RIDGE
ENERGY STORAGE
& GRID SERVICES L.P.

The Economic Impact of CAES on Wind in TX, OK, and NM

Final Report
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SECTION I – INTRODUCTION

BACKGROUND

With an aging and limited transmission infrastructure, utilities and independent power project developers face challenges in trying to integrate wind energy into the grid. Many of the challenges occur because renewable wind and solar power are intermittent and cannot be dispatched. Wind energy resources have the potential to create or exacerbate congestion problems and voltage/grid stability issues, due to their unpredictable delivery of energy. Furthermore, wind energy may not be available at the right time to offset peak demand requirements and reduce needs for traditional generation capacity. Though cost-effective wind energy has made significant strides in penetrating into the grid, the current wind generation capacity of 6740 MW[1] remains a minute fraction of the total wind energy capacity that could be developed to meet the country's electricity needs. Integration challenges need to be addressed in order to fully realize the potential of renewable energy to contribute to the diversity of our electric power supply.

Electric energy storage has the ability to complement wind and address many of the challenges noted above. Energy storage can transform an intermittent, renewable energy resource into one that has firm capacity value and that can be dispatched in accordance with load and market prices for energy. With energy storage, renewable dispatch can also be controlled to reduce or avoid congestion, relieving pressure on transmission systems and reducing the need for traditional wires infrastructure. Furthermore, many storage technologies can also provide other services, such as reactive power, that can enhance grid stability, particularly in locations remote from load where large-scale renewable generation is often located.

In 2003, the Department of Energy, through its State Energy Program, issued a Special Projects request for proposals to study the value of adding energy storage to the grid to support renewable energy. In partnership with the Texas State Energy Conservation Office (SECO), Ridge Energy Storage & Grid Services (RES) assembled a team to propose a study of compressed air energy storage (CAES) with wind in the control area of Southwestern Public Service Company (SPS), an operating company of Xcel Energy. SPS's control area spans a region extending from the eastern plains of New Mexico to the panhandle areas of Texas and Oklahoma. Team members included representatives from Southwestern Public Service Company, RnR Engineering, the Alternative Energy Institute at West Texas A&M University, the Oklahoma Wind Power Initiative, and the state energy offices of Oklahoma and New Mexico. This report documents the team's efforts and presents the results of the study of CAES and wind.

LOCATION OF STUDY - SPS CONTROL AREA

The reason for selecting the SPS control area as the region of study was twofold: First, the region has characteristics that would make energy storage particularly beneficial in helping to

[1] AWEA projects database, Jan 24, 2005

integrate further wind generation into the grid. With class 4 winds in much of the area, estimates of potential wind development for the region are over 40 GW.[2] With the tremendous potential for wind resource development, total interconnection requests for Study Wind projects exceed the peak load for the incumbent utility. While SPS has been rather aggressive in contracting for over 440 MW of wind projects (approximately 10% penetration), limited transmission infrastructure and lack of purchaser's of wind energy have been impediments to further wind development.

Second, this region has geologic features that are particularly conducive to the development of the selected energy storage technology, CAES. Along with pumped hydro, CAES is a technically proven solution for bulk energy storage, and the two technologies are the only energy storage options with the capability to provide services commensurate with the requirements of several hundred megawatts of wind. CAES uses compressed air to store energy (hence the name), and thus requires access to underground formations to hold the large volumes of high pressure air. Underlying much of the region are salt formations, which have the potential to be mined out into caverns that could store air in a CAES application, similar to the salt caverns that have been used to store natural gas and other hydrocarbons for decades. With its below ground geology and its plentiful wind resources, the SPS control area is an ideal location to consider combining wind and CAES, and is therefore an ideal location to study the value of doing so.

OBJECTIVES

This project had the following main objectives with specific application to CAES and wind in the SPS control area:

- Assess the ability of energy storage to positively affect dispatch of renewable resources.
- Assess and quantify economic benefits of using energy storage to improve grid reliability issues and congestion associated with renewable energy.
- Determine the economic advantage of using storage to firm and shape renewable energy sales.
- Determine institutional barriers and opportunities for energy storage combined with renewable energy facilities

SUMMARY RESULTS

This study was able to show significant benefits from the use of CAES to integrate large quantities of wind energy onto the grid. In particular, the study was able to show that CAES can add value in the following ways:

- Significantly improve the delivery profile of renewable energy to the grid.
- Ameliorate the impacts of wind energy on system ramping.
- Provide transmission benefits in excess of the cost of any transmission upgrades required by the CAES plant itself.

[2] Electric Power Engineers, Inc.

Finally, the economic feasibility of combining CAES with wind was demonstrated by evaluating the combined economic benefits of firming, shaped delivery, capacity value, and transmission impacts and comparing this against the added capital cost of the CAES plant. We estimate that SPS could realize approximately $10 Million per year in net value by using CAES to integrate an additional 500 MW of wind.

