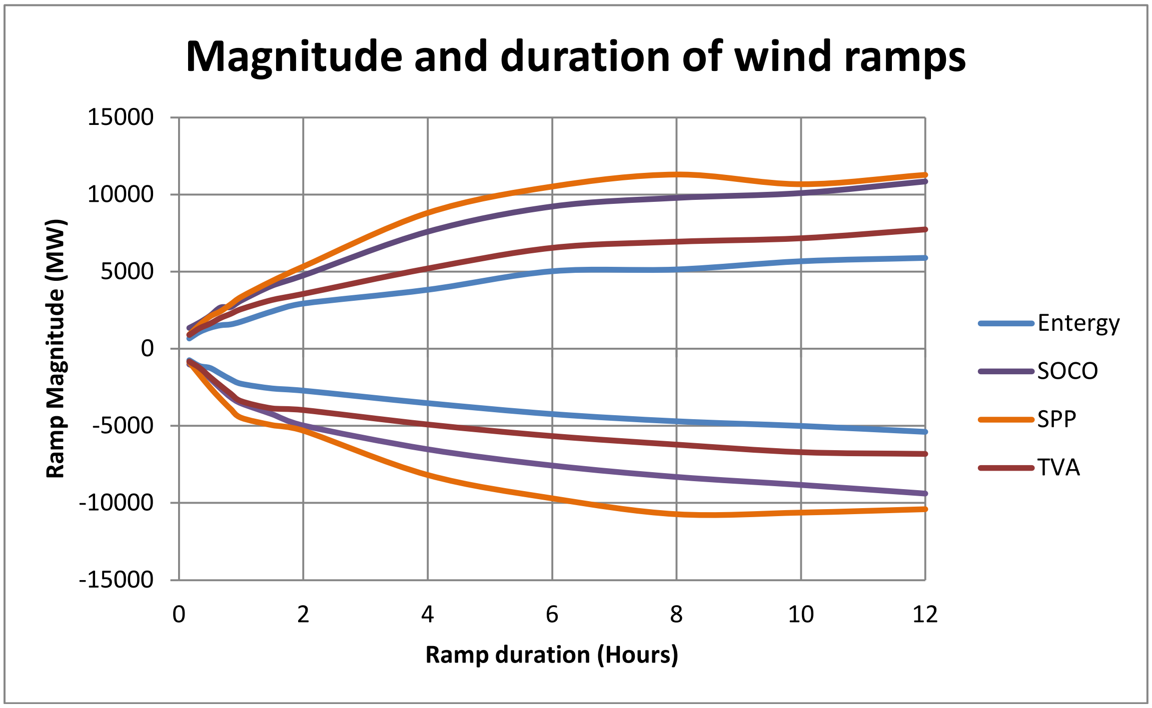

Figure 3-5
Wind ramp envelopes seen for each region

Because the method used to select the wind plants for each region gave a very even distribution of plants across the SPP footprint, the wind production for the four regions is highly correlated. This can be seen clearly looking at the two of the most extreme events seen in the data as shown in Figure 3-6 and Figure 3-7, where extreme is defined as the greatest magnitude changes and ramp rates.

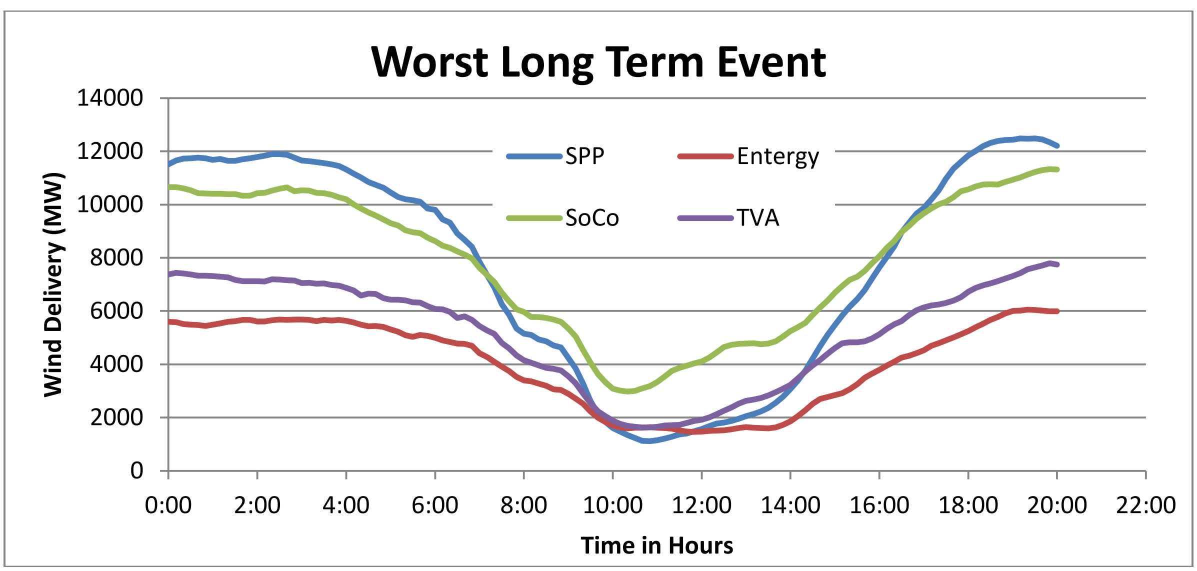

Figure 3-6
Worst long term event

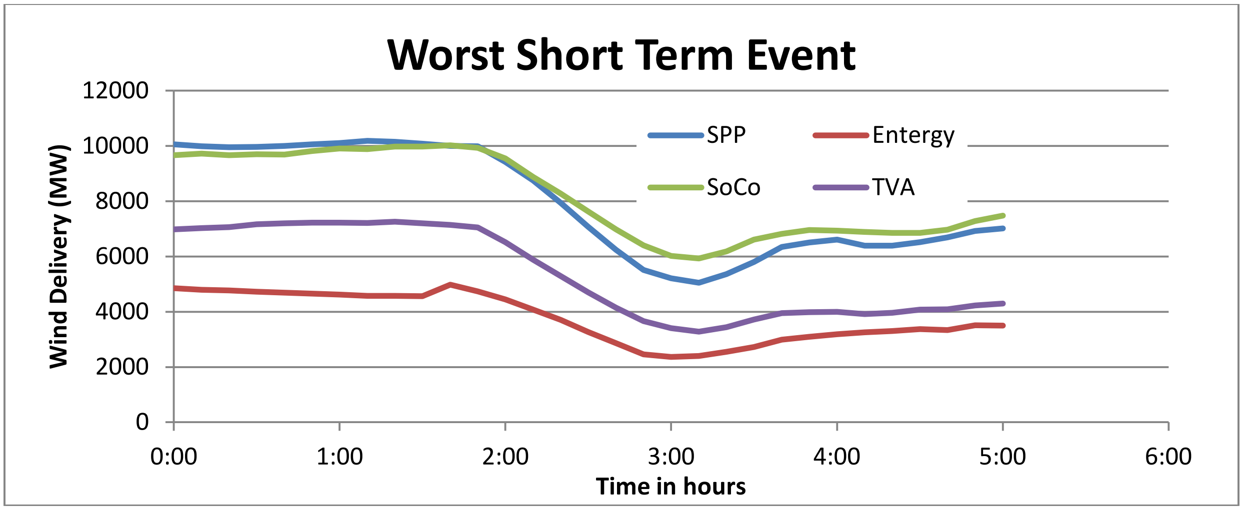

Figure 3-7
Worst short term event

In addition to the wind production data, the dataset for this study also contained a day-ahead forecast of the wind production that exhibited the approximate error characteristics of current state of the art forecast models. Individual wind plant forecasts have an MAE (mean absolute error) of 17% on average for all of the sites used in the study. However, the aggregation effects discussed earlier apply to the forecasts as well. The statistics for the forecast for each of the regions is shown in Table 3-3. These DA forecasts of wind output are used in the day-ahead commitment process of the SCUC/SCED simulations ensuring that the actual DA forecast errors have to be accommodated during the real-time dispatch using resources online or expensive quick start generation.

Table 3-3
Wind production forecast error statistics

	ENTERGY	SOCO	SPP	TVA	Footprint
MAE %Nameplate	8.3%	7.6%	8.6%	8.0%	7.7%
MAE MW	653	1141	1268	829	3710
Max Error	37%	35%	44%	35%	37%

Reserve Requirements

The increased variability and uncertainty from wind power causes an increase in operating reserve requirements. Those requirements have to be provided by some combination of flexible generation and responsive load. Together, these contribute to the operating reserve that is available to help manage the wind and load variability. This reserve is calculated dynamically, and is a function of the observed variability of the wind power and the load. A methodology was developed to estimate the increased requirements for reserves with wind variability in the Eastern Wind Integration and Transmission Study (EWITS).

Short-term variability is challenging because it is difficult to fully anticipate the scheduling changes and fluctuations that must be covered with reserves. In a system with 10-minute or faster dispatch update cycles, a typical approach is to forecast a flat value for wind output for the next interval based on the past 10 to 20 minutes (persistence forecast). The wind varies on that time scale, and an understanding is needed of how it will vary during the forecast interval. Figure 3-8 and Figure 3-9 illustrate how the forecast error is calculated for both 10-minute and 1-hour dispatch schedules for this study. The forecast error is the difference between the actual data and the forecast value.

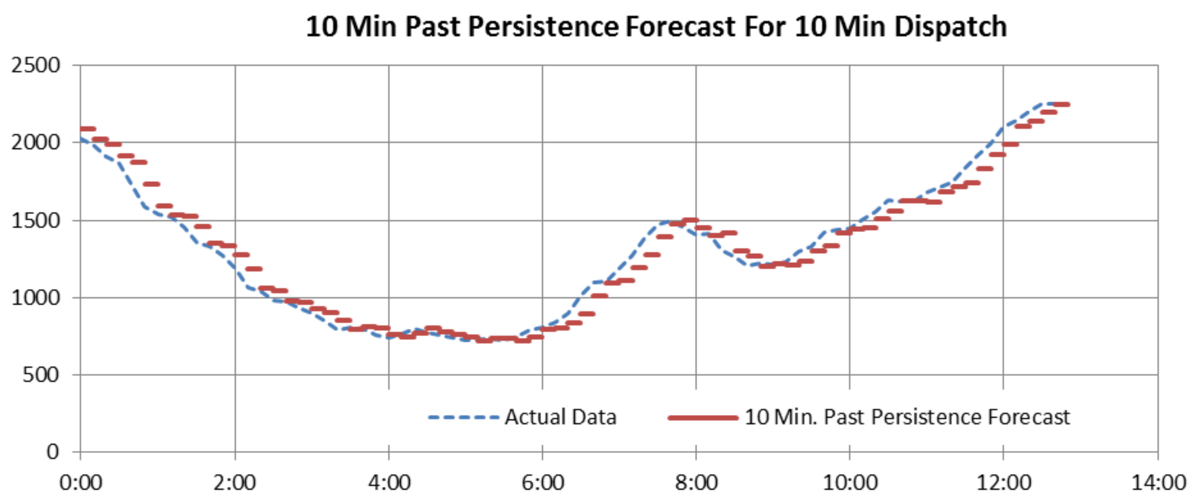

Figure 3-8
Forecast for 10-minute dispatch

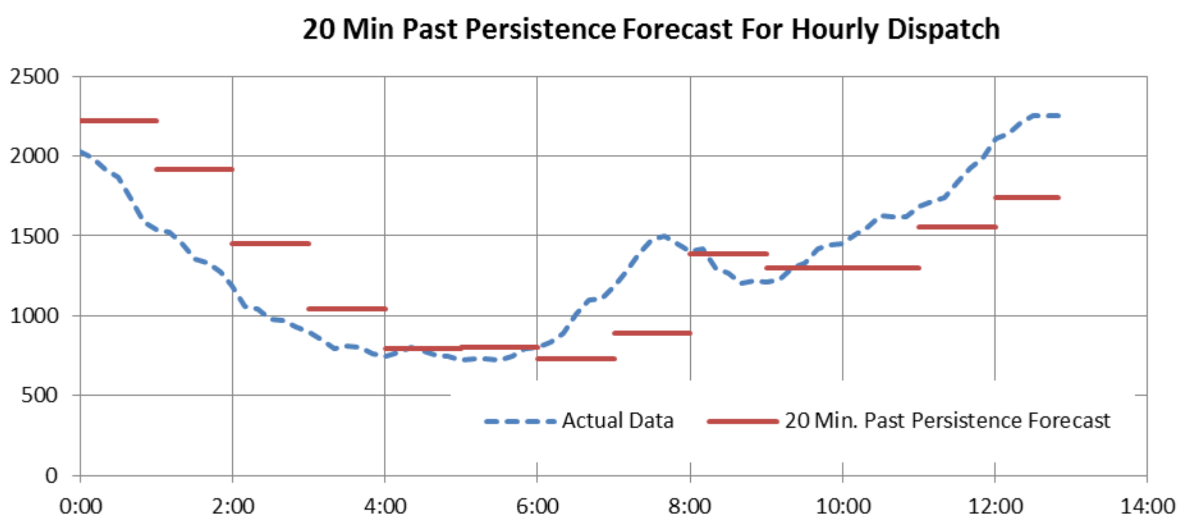

Figure 3-9
Forecast for 1-hour dispatch made at 40 minutes prior to the beginning of the operational period

An estimate of the reserve requirements can be made using a statistical approach. Based on detailed load, wind and forecast data, the standard deviation or other variability metric can be used to calculate this estimate.

For this study, the reserve requirements are broken down into three classes by the types of resources required to fulfill them (Types 2 and 3 are both types of contingency reserves):

1. **Regulation** is required to cover fast changes within the forecast interval. These changes can be up or down and can happen on a minute-to-minute time scale. Regulation requires resources on automatic generation control (AGC).
2. **Spinning** reserve is required to cover larger, less frequent variations that are primarily due to longer-term forecast errors. Spinning reserve is provided by resources (generation and responsive load) that are spinning and that can fully respond within 10 minutes. These resources do not necessarily require AGC.
3. **Non-spinning and supplemental** reserves are used to cover large, slower-moving, infrequent events such as unforecasted ramping events. Non-spinning reserve can be made available within 10 minutes and can come from quick start resources and responsive load. Supplemental reserves can be made available within 30 minutes.

Calculation Methods

At the root of the reserve requirement calculation method is the observation that the variability of wind plant output is a function of its production level and that the short-term variability in wind plant output and thus short-term forecast error is a normally distributed. Through analysis, an equation can be written for the standard deviation (sigma) of wind variability as a function of wind production level. That equation is derived by analyzing the wind production data over some long period of time (a year or more), sorting the data into ranges by production level and calculating the standard deviation for the variability in various ranges of wind output. Figure 3-10 shows an example of this function.

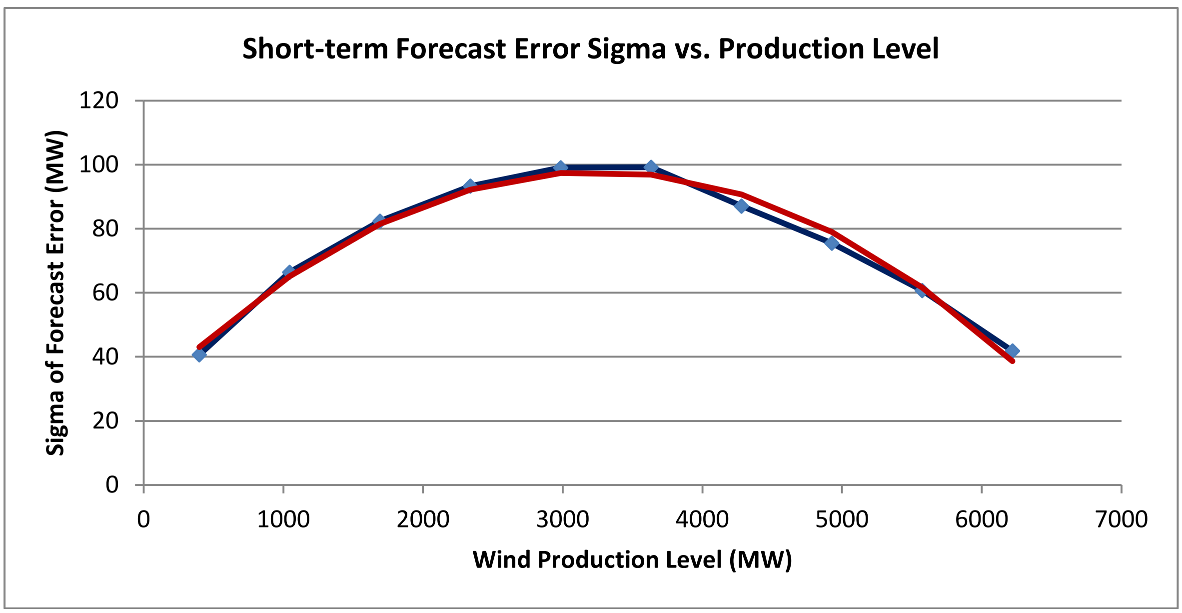

Figure 3-10
Short term forecast error sigma as a function of wind production level

The polynomial shown in Equation 1 is the curve fit shown as the smoothed line in Figure 3-10.

Equation 1 - Sample calculation of hourly wind standard deviation

The equation is used to calculate the standard deviation (sigma) of the wind power for each hour. A component to cover load variability is calculated as a fixed percentage of the hourly load. That fixed percentage is as 1.5% of the hourly load in each BA and is calculated to cover 3 standard deviations of the load variability. The wind component is scaled to 3 standard deviations and combined with the load component as the square root of the sum of the squares as shown in Equation 2.

Equation 2 - Calculation of intra-hour regulation requirement

The 3-sigma approach estimates reserve values that will cover 99.7% of all short-term variability for normal distributions which is generally true for the short term forecast error. This component must be covered by regulating reserves under AGC.

An additional uncertainty reserve component to cover hour-ahead wind forecasting error was calculated. This component is calculated in a similar manner to the short-term forecast error described above, using an equation to describe the standard deviation of hour-ahead forecast error. Figure 3-11 shows the development of the equation for hour-ahead forecast error standard deviation.

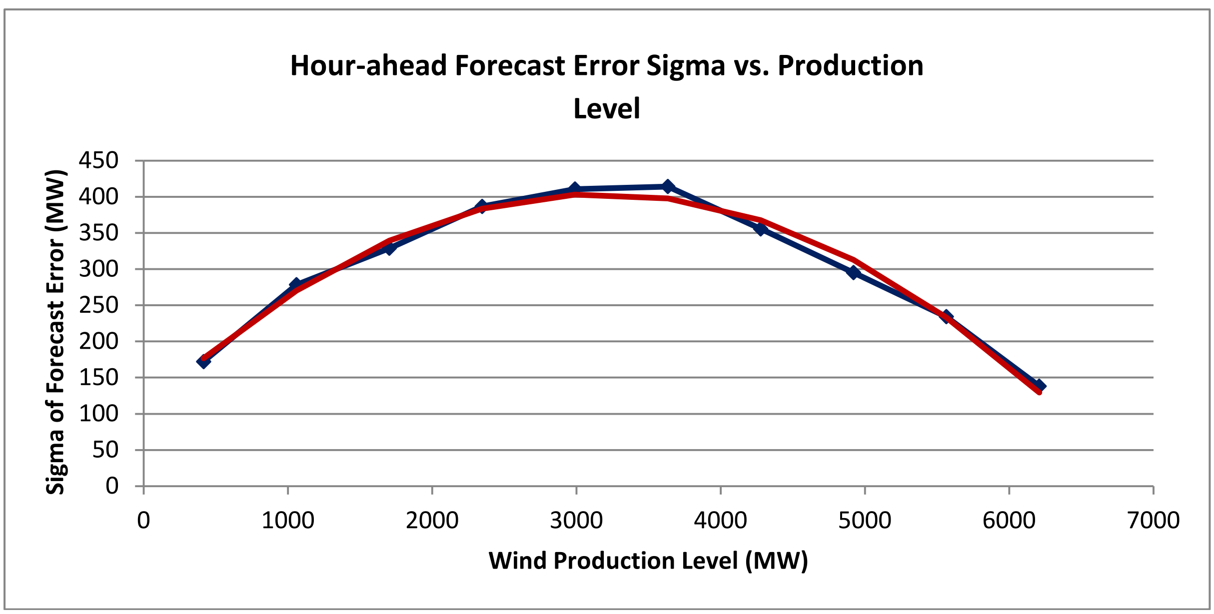

Figure 3-11
Hour-ahead forecast error sigma as a function of wind production level

The polynomial shown in Equation 3 is the curve fit shown as the smoothed line in Figure 3-11.

Equation 3 - Sample calculation of hour-head wind standard deviation

With this equation, the expected standard deviation for the forecast error is calculated based on the previous hour's production (persistence forecast). This component helps to insure the system is positioned with enough maneuverability to cover the probable forecast error and divided as 1 sigma assigned to spinning reserves and 2 sigma assigned to non-spin/supplemental reserves. Equation 4 shows the function for the spinning reserves. The equation for non-spinning/supplemental reserves is the same except that 2 * sigma is used.

Equation 4 - Calculation of spinning reserves requirement

To calculate the total reserve requirement, each of these three components, regulation, spin and non-spin, are added arithmetically.

Results

The method described above was applied to each of the scenarios defined for this study. The details of those scenarios are documented in chapter 4, but Table 3-4 shows a summary of the wind variability allocations to regions by scenario for reference.

Table 3-4
Balancing responsibility by scenario

Scenario	Description
1	SPP manages intra-hour variability for all wind
2	Each region manages intra-hour variability for the wind assigned to their region
3 & 4	All regions are combined into a single super-region and intra-hour variability is managed jointly

Table 3-5 shows the contingency reserve values used for each of the regions as modeled for the scenarios. For scenarios 3 and 4 where the regions in effect operate as a single balancing area, the contingency reserve was assumed to be the highest value from each of the regions. Here, only the single largest contingency is counted towards contingency reserve across the entire footprint; this reduction is not due to wind but the fact that only one contingency is now examined. Another approach would have been to count the two largest contingencies, as there would be a higher probability of multiple simultaneous outages. This would tend to lessen the aggregation benefit as the reduction in the aggregate reserve requirement would be less.

Table 3-5
Contingency reserves

Scenario	Area	Spin	Non-spin
1 and 2	SPP	800	800
	Entergy	1020	1020
	Southern	650	600
	TVA	300	1300
3 and 4	All	1020	1020

For all scenarios, a load regulation requirement of 1.5% of the hourly load was included in the total regulation requirement (load and wind).

Figure 3-12 shows the average regulation (load and wind) for all scenarios (with the bars representing maximum). Figure 3-13 and Figure 3-14 show the average total reserves (regulation, spin and supplemental) without and with contingency reserves included, respectively. The whiskers on the plots show the maximum values.

In scenario 1, SPP receives the greatest possible wind aggregation benefit since all of the wind is aggregated into a single pool. However, SPP only benefits there are no load aggregation benefits in this scenario since the regional loads have not been combined.

In scenario 2, there are slightly less wind aggregation benefits because the wind has been allocated to the individual regions for balancing. Since the wind is being netted with a much larger pool of load the net regulation for the overall footprint is decreased. The reduction in regulation is offset by a higher spin and supplemental to make the total reserves nearly the same for scenarios 1 and 2. Regulation is reduced in the footprint by 206 MW while spin and supplemental are increased by 118 MW and 235 WM, respectively, leading to a 147 MW increase in total reserves for the footprint in scenario 2.

