

Executive Summary

Arizona Public Service Wind Integration Cost Impact Study

**Prepared for
Arizona Public Service Company**

Prepared by



Sustainable Energy Solutions

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PREFACE

The purpose of this report is to describe the methods employed and results obtained in a wind integration cost impact analysis conducted for the Arizona Public Service Company (APS). This study was conducted under the direction of the Sustainable Energy Solutions Group at Northern Arizona University (NAU) under contract with APS. Important contributions to this work were provided by NAU, APS, EnerNex Corporation, and 3TIER.



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ARIZONA PUBLIC SERVICE WIND INTEGRATION COST IMPACT STUDY

EXECUTIVE SUMMARY

This Executive Summary, and the report it was extracted from, was produced by Northern Arizona University (NAU), with contributions from EnerNex Corporation, 3TIER, and Arizona Public Service Company (APS). The report is a result of an eight month study to characterize the impacts and costs due to the variability and uncertainty of wind energy associated with integrating wind energy into APS' utility resources and practices.

Introduction

Wind energy brings many positive benefits to the utility system, such as cost effective energy, long-term price stability, and some system capacity, but it also has different generation characteristics than conventional utility resources. In particular, since the wind is driven by meteorological processes it is inherently *variable*. This variability occurs on all time frames of utility operation from real-time minute-to-minute fluctuations through yearly variation affecting long-term planning. Recent wind integration studies have demonstrated that the variations of most importance and cost are those in the hourly and daily timeframe, related to the ancillary services of load following and unit commitment. Regulation costs, incurred by fast responding units that respond to the random minute-to-minute fluctuations on the system, are also incurred but are smaller in magnitude. In addition to being variable, wind power production is also a challenge to accurately predict on the time scales of interest to utility planners and operators: day ahead and for long-term planning of system adequacy (i.e., meeting the system peak load during the year). Wind energy is more predictable in the hour-ahead time frame, but even then the *uncertainty* in wind forecasts must be accounted for in utility operation and dispatching. In order to minimize impacts and maximize benefits, each utility that incorporates wind energy must learn how to accommodate the *uncertainty* and *variability* of wind energy in their operational and planning practices, and do so while maintaining system reliability.

The objectives of this study were to analyze operating impacts and costs of integrating various levels of wind energy in the APS balancing area (i.e., control area), due to the variability and uncertainty of wind energy. Specifically, attention was focused on the amount of wind energy the APS system may see in the relatively near term, and therefore would provide a fair integration cost to utilize in evaluating wind energy proposals in APS's current and future RFP's.

The results obtained in any integration study are highly dependent on the input assumptions and analysis methods. The philosophy adopted by APS in this study was to determine a realistic, yet conservative, value for the integration cost (i.e., within the limitations of the modeling, come as close as possible to the actual integration cost without underestimating). Furthermore, the study process was devised to produce meaningful, broadly supported results

through a technically rigorous, inclusive study process. Northern Arizona University was the lead organization in the study effort, working in collaboration with APS, EnerNex Corporation, and 3TIER. NAU was responsible for managing the project and for overall technical direction. EnerNex was the primary technical consultant on the integration analysis, 3TIER was responsible for the wind speed and power modeling, and APS was responsible for system characterization and modeling. There were two important advantages in APS performing the modeling: 1) they are experts in modeling and running their system, and best suited to model system operation; and 2) they gained an increased understanding of wind energy and its generation characteristics, and developed in-house expertise to conduct future integration cost impact studies. A Technical Advisory Group (TAG) was formed to provide external review and guidance to the study), and in particular were counted upon to assist in selecting key model assumptions and parameters used in the study. The project team and TAG were assembled so as to build upon prior wind integration studies and related technical work, to coordinate with recent and current regional power system study work, and to ensure that the assumptions and methods employed were appropriate. The public was informed of the study through stakeholder meetings conducted jointly by APS and NAU, and supported by the project team. Through the stakeholder meetings, the project team sought interaction and input regarding all aspects of the project, including wind resources, technical details, and policy ramifications. The organizations invited to the stakeholder meetings were also expected to serve as conduits of information to the people and organizations they represented.

Study Set-up

A critical aspect of any wind integration study is correctly accounting for the relationship between wind and load. System load is partly dictated by the weather, such as when hot weather causes high air conditioning loads. Wind power generation is obviously related to the weather, and so there will be some correlation between the weather, the load, and the wind power. In order to correctly capture this relationship in an integration study, a time-series of historical load data is matched with either the historical wind power data or a simulation of the wind power data. For the purpose of this study, APS 2004 hourly load data was employed in conjunction with simulated wind power production data over the same period. The study year was selected as 2010 so that the integration analysis could be conducted while knowing with some certainty the characteristics of the APS loads and generation resources. Thus, the 2004 loads were scaled-up to the level expected in 2010. A wind power simulation was conducted by 3TIER, using a meso-scale weather model employing 2004 historical weather data as an input. The idea here was that the meso-scale model does a good job predicting and downscaling the wind speed, air density, etc., when using the historical coarse resolution weather data to maintain a high correlation between the simulations and the actual weather. This type of predictive model using historical weather data is called a “backcast.” The wind speed data was then turned into wind power production through an algorithm that assumes a turbine type, makes reasonable assumptions about the wind power plant layout, and produces a simulated power output for several distinct wind power plants. For this study, a GE 1.5sl turbine (1.5 MW rated output) with a 77-meter rotor diameter and 80-meter hub height was the turbine model employed at all locations. Wind power output from the turbines was adjusted to account for the local air density, which is

lower at higher elevations. Key elements of this simulation were that the wind power prediction is correlated to the weather and any correlation with the load is implicitly captured, and that the variability of the wind power output is typical of what is actually realized at functioning wind power plants.