SECTION II – PROJECT ANALYSIS APPROACH

EXPECTED BENEFITS

Electrical energy storage does not come for free. By the time one includes the capital cost of the energy storage technology and account for operating costs and efficiency losses, the net production of electricity will certainly be more costly. Even with the configuration and storage technology analyzed in this project, we calculate that the resulting net energy deliveries would have to be priced at a $21-22/MWh premium over the price typically paid for wind energy in order to provide sufficient incentive to install the storage technology. Therefore, a study that aims to quantify the value and benefits of energy storage to wind needs to be focused on assessing two broad categories: the value from mitigating external costs associated with wind, such as transmission costs or integration costs; and the benefit from making the wind power worth more, such as by adding capacity value or by shaping the power flow over time to meet peaking requirements.

Within the scope of this project and the resources of the study team, we have focused on measuring the following potential benefits:

Capacity Value

Capacity value in this study is used in the sense of long term resource planning. Utilities are required to have firm generation capacity, either owned or contracted, that can be used to meet expected peak demand for electricity plus a reserve margin. In contrast to a thermal generation plant that can be dispatched, wind power cannot be called on at will, and for a single wind farm, it is uncertain how much wind power would be produced from that farm at any time in the far future; in other words, one can't know how hard the wind would be blowing at the time when the electric grid hits its system peak for a given year. When evaluating multiple wind farms across a wide area and taking into account seasonal and diurnal patterns, it should be possible to come up with a probabilistic assessment of how much wind power should be available to contribute to meeting the system peak. That assessment of wind capacity value is a subject of much debate and rigorous analysis and is not within the scope of this study. However, as a stand-alone generating asset, CAES has capacity value as if it were a thermal asset.

In discussing *capacity value* of wind, it is useful to distinguish that term from *capacity factor*, which is the amount of energy that is produced in an average year as a percentage of nameplate capacity.

To quantify the economic value of capacity for SPS, we use the approach of looking at the long term average cost of physical generating capacity to meet reserve requirements. Required capacity reserve margins are positive, in other words, a utility always needs to have more generating capacity available than the actual peak load forecast in order to meet reliability standards. Therefore, a portfolio of generation assets will include an amount of generation capacity that is not expected to operate very often, but that would be available when needed to produce electricity during the system peak. We are using the annualized capacity cost of a gas peaker to serve as a proxy for the minimum value of additional capacity to the system.

In a system where the minimum reserve margin is met every year, there will be some years when the reserve margin is higher than what is required for regulatory purposes. In such years, it would be tempting to argue that the value of capacity is zero. However, in a competitive market, plant developers would not have an incentive to build generation to meet reserve requirements unless they were paid enough by the market to cover the fixed costs (capital and operating costs) on average over the life of the plant. In a regulated market, the prudent cost of any generation that is built is included in rate base if it is deemed to be used and useful, which includes being used for reserve requirements, if not for full-time operating requirements. Therefore, it is reasonable to use the annualized cost of physical generation capacity as a proxy for long term capacity value, even when market conditions might result in short term traded capacity values falling below the long term average cost.

One common concern in using the nameplate rating of CAES as its capacity value stems from the approach of looking at CAES combined with wind. For the CAES plant to produce power on demand, two main things are needed: natural gas; and stored air in the cavern, which is produced from off-peak/excess wind generation. Thus, the concern is whether or not one can assign capacity value to the CAES plant if the wind hasn't blown in a long time and the cavern is empty. Our response is that the CAES plant always has the option to use non-wind generation during off peak hours to fill the cavern, even when the wind has not blown for several days in a row. Though this would require some advance planning in the operations of a CAES plant, this situation is not materially different than a gas-steam plant used for peaking purposes that needs 10 hours advance notice to get warmed up.

Firming Value

Firming value is distinct from capacity value. Capacity value can be thought of as the value of being able to guarantee that megawatts can be made available to serve peak load for long term planning purposes, and megawatts of capacity can therefore replace/defer the construction of the next physical generation asset. Firming value, in this study, is defined as the value of being able to guarantee the provision of energy, ancillary services, and short term capacity such that better unit commitment decisions can be made with the rest of the plants in the generation portfolio.

With an ample supply of transmission capacity, the process of dispatching power plants for a single point in time can be viewed relatively simply – the goal is to dispatch blocks of power in merit order (in order of increasing marginal cost) from power plants that are online until the supply of power meets the demand for electricity. This technique would minimize the production cost of electricity for that point in time. However, in order to minimize electricity production over time, several more variables need to be taken into account. Dispatch models will incorporate fuel costs, heat rates, and variable O&M costs, as well as generator maximum ramp rates, changes in load over time, startup costs, and minimum up and down times for generating units to develop a unit commitment and dispatch schedule that can most cost effectively meet load and short term reserve requirements. Many power plants require several hours to warm up and synchronize to the grid and must be committed several hours in advance of when their electric production is needed. Startup and shutdown costs often need to be spread out over a significant period of time for the use of those plants to be justified economically. Thus, unit commitment is a relatively inflexible plan and can result in higher costs when a significant degree of uncertainty is introduced into the system.