Scenarios 3 and 4 are identical for the reserve requirements and are labeled as scenario 4 on the graphs. These scenarios see a reduction in regulation and total requirements due to the aggregation of all load and wind into a single balancing area. The overall footprint regulation requirement is reduced about 190 MW over scenario 2 and 395 MW over scenario 1. The wind related spin and supplemental components of the reserves are based on the aggregated wind making these components the same for scenarios 1 and 4. There is a reduction of 118 MW and 235 MW for spin and supplemental from scenario 2 to 4. The reduction in total reserves is 542 MW in the same scenarios.

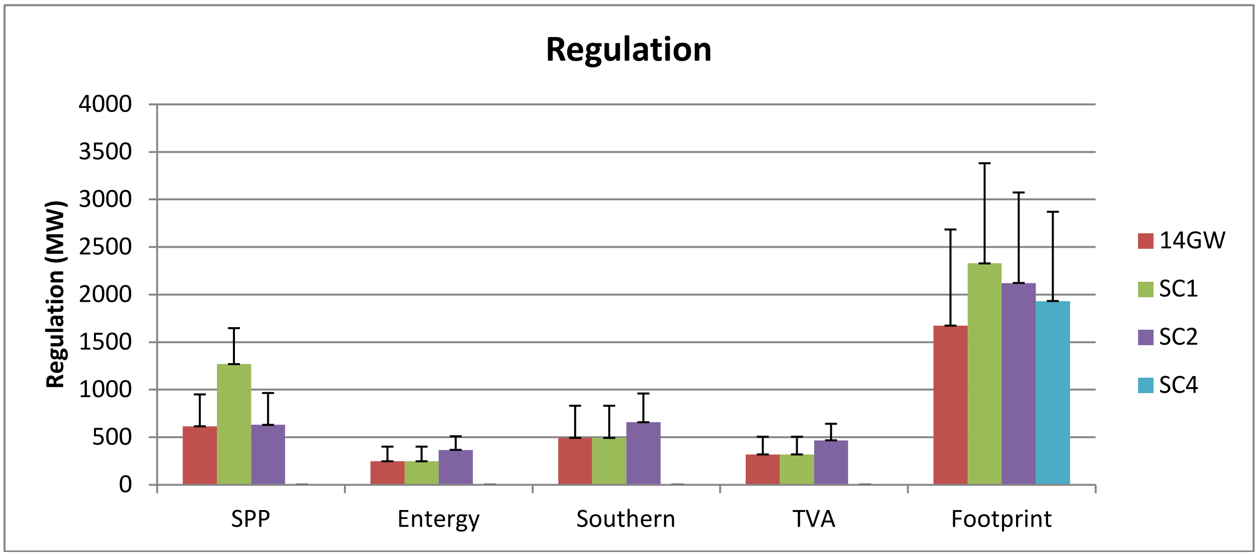

Figure 3-12
Summary of regulation requirements for each scenario

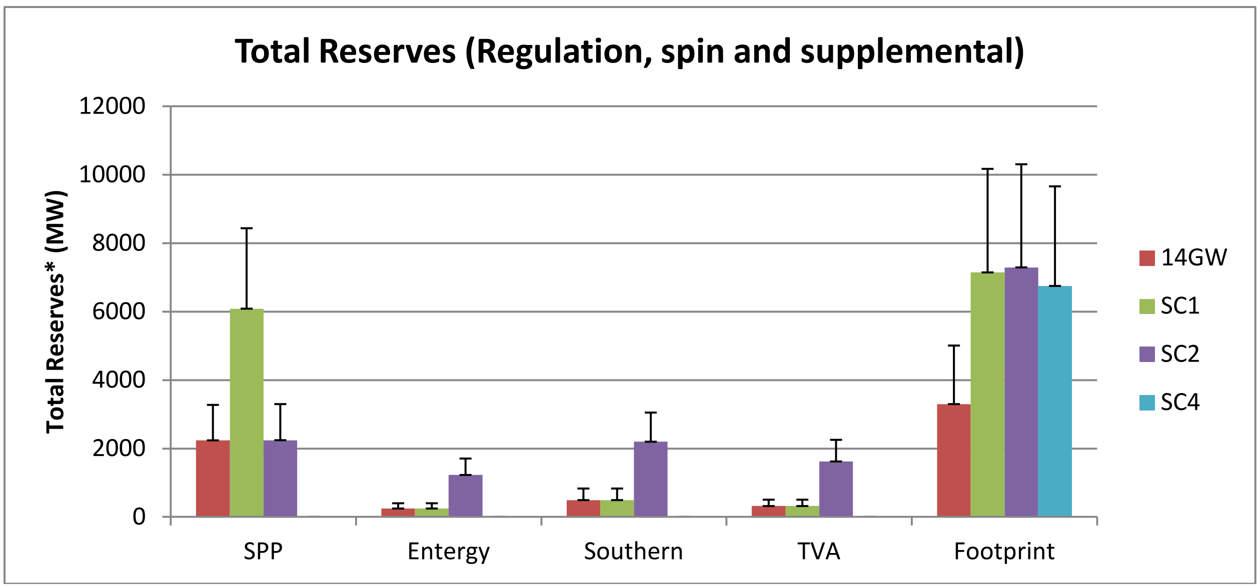

Figure 3-13
Total reserves (regulation, spin and supplemental but excluding contingency) for each scenario

The dramatic reduction in total reserves with contingency reserves included is because for scenario 3 and 4, the regional contingency reserves are aggregated by using the maximum of the regional requirements. Figure 3-14 shows the total reserves with the contingency requirements added to the load and wind related values from Figure 3-13. There is nearly a 5000 MW reduction in total reserves for scenario 4 over scenarios 1 and 2. All but about 550 MW of this reduction is due to consolidation of contingency reserves.

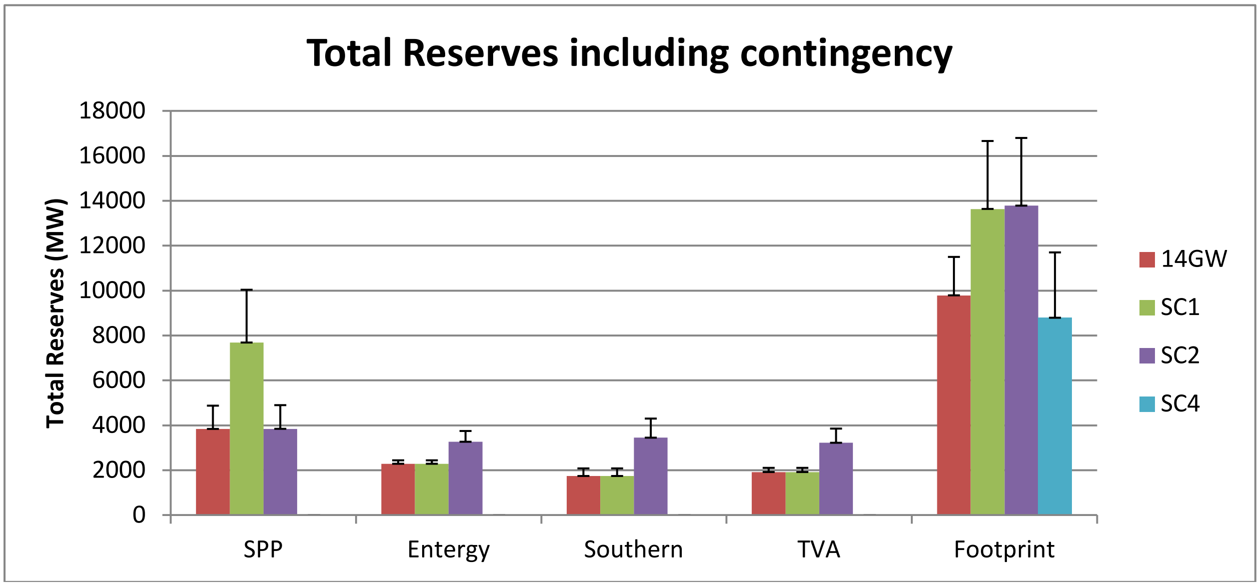

Figure 3-14
Total reserves requirements including regional contingency requirements

4

HIGH WIND TRANSFER SCENARIO DECRIPTIONS

This study used scenario analysis to quantify the cost of meeting the increased balancing requirements associated with four SERC BAs (TVA, Southern Co, Entergy, and Oglethorpe Power) obtaining large amounts of energy from wind generation that is physically located within the SPP footprint. There are numerous ways that power system reliability could be maintained as large amounts of wind generation are added to the power system. Wind generation will increase variability and uncertainty making balancing generation and load more difficult.[1] A fundamental assumption underlying the study methodology is that power system reliability will be maintained. Reserves will be increased and operating practices adjusted to accommodate the increased variability and uncertainty imposed by the increased wind generation. Required changes in unit commitment and economic dispatch will tend to increase costs. These increased costs were quantified with production cost modeling.

Four scenarios were developed to examine different methods for reliably dealing with the increased variability and uncertainty associated with increased wind generation. These scenarios span a range of balancing options. In all cases the new wind resources are physically located in SPP although the entities with the obligation to increase their renewable generation portfolios are in SERC as well as SPP. In all cases the wind plants "assigned" to each SERC load serving entity were spread geographically throughout SPP. All of TVA's wind plants could have been geographically clustered together, for example. This would have reduced the diversity and further increased the balancing costs for each of the SERC BAs. We did not elect to model this low diversity case. The study team determined that any scenario where wind from SPP was moved into the SERC study region would most likely have the wind plants serving each region distributed across the footprint.

The scenarios are numbered in order of increasing cooperation and expected decreasing balancing cost. Scenario 4 is described before scenario 3 because scenario 3 is a more complicated version of scenario 4.

Scenario 1: SPP Provides all Within-Hour Balancing

Scenario 1 imposes the entire within-hour balancing obligation on SPP. Wind is scheduled to each of the SERC BAs hourly but SPP deals with the within-hour forecast uncertainty and the inherent variability of the entire wind fleet. SPP does get the natural aggregation benefit of only having to balance the net variability and uncertainty of the wind generation assigned to all four SERC BAs rather than having to balance each SERC BAs wind resources separately. SPP receives the greatest possible wind aggregation benefit since all of the wind is aggregated into a

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[1] This study focuses on those balancing requirements and assumes that sufficient transmission will be built to both move the wind energy to load centers and to accommodate balancing requirements. Transmission costs will likely be significant but designing an optimal transmission network was beyond the scope of this study. If the balancing benefits found in this study are sufficiently large then it may be worthwhile to begin investigating what transmission investments would be required to allow the balancing savings to be realized and how those benefits compare to the transmission costs.

single pool. However, there are no load aggregation benefits in this scenario since the regional loads have not been combined.

The study team did not expect this scenario to be viable. The expectation was that SPP would not have sufficient reserves and flexible resources to be able to reliably balance this much additional wind generation. The scenario was defined simply as an extreme end of the balancing spectrum.

A proxy case for Scenario 1, with wind forecasts assumed perfect and no additional reserves needed to cater for intra-hour variability and uncertainty in wind, is also examined, to quantify the additional balancing costs incurred by wind.

Scenario 2: Dynamic Scheduling Wind to Each SERC BA

Scenario 2 dynamically scheduled each SERC BA's wind generation out of SPP and to the SERC BA. Each BA aggregates its wind with its load and uses its own internal resources to balance the net BA variability and uncertainty. This scenario increases the size of the load that wind is aggregated with and increases the pool of responsive generation but looses the aggregation benefits associated with combining the variability and uncertainty of all of the wind fleet together.

Scenario 4: Reserves Shared Throughout SPP and the SERC BAs Without Hurdle Rates

Scenario 4 provides the largest aggregation benefit. All of the resources throughout SPP and the SERC BAs are available for balancing and the balancing obligation is reduced through aggregation of the footprint wide variability and uncertainty of both wind and load. The regional contingency reserves are also aggregated by using the maximum of the regional requirements. The day-ahead unit commitment is done based upon each BAs obligations and expectations but the real-time balancing is optimized over the footprint.

Scenario 3: Reserves Shared Throughout SPP and the SERC BAs With Hurdle Rates

Scenario 3 is similar to scenario 4 in its aggregation benefits and reserve requirements but there are hurdle rates between the BAs that increase the cost of inter-BA transactions.

5

HIGH WIND TRANSFER CASE RESULTS

This chapter examines results from the High Wind Transfer scenarios described in the previous chapters. As noted in Chapter 2, all of the high wind transfer cases utilize the Transportation mode solution that provides an unconstrained transmission network model so that transmission does not curtail wind significantly. Utilizing these models, first, the impact of increasing SPP wind generation capacity from 14 GW to 48 GW is examined briefly to provide context as to the effect of high levels of wind on the unconstrained case so that the subsequent results are better understood. The bulk of the chapter examines in detail the differences in the four High Wind Transfer scenarios that are the basis for understanding the potential benefits of coordinated scheduling and balancing throughout the SPP-SERC footprint. Generation, interchanges between regions, costs, and reserve allocation are shown to better understand the possible benefits of cooperation.

Impacts of Increasing Wind Penetration to Meet 20% RES

This subsection examines how generation output and flows across the SPP-SERC footprint are impacted when wind generation capacity in SPP increases from the 14 GW level to 48 GW. Identifying these impacts is not the primary focus of the study, but understanding the change in generation which is due to high wind being added provides a better understanding of how the generation and flows between regions will change as the wind is being balanced differently, which is examined in the next section. The analysis is based on comparison of the 14 GW "unconstrained" case described in Chapter 2 and the High Wind Transfer Scenario #1 described in Chapter 4. Table 5-1 lists the only differences in the case setups, with all other aspects of the cases being the same.

Table 5-1
Differences in 14 GW Unconstrained and High Wind Scenario #1 Case Setups

	14 GW Unconstrained	High Wind Scenario #1
Installed Wind Cap	14 GW	48 GW
Scheduling of DA Wind Forecast	All to SPP	Shares to SPP and SERC
Intra-Hr Reserves for Wind	Carried by SPP alone for 14 GW	Carried by SPP alone for all 48 GW

Generation and Interchange Differences

Increasing installed wind capacity by 34 GW within the footprint obviously impacts the output levels of other types of generation within each region and the flows between regions. Table 5-2 shows the change in average generation when wind is increased from 14 GW installed capacity to 48 GW. As expected, wind displaces combined cycle gas (CC) and coal usage. Blue indicates a reduction in generation, green an increase, as wind is added to the system. There is a small

(390 MW) difference in total generation; this is due to the fact that, even though flows to MISO/PJM/WAPA were fixed from one scenario to another, the method used to fix the flows allowed slight changes in flows if it was seen as necessary by the model. For the remaining scenarios, flows do not change to outside regions.

Table 5-2
Increase in Average Generation Scenario 1 Relative to 14 GW Case

Change in GW	EES	TVA	SBA	SPP	SERC-W	SERC-E	Total
CC	(1.19)	(0.41)	(2.18)	(0.36)	(0.36)	(0.06)	(4.56)
GT	(0.03)	(0.05)	(0.16)	0.21	(0.20)	(0.20)	(0.43)
Hydro	-	0.00	0.00	-	-	(0.00)	(0.00)
Nuclear	(0.00)	-	-	(0.00)	-	(0.00)	(0.00)
Coal	(0.09)	(0.99)	(0.92)	(2.95)	(1.58)	(0.94)	(7.48)
GasOil	(0.34)	-	(0.00)	(0.01)	-	(0.00)	(0.34)
Wind	-	-	-	13.53	-	-	13.53
Other	(0.01)	(0.03)	(0.10)	(0.06)	(0.03)	(0.10)	(0.33)
Total	(1.66)	(1.48)	(3.35)	10.36	(2.17)	(1.31)	0.39

The change in interchange between regions is shown in Table 5-3. This shows the increase in interchange from the region along the side to the region along the top. As expected, SPP increases exports significantly, by almost 10 GW. This is for an increase in wind generation of 13.5 GW on average. Therefore, it appears that most of the wind gets moved out of SPP, but there is also some displacement of generation in SPP. The regions labeled ‘East’ and ‘West’ in the table refer to the SERC regions other than those explicitly shown in the study. As the model also allowed generation to change in these regions, these changes are shown. The regions are split into East and West as the western regions are expected to be most affected.

Table 5-3
Change in energy export/import from region to region - positive indicates increase in export

	EES	TVA	SBA	SPP	WEST	EAST	FRCC	MISO	PJM	Total
EES	-	556	2,062	(4,877)	913	-	-	159	-	(1,187)
TVA	(556)	-	(717)	-	208	(413)	-	-	0	(1,478)
SBA	(2,062)	717	-	-	(2,047)	41	0	-	-	(3,351)
SPP	4,877	-	-	-	3,425	-	-	1,193	-	9,494
WEST	(913)	(208)	2,047	(3,425)	-	1,580	-	(1,253)	0	(2,172)
EAST	-	413	(41)	-	(1,580)		-	(99)	0	(1,306)
FRCC	-	-	(0)	-	-	-	-	-	-	(0)
MISO	(159)	-	-	(1,193)	1,253	99	-	-	-	(0)
PJM	-	(0)	-	-	(0)	(0)	-	-	-	(0)

Figure 5-1 shows the net effect of adding wind to the entire SPP/SERC footprint. This does not show actual imports/exports changes between each region but rather the effect that this increase in wind has, in terms of where energy is increasing and decreasing. As shown in the previous two tables, SPP increases generation. This flows to all regions, with Southern Balancing Authority (SBA) decreasing generation to about one third of the SPP increase, and other regions decreasing smaller amounts. It is interesting to note that, even though the wind is committed day ahead in only the Entergy, SBA and TVA regions of SERC, the other SERC regions also end up decreasing generation in the economic dispatch phase, as it is less expensive to the entire system that they do so.

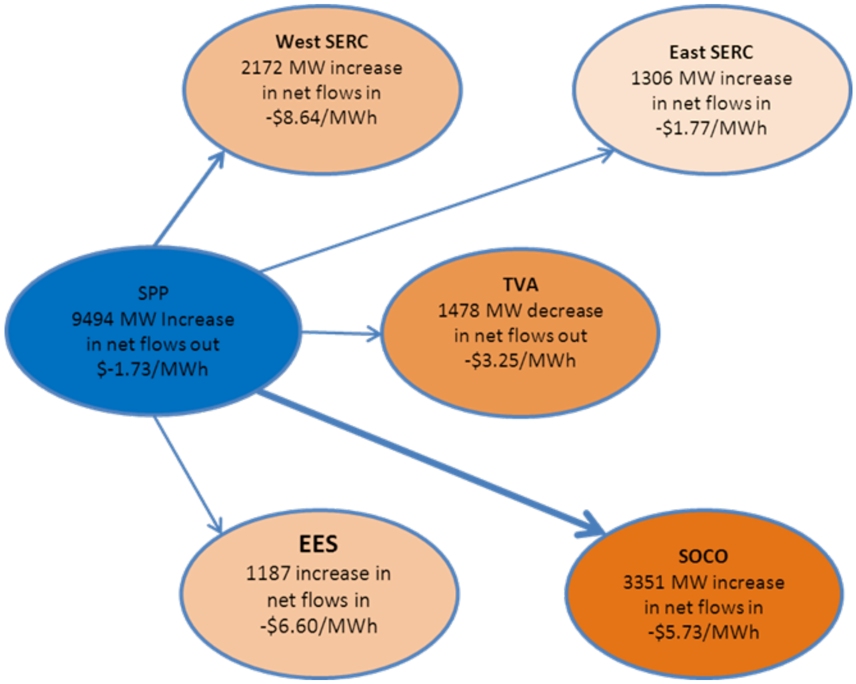

Figure 5-1
Effect of wind on system; blue indicates and increase in generation, orange a decrease in generation

Considerations for SPP Providing All Within-Hour Balancing for Scenario #1

The model does not show that Scenario #1, where SPP provides the within hour balancing for all 48 GW of wind, results in a loss of load reliability issue, as may have been expected when a system with a peak of 55 GW has to manage almost 48 GW of installed wind. Although initially unexpected by the project team, after consideration of the results, the following reasons for this result are provided:

- *High reserve margin modeled.* The planned generation for the Non-RES case is maintained for the high wind generation cases such that no plant is assumed to be retired despite the large increase in wind generation installed as we move from the 7 GW to 48 GW case. Therefore, SPP is left with large amounts of resources, both to meet energy and reserve requirements. Even not considering wind, it still has a reserve margin of 20% above peak demand (and as has been shown in the past, wind will have some capacity credit).

- *Availability of reserve capable generation.* Although the regulation requirements increase to 1.6 GW and spinning reserve increased to 3 GW, there is 4.5 GW of regulation capacity and 9.5 GW of spinning capacity. Although some of these capacities overlap, sufficient reserves are available assuming that the commitment and dispatch select the appropriate resources for providing energy and leaving available capacity on the reserve capable units. Later sections will show how this may be an issue for some hours as the resources which could otherwise be used to provide regulation are being asked to provide energy; however, this is only for a small amount of hours and could be remedied in reality.

- *Only within-hour balancing covered by SPP.* The wind generation allocated to each of the SERC BAs is committed out to Entergy, SBA and TVA day ahead. As a result, generation is scheduled in these BAs respectively to follow the inter-hour variability of much of the wind generation. SPP is only required to maintain reserves to cover the within-hour variability.

Comparison of High Wind Transfer Scenarios

This section summarizes the results of the UPLAN simulations of the high wind scenarios. The purpose of the production cost simulations is to examine the possible effects of different methods to balance the short term variability and uncertainty of the wind located in SPP much of which is exported to SERC. Three different balancing/cooperation methods are examined, with sensitivities around hurdle rates, effect of forecast uncertainty and increased reserves, and gas prices. The section is laid out as follows: firstly, the total average generation for the different scenarios is shown to enable quick comparison between scenarios. Next, the interchanges between regions are examined to show how the movement of energy around the system is likely to change with different balancing strategies. Finally, production costs are compared across all regions to quantify benefits. Having compared across all scenarios, comparisons between individual scenarios are shown in more detail, again concentrating on changes in generation and interchange. The reserve requirements and provision by unit type and region are then shown – as the focus of the study is different methods to carry this reserve, these results help explain many of the differences between scenarios. More detail is then given on start-ups and capacity factor of units. A sensitivity on gas prices is examined last. It should be noted that all results are based on the particular modeling assumptions utilized, including both on input data (e.g. fuel price, unit characteristics, plant mix, wind time series) and operational assumptions (e.g. how the unit commitment and dispatch is carried out, assumptions on hydro generation, assumptions about interaction between the regions in the study and also interaction of the study regions and outside areas, etc.).

Generation Summary

Table 5-4 shows the average generation per unit type for each region and the total for all regions. The data shows that the changes in generation due to balancing approach are relatively small and impact primarily CC, coal and GT. Note here the wind shown for the SERC regions is the wind located in SPP and distributed out to the SERC regions.