A range of wind energy penetration levels and geographic diversity in wind power production were considered, as shown in Table ES 1. All wind energy penetration levels listed refer to the expected APS energy production and peak load in 2010. In this table, “energy penetration” implies a percentage of the APS system energy consumption (estimated at approximately 34,600,000 MWh in 2010) provided by wind energy, and “penetration by capacity” is determined by dividing the MW capacity of wind power by the APS peak system load in 2010 (estimated at 7,905 MW). The “X” in the center of this table indicates that the 4% wind energy penetration, medium diversity case was considered the “base case” in this study. This was selected as the base case because it is a reasonable approximation of what may be achieved over the relatively near term in Arizona. The locations and sizes of the wind power plants simulated were determined as part of the project. Wind power plants were located in such a way that the prescribed level of energy and geographic diversity could be achieved (e.g., high, medium, or low), and so that the wind power plants would be located at sites within the zones where an adequate wind power potential existed as predicted by the simulation (minimum of a class 3 wind resource).

Table ES 1 – Matrix of wind energy penetration and geographic diversity scenarios considered.

Wind Scenarios		Geographic Diversity		
Energy Penetration	Penetration by Capacity	High	Med	Low
1%	1.5%			
4%	5.9%		X	
7%	10.4%			
10%	14.8%			

Gray shading = Cases run X= Base case

For the purpose of this study, wind power plants were considered in Arizona within the two zones shown on the 2003 high resolution Arizona wind energy map displayed in Figure ES 1 (for more information about the wind map, visit the Northern Arizona University Sustainable Energy Solutions website: <http://wind.nau.edu/maps/>). The more colorful areas shown on the map correspond to better wind resource areas, most of which are contained within the two zones. Furthermore, locating wind power plants in both of these zones allows geographic diversity in siting the plants, similar to what could be achieved in the state.

To summarize, the overall objective of this study is to compute the incremental integration costs incurred by the APS system in accommodating the variability and uncertainty of wind energy. This was accomplished as follows:

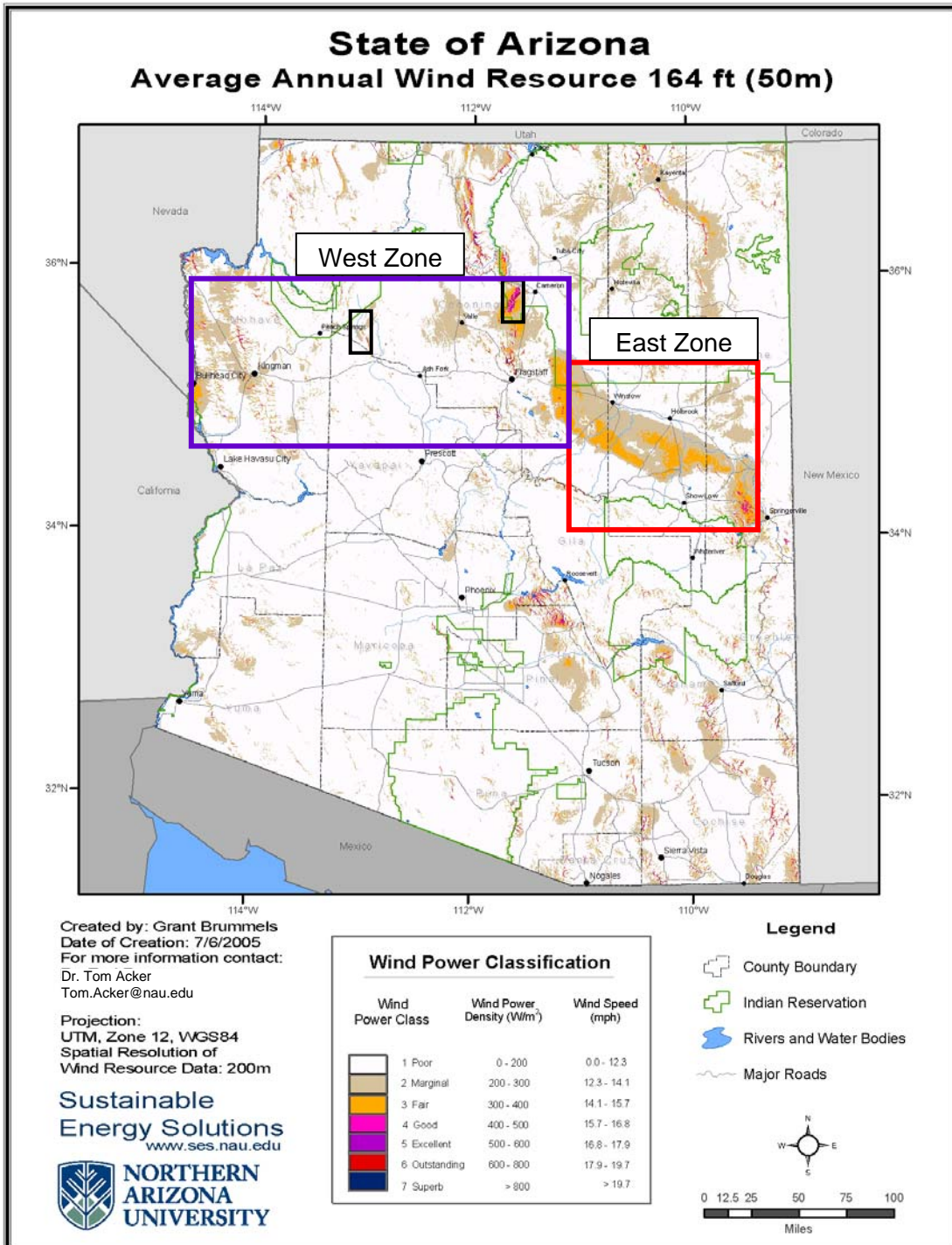


Figure ES 1 – Regions within which wind power plants were considered for the purpose of this study, shown on the 2003 Arizona high-resolution map of wind energy at 50-meters above the ground.

- Simulate APS system operation and planning for one typical year:
 - Determine the operating costs for the system excluding the effects of wind variability and uncertainty.
 - Determine the operating costs for the system with the actual wind, including the effects of its variability and uncertainty.
 - Deduce the integration costs as the difference between the costs computed in these two simulations.
- The study year was selected as 2010.
- Historical load data for APS in 2004 was scaled to match the expected load and energy required in 2010, maintaining the hour-to-hour shape of the load and its correlation to the weather.
- A reasonable set of wind power plants in Arizona were simulated, using a meso-scale weather model, 2004 historical weather data, and a wind power prediction model. This provided wind power data that is time-synchronized with the load data, maintaining any correlation inherent between the two.
- GE 1.5 MW wind turbines with a 77-m rotor diameter and an 80-m hub height were assumed in the wind power plant modeling.
- The sensitivity of wind integration costs to wind energy penetration and geographic diversity was investigated as indicated in Table ES 1. Wind Modeling Analysis and Results

There were two basic requirements for the wind energy modeling as used in this wind integration study: 1) it be physics-based and of sufficient resolution in both time and space to accomplish the goals of the integration study; and 2) it accurately convert wind speed information to wind power production data, including the correct characterization of the variability exhibited in the output of the wind power plants. As to this later point, because the wind speed and direction varies even over small areas, no two wind turbines see the same input wind speed nor have identical power output. Further, each wind turbine possesses a significant amount of inertia, hence its output cannot respond to the faster fluctuations of the wind speed. For these reasons, one cannot simply take the output of a meso-scale wind model (or wind anemometer data) and run it directly through a manufacturer's turbine power curve to accurately estimate the power output for an entire wind power plant. There must be some method to ensure that the variability of modeled wind plant output emulates the output that is actually realized in operational wind power plants. Given these considerations, the following parameters were defined for the wind modeling in consultation with the project technical advisory group:

- Wind speeds were simulated with 3TIER's meso-scale model throughout the zones shown in Figure ES 1, for the historical years of 1996 to 2006, with particular focus on 2003, 2004, and 2005.
- The East and West zones demarked by the blue and red boxes in this figure were both modeled using a grid spacing of 5-km (the meso-scale model predicts wind speed, direction, air density, etc., at pre-defined grid points), for the historical period 1996 to 2006.
- Two smaller zones, approximated by the small black rectangles in Figure ES 1, were selected for additional higher-resolution modeling with 1-km grid spacing. These

zones are the Aubrey Cliffs, north of Seligman, and Gray Mountain, west of Cameron, and are known to have good potential for wind resource development, but also have highly variable topography. Because a 5-km resolution simulation may not adequately capture the effects of the topographical features present in these areas, more refined 1-km resolution simulations were conducted. The higher resolution zones were modeled only for historical years 2003, 2004, and 2005.

- The time-step of the meso-scale simulation was 10-minutes (for all zones). This resolution in time allows study of the intra-hour wind variations, and can easily be modified for an hourly power system simulation.
- Wind speed and related meteorological parameters were predicted at 50-m, 80-m, and 100-m above the ground at each model grid point.

Maps displaying the results of the meso-scale wind simulation for the West and East modeling zones are displayed in Figure ES 2 and Figure ES 3. Each map displays the wind power density (W/m^2) at 80-meters above the ground since it is more directly indicative of the wind energy potential at a given site than the wind speed, and thus better suited to guide the selection of wind power plant locations. The wind class designations shown on the scale correspond to the mid-point of the wind class. Since class 3 is considered the minimum wind class that currently can support an economically feasible wind power plant, the areas where potential wind power plants could be located are colored light orange to dark red. It is worth recognizing that the base data used for creating these maps is the 5-km resolution data, and the smooth variation of the colors shown on this map resulted from applying an interpolating