In significant amounts, wind can create unit commitment issues due to its *uncertainty* and due to its *variability*. The distinction between the two concepts can best be understood by considering uncertainty first. Uncertainty is a product of forecast error. Forecasting the amount of wind power that will be delivered to the grid over the next day requires predicting what wind speeds will be for each hour and translating that wind speed into wind power production. Imagine a local weather station trying to give an accurate forecast of not only whether or not it will rain and how much rain to expect, but also at what time it will start to rain and at what time the rainfall will be heaviest. Sophisticated models and wind forecasting techniques continue to be improved, but as a stochastic process, forecast error remains, and therefore, wind power production cannot be known in advance with perfect certainty.

Uncertainty creates cost in the unit commitment and dispatch process. If actual wind power production is lower than expected, it can be difficult to commit additional generation units in real time. Therefore, a unit commitment plan needs to provide enough idle generation capacity to cover the expected wind power if the wind does not blow as predicted. On the flip side, higher than expected wind production may result in a situation in which thermal generation plants have to be backed down to suboptimal levels because of the inability to decommit thermal units in real time.

The cost of uncertainty, and therefore, the value of firming, can be measured with a production cost model that has the ability to set unit commitment based on a forecast of wind production, and then base the dispatch of the plants based on what "actual" wind energy production would have been. The COUGAR production cost modeling tool is one that has this capability, and one that we were hoping to use for this purpose. Unfortunately, given the scope and budget for this study, we were unable to obtain the resources required to perform production cost runs with COUGAR. The production cost model we did use, PROSYM, did not have the ability to perform this type of analysis efficiently for the time period we were modeling. Therefore, our approach for calculating firming value draws from results obtained from wind integration studies where the cost of uncertainty was measured.

Even if wind flows could be forecasted perfectly, wind production shows a pattern of fluctuation (or variability, as opposed to uncertainty) that can cause added costs in unit commitment and dispatch related costs. Unit commitment decisions take into account the need to have fast ramping capacity online at certain periods of the day to respond to expected changes in load. Additional ramping capability needs to be available to balance out changes in wind production, which become more significant in magnitude as wind penetration (percent of wind plant nameplate capacity to the overall system load) increases. The benefit that storage can provide by reducing the variability of wind production is described in the shaping value section.

Shaping Value

As described above, wind production causes some integration costs that are a result of the variability of wind energy deliveries onto the grid. By storing the peaks in wind energy production and by delivering stored energy during lulls in wind output, CAES can smooth the profile of net energy deliveries and reduce the requirement to have other generation units online merely to respond to variability in wind output.

Furthermore, in examining the average diurnal profiles of wind in the Panhandle area, it is clear that wind speeds tend to be higher during the night, resulting in greater volumes of wind energy delivered during off peak hours, when electricity demand is low and marginal electricity production costs are low. Conversely, during the peak hours when power costs are the highest, average wind energy production is low. CAES clearly can add value by storing low value wind energy during these off-peak times and delivering energy during the peak hours when power demand and prices are high.

Our approach to valuing the shaping benefits is based on production cost modeling using PROSYM. PROSYM is the chronological electric power production costing simulation computer software package produced by Global Energy Decisions and used by several utilities and wholesale power producers all over the country for planning and operational studies.

Ridge Energy's wind shaping models have been used to simulate the operations of a CAES plant that is operated specifically to balance and shape energy output from a wind farm or group of wind farms. While the wind farms and the CAES plant do not need to be co-located, we suppose that electronic data communications exist between the plants such that the CAES plant can respond in real time to the output of the wind farm. Another key underlying assumption is that energy is delivered according to a combined schedule, and that it doesn't matter whether the energy is coming from the wind farms, from storage, or from both. The important factor is the net energy delivery to the grid. Effectively, the wind shaping model assumes that operations of the CAES plant and the various wind farms are *hybridized*, in other words, that the output is cooperatively dispatched to meet a common schedule.

Hourly wind energy production profiles for an entire year are entered into the wind shaping model, along with assumptions regarding the CAES configuration and incremental heat rate and energy ratio. On a monthly basis, the user defines the target shape for the net firm energy output from the wind/CAES plants. This occurs by specifying the number of megawatts of energy to deliver in various shapes. For example, a user could specify the delivery of a 100 MW block of 7x24 energy, supplemented by a 100 MW block of 5x16 energy to meet energy needs during the peak period. Alternatively, the user also could select a "shaped" on-peak block, which provides for a graduated delivery of energy over the peak period, ramping up and down in rough proportion to load. Finally, a user can also enter a manual schedule, which can be used as a proxy for additional firm deliveries of energy to be provided based on short-term forecasts of wind availability.