Table 5-4
Average Generation in GW by region and type for all areas and high wind scenarios

	Unit Type	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 1 Proxy
Entergy	CC	2.1	2.2	2.2	2.3	2.0
	GT	0.0	0.0	0.0	0.0	0.0
	Hydro	0.2	0.2	0.2	0.2	0.2
	Nuclear	4.9	4.9	4.9	4.9	4.9

	Coal	3.6	3.6	3.6	3.6	3.6
	GasOil	0.7	0.7	0.7	0.7	0.7
	Wind	3.7	3.7	3.7	3.7	3.7
	Other	0.1	0.1	0.1	0.1	0.1
	Total Gen	*15.3*	*15.4*	*15.4*	*15.5*	*15.2*
SBA	**CC**	5.0	5.7	4.2	3.2	4.9
	GT	0.1	0.1	0.1	0.1	0.1
	Hydro	0.8	0.8	0.8	0.8	0.8
	Nuclear	7.4	7.4	7.4	7.4	7.4
	Coal	14.7	14.5	15.0	14.4	14.8
	GasOil	0.0	0.0	0.0	0.0	0.0
	Wind	6.3	6.3	6.3	6.3	6.3
	Other	0.7	0.7	0.8	0.7	0.7
	Total Gen	*34.9*	*35.4*	*34.5*	*32.8*	*35.0*
TVA	**CC**	1.5	2.1	1.1	1.4	1.5
	GT	0.1	0.3	0.0	0.0	0.1
	Hydro	2.0	2.0	2.0	2.0	2.0
	Nuclear	8.3	8.3	8.3	8.3	8.3
	Coal	10.8	10.5	11.0	10.9	10.9
	GasOil	-	-	-	-	-
	Wind	4.2	4.2	4.2	4.2	4.2
	Other	0.4	0.4	0.4	0.4	0.4
	Total Gen	*27.4*	*27.8*	*27.1*	*27.3*	*27.4*
SPP	**CC**	3.1	2.3	2.3	2.9	2.1
	GT	0.5	0.1	0.1	0.1	0.1
	Hydro	0.8	0.8	0.8	0.8	0.8
	Nuclear	2.2	2.2	2.2	2.2	2.2
	Coal	19.2	19.4	20.1	21.0	20.0
	GasOil	0.0	0.0	0.0	0.0	0.0
	Wind	5.9	5.9	5.9	5.9	5.9
	Other	0.8	0.8	0.8	0.8	0.8
	Total Gen	*32.6*	*31.6*	*32.2*	*33.8*	*32.0*
SERC East	**CC**	2.2	2.1	2.2	2.2	2.2
	GT	0.6	0.6	0.6	0.7	0.6
	Hydro	1.0	1.0	1.0	1.0	1.0
	Nuclear	10.4	10.4	10.4	10.4	10.4
	Coal	19.7	19.7	20.0	20.0	19.9
	GasOil	0.0	0.0	0.0	0.0	0.0
	Wind	-	-	-	-	-
	Other	0.6	0.6	0.6	0.6	0.6
	Total Gen	34.4	34.4	34.8	34.8	34.6
SERC West	**CC**	1.4	1.5	1.5	1.4	1.5
	GT	0.3	0.2	0.3	0.3	0.3
	Hydro	0.0	0.0	0.0	0.0	0.0
	Nuclear	-	-	-	-	-
	Coal	8.4	8.3	8.8	8.7	8.6
	GasOil	-	-	-	-	-
	Wind	0.1	0.1	0.1	0.1	0.1
	Other	0.0	0.0	0.0	0.0	0.0
	Total Gen	*10.3*	*10.3*	*10.9*	*10.6*	*10.6*
All regions	**CC**	15.3	15.9	13.5	13.4	14.2
	GT	1.6	1.4	1.2	1.3	1.2

	Hydro	4.8	4.8	4.8	4.8	4.8
	Nuclear	33.1	33.1	33.1	33.1	33.1
	Coal	76.4	76.0	78.5	78.6	77.8
	GasOil	0.8	0.8	0.7	0.7	0.7
	Wind	20.3	20.3	20.3	20.3	20.3
	Other	2.6	2.6	2.7	2.6	2.7
	Total Gen	*154.8*	*154.8*	*154.8*	*154.8*	*154.8*

To examine the individual regions in better detail, Figure 5-2 through Figure 5-6 show the generation by unit type in each region for all scenarios. Figure 5-2 shows that the main change in Entergy is an increase in CC output relative to scenario 1 for all but the proxy (balancing cost) scenario. As each subsequent scenario represents a greater level of coordination in terms of balancing, scheduling and reduced contingency requirements, the increasing utilization of Entergy CCs as cooperation increases indicates that in the models utilized, they are less expensive than other CCs (and GTs) and can displace these types of generation when allowed to do so. From the results, it seems that Entergy would increase its participation in the region as more cooperation is allowed.

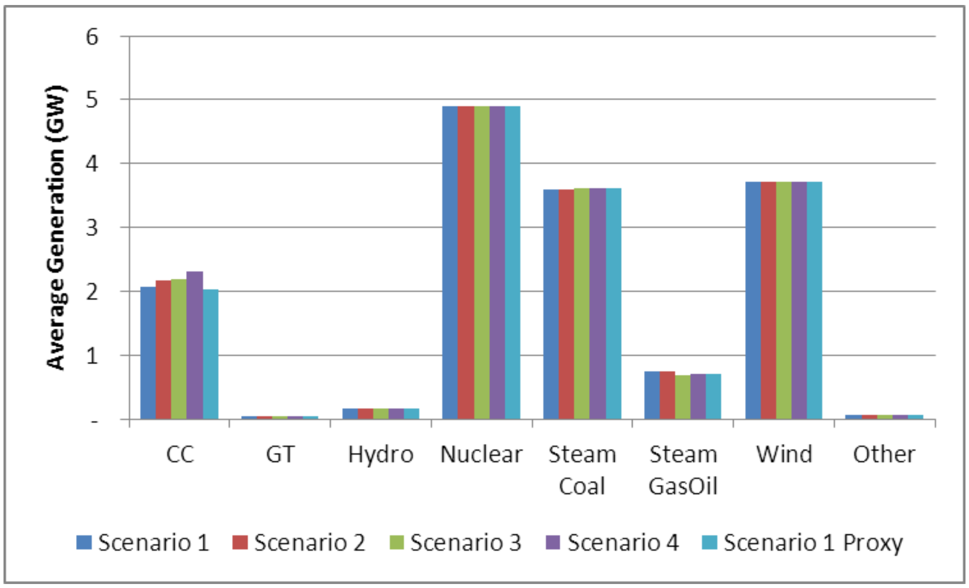

Figure 5-2
Average hourly generation in Entergy

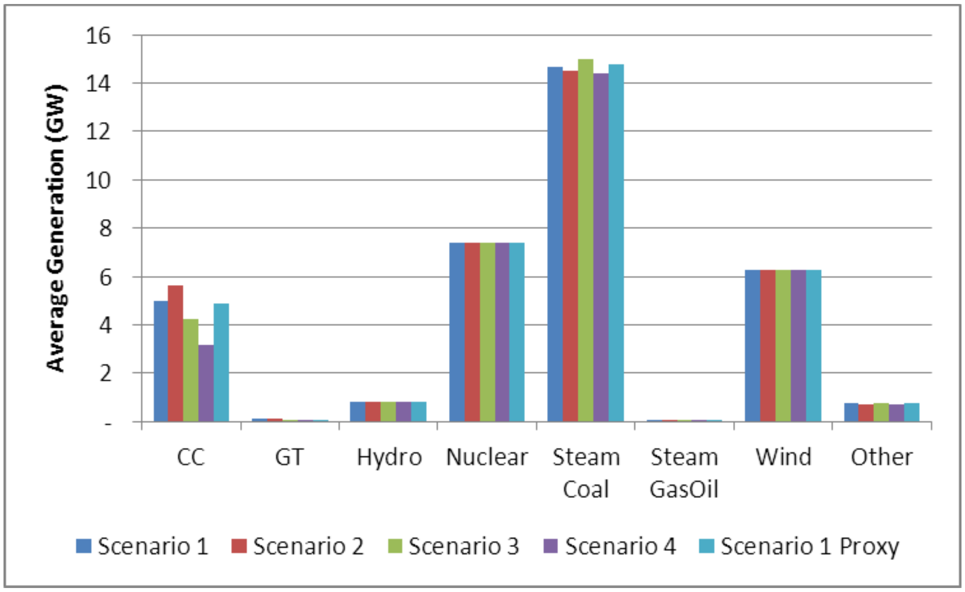

Figure 5-3
Average hourly generation in SBA

Figure 5-3 shows the SBA average generation by unit type for the different high wind scenarios. This shows relatively significant changes for both CC and coal for different balancing and reserve provision strategies. SBA CC usage increases from Scenario 1 to Scenario 2, as each of the regions becomes responsible for balancing the intra hour variability and uncertainty in the wind assigned to them from SPP. This corresponds to a small decrease in coal. For scenario 3, when all regions share the with-in hour reserve requirements, SBA coal output increases and CC decreases. This would be expected as the assumptions on fuel price in the model mean coal is significantly cheaper across the footprint, and so production is maximized, while CC in SBA is modeled as more costly and therefore decreases generation when not needed to provide reserve.

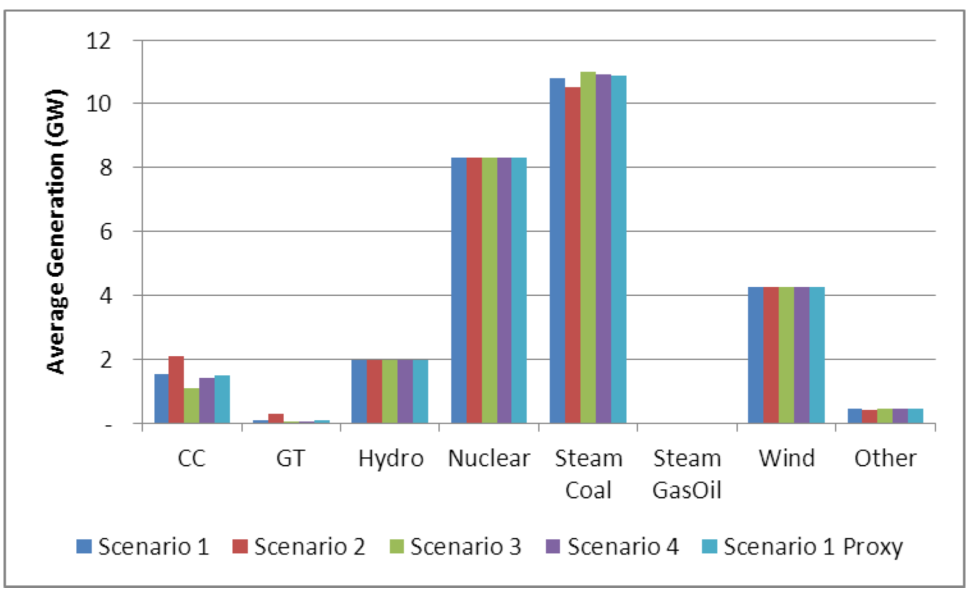

Figure 5-4: Average hourly generation in TVA

Figure 5-4 shows the average hourly generation in TVA. Again, coal and CC change most significantly. CC usage increases in Scenario 2 with the increase in reserve requirements for TVA. There is an associated decrease in coal usage as more CCs are online for reserve purposes. GTs are also used to provide reserve in Scenario 2.

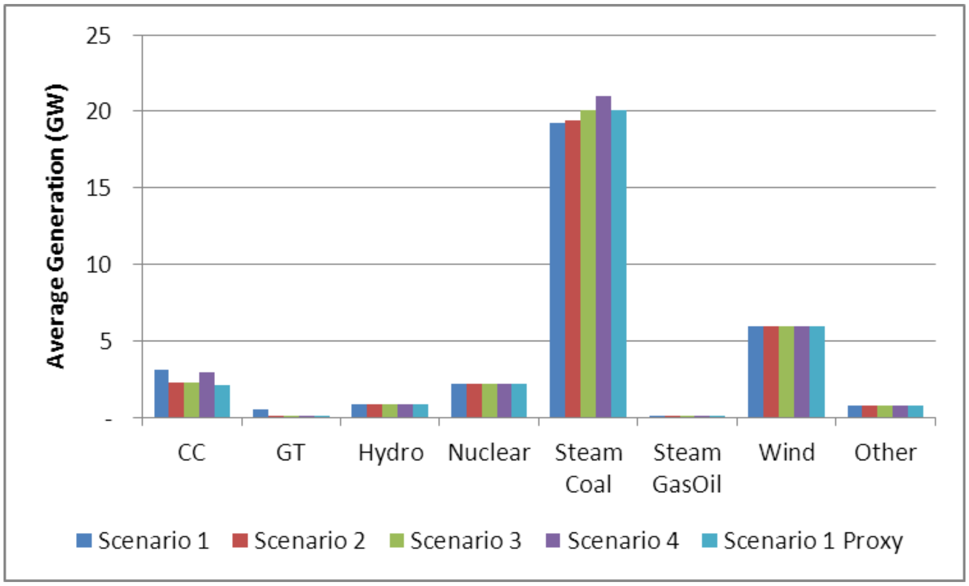

Figure 5-5: Average hourly generation in SPP

Figure 5-5 shows the average hourly generation for SPP. As Scenario 2 no longer requires SPP to balance all the additional intra-hour reserve needed for wind, there is a decrease in CC and gas turbine usage. This allows more coal to be used, as well as decreasing the net export from SPP. Scenario 3, where all areas balance wind and other reserve requirements together, allows for an increase in the coal, which is modeled as cheaper than other footprint coal in this model. Scenario 4 shows a large increase in coal usage as hurdle rates are removed and the energy modeled as cheapest here is allowed to flow throughout the region.

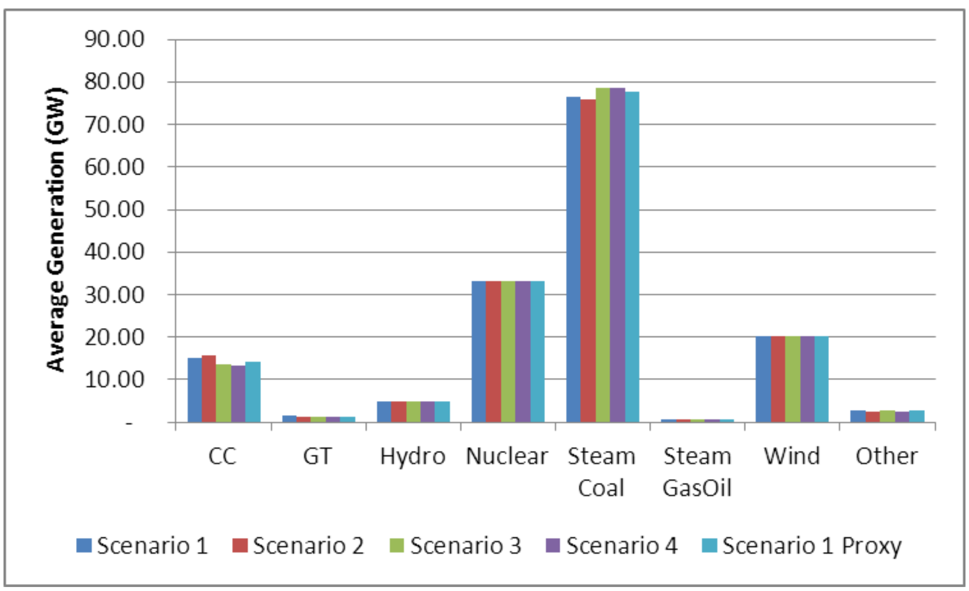

Figure 5-6: Average hourly generation in all regions

Figure 5-6 shows the average hourly generation for all regions, including those other SERC regions which also change operation across scenarios, even though none of the wind is assigned to them. As shown before, coal and CC are most affected. CC is increased in scenario 2 as Entergy, SBA and TVA need to provide reserve to balance the wind assigned to them. For scenarios 3 and 4 the coal which is modeled as cheaper throughout the footprint can increase to provide generation in response to a reduction in overall reserve requirements as well as the fact that greater cooperation throughout the footprint allows a more optimal reserve allocation.

Interchange Summary

Table 5-5 shows the interchange, or aggregate flow of energy, between regions. These flows are determined based on the relative economics of the generation within the different regions.

Table 5-5: Imports and exports between regions for different scenarios- positive is export

Scenario	Region	EES	TVA	SBA	SPP	WEST SERC	EAST SERC	FRCC	MISO	PJM	Total
Scenario 1	EES	-	86	3,139	(8,125)	365	-	-	78	-	(4,456)
	TVA	(86)	-	1,070	-	991	(397)	-	(403)	339	1,513
	SBA	(3,139)	(1,070)	-	-	(2,265)	68	2,000	-	-	(4,406)
	SPP	8,125	-	-	-	4,051	-	-	1,387	-	13,562
	WEST SERC	(365)	(991)	2,265	(4,051)	-	2,088	-	(1,112)	86	(2,081)
	EAST SERC	-	397	(68)	-	(2,088)	(0)	-	(1)	160	(1,601)
	FRCC	-	-	(2,000)	-	-	-	-	-	-	(2,000)
	MISO	(78)	403	-	(1,387)	1,112	1	-	-	-	52
	PJM	-	(339)	-	-	(86)	(160)	-	-	-	(585)
Scenario 2	EES	-	(23)	2,731	(7,025)	(121)	-	-	84	-	(4,353)
	TVA	23	-	1,309	-	1,839	(1,123)	-	(403)	339	1,984
	SBA	(2,731)	(1,309)	-	-	(1,959)	71	2,000	-	-	(3,928)
	SPP	7,025	-	-	-	4,181	-	-	1,357	-	12,563
	WEST SERC	121	(1,839)	1,959	(4,181)	-	(231)	-	2,024	86	(2,060)
	EAST SERC	-	1,123	(71)	-	231	(0)	-	(3,114)	160	(1,672)
	FRCC	-	-	(2,000)	-	-	-	-	-	-	(2,000)
	MISO	(84)	403	-	(1,357)	(2,024)	3,114	-	-	-	52
	PJM	-	(339)	-	-	(86)	(160)	-	-	-	(585)
Scenario 3	EES	-	95	3,416	(8,790)	916	-	-	23	-	(4,340)
	TVA	(95)	-	1,022	-	1,606	(1,231)	-	(403)	339	1,238
	SBA	(3,416)	(1,022)	-	-	(2,468)	51	2,000	-	-	(4,856)

	SPP	**8,790**	**-**	**-**	**-**	**3,245**	**-**	**-**	**1,126**	**-**	**13,161**
	WEST SERC	**(916)**	**(1,606)**	**2,468**	**(3,245)**	**-**	**2,112**	**-**	**(375)**	**86**	**(1,475)**
	EAST SERC	**-**	**1,231**	**(51)**	**-**	**(2,112)**	**0**	**-**	**(422)**	**160**	**(1,195)**
	FRCC	**-**	**-**	**(2,000)**	**-**	**-**	**-**	**-**	**-**	**-**	**(2,000)**
	MISO	**(23)**	**403**	**-**	**(1,126)**	**375**	**422**	**-**	**-**	**-**	**52**
	PJM	**-**	**(339)**	**-**	**-**	**(86)**	**(160)**	**-**	**-**	**-**	**(585)**
Scenario 4	**EES**	**-**	**(496)**	**2,691**	**(7,193)**	**804**	**-**	**-**	**(22)**	**-**	**(4,216)**
	TVA	**496**	**-**	**2,860**	**-**	**(2,831)**	**1,025**	**-**	**(403)**	**339**	**1,485**
	SBA	**(2,691)**	**(2,860)**	**-**	**-**	**(3,407)**	**384**	**2,000**	**-**	**-**	**(6,573)**
	SPP	**7,193**	**-**	**-**	**0**	**6,154**	**-**	**-**	**1,450**	**-**	**14,796**
	WEST SERC	**(804)**	**2,831**	**3,407**	**(6,154)**	**-**	**715**	**-**	**(1,847)**	**86**	**(1,767)**
	EAST SERC	**-**	**(1,025)**	**(384)**	**-**	**(715)**	**(0)**	**-**	**772**	**160**	**(1,193)**
	FRCC	**-**	**-**	**(2,000)**	**-**	**-**	**-**	**-**	**-**	**-**	**(2,000)**
	MISO	**22**	**403**	**-**	**(1,450)**	**1,847**	**(772)**	**-**	**-**	**-**	**52**
	PJM	**-**	**(339)**	**-**	**-**	**(86)**	**(160)**	**-**	**-**	**-**	**(585)**
Scenario 1 proxy	**EES**	**-**	**37**	**3,076**	**(8,171)**	**513**	**-**	**-**	**49**	**-**	**(4,495)**
	TVA	**(37)**	**-**	**1,165**	**-**	**2,835**	**(2,341)**	**-**	**(403)**	**339**	**1,557**
	SBA	**(3,076)**	**(1,165)**	**-**	**-**	**(2,202)**	**57**	**2,000**	**-**	**-**	**(4,385)**
	SPP	**8,171**	**-**	**-**	**(0)**	**3,569**	**-**	**-**	**1,295**	**-**	**13,035**
	WEST SERC	**(513)**	**(2,835)**	**2,202**	**(3,569)**	**-**	**(296)**	**-**	**3,130**	**86**	**(1,796)**
	EAST SERC	**-**	**2,341**	**(57)**	**-**	**296**	**-**	**-**	**(4,123)**	**160**	**(1,383)**
	FRCC	**-**	**-**	**(2,000)**	**-**	**-**	**-**	**-**	**-**	**-**	**(2,000)**
	MISO	**(49)**	**403**	**-**	**(1,295)**	**(3,130)**	**4,123**	**-**	**-**	**-**	**52**
	PJM	**-**	**(339)**	**-**	**-**	**(86)**	**(160)**	**-**	**-**	**-**	**(585)**

Table 5-5 shows that flows to MISO and PJM change somewhat for different cases; however the net exchange to these is fixed in each hour; what changes is where this comes from in the study footprint. Therefore this does not significantly affect results.

Figure 5-7 shows the net flow from each region, as given in the last column of Table 5-5. It can be seen that the other SERC regions also change. However, they do not change as much as those utilities with wind assigned in the study. Notable results here include the fact that Entergy does not change significantly in the different scenarios, as also shown earlier with generation. However, the average flows between Entergy and individual regions change significantly; for example Entergy goes from exporting 3.1 GW on average in Scenario 1 to SBA, to 2.7 GW in Scenario 2. It can be seen that Entergy is thus importing less from SPP and exporting less to

SBA. More details on these types of changes are given for individual scenario comparisons later. Other aspects of interest include the fact that SBA imports increase significantly if hurdle rates are removed. While this assumption is likely unrealistic, it does show that, for the prices and plant mix assumed in the model, hurdle rate levels are impacting the flow of energy; removing them entirely can be thought of as the extreme case. In reality, these may be needed to pay for transmission and so additional wind, with its required additional transmission may actually increase hurdle rates.