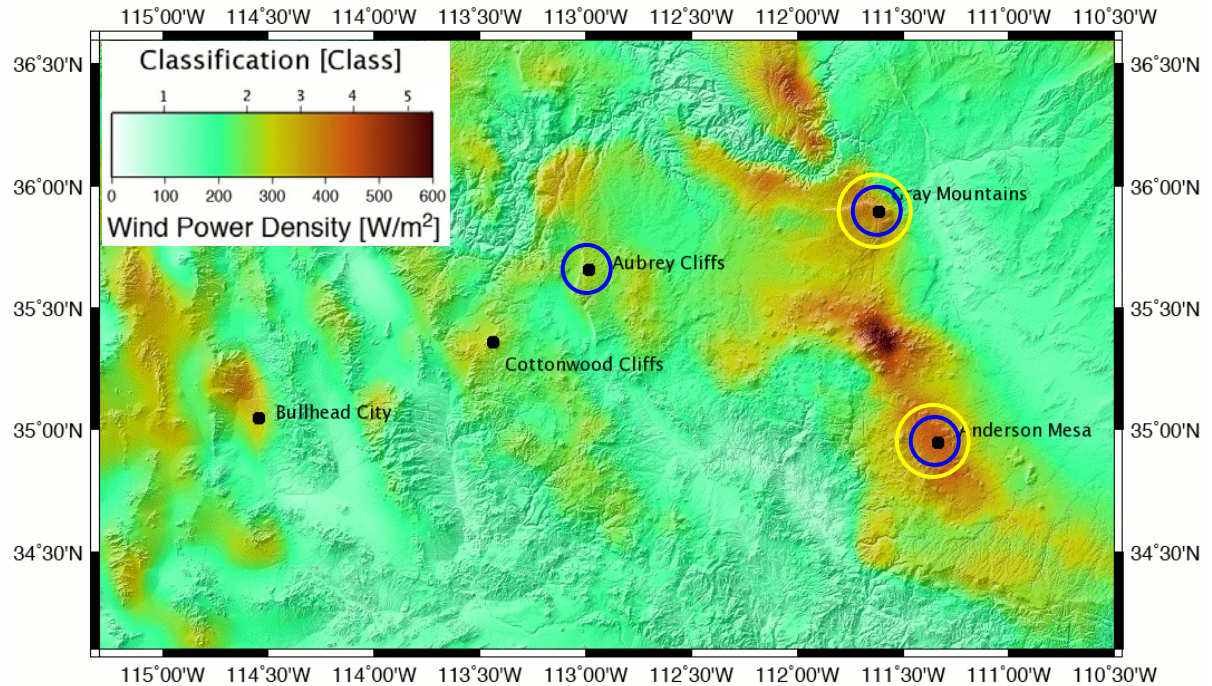


Figure ES 2 - Wind power density map of the West (APA) modeling zone at 80-meters above the ground.

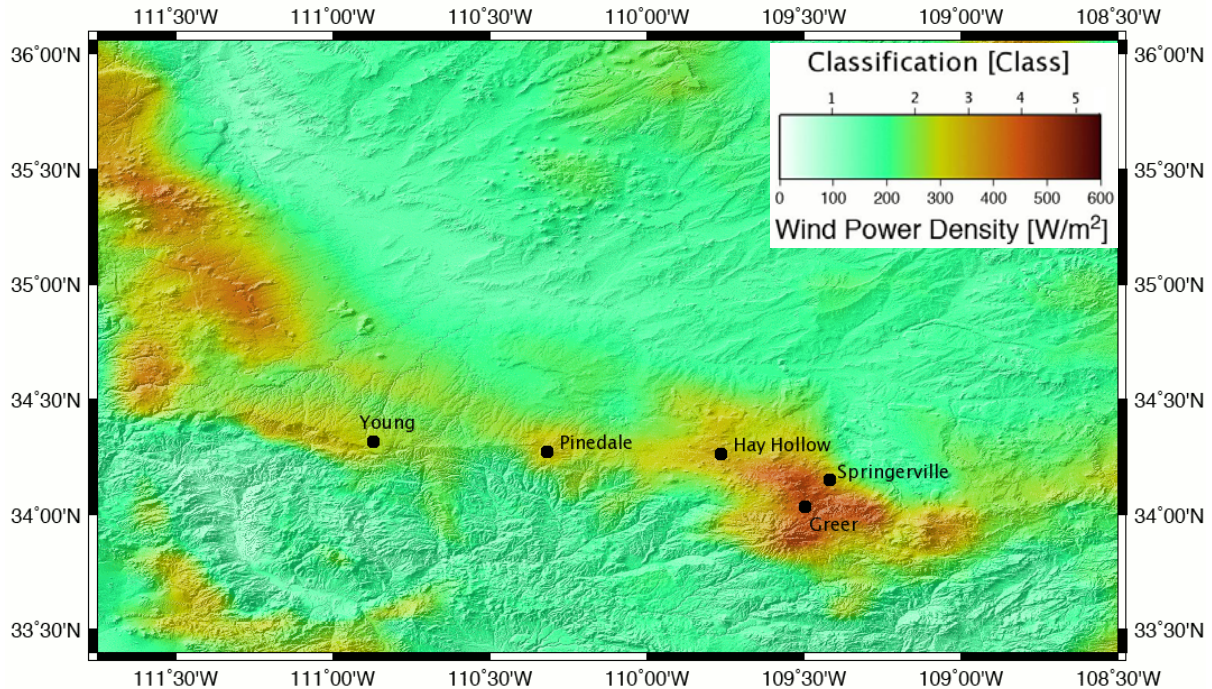


Figure ES 3 – Wind power density map of the East modeling zone at 80-meters above the ground.

technique between the points. The figures also show five sites in each zone (a total of 10 sites) where the hypothetical wind power plants were located for the purpose of this study. As can be seen, these sites have been located in areas where the wind resource is sufficient to support wind development, and spread across the zones such that the impact of geographic diversity can be investigated. It is worth mentioning that no preliminary screening of nearby available transmission capacity was made in citing the wind power plants. If the hypothetical plants modeled for this study were actually constructed, some additional transmission capacity would no doubt be required. However, since this study seeks to determine the impact on system operating costs due to the wind power variability and uncertainty (only), it is appropriate to neglect transmission costs (note, the transmission costs would be important in determining which resources to add to the system, but not in its “integration” cost).