Based on the firm, target schedule, the wind shaping model determines how to dispatch the CAES facility in conjunction with the wind to meet the firm schedule desired by the user. Basically, CAES compression and CAES generation are both used to decrement or supplement and balance wind production to meet the desired net dispatch profile. The model takes into account minimum load requirements on the turbine and compressors. Cavern "inventory" tracking formulas ensure that the model doesn't dispatch CAES generation if there is no stored air in the cavern, and that it doesn't dispatch CAES compression if the cavern is at maximum pressure. Therefore, the model predicts some variance from the target schedule. The user can modify the desired schedules for firm energy deliveries to minimize the negative variance, the underlying assumption being that for reliability purposes, it is better to underpredict the amount of firm energy delivered rather than overpredict and suffer the consequences of negative variance.

From the wind shaping model, we extracted two data series. One was the hourly schedule of total firm energy deliveries; the other was the schedule of variances from the firm schedule, or what we called "non-firm" energy. Without CAES, the firm schedule would be zero, and the hourly delivery schedule of wind energy is considered to be positive variance, in other words, non-firm energy.

The two data series were modeled in PROSYM as must take purchase transactions. Since the purpose was to calculate the avoided cost benefits to the host utility, SPS, no purchase price was associated with either of the two data streams.

Ancillary Service Value

The rapid response of a CAES plant enables it to provide various ancillary services. The second-to-second response capability allows it to provide automatic generation control/regulation in both generation and compression modes. The ability to rapidly shed load while in compression mode, or ramp up while in generation mode enables the CAES plant to provide spinning reserve. Even while in compression mode, a CAES plant with independent compression/generation trains can bring the full generation capacity online in less than 10 minutes, so the CAES plant can also be considered to be providing quick start or operating reserve. CAES can also provide other ancillary services such as balancing energy and voltage/VAR support.

We must carefully measure the amount of ancillary services that can be provided by a CAES plant, keeping in mind that oftentimes tradeoffs need to be made between the provision of energy and the provision of ancillary services. For example, in order to provide spinning reserve, a generation asset must be kept online, yet only partially loaded. The full capability cannot be used to provide both energy and spinning reserves at the same time.

The valuation approach varies by the type of ancillary service being considered. Since our analysis focused mainly on the hour-to-hour time frame, we were not at the level where we could do a thorough analysis of the value of automatic generation control or regulation. However, with the amount of the wind being modeled, and using results from other wind integration studies, it was assumed that the costs of automatic generating control or regulation to balance the wind would be relatively small, and therefore, the value of a CAES plant in mitigating those costs would also be relatively small.

The value of spinning and operating reserve was captured via production cost modeling. While the CAES plant was in compression mode, the loaded capacity of the compressors was considered to be spinning reserve, since in an emergency, the compression could be treated as interruptible load, providing generation capacity to the grid at short notice. In generation mode, any unloaded capacity on a turbine that was online was considered to be spinning reserve. The capacity of turbines not online, whether the plan was in generation or compression mode, was considered to be operating reserve, since the CAES plant would be able to get its turbines online within 10 minutes, even if it was required to convert from compression mode. The amount of spinning and operating reserve available at any hour was compiled into an 8760 dataset and fed into the PROSYM model. While it was not possible to separate the value of the ancillary services, this approach ensured that any benefits from taking CAES spinning/operating reserve capability into account were captured in the analysis of system production costs.

Balancing energy might be considered to be energy up or down that is provided in real-time, as opposed to on an hour-ahead or day-ahead basis. Unfortunately, we did not have the resources for this study to do the type of evaluation that would have allowed us to quantify the value of balancing energy provided by a CAES plant in conjunction with wind. Therefore, this value is ignored for now.

The value of voltage/VAR support is addressed as a transmission value, below.

Transmission Value

Strategic location of a CAES plant may be valuable from a transmission perspective. The transmission value may or may not be related to wind production. For example, energy storage could relieve congestion of highly loaded lines by redirecting energy flows during times of congestion. When located in an area where wind production is congesting the local transmission lines the CAES plant has the potential to significantly reduce or eliminate congestion and increase grid efficiency by storing the wind energy and releasing it when the wind plants are at low output and more transmission line capacity is available.

A CAES plant can provide a voltage reliability benefit to the transmission grid. The CAES plant has reactive capability in the generation and compression modes but if configured in the synchronous condenser mode, it can provide and absorb reactive power as needed. The CAES plant synchronous condenser can provide support to the transmission grid during the loss of a major transmission line, thereby deferring or eliminating the need for transmission improvements. CAES plant reactive support can be particularly useful when combined with wind plant operation because historically, wind plants have been manufactured with limited reactive capability and installed on weak areas of the grid. When the wind plants are operating, they replace the conventional generation which has more reactive capability and the voltage stability problem is exacerbated. The CAES plant can act as a dynamic reactive device and negate or reduce the negative effects wind may have on the transmission grid.

Our approach to valuing the benefits of CAES involved performing loadflow studies of the system with and without CAES and seeing whether there were any identifiable transmission benefits such as reduced congestion, increased system efficiency or improved reliability. The results were also examined to determine if any transmission improvements were needed to accommodate flows into the plant during compression or out of the plant during generation.