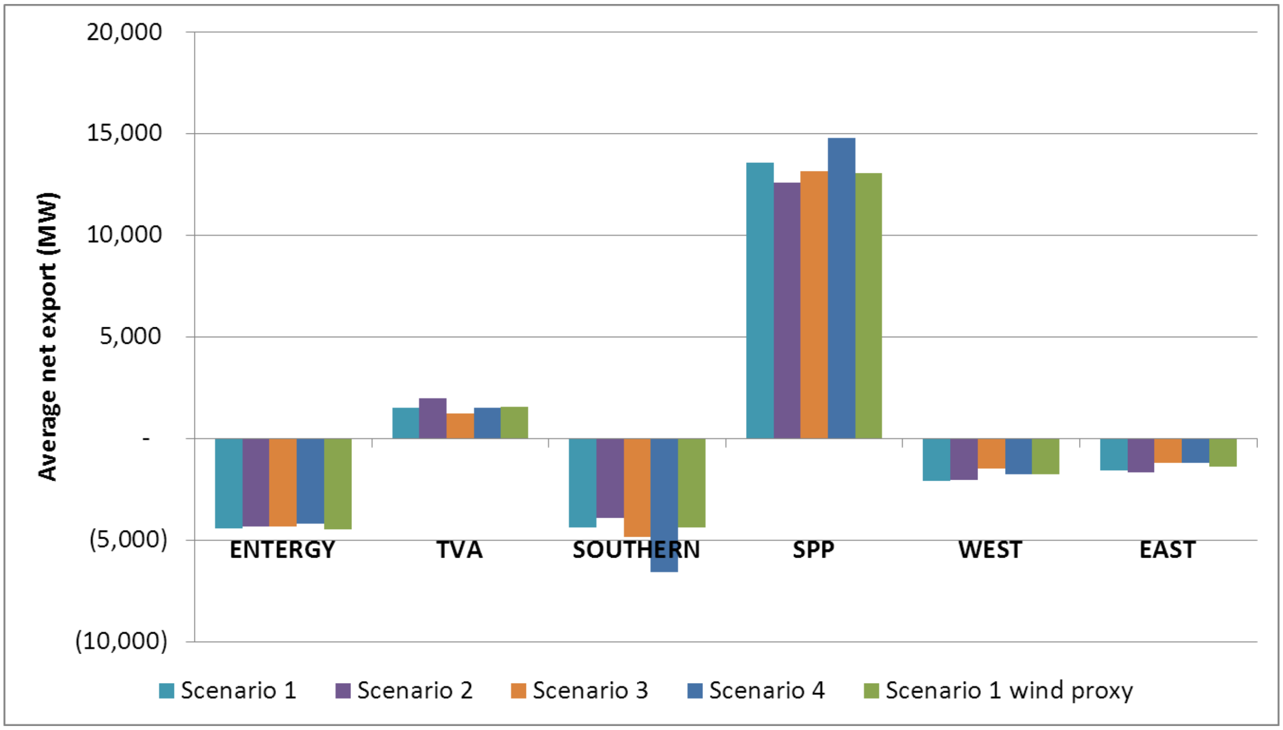

Figure 5-7: Average net flow by region

The changes in imports/exports between scenarios are obviously very dependent on relative economics between regions. From hour to hour, the average net flow between any two BAs may be in the opposite direction of the average values across the year. For example, there would likely be periods when low wind power output from the wind plants in SPP, coupled with other load and generation differences, would result in a change in the general flow of energy across the footprint such that Entergy or SBA would be net exporters and SPP a net importer. The data shown in Table 5-5 and Figure 5-7 only show average flows. Additionally, different assumptions about plant mix in each region and relative fuel prices will change the flows. The specific flow results shown here are dependent on the modeling assumptions utilized for our study. The results do show, however, that different strategies to balance the intra-hour variability and uncertainty inherent in wind power will cause changes in how energy is moved across the large region.

Production Cost Summary

This section describes the differences between production costs for different cooperation scenarios to provide an understanding of the magnitude of impact different balancing strategies may have on costs. As with any production cost model for future year scenarios, the absolute magnitude of the costs are dependent on the modeling assumptions. As such, the absolute cost values presented should be taken as indicative only with the real emphasis being on the change in costs between scenarios. Table 5-6 shows total production costs for each region; these are costs of generation only and therefore do not reflect the fact that one region may be importing while the other may be exporting. The generation costs include the short run fuel, O&M and start costs, and do not include any representation of capital expenditures.

Table 5-6: Production costs ($M)

2010 $	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 1 proxy
Entergy	4,147	4,214	4,162	4,246	4,093
SBA	9,959	10,301	9,563	8,755	9,904
TVA	6,674	7,135	6,431	6,590	6,679
SPP	9,265	8,290	8,350	8,926	8,329
East SERC	12,303	12,273	12,480	12,505	12,391
West SERC	4,269	4,293	4,539	4,414	4,369
Total Costs	*46,618*	*46,506*	*45,524*	*45,435*	*45,765*
Total Costs/MWh	*34.37*	*34.28*	*33.56*	*33.49*	*33.74*

The same cost results are shown graphically in Figure 5-8. As expected from the generation and flow results, the changes are relatively small from scenario to scenario. Entergy and the other SERC regions not assigned wind can be seen to change very little. SPP as expected decreases in costs when no longer required to carry all the additional reserve for wind. SBA generation costs decrease for Scenario 3 and 4 versus Scenario 2, as the region imports more due to the modeled cheaper units in SPP and Entergy. TVA sees a large increase in generation costs in Scenario 2, while other scenarios are similar in costs. SPP increases its costs in Scenario 4, as its coal is increased to be moved to the SBA region, which is assumed to have more expensive modeled units which are turned off when hurdle rates are removed.

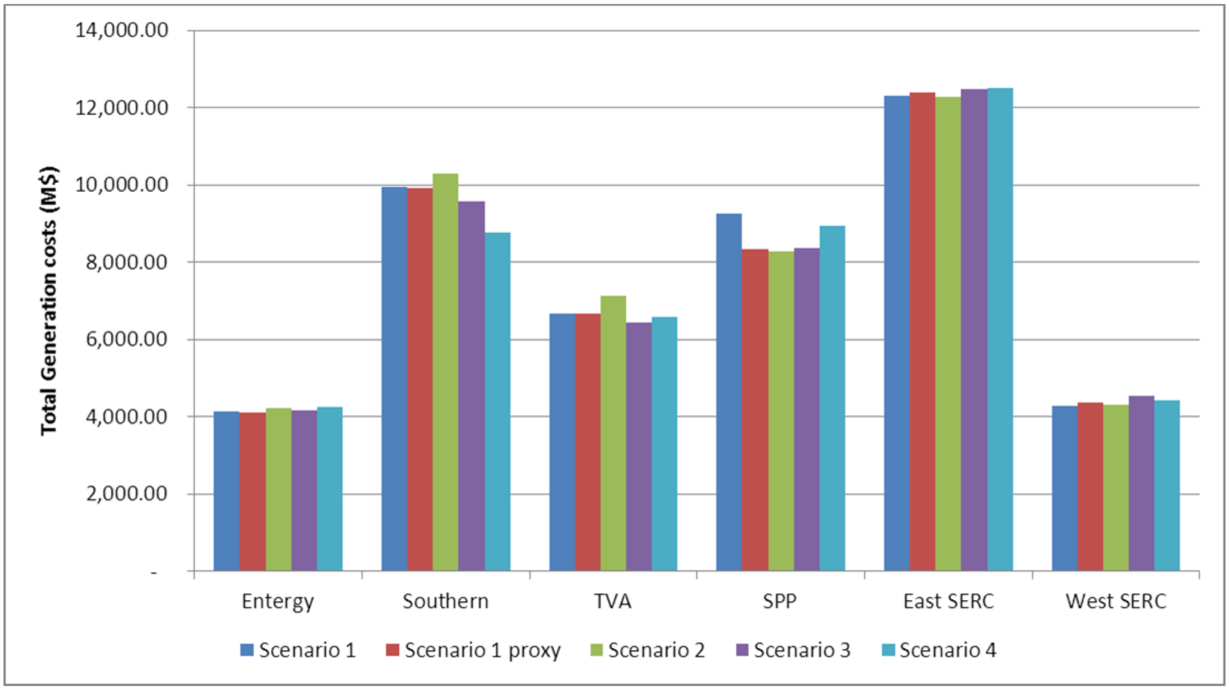

Figure 5-8: Total production costs for different regions for different scenarios

Figure 5-8 shows that there is significant savings for SPP moving from Scenario 1 to Scenario 2, while Entergy, Southern, and TVA see an increase in costs as they pick up the reserve requirements for the wind allocated to them. Scenario 3 does not show a significant difference for SPP, but does show a significant change in costs for other regions. Considering both the costs and generation tables shows that moving from Scenario 2 to Scenario 3 where there is increased cooperation in scheduling and balancing across the footprint, allows more usage of SPP and West SERC coal displacing CC usage in Entergy, SBA and TVA, which are modeled as more expensive options.

Table 5-7: Change in production costs vs. Scenario 1

2010 $	Scen #2	Scen #3	Scen #4	Scen #1 proxy
Decrease vs. Scen #1 (M$)	112	1,094	1,182	852
% decrease vs. Scenario 1	0.2%	2.3%	2.5%	1.8%
Decrease vs. Scen #1 ($/MWh)	0.1	0.8	0.9	0.6

Table 5-7 shows the change in production costs for all scenarios relative to Scenario 1. The data show the scale of benefits that were calculated for increasing levels of coordinating reserve requirements and scheduling/dispatching resources throughout the SPP/SERC footprint. Scenario #2, where each BA schedules its own resources and carries reserve for its own wind, is slightly less costly (less than half a percent) than Scenario #1 where SPP carries all the reserves for the within-hour variability and uncertainty. There is very little difference between scenarios 1 and 2, showing that, with the plant mix as modeled here, reserve requirements are essentially moving from being provided by SPP CCs (and some GTs) to other regions CCs and GTs. Overall, this does not affect costs significantly, however, it does mean less burden on SPP.

The most significant benefit is realized in moving to Scenario 3, where all of the scheduling, balancing, and reserves are shared across the footprint. Scenario #3 results in an additional decrease of approximately 2% of total production costs beyond the gains from Scenario 2. This corresponds to approximately 70c/MWh relative to Scenario #2 and 80c/MWh relative to Scenario #1. While not extremely large on a percentage basis, it does represent more than 2% of the total annual production costs at over a billion dollars in savings. The cost saving from the extended cooperation modeled in Scenario #3 are perhaps more meaningful viewed in context of the savings that would be seen if the hourly wind output could be perfectly forecasted day-ahead and had no intra-hour variability as is modeled in the proxy for Scenario 1. Removing the need for additional reserves for wind and perfectly forecasting it day ahead saves 60c/MWh, if each region still carried their own reserve for covering load variability and contingencies. While this is obviously a fictitious case, it provides some context to the coordinated benefits seen in Scenario #3 which are higher than the benefits of removing wind uncertainty.

Scenario #4 shows that removing hurdle rates does decrease the costs further beyond the reduction from cooperation in Scenario #3, but not significantly so.

The next sections will examine in more detail differences between individual scenarios, to pinpoint better what is happening in the model for various assumptions about balancing wind and reducing contingency reserves.

Scen. #2 vs. Scen. #1 – Benefits of Each BA Carrying Wind Balancing Reserves

The within-region generation, between region flows, and production costs shown previously between Scenario 2 and Scenario 1 is due to the fact that Scenario 2 increases reserves for Entergy, SBA and TVA, with a corresponding decrease in SPP reserves. The total reserve requirement increases slightly as described in Chapter 3. Regulation requirements decrease about 100 MW on average, while spin and non-spin increase slightly more. Table 5-8 shows the resulting difference in generation across the footprint with positive values indicating an increase in generation in Scenario #2 relative to Scenario #1. As noted previously, the primary impact is that SERC BA CC and GT usage increases to carry the reserve that is dropped by SPP CC and GT decreases.

Table 5-8: Difference** in Generation for Scenario 2 vs. Scenario 1

Change in GW	EES	TVA	SBA	SPP	SERC West	SERC East	Total
CC	0.10	0.57	0.66	(0.80)	0.10	(0.01)	0.61
GT	0.00	0.21	0.01	(0.37)	(0.01)	(0.01)	(0.17)
Hydro	-	-	-	-	-	-	-
Nuclear	(0.00)	-	-	(0.00)	-	0.00	(0.00)
Coal	(0.01)	(0.29)	(0.17)	0.22	(0.07)	(0.04)	(0.36)
Gasoil	0.01	-	0.00	(0.01)	-	(0.00)	0.00
Wind	-	-	-	-	-	-	-
Other	(0.00)	(0.01)	(0.02)	(0.04)	0.00	(0.01)	(0.08)
Total	0.10	0.47	0.48	(1.00)	0.02	(0.07)	0.00

**Positive value represents increase in generation in Scenario #2 relative to Scenario #1.

The flow chart shown in Figure 5-9 summarizes the generation impacts across the footprint when moving from SPP carrying all intra-hour reserves for the wind to each BA managing its own wind's within-hour reserves. Note that the lines between regions in do not show the change in specific flows or interchanges between regions, but rather the change in net export for a given region and general "direction" of the change. An orange color indicates a decrease in generation and corresponding increase in exchanges scheduled into the area. A blue color indicates an increase in generation and corresponding increase in energy scheduled out of the region. It can be seen, from Table 5-8 and Figure 5-9 that the change in balancing strategy to have SERC BAs balance their on within-hour wind variability and uncertainty (Scen #1 → Scen #2) moves conventional generation from SPP into the other areas. This increases their production costs while decreasing SPP's (production cost here is per MWh production in the region).

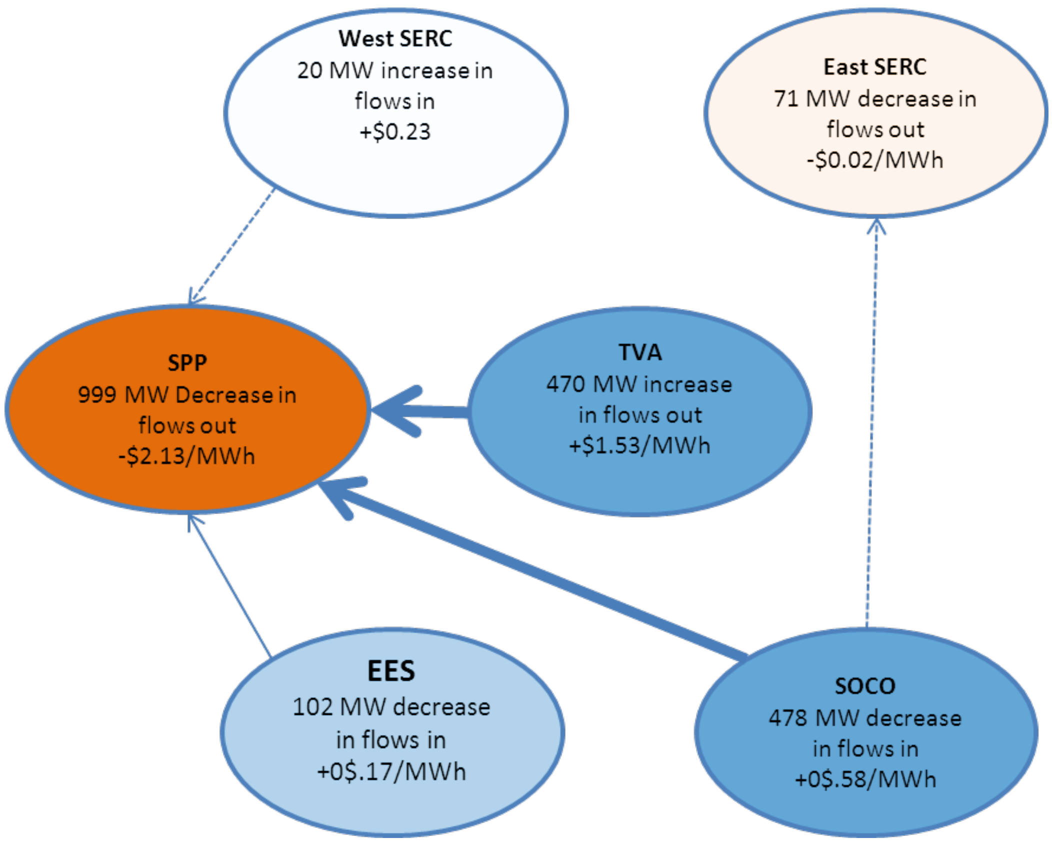

Figure 5-9: Change in generation across the footprint from Scenario 2 vs. Scenario 1; lines are not actual interchanges but indicate where change in generation goes

As noted previously, Scenario 2 shows very little overall production costs benefits. The benefits that are identified are due to the fact that SPP no longer needs to carry all the within-hour balancing reserves for the wind it is exporting to the SERC regions. This is a more realistic as to how the system would operate, as SPP would likely not carry all reserves for wind it is moving out. From the above figure, it can be seen that, compared to the additional wind Scenario 1 moves out of SPP vs. the 14 GW case, about 10% less wind is moved out when other regions need to keep units online to carry reserve.

It should be noted that, for Scenario 1, there are about 350 hours for which the UPLAN model finds there is not enough available regulating capacity to ensure regulation requirements are met. The shortage does not occur because insufficient regulating capacity exists, but rather because the UPLAN solution prioritizes some regulating units for providing energy under the tight system conditions where SPP is carrying all within-hour reserves. While in reality, the system would be able to operate out of this relatively easily by bringing additional "non-regulating" units online to free up regulating capacity, the model places more of a premium on meeting energy requirements at low cost and therefore does not meet regulation requirements for these hours in Scenario #1 and a smaller number of hours in Scenario #2. This is summarized in Table 5-9. For Scenarios 3 and 4 this does not happen. As can be seen, this is relatively small in comparison to system size, however it does indicate that SPP would have to operate its system very tightly if it had to meet regulation requirements to balance wind by itself. For some hours of the year, the operators may find themselves needing to move units out of merit to provide regulation.

Table 5-9: Regulation requirement violations for SPP

	# Violations	Avg (MW)	MWh	Max (MW)
Scenario 1	352	285	100548	984
Scenario 2	41	193	7942	541
Increase in SC 1	311	92	92606	443

Scen. #3 vs. Scen. #2 – Benefits of Sharing Scheduling and Reserve Requirements

Relative to Scenario #2, Scenario #3 is modeled such that SPP, TVA, SBA, and Entergy share resources for scheduling day-ahead and share contingency and with-in-hour reserve requirements for the wind. As noted in chapter 3, this allows for a significant reduction in total reserve carried due to load and wind diversity and reduced contingency requirements. Regulation decreases 200 MW and spin reduces 1900 MW due to the contingency reserve reduction. This reduction in reserve and sharing of resources in the day-ahead commitment leads to the larger differences in production cost results described previously.

Table 5-10: Difference** in Generation for Scenario 3 vs. Scenario 2

Change in GW	EES	TVA	SBA	SPP	SERC West	SERC East	Total
CC	0.03	(1.00)	(1.41)	(0.03)	0.00	0.05	(2.37)
GT	0.00	(0.26)	(0.03)	(0.02)	0.09	0.07	(0.15)
Hydro	-	-	-	-	-	-	-
Nuclear	0.00	-	-	0.00	-	(0.00)	0.00
Coal	0.03	0.50	0.47	0.62	0.50	0.32	2.45
Gasoil	(0.06)	-	(0.00)	(0.00)	-	0.00	(0.06)
Wind	-	-	-	-	-	-	-
Other	0.01	0.01	0.05	0.02	(0.01)	0.04	0.12
Total	0.01	(0.75)	(0.93)	0.60	0.58	0.48	(0.00)

**Positive value represents increase in generation in Scenario #3 relative to Scenario #2.

Table 5-10 shows the difference in generation between scenarios #3 and #2. As shown earlier, coal output from across the footprint increases significantly displacing primarily TVA and SBA CC output. This occurs because the lower reserve requirement across the footprint results in less need for CCs to be online and spinning and because the other SERC regions not assigned wind (SERC West and SERC East) can now also provide reserve to balance the intra hour variability of the wind from their cheapest generation.

Entergy's generation contribution does not change significantly, but TVA and SBA decrease generation corresponding to their CC decrease being greater than coal increase. SPP increases generation due to its coal, while coal increases also account for an increase in other Western and Eastern SERC regions. The net effect of this is a decrease in production costs of approximately $0.7/MWh.

Figure 5-10 shows the net effect of the changes in Scenario 2 vs. Scenario 1. Entergy stays much the same, while SPP and the SERC East and SERC West regions with no wind assigned increase and TVA and SBA decrease generation. This results in the total cost reduction, as the cheaper coal generation from across the footprint can be used instead of CCs in TVA and SBA.

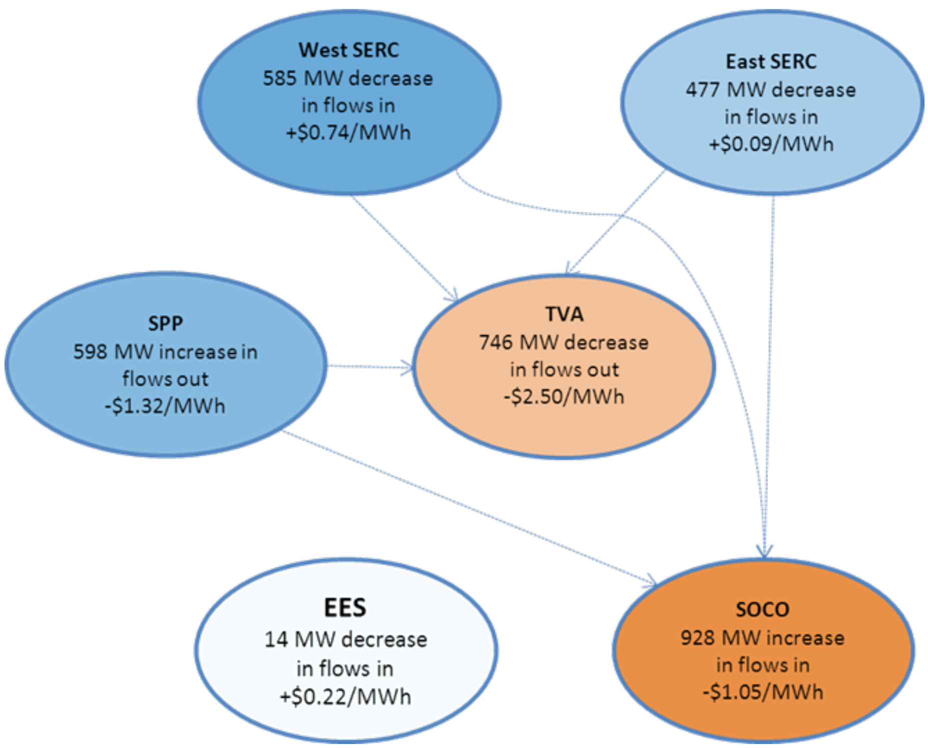

Figure 5-10: Net effect of Scenario 3 vs. Scenario 2 - blue indicates increase in generation

Figures Figure 5-11 and Figure 5-12 show the aggregate footprint wide generation stack dispatch for a selected week in April for Scenarios 2 and 3. This week was picked as it had high wind variability and relatively low load, and therefore should show times when the benefits of closer coordination can be seen.