Using the output of the meso-scale modeling as an input, the wind power plant output was computed using 3TIER’s Statistically Corrected Output from Record Extension (SCORE) methodology. This technique was developed specifically to accurately predict the magnitude and variability of the output from a wind power plant. The technique employed power curves for a GE 1.5sl MW wind turbine with a 77-m rotor diameter, an 80-m hub height, and with adjustment for the local air density at each proposed site. Ten-minute resolution power outputs from the 10 wind power plants were simulated. Details of the simulation are as follows:

- Each wind power plant was composed of nine separate groupings of turbines, typically 36-MW per group of turbines (24 turbines per group), totaling a maximum of 324-MW per site. In simulating the power output at each site, strings of turbines were placed with a minimum spacing of four rotor diameters between turbines on the

same string and a minimum spacing of 10 rotor diameters between the rows of turbines.

- The 10-minute wind power output from the SCORE methodology was aggregated into hourly power sequences for each scenario for input into the APS power system model.
- Wind power output from all 10 sites shown in Figure ES 2 and Figure ES 3 were employed for the high geographic diversity case. For the medium diversity cases, output from wind power plants from three sites centrally located in the state was used (those with blue circles in Figure ES 2). For the low diversity case, output from only two wind power plants were employed (those with yellow circles in Figure ES 2).

Table ES 2 shows the megawatts (MW) of installed capacity selected at each site, for each scenario defined in Table ES 1. Note that to produce 4% of APS’ annual energy in 2010, it took 468 MW of wind power for the medium and low diversity cases, but 510 MW in the high diversity case. The reason for this is that some turbine groups from higher producing sites (e.g., Gray Mountain and Aubrey Cliffs) were replaced with turbine groups from lower producing sites (e.g., Springerville, Hay Hollow, etc.), requiring more wind power capacity to produce the same amount of wind energy.

Table ES 2 – Megawatts (MW) of installed capacity from each site employed in the various scenarios considered.

Modeling Zone	Wind Energy: Site \ Diversity:	MW of Installed Capacity				
		1% Med	4% High	4% Med	4% Low	10% Med
West / APA	Bullhead City		78			
	Cottonwood Cliffs		36			
	Aubrey Cliffs	36	72	144		324
	Gray Mountain	72	36	180	288	324
	Anderson		72	144	180	324
East / APSCO	Young		36			288
	Pinedale		36			
	Hay Hollow		36			
	Greer		72			
	Springerville		36			
Total		108	510	468	468	1260

An in-depth analysis of the output from the wind power simulation yielded the following conclusions:

- The capacity factor of the 10 simulated wind power plants varied from the 22% to 36%.
- The seasonal variation of Arizona wind power indicates that highest wind capacity factors (energy output) occur in the spring, and the lowest in the summer.
- The diurnal profile of Arizona wind power output signifies an afternoon peaking wind with the highest capacity values in the afternoon and lowest in the early morning hours.

- The capacity value of an Arizona wind resource located in the regions modeled in this study will likely be a significant fraction of, but less than, its annual capacity factor.
- The vast majority of 10-minute ramping events are less than 10% of the wind power plant capacity. The combined output from all wind power plants is considerably smoother than any of the individual power plants.
- Large ramp events (larger than 10% of nameplate) at the hourly timescale take place about 15% of the time for individual wind power plants, and about 5% of the time for geographically diverse wind power production. Geographical diversity results in some smoothing of large ramps.

Wind Integration Analysis Technique

The basic approach in conducting this integration cost study was to simulate system planning, operational activities and decisions over the course of a set time period. In APS's case, this entailed running the modeling software RTSimⁱ over the course of one simulated year. RTSim is the tool used by APS on a daily basis to model their system planning and operation, and uses an hourly time step. The simulation performs an optimal commitment of available generating units (unit commitment) in the day-ahead time frame, ensuring there is adequate generation available to cover the next day's load, the variations in the load (e.g., ramps), and setting aside sufficient reserves. As the simulation proceeds into the day of operation, units that were committed for use during the day are re-optimized and even re-committed on an economic basis in the hour-ahead timeframe, when the expected load, generation, and wind is more certain. The units available during the hour ("real time") must be sufficient to follow the load swings within the hour and hour-to-hour (load following), as well as the short term minute-to-minute fluctuations (regulation). After simulating the system operation for a year, an overall cost to run the system and meet the load is determined, including all market transactions. In order to assess the incremental cost to integrate the wind energy, the system operation is first simulated with some baseline set of resources that does include the wind energy but in a way that attempts to remove the effect of its uncertainty and variability. The system is then simulated again with the actual wind energy, accounting for its uncertainty (inaccuracy in prediction) both day ahead and hour ahead, and accommodating for its actual variability. The cost incurred during this simulation is then subtracted from the cost incurred with the baseline resources to deduce the "integration" costs.