Comparison to Alternative Resources

The final method for looking at CAES value involves calculating the combined cost for wind and CAES, including fixed capacity costs for CAES and for wind, and variable costs associated with CAES operations in wind shaping mode. These costs are averaged over the combined energy output from wind and from CAES to arrive at an average cost per MWh for shaped, dispatchable wind. This cost is compared to the lifecycle cost per MWh for various alternatives for adding new generation capacity to the grid, including gas peakers, combined cycle, and coal plants.

GENERAL FRAMEWORK

In order to assess the value of CAES, we have followed the following framework for the analysis:

- Define scenarios for analysis
- Model wind profiles
- Develop CAES dispatch scenario
- Analyze scenarios

Scenario Development

The first step in our analysis was to define the scenarios that we wanted to study. We focused on two key scenarios. The first scenario, entitled the ***Base Wind Scenario*** assumes by 2006, that all of the wind projects that have been announced by Xcel Energy in the SPS control area are online and producing energy.

SPS had:

- Operating – 80 MW Llano
- Under Construction – 80 MW Caprock
- Under Development – 120 MW Elida, NM
160 MW Wildorado, Texas.

With all four projects assumed to be online, we were looking at a total of 440 MW of wind farms in SPS's control area, which corresponds to almost 10% penetration when measured as a percentage of peak load.

In the second scenario, called the ***Study Wind Scenario***, we wanted to look at the impacts of even more wind development in the area of study. Therefore, we selected three sites, one in

Oklahoma, one in Texas, and one in New Mexico, that represented reasonable sites for Study Wind projects, and we modeled a total of 500 MW of Study Wind to be developed across the three locations. For ease of comparison purposes, we assumed that the 500 MW of Study Wind would also be online by 2006 so that we could focus our modeling on one year. Since this is not a planning study, but rather an assessment of the value of a CAES plant within a certain situation, we chose to model conditions that could be modeled with confidence. If we had chosen to model a year further out in the future, there would have been much more uncertainty about the state of the generation and transmission systems, and very little additional value would have been gained from that assessment in understanding where the CAES value comes from. In the Study Wind Scenario, a total of 940 MW of wind is modeled as being on the grid in SPS's service territory. The Study Wind Scenario is also referred to as Study Wind in the loadflow modeling.

The following table summarizes the key assumptions for each scenario.

Scenario	Year	Wind Projects Online	Total Wind MW Online
Base Wind Scenario	2006	White Deer Caprock Padoma Wildorado	440 MW
Study Wind Scenario	2006	White Deer Caprock Padoma Wildorado New TX Farm New OK Farm New NM Farm	940 MW

Wind Modeling

For each of the scenarios, we had to model what the wind resources looked like. Our wind modeling was focused on understanding how much wind would be produced on an hourly basis for a representative year, with all of the modeled wind farms working together. The wind modeling chapter describes in detail how we developed the wind profiles for each of the wind farms and for the aggregate wind energy production. In the wind modeling, we also spent time on understanding how the wind energy profiles compared with load profiles.

CAES Dispatch Modeling

We also had to model how a CAES plant would operate in conjunction with the wind in each scenario. To start, we developed assumptions about what the plant configuration would look like and what the operating and cost parameters would be for a CAES plant. These assumptions are detailed in the compressed air energy storage chapter. We developed assumptions for a single CAES plant, and we did not do any modeling to optimize the configuration or size of the CAES plant. Once the operating assumptions were developed, we used these assumptions in various models to estimate what the CAES dispatch would/should look like in order to balance the wind. Our main tool for developing the CAES dispatch profiles is a wind shaping model developed by Ridge Energy. The wind shaping model estimates what CAES operations would have to look like in order to balance and shape wind to meet a particular dispatch strategy. The modeling of CAES using this tool is described in detail in the CAES dispatch scenario chapter. CAES operating parameters were also fed into PROSYM, which provided an alternate estimate of how CAES would be dispatched to create value on the system.

Scenario Analysis

Once the profiles for wind and for the CAES dispatch were developed, we were able to analyze the scenarios and compare the change cases with CAES to the reference cases with wind only. Analysis focused on several areas. Descriptive analysis showed how net profiles of energy production changed, particularly with respect to load, and much of this analysis is detailed in the CAES dispatch scenario chapter. Load flow analysis was performed to analyze the impacts of wind on the transmission system and to identify whether the addition of CAES made any significant changes to the requirements for new infrastructure to integrate wind. Two chapters on load flow modeling and results describe the load flow analysis. Finally, production cost analysis and other methods were used to quantify savings that could be achieved by wind and wind with CAES, and the difference between the two represented the economic value of adding CAES to the system. These savings were compared against the cost of adding CAES to determine the net economic impact of energy storage in conjunction with wind. The economic analysis chapter describes the analysis and the conclusions about whether CAES is economically justifiable as a tool for integrating wind into the grid.