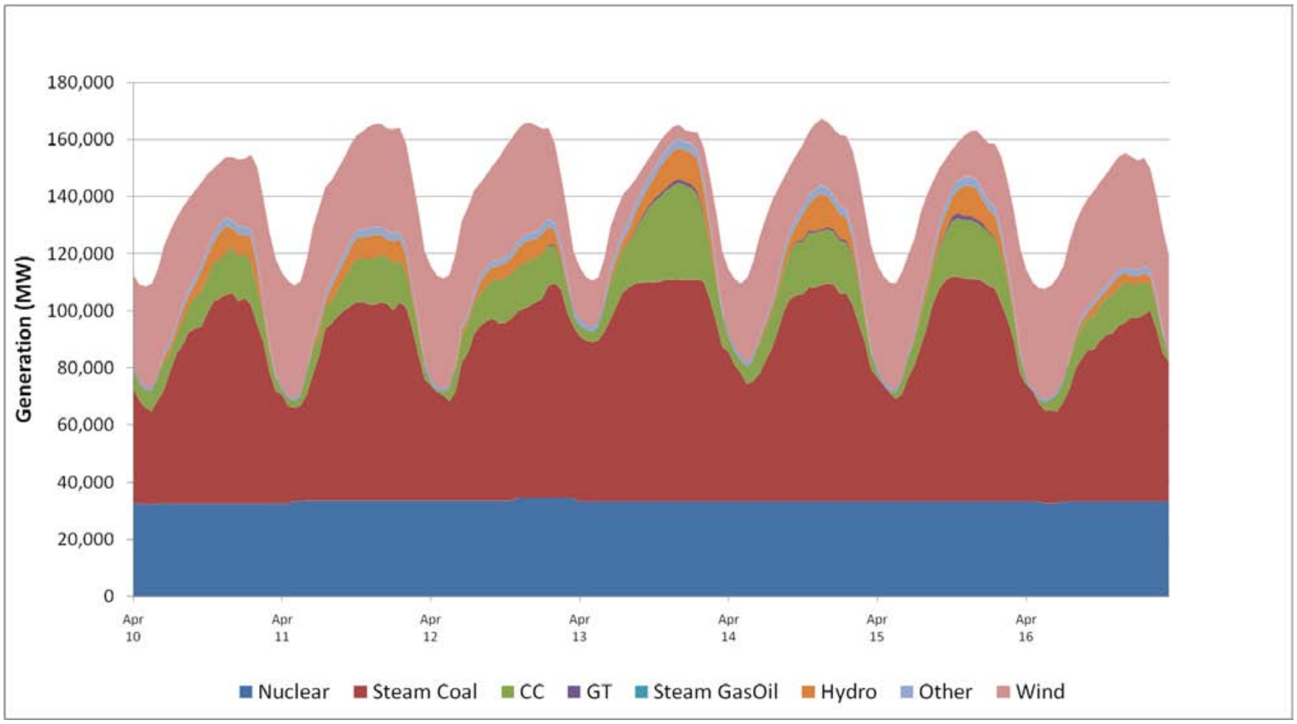

Figure 5-11: Weekly dispatch of entire system by unit type for one week in April, Scenario 2

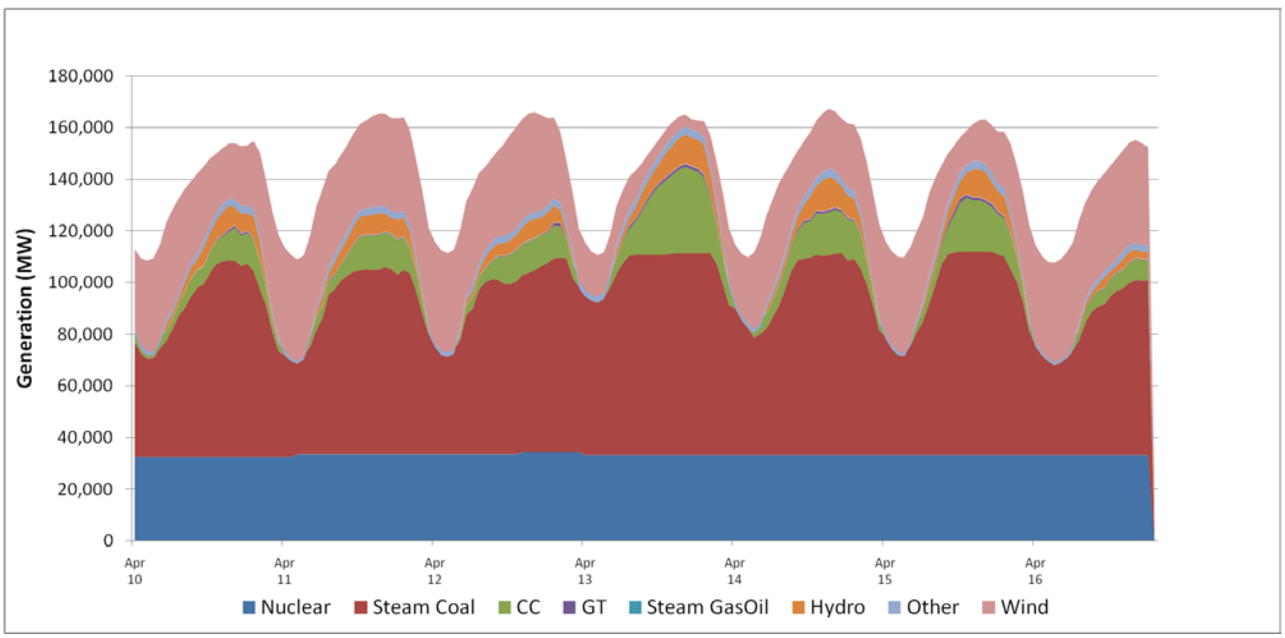

Figure 5-12: Weekly dispatch on entire system by unit type for one week in April, Scenario 3

This shows the small changes in dispatch which result in the difference in capacity factor and production cost changes. Day 3 gives the clearest example where coal usage increases and the nighttime period of April 16/17 shows no usage of CC in Scenario 3. It can be seen that CCs are more likely to be turned off during the night in high wind days when balancing requirements are shared.

Scenario #4 – Effect of Removing Hurdle Rates

The only difference between Scenarios #3 and #4 is that hurdle rates are removed from Scenario #4. It was shown previously, that production costs are only slightly reduced with Scenario 4, while generation was shown to change mainly in SPP and SBA. Table 5-11 shows the change in generation for Scenario #4 relative to #3. Hurdle rates around SBA are highest, and therefore SBA would be expected to show the greatest change. SPP increases CC and coal usage as these are modeled as cheaper (cheaper fuel price, better heat rates assumptions). SBA has correspondingly more expensive CCs and coal units. This has the effect of increasing total interchange into SBA and out of SPP. While removing hurdle rates completely may not be reasonable or likely (in fact they may increase as more transmission is built for wind), it does show the bookend of what reduced rates may do in terms of impact of balancing high amounts of wind.

Table 5-11: Difference** in average generation for Scenario 4 vs. Scenario 3

Change in GW	EES	TVA	SBA	SPP	SERC West	SERC East	Total
CC	0.12	0.34	(1.05)	0.66	(0.15)	(0.01)	(0.09)
GT	0.00	0.01	(0.02)	0.00	0.01	0.03	0.02
Hydro	-	-	-	-	-	-	-
Nuclear	0.00	-	-	0.00	-	0.00	0.00
Coal	(0.01)	(0.09)	(0.57)	0.92	(0.15)	0.01	0.11
Gasoil	0.01	-	(0.00)	(0.00)	-	0.00	0.01
Wind	-	-	-	-	-	-	-
Other	(0.00)	(0.01)	(0.08)	0.02	(0.00)	(0.03)	(0.10)
Total	0.12	0.25	(1.72)	1.60	(0.29)	0.00	(0.04)

**Positive value represents increase in generation in Scenario #3 relative to Scenario #2.

Scenario #1 Proxy – Effect of Forecast Uncertainty and Increased Reserve Requirements Associated with Wind

The scenario 1 proxy uses only the reserve requirements from the 7 GW wind case examined earlier. Additionally, wind is assumed to be perfectly forecast. This case is analyzed to evaluate the balancing costs that wind imposes on the system. While this does not give so-called 'integration costs' of wind, it does show the effect of intra-hour variability and uncertainty. This can be used to place other costs in context. As shown earlier, the cost reduction from higher cooperation across the footprint is larger than that which could be achieved with smaller balancing areas if wind could be perfectly forecast and had no intra-hour variability.

The change in the average generation between the Scenario #1 and the Proxy case is shown in Table 5-12. As expected, the largest change is in SPP, which carries all of the intra-hour reserves for the wind in Scenario #1. Due to reduced reserve requirements, SPP CC generation decreases and coal is increases slightly. Coal also increases elsewhere in the region reducing SPP exports. Looking at the costs savings shown and placing them in context of savings per MWh of wind it can be seen that the balancing costs of the wind come to approximately $5/MWh, which is consistent with balancing costs seen in other wind integration studies, if somewhat on the low side.

Table 5-12: Difference** in average generation for Scenario 1 vs. Scenario 1 Proxy

Change in GW	EES	TVA	SoCo	SPP	SERC W	SERC E	Total
CC	(0.03)	(0.04)	(0.09)	(0.93)	0.02	0.03	(1.05)
GT	(0.00)	0.01	(0.02)	(0.38)	0.02	0.03	(0.34)
Hydro	-	(0.00)	0.00	-	-	0.00	(0.00)
Nuclear	0.00	-	-	0.00	-	0.00	0.00
Steam Coal	0.02	0.08	0.12	0.82	0.24	0.15	1.42
GasOil	(0.03)	-	(0.00)	(0.01)	-	0.00	(0.04)
Wind	-	-	-	-	-	-	-
Other	0.00	0.00	0.01	(0.02)	0.00	0.02	0.01
Total	(0.04)	0.04	0.02	(0.53)	0.29	0.22	(0.00)

**Positive value represents increase in generation in Scenario #1 Proxy relative to Scenario #1.

Reserve Requirements and Provision

One of the significant differences in each of the High Wind Transfer scenarios is how reserves are carried across the footprint. The changes in reserve requirements for each scenario are presented in Chapter 3. This section examines how those reserves are provided in each of the scenarios. Regulation up requirements and spinning reserve requirements were seen to be the significant, and are examined here, together with total reserve requirements.

Regulation Up

The analysis of reserve requirements presented in Chapter 3 show that moving to larger areas decreased regulation requirements, from an average of 2.2 GW in Scenario 1 to 2.1 GW in Scenario 2 to 1.9 GW in Scenarios 3 and 4. Figure 5-13 shows the average allocation of regulating up reserve by unit type for each of the scenarios. The first conclusion from this is the importance of CC units to providing the regulating reserve needed, especially considering the earlier point that some of these CCs may not be built if 48 GW of wind were to be installed. Hydro units are also shown to be important, however, these are probably going to remain in operation. Coal units provide less regulation in Scenario 3 as they provide more energy with the reduced reserve requirements resulting in fewer online CCs. It can be seen that GTs are needed in Scenario 2 to provide regulation offsetting some of the benefits of moving Scenario 1 regulation from SPP to other regions.

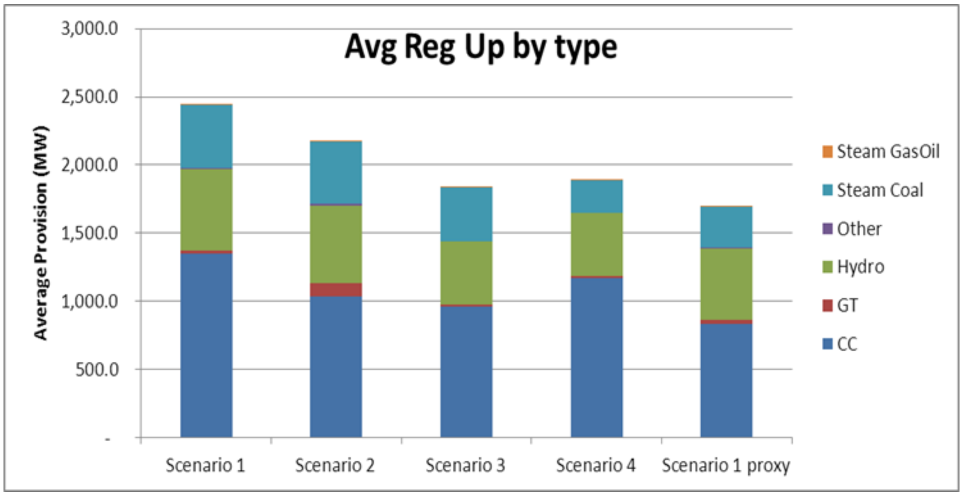

Figure 5-13: Average Regulation up provision by unit type

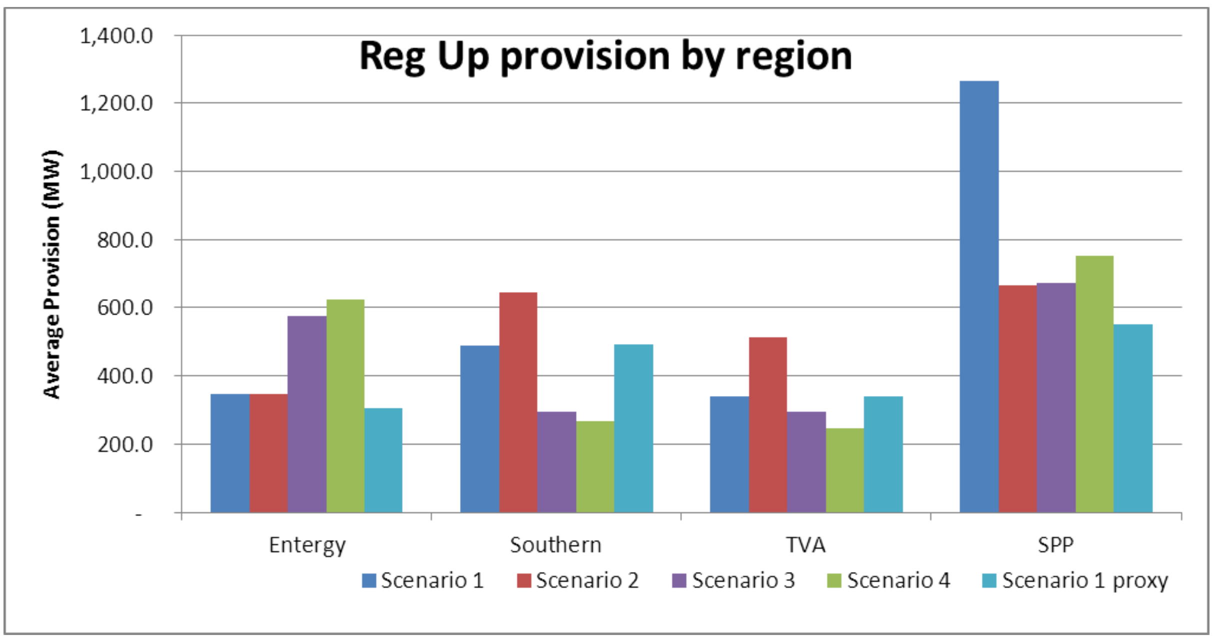

Figure 5-14: Average regulation up provision by region

Figure 5-14 shows the regulation provision by region. While total Entergy generation was shown to remain approximately the same throughout the scenarios, it can be seen that it provides significantly more regulation from its CCs in 3 and 4 as they tend to be less expensive based on the inputs to this model. This means that the SBA and TVA units which provide reserve in Scenario 2, modeled as more expensive than the Entergy units, are turned down. SPP can be seen to carry far less regulation in Scenarios 2 and 3 versus Scenario 1, with some increase for Scenario 4.

Spinning Reserve

Spinning reserve requirements are also reduced in Scenario 2 vs. Scenario 1, but there is a very significant reduction in Scenario 3 as there is only need to now cover the single largest contingency across the entire footprint. This assumption is obviously dependent on the ability to deliver the reserves across the large area. This is also independent of the wind energy in the footprint.

Figure 5-15 shows the spinning reserve provision by generating type for each scenario. Again, CCs are shown to be important, even more so than for regulation. For Scenarios 3, 4 and the proxy they serve the majority of spinning reserve requirements. In scenario 1, it can be seen that SPP needs to use GTs quite often to provide this reserve, which would contribute to increase in costs (offset somewhat in Scenario 2 by GTs providing regulation). Coal only provides a significant amount of spinning reserve in Scenario 2. This figure shows clearly why moving to coordinated balancing and reserve sharing can provide benefit. Far less reserve needs to be allocated to coal, GTs or other units, and there is a reduction in total requirements; the CCs, which seem to be most efficient in doing so, can carry most of the spinning reserve.

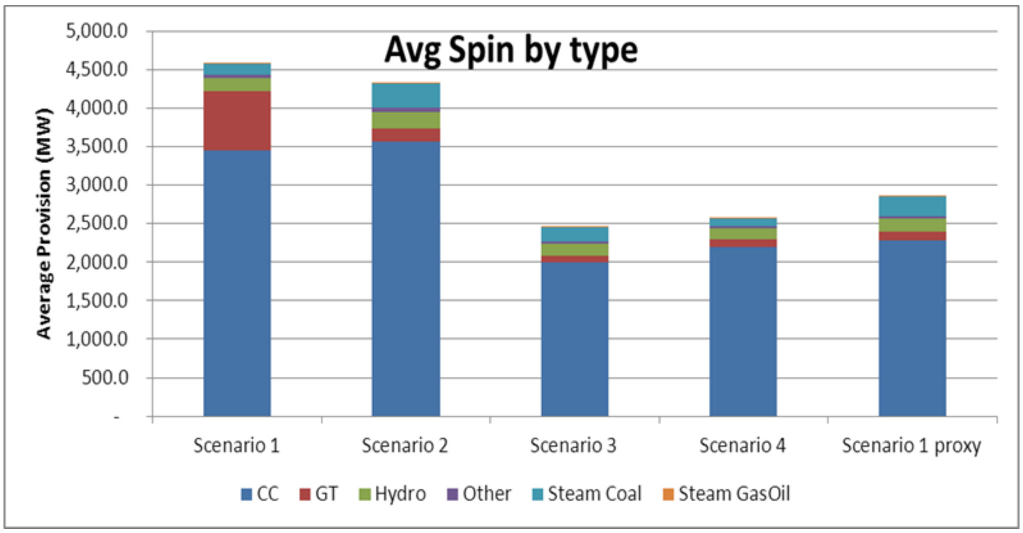

Figure 5-15: Average Spinning Reserve by unit type

Figure 5-16 shows the spinning reserve requirements by region. As expected all regions carry less for the lower requirements in Scenarios 3 and 4. As shown earlier, CCs are modeled as more expensive in SBA and TVA, and so their reduction is greater than for Entergy or SPP. The fact that Entergy's spinning reserve provision does not change between Scenarios #1 and #2 shows that this region can provide this reserve more effectively as it is modeled in this study.

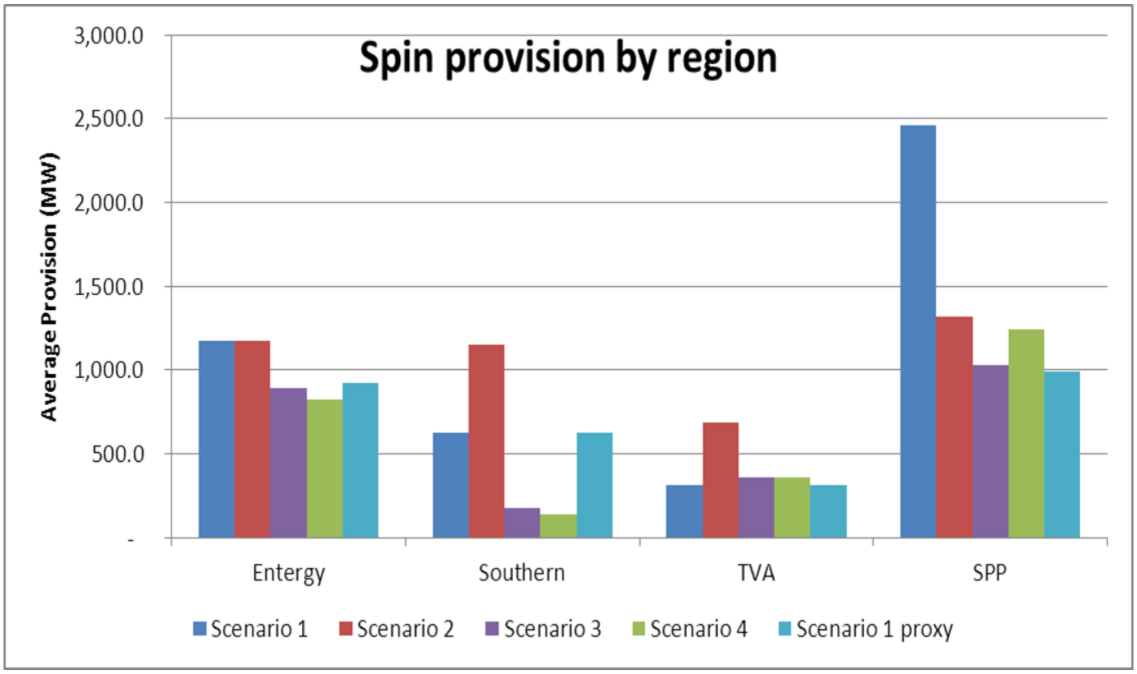

Figure 5-16: Average Spinning reserve provision by region

Spinning and regulating reserve are therefore shown to cause significant changes in the commitment and dispatch of generation throughout the study footprint. Regulation down and non-spinning reserve, which are generally easier and cheaper to obtain, do not seem to significantly affect results, and are therefore not examined in detail here. One point of interest is that those regions that didn't provide significant spin or regulation up (i.e. SBA and TVA), provide a large share of non-spin, as offline GTs are used to provide this reserve.

Capacity Factors

While the generation levels shown before give a good indication of usage of plant, it is instructive to look at capacity factors. These will provide insights as to the likelihood that units may still be built if there was a large wind build-out in SPP. It also shows how much their generation changes will impact on plant operating strategy.

Entergy capacity factor by unit type are given in Figure 5-17. For comparison, the 14 GW case is included. This shows that there is a capacity factor reduction, of about 10% for CCs and 7% for coal when wind is added. This may affect plant economics, but it is not clear how significantly. Small changes throughout the scenarios can also be seen but capacity factors do not change significantly in the high wind cases; this is consistent with earlier results for generation in Entergy. A breakdown of the capacity factors for individual units is provided in Appendix A.

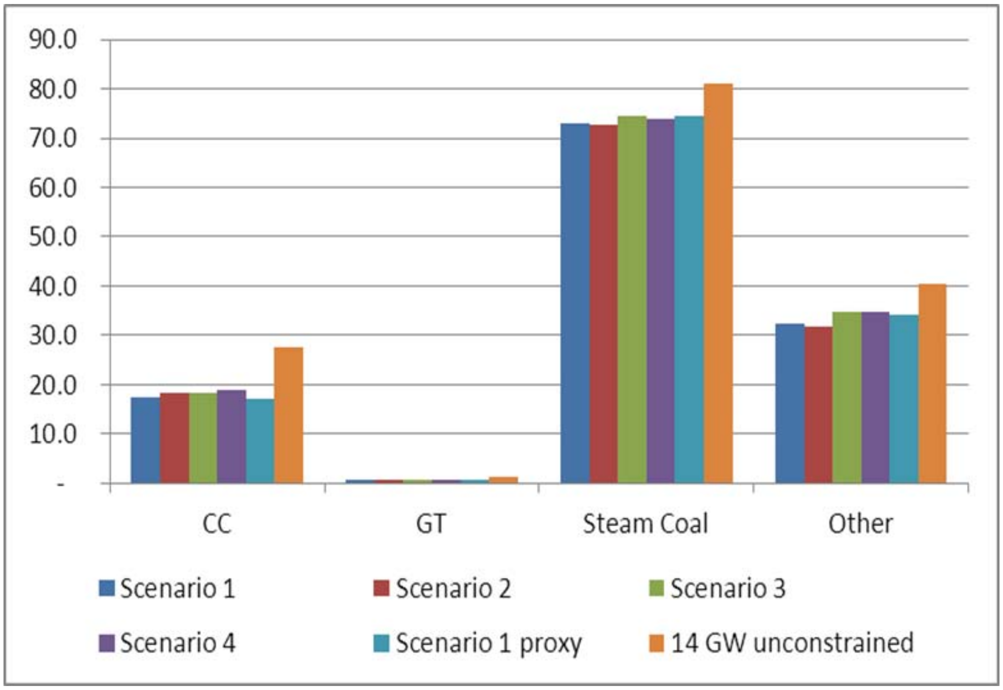

Figure 5-17: Entergy capacity factors by unit type

Figure 5-18 shows the capacity factors by unit type for SBA. As expected from results shown previously, the change in capacity factors is more significant for SBA than Entergy. CC in particular goes from a capacity factor of approximately 28% in the 14 GW wind case, to 22% in Scenario 2, to 12% in Scenario 4. It can be seen therefore that different balancing strategies would significantly affect the usage of these units, possibly changing the business case for them being built. This is examined in more detail in Appendix A where a breakdown of the capacity factors for individual units is provided.