The integration cost depends upon the variability and output of the wind power, the variability and magnitude of the load, and the characteristics of the generation. APS is a summer-peaking utility with its peak driven primarily by residential customer growth and the associated cooling loads. As the customer base grows, the summer period load grows at a faster rate than the winter and shoulder months. In meeting its load obligation, APS employs a mix of generation resources. The base load resources are coal and nuclear and contribute about 2/3 of the energy requirement, while only accounting for about 1/3 of the capacity. The remaining 1/3 of the energy is supplied by gas-fired intermediate and peaking resources.

ⁱ RTSim is a production cost simulation model developed by Simtec in Madison, Wisconsin (see rtsim.com). It is an hourly simulation tool that can perform comprehensive simulation and optimization.

When APS employs its generation resources, it does so in the most economical way, typically utilizing the least expensive of its resources possible.

Integration cost in this study was defined as the difference between the actual production cost incurred to serve the net of actual load and actual wind generation and the production cost from the reference case, where wind is perfectly known and adds no variability to the control area, and where next-day load is the only uncertainty. The basic method for determining the costs at the hourly level developed in previous studies proceeds as follows:

- 1) Run the unit commitment program in “optimization” mode to develop a plan for serving the forecasted load. Wind generation for the day is known perfectly, and is delivered in some predescribed pattern (either a flat block with equal amounts each hour throughout the day, or some diurnal distribution). Save the unit commitment as the starting point for the next case.
- 2) Using the unit commitment from 1), re-run the day with forecast load replaced by actual load. Do not allow the program to re-optimize, but allow it to re-dispatch available units to meet the actual load. Manually commit generation to meet load that cannot be served from the previous day commitment. Save the total production cost for the period and define it as the “reference production cost”
- 3) Repeat Step 1) with a next-day hour-by-hour wind generation forecast. Save the unit commitment as the starting point for the next case.
- 4) Using the unit commitment from 3), re-run the day with forecast load and forecast wind generation replaced by actual load and actual wind generation. Do not allow the program to re-optimize. Ensure the operating reserves have been appropriately incremented to account for the additional variability of wind generation. Re-dispatch available units and manually commit off-line units to meet the control area demand. Save the total production cost for the period and define it as the “actual production cost.”
- 5) Compute the integration cost as the difference between the “actual production cost” and the “reference production cost.”

Some modifications to the basic methodology outlined above were necessary to accommodate using RTSim. These included:

- Day-ahead load forecasts were automatically generated by the program, and therefore were not “historical” forecasts for the load pattern years from APS. RTSim generates a day-ahead forecast by averaging n days of (actual) hourly loads from its database, where n is a number of days defined by APS, typically less than 10. APS used $n=1$ for this modeling effort.
- Concerning wind energy forecasts, the version of RTSim utilized by APS at the time of the study would not allow any change in the actual wind that showed up during the day of operation from that which was forecast day ahead. The practical implication here was that the actual wind power time-series (from the simulation) had to be used for the forecasted wind, and that the impact of different wind forecasts could not be directly investigated (e.g., a professional forecast vs. a persistence forecast vs. a perfect forecast, etc.). In order to account for uncertainty in the day-ahead wind

forecast in the day-ahead optimization, RTSim allows a “firmness” factor to be applied to the wind energy. The firmness factor allows a fixed percentage between 0% and 100% of the forecasted wind generation for the day to be considered “firm” in the day-ahead optimization. The day-ahead firmness factor for all scenarios considered was selected as 60%. Therefore, RTSim would consider 60% of the wind forecasted for each hour to be firm and could be scheduled while the remaining 40% would not be counted on to serve load. RTSim’s optimization routine, therefore, always knows about the “shape” of the wind energy delivery for the next day, and the amount of wind energy delivered was always greater than what was forecast (unless a 100% firmness factor was used). The approach results in an over-commitment of conventional generating units on all days where wind energy delivery is not zero.

- Similar to the day-ahead forecast, RTSim requires the hour-ahead forecast of wind energy to be the same as the actual wind that shows up; however, an hour-ahead firmness factor can be set. By varying the hour-ahead firmness factor between 0% and 100%, the effect of uncertainty in the hour-ahead forecast can be deduced. The hour-ahead firmness factor varied for each scenario, depending on the specific wind power time-series at each site. Overall, the hour-ahead firmness factors varied from 85% (low geographic diversity) to 99% (low wind energy penetration), with a value of 87.5% for the base case of 4% wind energy and medium geographic diversity.
- Because RTSim is an hourly simulation model, it cannot by itself determine the amount of additional spinning reserve needed to accommodate the increased regulation due to the minute-to-minute fluctuations of the wind power. Using samples of 1-minute wind power data from an existing wind power plant and 1-minute APS load data, a calculation was performed to define the additional regulation burden due to wind energy. The range of additional spinning reserve required varied from 0.5 MW to 6.2 MW for 1% and 10% wind energy penetration, respectively (2.4 MW for the base case of 4% wind energy).