SCENARIO/CASE NOMENCLATURE

For each of the defined scenarios, the situation with wind only on the grid represents the reference case. We then developed a series of change cases that represented the addition of a CAES plant onto the system under various assumptions. The following table summarizes the description of each scenario/case.
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Scenario	Case	Description
Base Wind Scenario	Reference Case	• 440 MW of existing wind on the grid • No use of energy storage
Base Wind Scenario	Change Case	• 440 MW of existing wind on the grid • CAES used to manage 440 MW of wind • CAES dispatch defined by user according to wind/ CAES hybridization model
Base Wind Scenario	Change Case – Alt	• 440 MW of existing wind on the grid • CAES modeled in the system • CAES dispatch defined by PROSYM's pumped storage module
Study Wind Scenario	Reference Case	• 500 MW of Study Wind added to 440 MW of existing wind for a total of 940 MW of wind on the grid • No use of energy storage
Study Wind Scenario	Change Case	• 500 MW of Study Wind added to 440 MW of existing wind for a total of 940 MW of wind on the grid • CAES used to manage 500 MW of Study Wind • CAES dispatch defined by user according to wind/ CAES hybridization model
Study Wind Scenario	Change Case – Alt	• 500 MW of Study Wind added to 440 MW of existing wind for a total of 940 MW of wind on the grid • CAES dispatch defined by PROSYM's pumped storage module

SECTION III – COMPRESSED AIR ENERGY STORAGE

OVERVIEW

How CAES Works

A CAES plant stores electrical energy in the form of air pressure, then recovers this energy as an input for future power generation. Essentially, the CAES cycle is a variation of a standard gas turbine generation cycle. In the typical simple cycle gas fired generation cycle, the turbine is physically connected to an air compressor. Therefore, when gas is combusted in the turbine, approximately two-thirds of the turbine's energy goes back into air compression. With a CAES plant, the compression cycle is separated from the combustion and generation cycle. Off-peak or excess electricity is used to "pre-compress" air, which is held for storage in an underground cavern, typically a salt cavern. When the CAES plant regenerates the power, the compressed air is released from the cavern and heated through a recuperator before being mixed with fuel (natural gas) and expanded through a turbine to generate electricity. Because the turbine's output no longer needs to be used to drive an air compressor, the turbine can generate almost three times as much electricity as the same size turbine in a simple cycle configuration, using far less fuel per MWh produced. The stored compressed air takes the place of gas that would otherwise have been burned in the generation cycle and used for compression power.

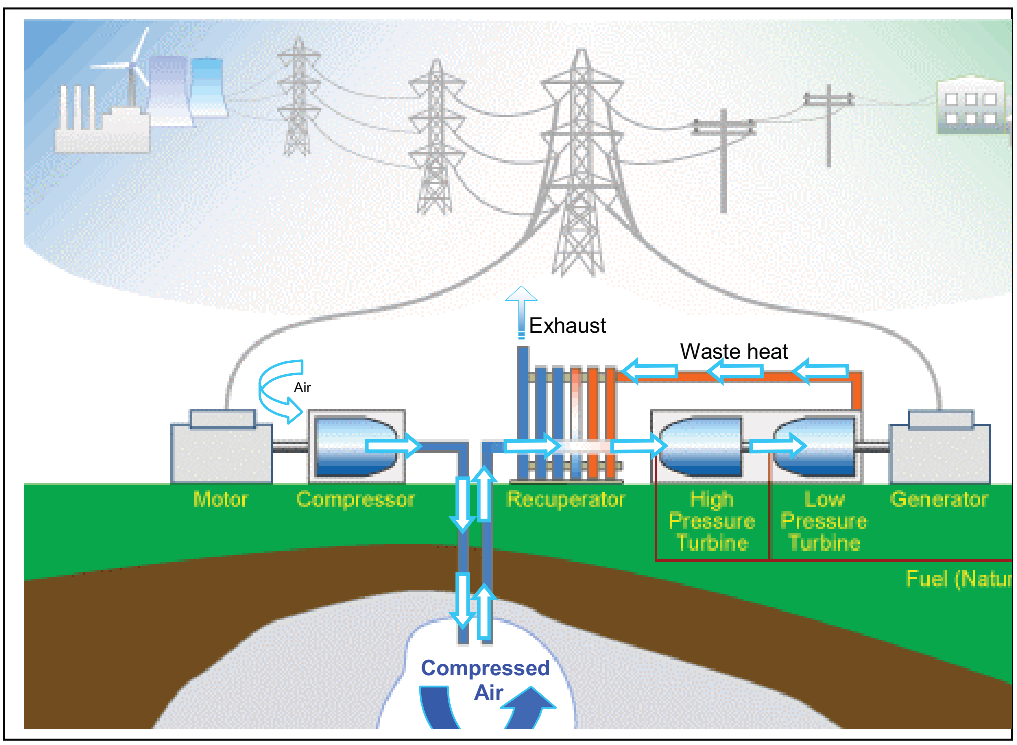


Figure III-1: How CAES Works

The volume of air storage required for a typical CAES plant is most economically provided by geological structures. Salt caverns, aquifers, depleted oil and gas reservoirs and rock mines have all been considered as possibilities for air storage in a CAES application. A 1990's DOE study estimated that approximately 85% of the land area of the US would be able to access suitable geology for a CAES project. The next graph indicates areas of the US potentially suitable for CAES.