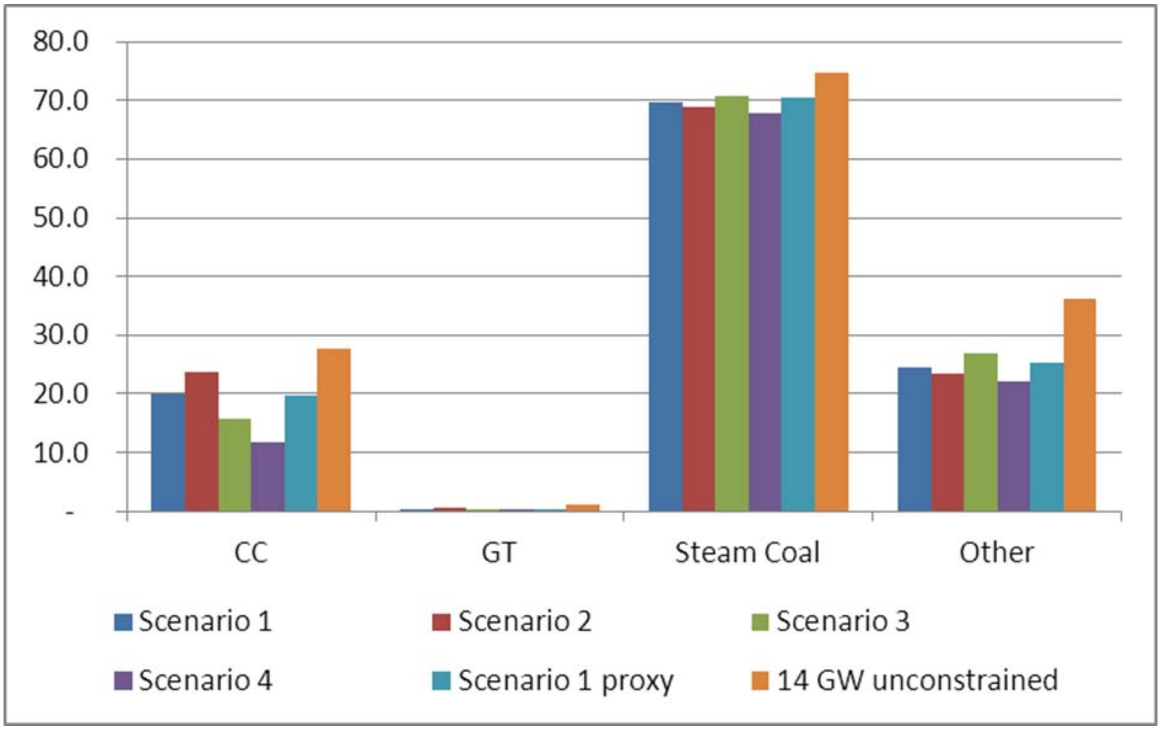

Figure 5-18: SBA Capacity Factors by Unit Type

Figure 5-19 shows TVA capacity factors by unit type. These are as expected from earlier results; showing CC units with the greatest change. Coal can be seen to decrease significantly when wind is added, and the lowest coal usage is when TVA needs to balance the wind assigned to it in SPP in Scenario #2. Moving to Scenario 3 allows greater utilization of the coal, which is cheaper in the model than gas units. CC is actually used more in Scenario 2 than in the lower wind case, as it is needed to provide reserve. Only in Scenario 3 is the capacity factor of CC units reduced by more than 10% compared to the lower wind case. Gas turbines can also be seen to be needed more in Scenario 2 to provide increased reserve needs. A breakdown of the capacity factors for individual units is provided in Appendix A.

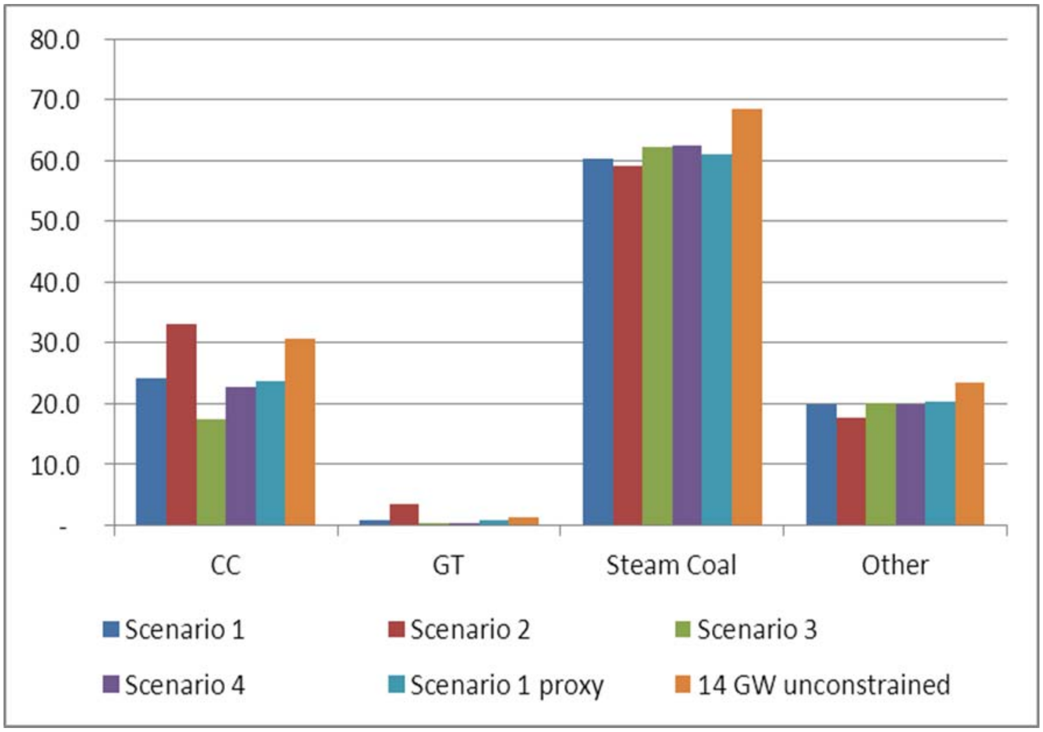

Figure 5-19
TVA Capacity Factors for Unit Type

Figure 5-20 shows the capacity factors by unit type for the year in SPP. This again reflects earlier results. It can be seen that adding wind barely changes CC capacity factor in Scenario 1, but reduces it by 10% in Scenario 2, where SPP no longer has to provide all of the within-hour reserves for the 48 GW of wind. GTs can be seen to only be significant in Scenario 1 and the lower wind cases; this indicates that at higher wind cases, they may not be built and thus not available for reserves if needed (although earlier results indicated this may not be the case). Coal capacity factors in SPP increases with more shared balancing requirements, from scenario 1 through scenario 4. A breakdown of the capacity factors for individual units is provided in Appendix A.

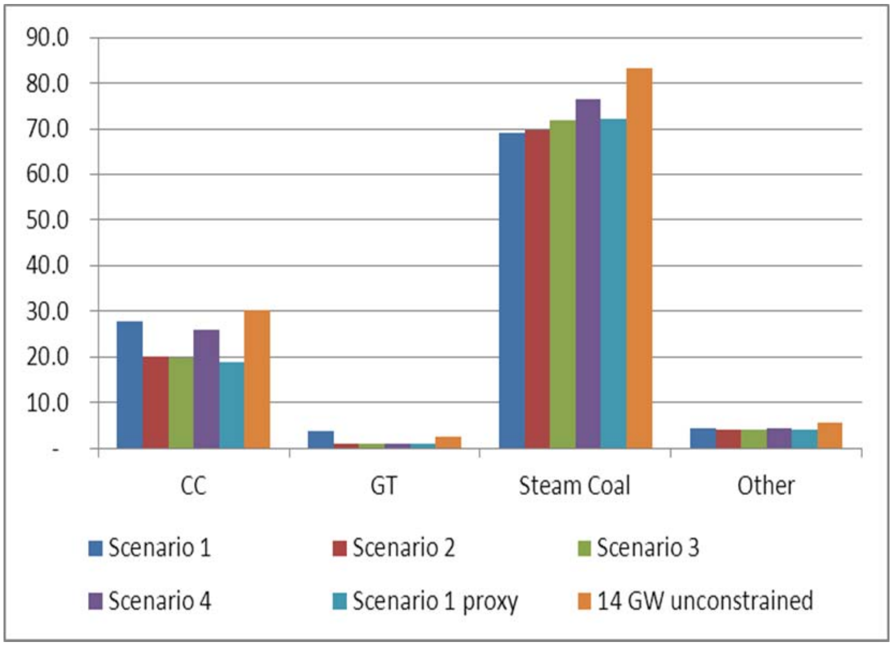

Figure 5-20: Capacity Factors for SPP by unit type

There is little significant change in capacity factors across scenarios for the other SERC regions across the scenarios. The eastern SERC regions (mainly VACAR) do not change noticeably, while CCs and to a lesser extent coal change in the western regions, as shown earlier. Another note of significance for those regions is the fact they both have significant GT capacity factors, indicating that they use these units more than the main study regions.

Figure 5-21shows capacity factors across the entire footprint. Again, this is similar to generation described earlier. It can be seen that much of the differences again lies in CC usage. There is a significant decrease in CC usage in Scenarios 3 and 4 in particular, indicating that they may not all be present in a future plant mix with this much wind. This would be crucial as these units are shown to provide much of the reserve requirements. Alternatively, if it is shown that they are needed to provide reserve, then they may be built, or not retired. This would impact capital cost recovery, not studied here. Looking at the average CC capacity factor, 20% still seems relatively high, though lower than it would be with low wind.

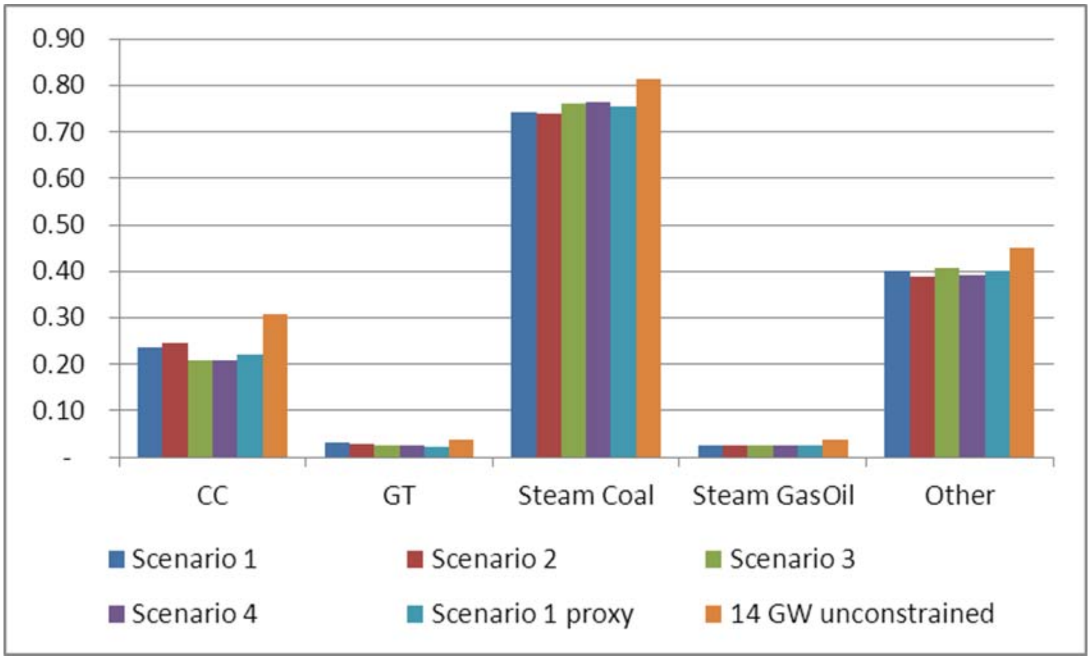

Figure 5-21
Capacity Factor by Unit Type across Entire Study Footprint

Unit Startups

Changing the balancing strategy can change the number of starts for units. The cost of cycling and ramping on conventional generation in terms of effect on forced outage rate, maintenance costs and heat rate degradation is not studied here (and is in fact not well understood in general at present). As such, the effect of wind on cycling can only be seen from the UPLAN production cost model results in how it changes the number of start/stop operations of units. More cycling operation would likely result in more breakdowns, maintenance scheduling and possibly early retirement, therefore strategies that reduce this will be beneficial, in particular for coal or older CC units.

Figure 5-22 shows the average number of starts per year by unit type for each region. Note that these starts are not necessarily attributable to wind variability as normal load cycling and forced or unforced outages also drive some portion of the starts. Increased levels of wind, however, will increase the cycling of the units. Given that the data in Figure 5-22 compares scenarios all with 48 GW of wind, the differences between scenarios indicates how balancing cooperation strategies impact cycling. Only CC and coal are shown as these are the units not specifically designed to start and ramp as frequently as GTs would be. In addition, coal in Entergy is not shown as starts do not change. As expected, coal units, which have larger start costs and times and longer minimum up times, do not cycle on and off significantly.

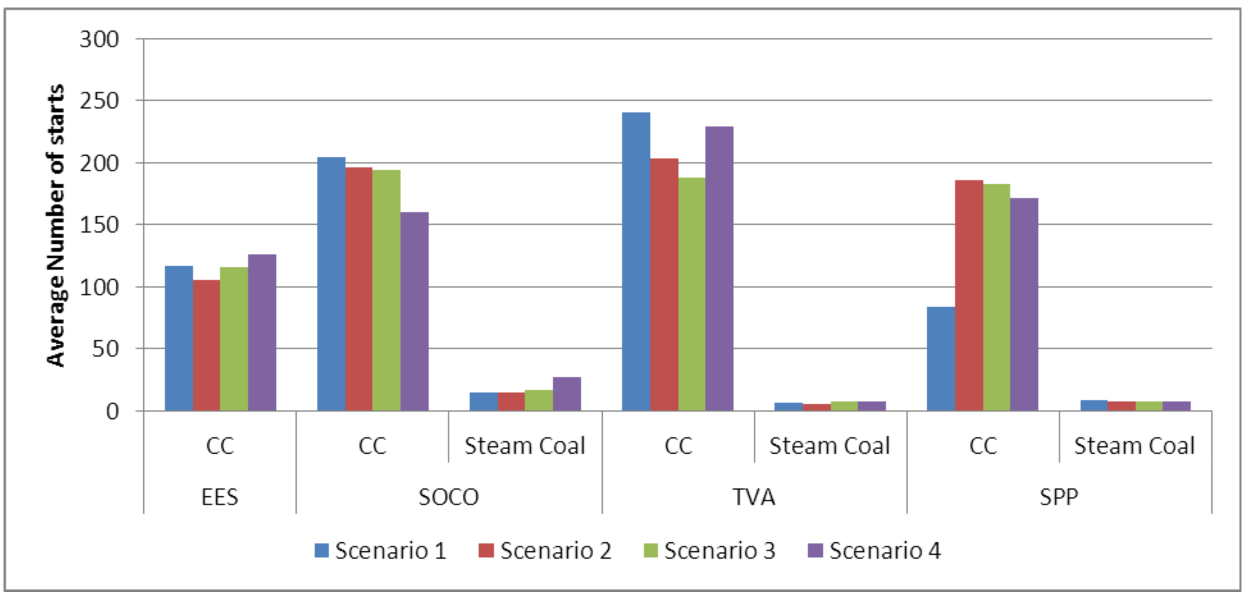

Figure 5-22
Average number of starts by unit type

Table 5-13 shows the average number of starts per unit of each type per year for Scenario #1 and the change in the number of starts for each of the other scenarios relative to Scenario 1 with a positive value indicating an increase in starts versus scenario 1. In addition to the high wind transfer case scenarios, the low wind case of 14 GW with unconstrained transmission is shown for comparison of how the additional 34 GW of wind impacts unit starts. The additional 34 GW of wind generally results in more starts in the SERC regions as more cheap and variable energy is available, but the numbers are not as dramatic as might be expected. CC units in Entergy and TVA cycle off on average 25 and 16 times more per unit per year in the high wind case, respectively. Conversely, however, the number of starts on the SPP and SBA CC units decreases by 22 and 3, respectively. The only place where there is a significant decrease in average number of starts when wind is added is for CC units in SPP, likely as units are left online to provide reserve. The average number of starts for each coal unit increase slightly with the additional wind for SBA (3), TVA (3), and SPP (1). Although the numbers are small (1-3 additional starts per year per unit), they could be significant as many of these units are not likely designed to cycle.

Table 5-13: Change in starts vs. Scenario 1

Region	Type	Scenario 1 starts	14 GW	Scenario 2	Scenario 3	Scenario 4	Scenario 1 Proxy
EES	CC	117	-25	-12	-2	9	-1
SOCO	CC	204	3	-7	-9	-45	-6
	Steam Coal	15	-3	0	2	12	1
TVA	CC	240	-16	-37	-53	-11	-9
	Steam Coal	7	-3	-1	1	1	0
SPP	CC	84	22	103	99	88	109
	Steam Coal	8	-1	0	-1	-1	-1

Comparing Scenario 2 to scenario 1, it can be seen that there is a reduction in starts for CCs in each of the three SERC BAs when they are required to carry reserve to cover the intra-hour variability of their wind allotment. As a result, the CCs are required to remain on line more often to ensure sufficient reserve exists. Conversely, the CCs in SPP cycle more frequently as they no longer have to maintain all reserves for the wind and the CCs correspondingly can be turned off more frequently in SPP. This increase is not as significant in Scenarios 3 and 4 as the SPP CC units are utilized more in these shared balancing scenarios due to the relative economics of these units as modeled. On the other hand, TVA shows a larger decrease in CC starts in Scenario 3 and SBA in Scenario 4, as these units are being turned off for longer periods of time when the less expensive CCs in SPP and Entergy can be used to support the "shared" reserve requirement. (Although noted previously, it should be noted again that the relative economics of the units in different regions result from the input data utilized in the UPLAN model and may likely differ in actual implementation in the future.) In Entergy, Scenario 4 shows an increase in CC starts compared to other scenarios; this is also true for coal in SBA; no hurdle rates means the coal is started more often to provide energy.

More detailed analysis of start-ups for individual CC units is presented in Appendix B.

Gas Price Sensitivity Case Results

Between the time of the start of this study and the end, projected gas prices for the 2022 study year decreased significantly. The results of the study presented thus far are based on assumed natural gas prices in the range of $8-$9/MMBtu, depending on region and month. Gas prices projections near the end of the study are significantly lower, by at least $3. Therefore, the UPLAN model was rerun for Scenarios #2 and #3 with natural gas prices reduced by $4/MMBtu across the board to ascertain the sensitivity of the results to the gas price assumption. The effect of the significantly reduced gas prices on the changes in production cost and generation results between Scenarios #2 and #3 are analyzed. The main question was how differently the benefits of increased cooperation and reserve sharing would appear with lower gas prices, i.e. how does the total difference in scenario #2 and #3 production costs change, and how does this impact generation.

Table 5-14 shows the change in average generation per unit type per region for Scenario 2 with the lower gas prices. As should be expected, CC and GT generation increases displacing coal. This resulted in an increase in generation in Entergy and SBA compared to all other areas. It should be noted that the changes seen here are significantly greater than, for example, the differences between Scenarios 2 and 3 shown in Table 5-10. This shows that gas prices can have far more effect than balancing of wind generation in the generation of future power systems with high amounts of wind.

Table 5-14
Change in average generation for scenario 2 with lower gas price**

Change in GW - Scenario 2 low vs high	EES	TVA	SoCo	SPP	SERC W	SERC E	Total
CC	3.20	1.41	6.77	3.10	1.95	1.91	18.35
GT	0.18	(0.03)	0.01	0.35	0.19	1.23	1.93
Hydro	-	-	-	-	-	-	-
Nuclear	(0.00)	-	-	(0.00)	-	(0.00)	(0.00)
Steam Coal	(0.18)	(3.46)	(4.49)	(5.19)	(3.20)	(3.89)	(20.41)
Steam GasOil	0.58	-	0.00	0.04	0.00	(0.00)	0.63
Wind	(0.19)	-	-	0.02	-	-	(0.16)
Other	(0.00)	(0.08)	(0.24)	(0.08)	0.17	(0.11)	(0.33)
Total	3.58	(2.15)	2.06	(1.74)	(0.88)	(0.86)	0.00

Positive value represents increase in generation in lower gas price sensitivity case.

The same difference in generation is shown Table 5-15 for Scenario 3 with lower gas prices. Here it can be seen that much the same effect happens. However, gas is increased even further, and more coal is displaced. The prior results (higher gas prices) showed that the benefit of moving to Scenario #3 versus Scenario #2 was the ability to reduce gas generation and replace it with coal when all resources are shared throughout the footprint. Decreasing gas prices has the effect of reducing the benefit that can be drawn from sharing reserve. While the more efficient reserve sources can still be shared better, there is less difference between those and other resources, and therefore less benefit in Scenario #3 versus #2 with lower gas.

Table 5-15
Change in generation for Scenario 3 with low gas prices

Change in GW - Scenario 3 low vs high	EES	TVA	SoCo	SPP	SERC W	SERC E	Total
CC	3.27	2.42	7.87	3.29	2.02	1.87	20.75
GT	0.16	0.01	0.00	0.29	0.12	1.16	1.75
Hydro	-	(0.00)	-	-	-	-	(0.00)
Nuclear	(0.00)	-	-	(0.00)	-	(0.00)	(0.00)
Steam Coal	(0.17)	(4.03)	(5.08)	(5.66)	(3.45)	(4.06)	(22.46)
Steam GasOil	0.54	-	0.00	0.03	-	(0.00)	0.57
Wind	(0.19)	-	-	0.03	-	-	(0.16)
Other	(0.01)	(0.10)	(0.27)	(0.11)	0.16	(0.12)	(0.45)
Total	3.61	(1.69)	2.52	(2.13)	(1.15)	(1.15)	0.00

The change in generation between Scenarios #3 and #2 with low gas prices is given in Table 5-16. There is now very little difference in CC usage; most of the benefits that come from moving to larger reserve sharing areas now comes from the fact that this allows a reduction in less efficient GTs and increase in coal. This results in small increases in generation in SPP and the SERC non-wind regions, with a decrease in TVA and SBA where GTs had been providing significant amounts of energy. Comparing this with Table 5-10, it can be seen that there is now far less difference between scenarios; the benefits of cooperating across the footprint is reduced as costs are more equal throughout the region with coal and gas being somewhat similar. There is still a small move to more efficient (in the model) CC in SPP compared to CC elsewhere, but total CC usage is not decreased as gas prices are so low that this is not as desirable as it was with higher gas prices.