Certain aspects of the methodology listed above merit additional emphasis:

- Load energy (MWh) and wind energy (MWh) delivered in “reference” and “actual” cases are identical. If wind generation is assumed to be a “must take” resource, the payment from APS to the wind generators is identical in both the “reference” and “actual” cases. Therefore, the cost per MWh of wind energy is not relevant to the analysis (i.e., it “subtracts out”).
- Optimization cases are run with next-day forecast data. All binding decisions (unit commitment or de-commitment, day-ahead purchases, etc.) must be carried forward to the simulation of the actual day.
- Simulation cases are run with actual hourly load and wind data, and start from the optimized day-ahead plan. However, RTSim does allow a re-optimization of its available resources in the hour-ahead timeframe, based upon the generation resources set forth in the day-ahead commitment and those available within an hour of use (including resources on the market).

Finally, there is the issue of the wind generation attributes defined for the “reference” case. In this method, wind energy delivery is allowed to vary day-by-day and hour-by-hour. In the reference case, the wind energy is assumed to be 100% firm both day-ahead and hour-ahead

and therefore have no uncertainty. As will be discussed later, there is also no additional spinning reserve added to that required within each hour due to the wind in the reference case (thus no impact of the wind upon the within-hour regulation required in the reference case). The reference resource for wind assumed here is equivalent to an “as-available” energy contract with a third-party, where the terms of the contract allow the delivery to be scheduled a day in advance.

Wind Integration Cost Impact Results

Figure ES 4 shows the integration cost results for the medium geographic diversity case with 1%, 4%, 7% and 10% wind energy penetration. The overall height of each vertical bar on the chart signifies the full integration cost, with the colored sections of each bar indicating the proportion of the cost contributed by the regulation (added spinning reserve; green section), the hour-ahead uncertainty (hour-ahead firmness being less than 100%; red section), and the day-ahead uncertainty (day-ahead firmness being less than 100%; blue section). For the base case of 4% wind energy, the total integration cost is \$3.25/MWh, varying from \$0.91/MWh (1% wind energy) to \$4.08/MWh (10% wind energy).

Figure ES 5 displays the sensitivity of integration cost to geographic diversity, for the 4% wind penetration case. The center column on this chart corresponds to the base case and is identical to that shown in Figure ES 4. The main result demonstrated in this figure is the effect of geographic diversity on reducing the integration cost. As turbines are spread over a

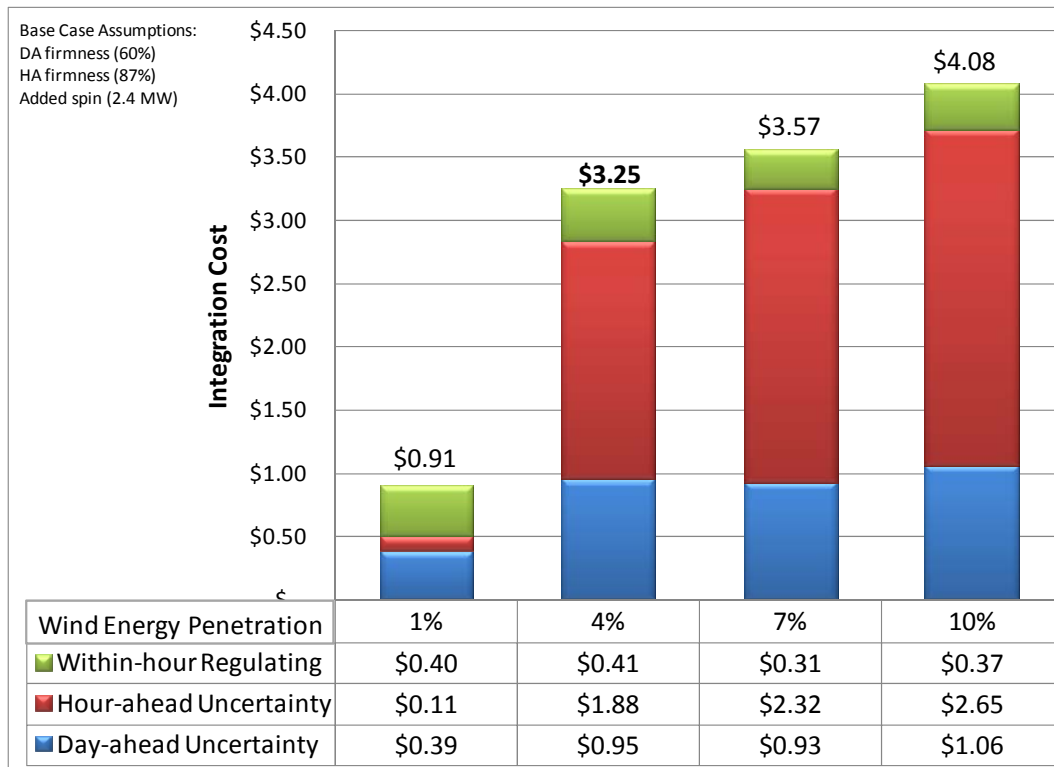


Figure ES 4 – Sensitivity of integration cost to percent penetration of wind energy, under base case assumptions.