Nuclear and Alternative Energy Supply Options for an Environmentally Constrained World: A Long-Term Perspective. Draft for review and comment only. 4.4.2001

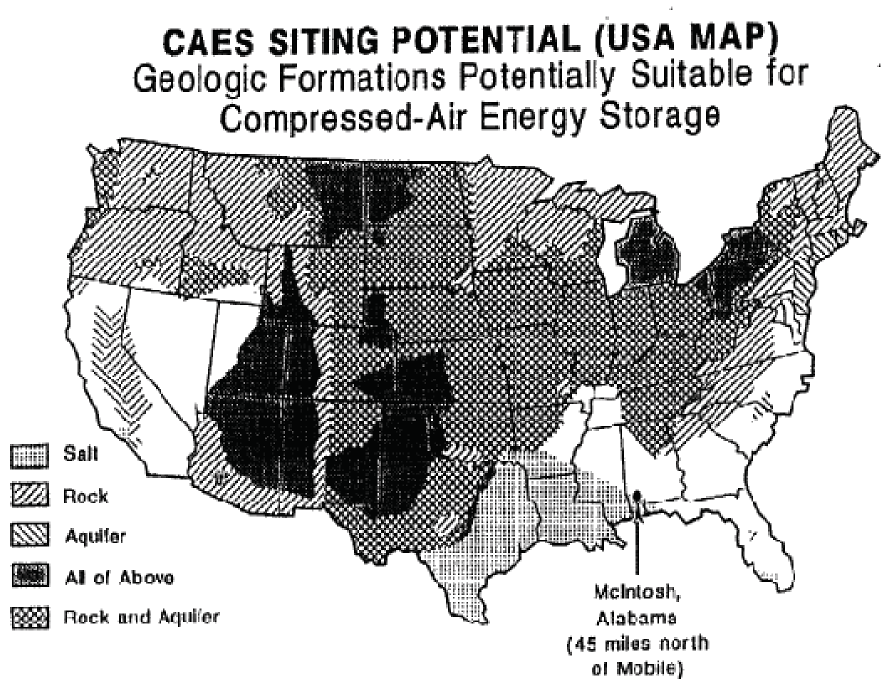


Figure III - 2: : Regions of the United States with Potentially Suitable Sites for Compressed Air Energy Storage

Source: Cohn and Louks (1991).

History of CAES

The CAES concept has been well proven through the operating history of two existing CAES plants, one in Huntorf, Germany and the other in McIntosh, Alabama. The Huntorf plant is a 290 MW plant that started up in 1978. The McIntosh CAES plant belongs to Alabama Electric Cooperative. The McIntosh plant is 110 MW and commenced operation in 1991. Both of these facilities have compression trains that are linked to the generation train via a common motor-generator and sets of clutches. The McIntosh plant incorporated a recuperator (air to air heat exchanger) to recover exhaust heat in order to preheat air from the cavern. This design change improved the heat rate. The successful operation of these two plants has demonstrated the technical viability of the CAES technology in supplying ancillary services, load following and intermediate power generation.

In the CAES design assumed for this study, the compression train is separated from the generation train so that each combined train can be designed for maximum efficiency. However, the two trains can be run simultaneously if the market conditions warrant it. Standard compression blocks of 100 MW each can be combined with standard generation blocks of 135 MW each in order to configure a plant that optimizes the ability of the facility to capture the market opportunities present at any given location. The use of multi-unit trains, each with a wide span and speed of response, on both the compression and generation side gives the operator maximum flexibility to manage the load, storage, and generation aspects of CAES in a very efficient and cost effective manner. The current design includes an SCR (Selective Catalytic Reduction) system to reduce NOx emissions to BACT levels.

The following table compares the design and operating parameters of the two existing CAES plants with the design of the CAES plant assumed for this study.

CAES PROJECT COMPARISON			
	Germany (Huntorf)	USA (McIntosh)	DOE Panhandle Study
Equipment Manufacturer	Brown-Boveri	Dresser-Rand	Dresser-Rand
Plant Capacity (MW)	290	110	135
Generation Hours	2	26	10-16
Hours compression/generation	4	1.6	1
Geology	Salt	Salt	Salt
Caverns	2	1	6
Volume (million cu.ft.) Total	11	19.8	28.5
Fuel	Gas	Gas/Oil	Gas
Compression Power (MW)	62	53	200
Compression Air Flow (lb/sec)	238	208	400/unit
Expansion Air Flow (lb/sec)	920	346	400/unit
Charging Ratio [MW in / MW out]	-	0.82	0.75
Water Injection for NOx/SCR	No/No	Yes/No	No/Yes
Recuperator Air In/Out (F)	No	95/584	95/599
High Pressure Expander			
Inlet Press (psig)	667	620	699
Inlet Temp (F)	1000	1000	1000
Low Press Expander			
Inlet Press. (psig)	160	213	232
Inlet Temp (F)	1600	1600	1600
Heat Rate (BTU/KWH, HHV)	6050	4510	4300

Recent CAES Development Activity

Several factors in recent years have led to a resurgence of interest in potential CAES projects. Deregulation, volatility in wholesale power markets, and the rise of merchant power producers initially were the main reasons for interest in development of CAES projects. Two additional factors have come into play. The northeast blackout in August of 2003 highlighted the need for reliability, particularly in the transmission system. CAES was seen as a solution that would support reliability and grid security. Finally, the tremendous growth of wind energy has created interest in CAES and other forms of energy storage as a tool for managing the integration of large amounts of intermittent generation into the grid.