Table 5-16
Change in generation Scenario 3 vs. 2 low gas price

Change in generation Scenario 3 vs 2 low gas	EES	TVA	SoCo	SPP	SERC W	SERC E	Total
CC	0.10	0.01	(0.31)	0.15	0.07	0.01	0.02
GT	(0.01)	(0.22)	(0.04)	(0.08)	0.02	0.00	(0.33)
Hydro	-	(0.00)	-	-	-	-	(0.00)
Nuclear	0.00	-	-	0.00	-	(0.00)	0.00
Steam Coal	0.04	(0.07)	(0.13)	0.16	0.25	0.15	0.40
Steam GasOil	(0.10)	-	(0.00)	(0.01)	(0.00)	0.00	(0.11)
Wind	-	-	-	0.01	-	-	0.01
Other	0.00	(0.00)	0.02	(0.01)	(0.02)	0.02	0.01
Total	0.04	(0.28)	(0.47)	0.21	0.32	0.19	(0.00)

The net effect of reduced gas prices on cost is to reduce the cost difference from approx. $0.7/MWh to approx. $0.25/MWh, a factor of three. The benefits now are not in being able to switch from CC usage to coal when sharing reserve requirements, but the less attractive (as less MWh) benefits of switching from GTs to coal and being able to use the more efficient coal and CC units. It is unclear how increasing relative costs of coal (by having carbon price for example) may affect these results. Coal may be reduced further, and shared reserve requirements may allow greater usage of CC, but that has not been modeled.

6
CONCLUSIONS AND RECOMMENDED NEXT STEPS

The objective of this study is to evaluate the balancing/scheduling impact of high levels of wind generation in SPP for consumption and export to SERC and to evaluate the benefits of increased coordination in scheduling, balancing and reserve provision across the SPP/SERC region. To this end, a detailed UC/ED model of the SPP/SERC region was developed and utilized to run production cost simulations for different high wind transfer scenarios. As in any study like this, modeling and data input assumptions have a significant impact on results. These assumptions have been noted in this report with the presentation of the simulation results, but the following most crucial assumptions provide context for the subsequent conclusions:

- *Unconstrained transmission.* Thermal constraints are removed and losses ignored for the SPP/SERC network in the SCUC/SCED model for which results are presented. Analysis to quantify the effect of unconstraining the transmission with low wind levels shows that the assumption results in greater utilization of those resources modeled as cheaper across the study footprint and subsequent larger economic energy flows between regions. It's noted, however, that any high wind build-out would necessarily be accompanied by a significant transmission build-out that would in fact enable additional flows within and between regions, just not to the extent modeled in this work.
- *Gas and emission prices.* The fuel price was shown to be important with the gas price sensitivity. While there is always likely to be a benefit from sharing reserve requirements and thus reducing them, fuel prices may change how significant the benefit is. This is seen in the fact that with reduced gas prices, CC production barely changes in total, but does shift from one region to another. Carbon prices would also impact results. Higher carbon prices would make coal less attractive and therefore the benefits of being able to use coal more with shared reserve requirements would be reduced.
- *Reserve margin and conventional generation plant mix.* The additional 40 GW of wind was added to the High Wind Transfer cases without removing any of the conventional generation in the 2022 Non-RES case resulting in a reserve margin in the model which would likely be higher than that which would be seen in reality. In reality, the additional wind would likely displace some conventional generation. Assuming for example a capacity credit of 10% for the 40GW of wind added to the 7 GW case, then 4 GW of conventional plant would not be required to maintain capacity adequacy at the same level. This could lead to a reduction in the CC units which are shown to be the main units used to provide the increased reserve and ramping needed for high penetrations of wind. In addition, the plant mix for the conventional generation assumed in the model is an important assumption. Although the model is based on the best information available

from the participating utilities at the time of the study, in reality, the plant mix may be different due to impending EPA regulations.

Despite these assumptions, the results of the study provide insights as to the balancing impacts associated with the high wind build-out in SPP and as to the benefits of increasing levels of coordination across SPP and SERC BAs in responding to those balancing impacts. Given the assumptions and the nature of future scenario production cost modeling, the insights tend to be based more on the order of magnitude and trends between results than the absolute value of the results presented.

System and Cost Impacts of High Wind

Although the focus of the study was not to conduct an evaluation of all system impacts of 48 GW of wind on the SPP/SERC region, the analysis and modeling does provide some insight as to certain aspects of the impact of increasing wind penetration on the unconstrained system when comparing the results between the 14 GW and 48 GW installed wind cases.

Cost Impacts

The increase of 34 GW of wind in SPP (from 14 GW to 48 GW) results in a total production cost reduction of approximately $5.4 billion or $4/MWh of demand. This cost reduction represents the reduction in fuel costs from the wind generation and does not consider the offsetting cost to purchase the wind energy or the capital/O&M costs to build the wind plants.

Comparison of the Scenario #1 and Scenario #1 proxy cases show that the costs of the intra-hour variability and uncertainty and the day ahead uncertainty for the total 48 GW of wind in the High Wind Transfer cases are approximately $0.6/MWh of load, or $5/MWh of wind, for Scenario 1. This value represents most of the balancing cost that is reported in many studies as an "integration cost." As such, the $5/MWh of wind value is on the low end of results reported in similar studies. This may be due to the value not including a cost associated with the inter-hour variability (movement of conventional units to follow the perfectly known variation of wind across the hours) and the unconstrained transmission. It should also be noted that this value does not include any capital costs for the wind generation or transmission to deliver the wind or costs associated with increased cycling of conventional plants due to increased ramping and start/stop operations. The analysis does show, however, that the number of conventional generator starts does generally increase as the wind increases, but not as significantly as might be expected for 48 GW of wind.

Generation and Reliability Impacts

The addition of 34 GW of wind in SPP (14 GW to 48 GW) for the High Wind Transfer Cases results in wind primarily displacing combined cycle gas (CC) and coal usage. Aggregate capacity factors for coal and CCs across the SPP/SERC footprint drop approximately 7-8% when wind was added. This relates to the addition of the wind without retiring any conventional generation assumption described above and may mean some units would not be present (either retired or not built) in a high wind system. Based on the assumptions in the model on the relative generation characteristics across regions, the average generation in TVA and SBA are reduced the most. Additionally, it is shown that some of the wind which is committed in SPP to other regions ends up staying in SPP resulting in coal being significantly reduced in SPP.

CCs are seen to be used most to integrate the wind, with coal and CT units also changing operation. While all types of generation decrease output, it is clear that CC units are most used to provide the additional reserve requirements for wind.

The most severe integration case (48 GW Scenario #1 case) where all of the intra-hour wind variability is balanced by SPP does not result in significant reliability problems. This is due to the fact that adding the wind capacity without removing other conventional capacity results in high reserve margins such that there is sufficient capacity to manage the wind, assuming some of it is committed out of SPP based on day-ahead forecasts.

Benefits of Increased Cooperation in Scheduling, Balancing, and Reserve Sharing

The analysis of the High Wind Transfer scenarios shows that increasing levels of cooperation among SPP, Entergy, SBA, and TVA does result in changes to the operation of the system that produce aggregate system benefits. These result from changes to the amount of reserve required for the different scenarios. Scenarios 3 and 4 show a reduced reserve requirement due to cooperation between regions. This is the most significant result in the study; there is a 5000 MW decrease in total reserves needed when there is full cooperation in Scenarios 3 and 4 versus Scenario 1. In particular, regulation needs are reduced by approximately 400 MW.

Cost Impacts

There is a clear, though possibly small, societal cost benefit to sharing the reserve requirements throughout the region. The difference between Scenario 1 where SPP balances all wind and and Scenario 2 where each BA balances its own wind is small – only $0.1/MWh. This is due to the fact that the main difference in these two scenarios is to shift from using CCs and GTs to provide reserve for wind in SPP to the same units providing it elsewhere. Comparing costs for Scenarios 2 where each BA balances their own assigned wind and Scenario 3 where balancing requirements are shared across all BAs shows that costs decrease as result of the reduction in aggregate reserve requirement (including contingency reserve) and a more optimal usage of the system generation to meet energy and reserves as scheduling is shared. The cost reduction is approximately $0.7/MWh of demand for the assumed gas prices. Reducing gas prices by approximately 50% reduces this benefit by a factor of 3. This implies that the benefits derived from regional coordination or cooperation are reduced as the diversity in plant mix and fuel costs (coal vs. gas) across regions is reduced.

Removing hurdle rates reduces costs further, although the reduction in production costs is relatively small – approx. $0.1/MWh. While it may be unrealistic that hurdle rates might be completely removed, the analysis provides a boundary case as to the high end benefit of cooperation. The small incremental benefit seen when hurdle rates are removed indicates that smaller changes in hurdle rates will likely not significantly impact the results found in the study.

As for the magnitude of the benefits of increased cooperation, while all the cost differences seen are small, they should be put in context of a total production cost reduction of approximately $4/MWh of demand when 34 GW of wind is added. It should be noted that the cost benefit of moving to larger scheduling/reserve areas (scenario 3 vs. Scenarios 1 and 2) are actually greater (by approx. 25%) than if the wind could be perfectly forecast and intra hour variability flattened out but each area still carried their own reserve (Scenario #1 and proxy).

Generation and Reliability Impacts

While the production cost impacts examine many of the benefits of increased cooperation in scheduling, balancing and reserve-sharing, other operational insights and benefits are noted as follows:

- There is very little difference overall in the amount and type of generation used, particularly when moving form Scenario 1 to 2; however the location of the generation is often changed. When regions balance their own assigned wind, they increase CC usage, and sometimes decrease coal usage. Scenario 2 moves generation from SPP to SERC regions, while changing very little in terms of the entire footprint.
- Moving from Scenario 2 to 3 allows more usage of the less costly units on the system. In the model here, based on assumptions on fuel price and plant mix, this means that SPP coal and CCs can be used more, replacing more expensive CCs from SERC in the generation mix.
- Starts increase with amount of wind added, but then decrease for most generation (with the exception of SPP CC) as cooperation is done on a wider basis.
- CCs can be seen to be crucial to the plant mix as they carry much of the ramping and reserve requirements. This is true regardless of scenario or gas price.

Recommended Follow-On Work

This study has produced a SCUC/SCED model of the SPP/SERC footprint with significant engagement and review from SPP and SERC BAs staffs. The model simulation results have provided insights as to some of the impacts of integrating 48 GW of wind generation into the SPP/SERC footprint and as to the benefits of increased levels of cooperation among the SPP and SERC BAs in integrating that wind generation. While the study results provide a good basis for understanding these issues, the underlying model contains many assumptions and the number of sensitivities that could be performed was limited. The investigators believe that additional insights and value could be obtained by building on the existing effort in the following ways:

- *Inclusion of a conceptual transmission plan for delivering the 48 GW of wind generation*. As noted, the assumption of the unconstrained transmission is significant in that it overstates the ability of the system to deliver energy and reserves between regions. Including a conceptual transmission plan with all constraints and losses considered would provide a better analysis of the magnitude of the impacts integrating the wind and the benefits of cooperation among BAs to do so.

- *Conduct additional sensitivities around fuel and emission prices*. All of the results presented are based on a single set of gas prices and no carbon price. The one sensitivity with a sizeable reduction in gas price conducted for Scenarios #2 and #3 to bound how the fuel assumption impacted results showed a sizeable impact. Additional sensitivity cases should be run for varying combinations of gas and carbon prices.
- *Conduct additional sensitivities around reserve margin and generation mix*. The higher than typical reserve margins in the footprint that resulted from adding the wind generation without altering the conventional generation plan yields more flexibility in the fleet to accommodate variability and uncertainty. Additionally, the impact of EPA regulations on expected generation fleet in the 2022 time frame may also impact the flexibility of the conventional generation that does exist. Further, the relative generator characteristics across regions for the same types of units impact the flows and where generation is produced. The SCUC/SCED model should be exercised for different generation mix scenarios to determine the sensitivity of the results to these factors.

A
INDIVIDUAL GENERATING UNIT CAPACITY FACTORS

Entergy Individual Unit Capacity Factors

Looking at individual capacity factors for CCs, Figure 6-1 shows the capacity factor for each unit for the same 6 scenarios (high wind cases plus 14 GW unconstrained). Scenario 1 is taken as the base scenario against which others are compared. So for example, the rightmost unit sees an increase in capacity factor from approx 53% to 60% for the 14 GW case versus Scenario 1, with a decrease to approximately 42% for Scenario 2 (likely to provide the additional regulation or spinning reserve needed in Entergy in Scenario 2). Again, some can be seen to change significantly when wind is added, but very little overall differences are observed.

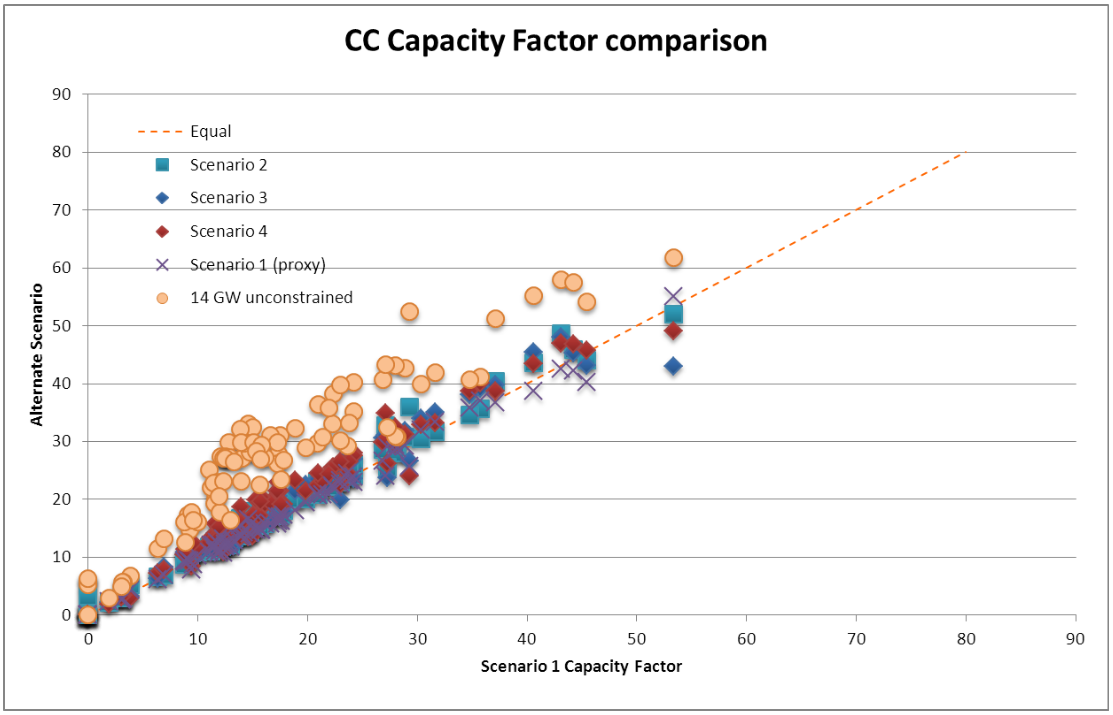

Figure 6-1: Individual CC capacity factors in Entergy

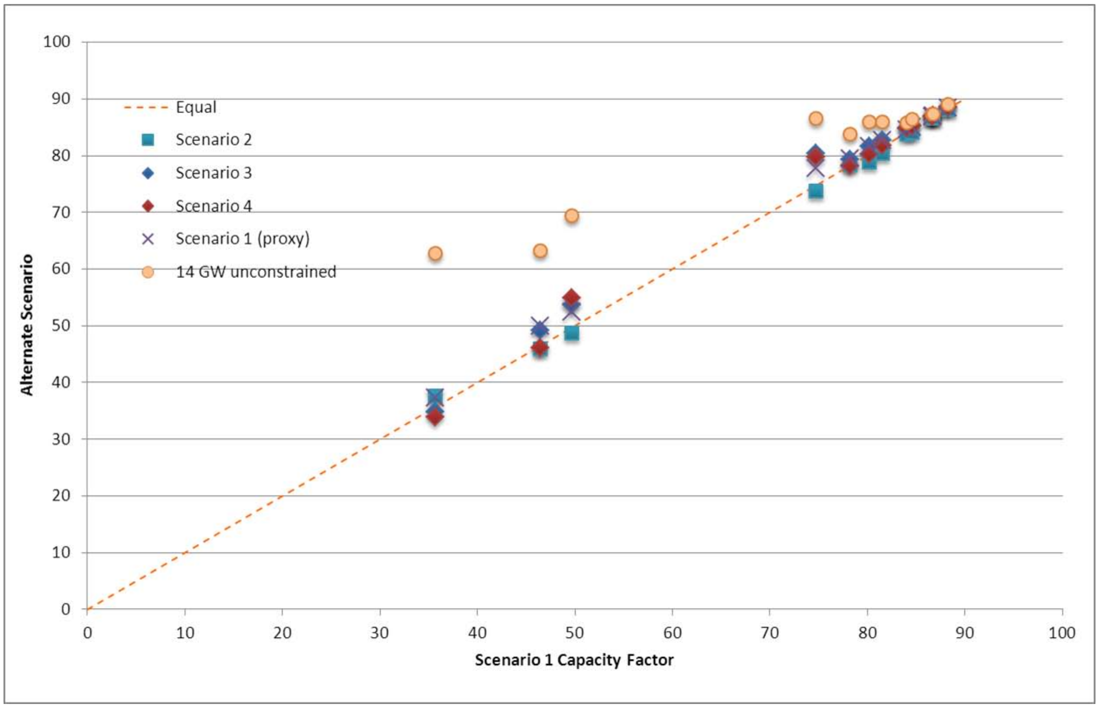

Figure 6-2: Individual coal capacity factors in Entergy

A similar figure is shown for individual coal units in Entergy in Figure 6-2. Here, very little difference is observed in the high wind cases, especially at higher capacity factors. Some of the lower capacity factor units can be seen to be used far less when wind is added, indicating they may not be built; this would thus change the relative economics and the interchanges between regions. However, there would still be benefit from coordination of reserves, but the areas obtaining that benefit may change – Entergy, which does not change significantly here, may change with a different assumed plant mix. As it is not clear how exactly different capacity factors change the likelihood of the coal being built- they are also used more for reserve in the high wind cases, which would increase their revenue- it is assumed here that plant mix does not change.

SBA Individual Unit Capacity Factors

Figure 6-3 shows a significant spread in individual SBA CC generating unit capacity factors for the different scenarios. There is the overall trend in scenarios as observed in earlier results with a decrease in generation in Scenarios 3 and 4. However, it can be seen that this will affect some units more than others. This is due to the relative economics of different generation, depending on age, size, and technical constraints such as minimum stable generation.

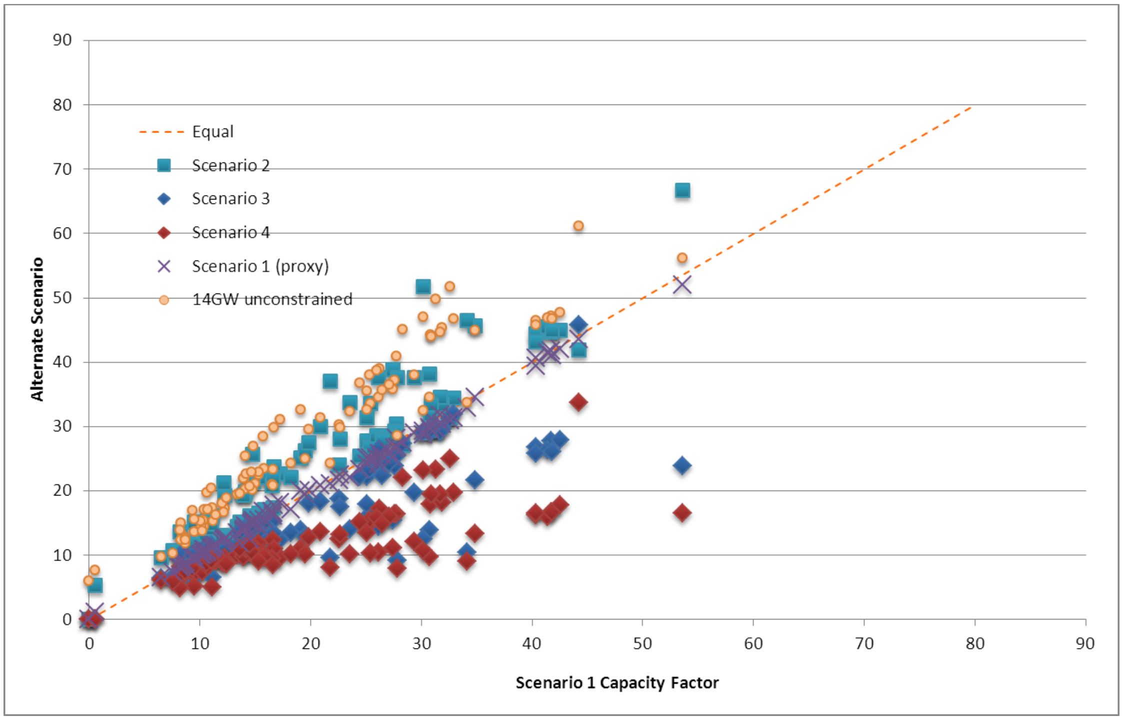

Figure 6-3: Individual CC capacity factor in SBA

Figure 6-4 shows the individual capacity factors for SBA coal units. These can be seen to be a lot tighter than CC units, with more uniform reduction for scenario 4.

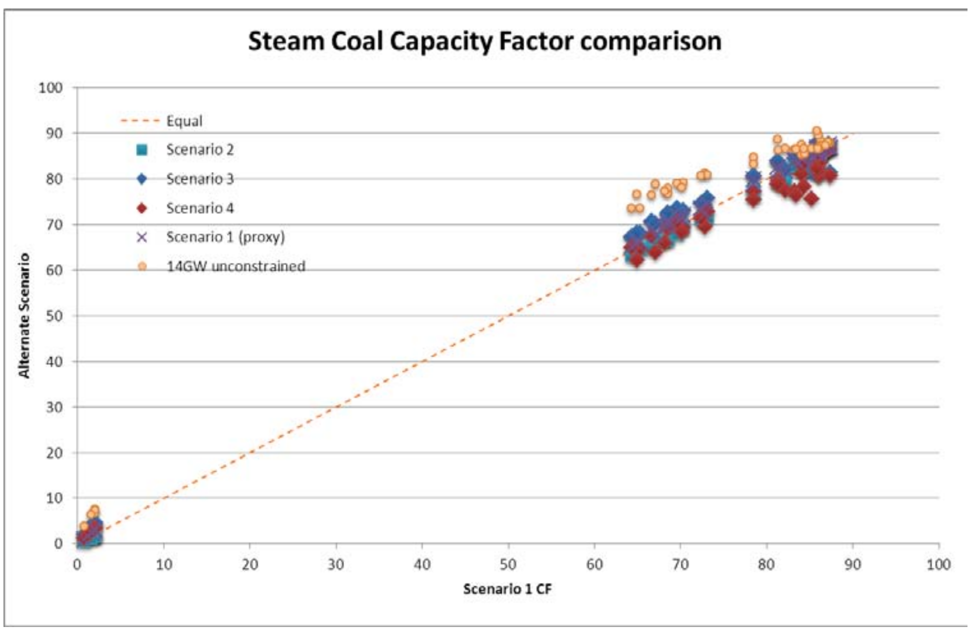

Figure 6-4: Individual Coal capacity factor for SBA

TVA Individual Unit Capacity Factors

Figure 6-5 shows the individual capacity factors for CC units in TVA. All are in the 15-35% range for scenario 1. This decreases to 10% to 28% (read along y-axis) in Scenario 3, while it is in the 22% to 50% in Scenario 2. This shows a very wide variety of capacity factors. It should be noted that in all but scenario 3 all units are above 10% - 15%, which is in the range of minimum expected capacity factors for a CC today. Figure 6-6 shows the coal capacity factors; these are again very tight in the high wind cases.