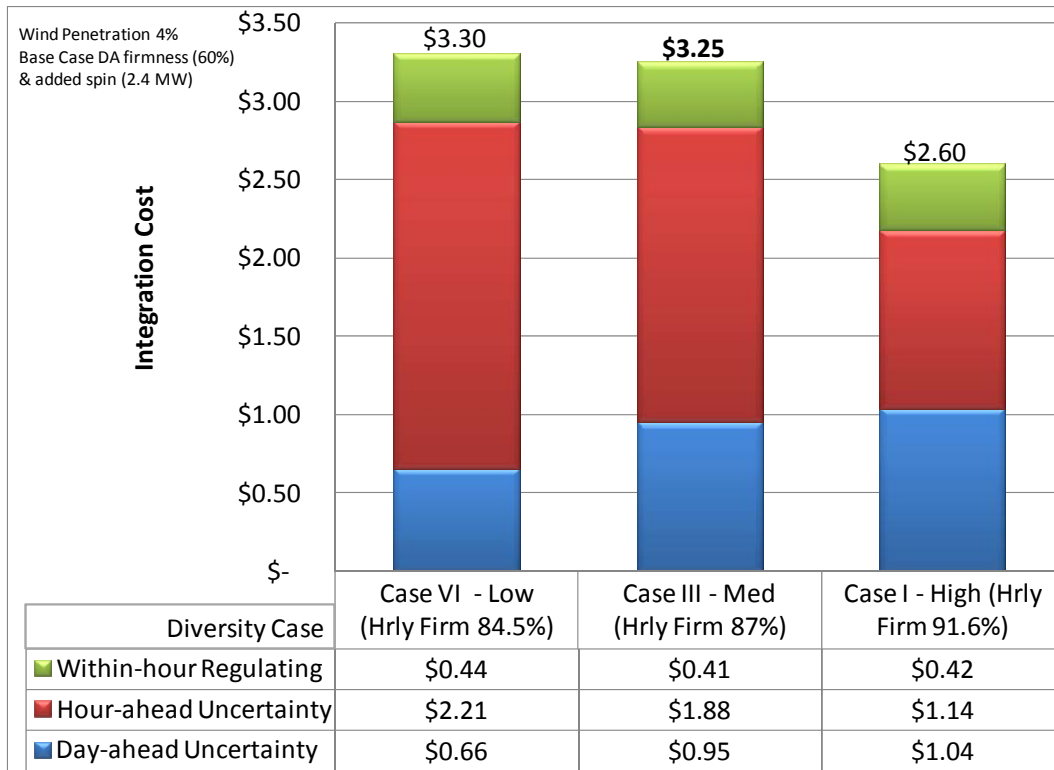


Figure ES 5 – Sensitivity of integration cost to geographic diversity of wind energy, under base case assumptions.

broader geographic area, the variability in the output is reduced, both hour-to-hour and day-to-day. This effect is characterized in the hour-ahead firmness factor, which is highest for the high diversity case and lowest for the low diversity case. A summary of the integration costs for the full set of cases run is shown in Table ES 3.

The primary conclusions from the integration cost study are as follows:

- Wind integration costs in the APS system, defined as the increase in operating costs due to the variability and uncertainty associated with wind generation divided by the total wind energy delivered, are consistent with results from other studies around the country. For APS, the costs range from just under \$1.00/MWh of wind energy delivered at 1% penetration to just over \$4.00/MWh at 10%.
- The integration costs of 4% wind energy (468 MW) in APS' system (2010 peak load estimated at 7,905 MW) was estimate to be \$3.25/MWh, with medium geographic diversity in locating wind turbine power plants in northern Arizona.
- Hour-ahead uncertainty, as employed by APS' modeling tool RTSim for in-the-day commitment of generating units, is the largest component of integration cost. This quantity is effectively a type of operating reserve, and can be significant in magnitude relative to the other reserve amounts attributable to wind generation.

- The beneficial effect of geographic diversity on reducing variations in aggregate wind energy production reduces integration costs.
- In RTSim, day-ahead forecasts of wind generation for unit commitment and scheduling are modeled as a firmness factor. The result of the sensitivity cases for firmness factors ranging from 0 to 100% show that a better, i.e., less costly, day-ahead plan is possible as more of the wind energy that is to be delivered can be accounted for in the unit commitment optimization. Conversely, if wind energy is ignored, more APS units are committed to operation than are actually needed, increasing operating costs.
- Because Arizona wind generation is high during the spring when the system load is only moderate and only a modest amount of flexible generation resources are required, this is the season during which the highest integration costs are incurred. Integration costs are lowest during the summer, when wind output is relatively light and virtually all of the flexible gas generation resources are on-line.
- Costs associated with gas supply imbalance were considered and found to be a small contributor to the total integration costs, in all cases less than \$0.10 to \$0.15/MWh. The cost is significant if there is either no day ahead forecast of the wind energy, or a very poor day ahead forecast. For any reasonable wind power forecast, the gas supply imbalance costs are quite small.

Table ES 3 – Matrix of wind integration scenarios considered with the associated integration costs listed in \$/MWh.

Integration Cost Summary (\$/MWh)

Wind Scenarios		Geographic Diversity		
Energy Penetration	Penetration by Capacity	High	Med	Low
1%	1.5%		0.91	
4%	5.9%	2.60	3.25	3.30
7%	10.4%		3.57	
10%	14.8%		4.08	

Gray Shading = Cases run **Bold** = Base Case