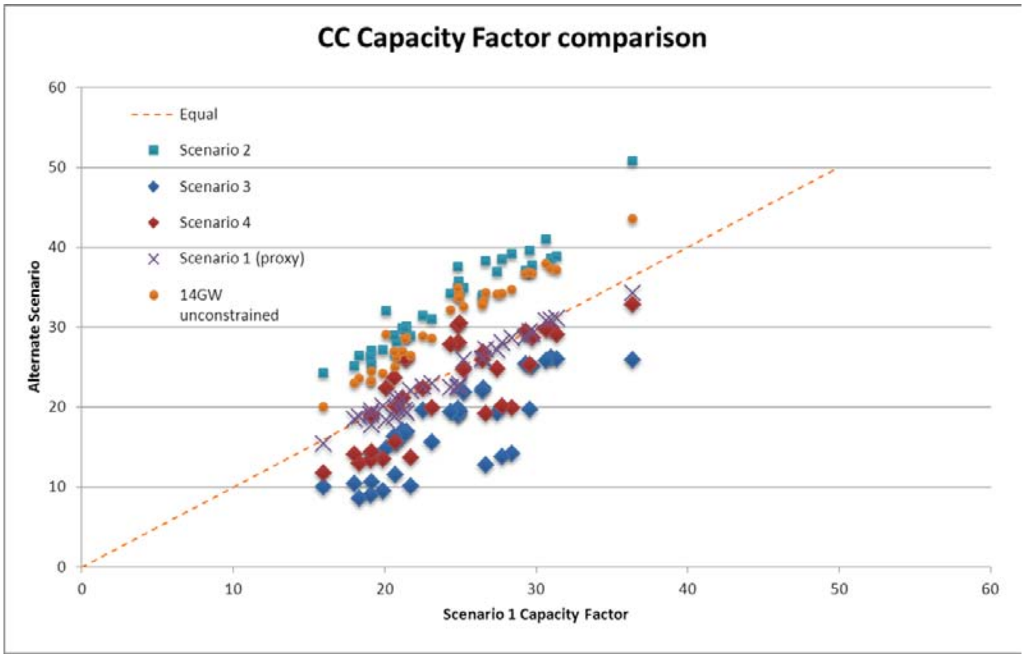

Figure 6-5
Individual CC capacity factor for TVA

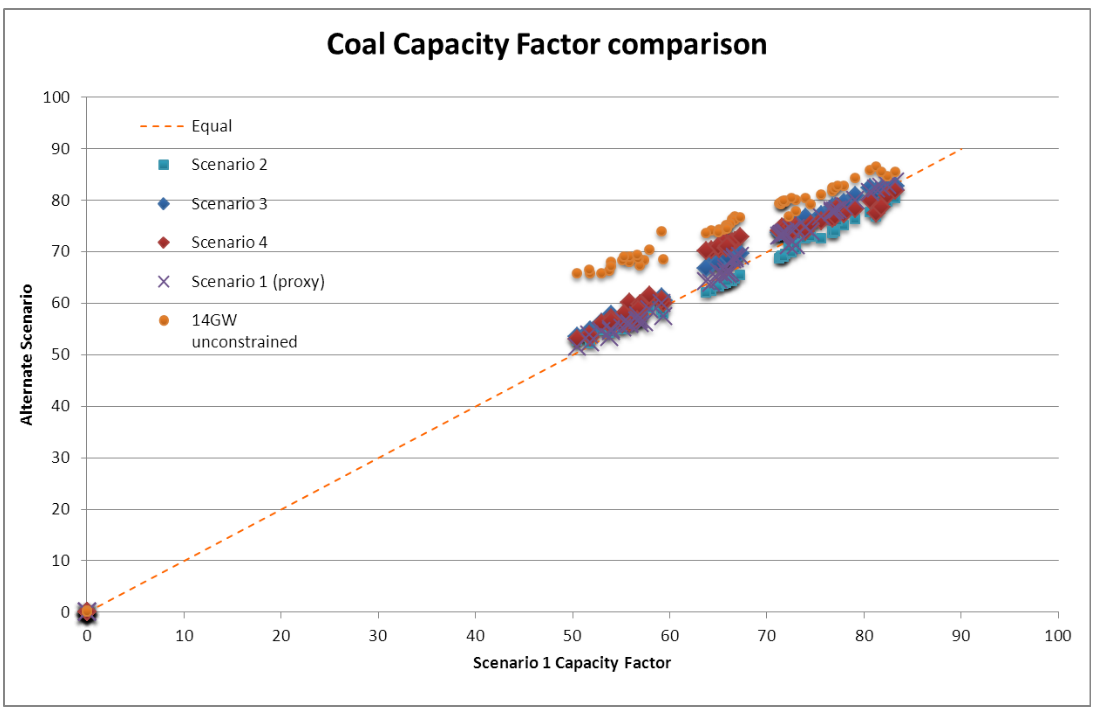

Figure 6-6: Individual Coal Capacity Factors for TVA

SPP Individual Unit Capacity Factors

Individual SPP CC generating unit capacity factors are shown in Figure 6-7. This shows a significant decrease in capacity factors across most units for scenarios 2 and 3 vs. scenario 1 and the low wind case. It can also be seen that some units are affected more than others – particularly those units with 35% or greater capacity factors in Scenario 1 – these can be significantly reduced.

Figure 6-8 shows the individual SPP coal unit capacity factors. As before, these do not show as wide a range as CC units. However, lower (likely less efficient) capacity factor units from scenario 1 can be seen to show some variability in their capacity factor across scenarios. It can be seen here that coal is going to be most affected in SPP by the balancing strategy, whereas CCs are affected elsewhere in the SERC regions. This is based on the modeling assumptions in terms of fuel price and plant mix in different regions.

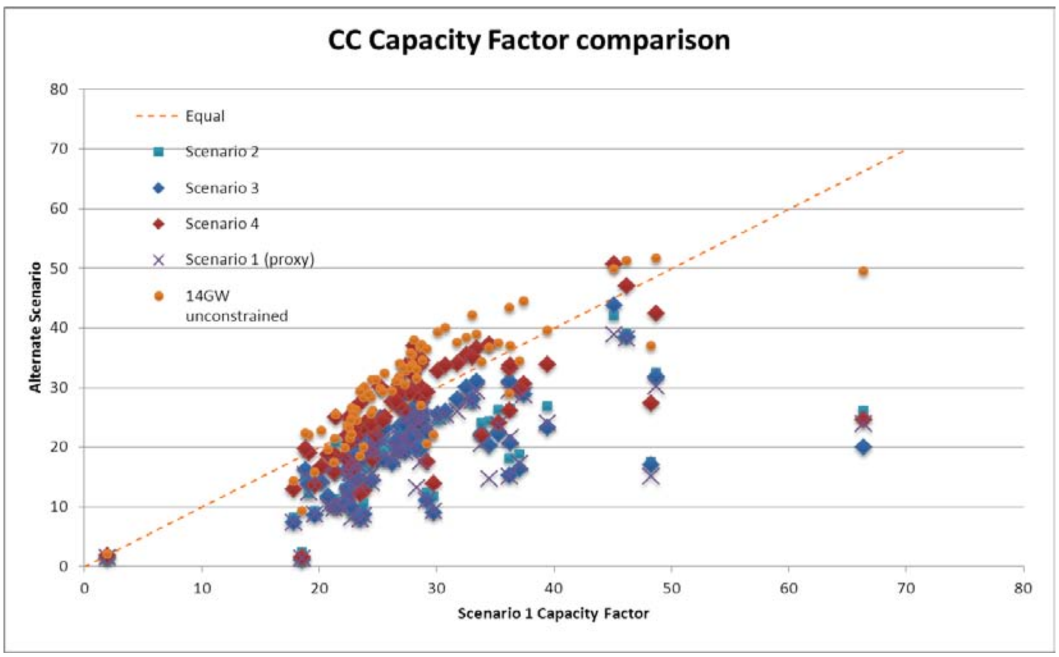

Figure 6-7: Individual CC capacity factors for SPP

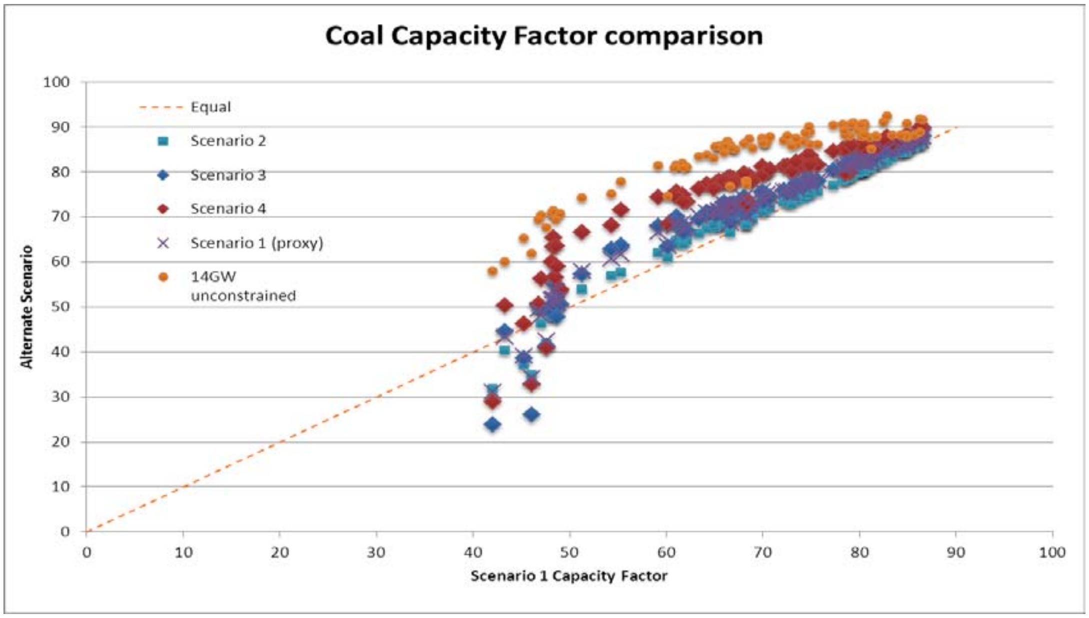

Figure 6-8: individual coal capacity factors for SPP

B

INDIVIDUAL GENERATING UNIT START-UPS

Figure 6-9 shows a scatter plot of number of starts for each Entergy CC unit for the various scenarios against the number of starts for Scenario #1. It can be seen that, in general, CC starts increase in Entergy when wind is added as more cheap, but variable, energy is available from the wind without any requirement to maintain reserve for the wind. As the level of cooperation in reserve sharing and scheduling/balancing increase from Scenarios 2-4, however, the number of CC starts increase. In Scenario #2 there are fewer starts than in Scenario #1 as some of the CCs have to be held online to provide some portion of the additional reserves to cover Entergy's portion of the wind. The number of CC starts progressively increases in Scenario #3 and Scenario #4, where Entergy CCs are used extensively to provide reserve, but the amount of spin reserve decreases significantly because of the shared contingency requirement across the footprint.

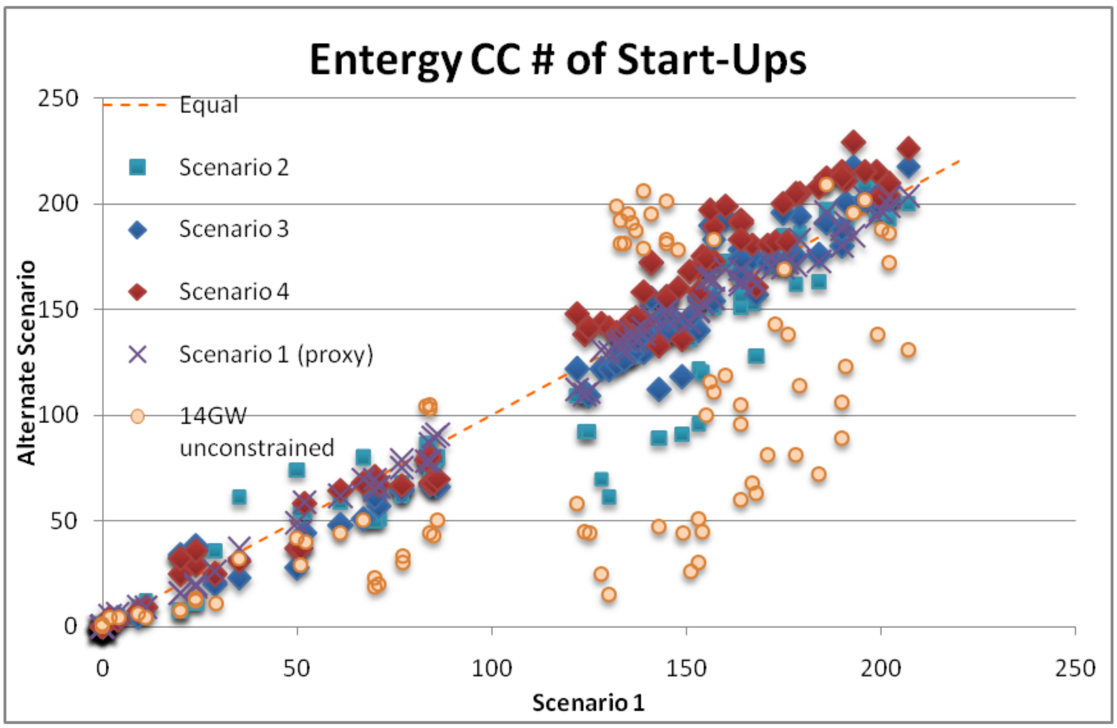

Figure 6-9
Individual Startups for CCs in Entergy

Figure 6-10 shows a scatter plot of number of starts for each TVA CC unit for the various scenarios against the number of starts for Scenario #1. TVA can be seen to have a reduced number of starts for all CCs in all scenarios compared to Scenario 1 in general; however as with other results, there are certain units which do not follow this pattern, as their characteristics assumed in this model mean they are used differently. Scenario 2 can be seen to reduce the number of starts the most as CCs are kept online to provide the increased reserves that TVA must supply for the wind in this scenario. The number of starts decrease further in Scenario #3 as scheduling is shared across the footprint and less expensive resources (as modeled here) are able to carry some of the reserve that the TVA CCs carry in Scenario #2 and the CCs stay offline longer as the lower capacity factors indicate. In Scenarios # 4, the number of TVA starts increase as these units begin to provide some reserve to SBA due to the relative economics with the hurdle rates removed. In Scenarios #3 and # 4 starts increase for some units and decrease for others.

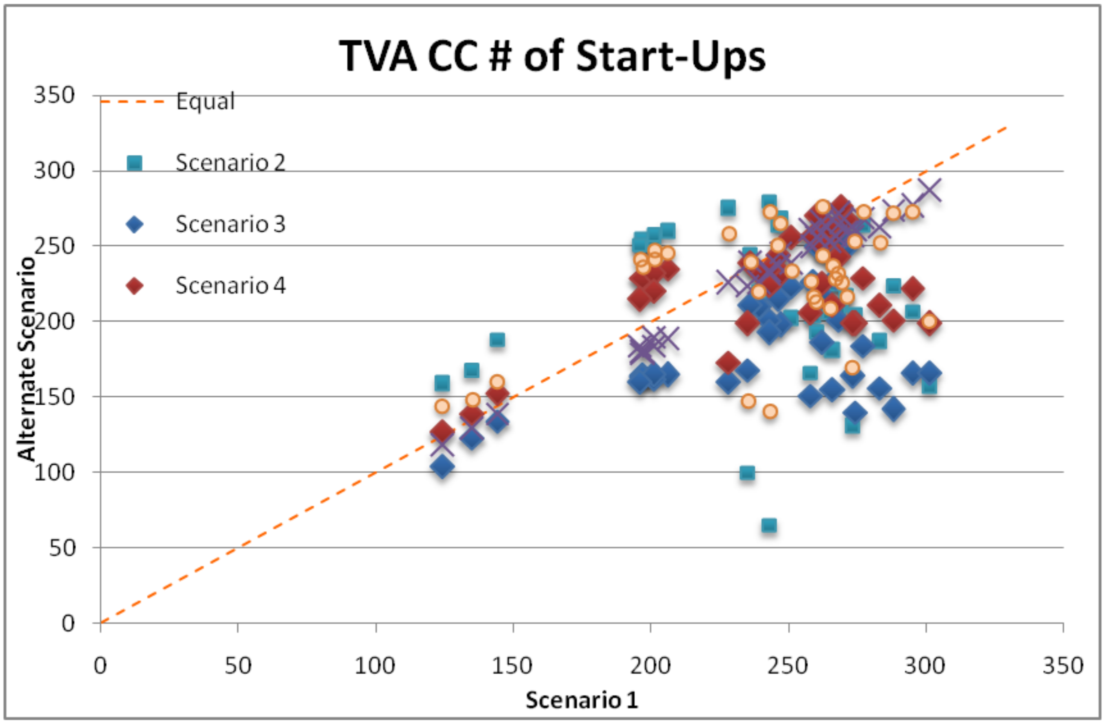

Figure 6-10: Individual CC starts for TVA

Figure 6-11 shows a scatter plot of number of starts for each SBA CC unit for the various scenarios against the number of starts for Scenario #1. SBA CC units are started slightly few times in Scenario #2 when SBA has to carry its own reserves for wind. The starts decrease further in Scenario #3 as cheaper resources from other regions (as modeled here) can provide reserve, but the decrease isn't as significant as for TVA due to the higher hurdle rates. When the hurdle rates are removed in Scenario #4, other regions' units are used more for SBA reserve requirements and energy and the SBA CC units are pushed offline for longer periods of time. Again, it can be seen that individual units behave differently from each other, likely due to different characteristics and consequent usage by the model. In general, units with higher starts in Scenario 1 appear to reduce in starts, while those with numbers of starts in Scenario 1 increase in starts. Adding wind to the system can also be seen to produce no clear pattern in terms of numbers of starts.

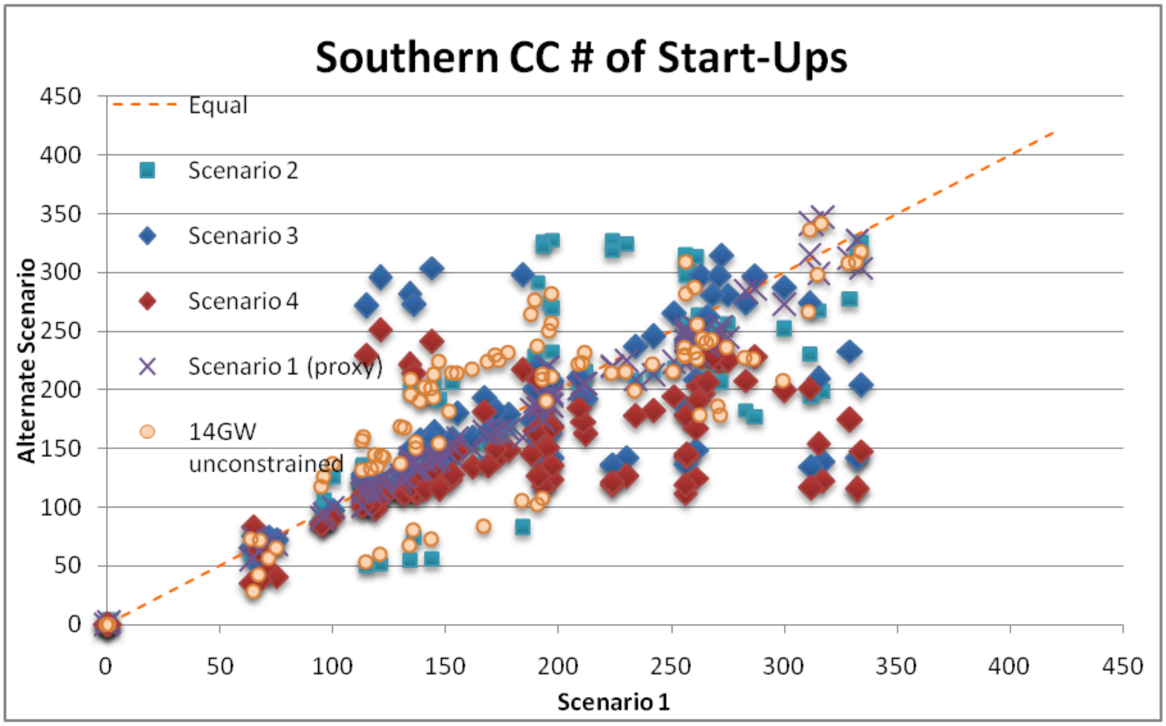

Figure 6-11: Individual CC starts for SBA

Figure 6-12 shows a scatter plot of number of starts for each SPP CC units for the various scenarios against the number of starts for Scenario #1. Relative to Scenario 1 where CCs are left online to provide for the increased reserve needs, other scenarios increase starts. Scenario 4 in general shows the greatest increase, but again there is quite a spread.

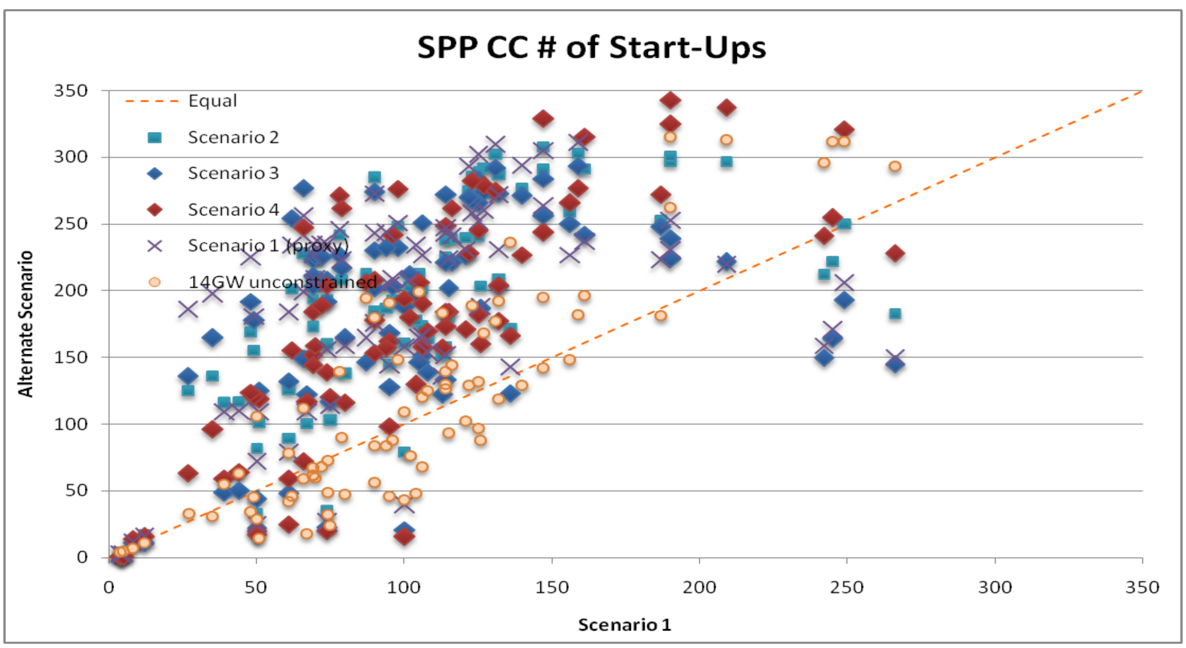

Figure 6-12: Individual CC starts for SPP

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