CAES projects have been proposed in several areas of the country using a variety of geological structures for air storage. A huge, 2,700 MW CAES project has been proposed in Norton, Ohio which would use an abandoned limestone mine as the air storage reservoir. The Iowa Association of Municipal Utilities has been sponsoring the development of a CAES project near Fort Dodge, Iowa. The Iowa Stored Energy Project would consist of a 200 MW CAES plant coupled with 100 MW of wind. Low cost off-peak energy from coal would be used to supplement the compression requirements. The proposed air storage structure for this project is a sandstone aquifer. Ridge Energy has proposed several CAES plants in Texas using both bedded and dome salt formations for solution-mined air storage caverns. None of the various CAES projects under development have moved to the construction phase yet, but progress is being made on the development of project economics and an understanding of the risks and rewards of investment in such facilities.

General Component Description

The major equipment in a CAES plant can be divided into four parts: (i) the power island, (ii) the compression island, (iii) the underground portion, and (iv) the balance of the plant. The power island consists of the air turbine, the combustion turbine, the generator and the recuperator/selective catalytic reduction (SCR) unit. The compression island consists of the axial and centrifugal compressors complete with coolers. The underground facilities consist mainly of the air storage cavern and the airflow piping and controls. The balance of plant equipment consists of plant control equipment, the substation, the cooling tower system, the switchgear and all other equipment required to operate the plant. Specifics are described in Appendix A.

PANHANDLE CAES ASSUMPTIONS

Configuration

Prior studies and project evaluations performed by Ridge Energy have indicated that stand alone compression and generation components are required to optimize the CAES plant. This optimization is directly correlated to the flexibility of operating in one or several modes such as compression, generation or VAR support at partial or full output levels. Physical limitations imposed by the integrated single train of compressor-motor/generator-gas turbine do not allow the same level of operating flexibility.

Therefore, this study was performed based on the following equipment configuration:

- Compression – Two 100 MW trains allow a plant operating range of 60 MW to 200 MW load and resulting injection into storage.
- Generation – Two 135 MW trains allow a plant operating range of 67.5 MW to 270 MW generation and resulting withdrawal from storage.
- Storage volume is optimally sized to allow a daily exchange of injection and withdrawal volumes. Due to periods of high wind output, the storage volume was designed to accommodate a maximum of 50 hours of rated injection into storage.

The resulting CAES plant with 270 MW generation, 200 MW of compression, and 10,000 MWh of storage is a size that matches well with 400-500 MW of wind. Due to economies of scale, a smaller CAES plant would be unlikely to demonstrate economic viability, since the capital costs per kW would be disproportionately high. Prior Ridge Energy RES? studies have suggested that a 270 MW CAES plant coupled with 500 MW of wind has reasonable economics, so it makes sense to use that configuration as a starting point for this study of CAES and wind in the Panhandle area.

CAES Plant Location

In general, the CAES plant site location is somewhat independent of the generation resource(s) providing energy intended for storage. Locating within the same control area is preferred and if possible, the CAES plant should be located to maximize the operational and economic benefits to the local transmission system.

The Panhandle area of Texas has generally favorable geology for salt cavern development. The initial CAES site review was located in Hutchinson County north of Amarillo in order to be nearby to the proposed Study Wind generation sites and to provide benefits complementary to a north-south transmission constraint in that area. Detailed review of that area indicated that almost three times the number of caverns that are estimated for the Hale County location (north of Lubbock) would be required. This was due to the thickness of the salt layer in the Hutchinson County area. Since a significant cost component of cavern construction is associated with drilling and completing the well (cemented casings, air removal piping and solution mining piping), it is desirable to minimize the number of air caverns.

A Hale County site would have six caverns with each having a nominal volume of 4.75 million barrels for a total storage of 28.5 million barrels (160 million ft^3). The caverns and associated infrastructure are designed to receive and deliver up to 800 lbs. of air per second over an expected operating pressure range between 950 psig and 1250 psig. The volume of the caverns would allow up to 50 hours of storage at the maximum rate. Additionally, up to 50 hours of generation could be achieved without recharging, presuming a starting point with the caverns holding the maximum of 10,000 MWh of stored energy at 1250 psig.

Study Period

The CAES plant was modeled as if it would be online in 2006. Realistically, a CAES plant would require 30 months from notice to proceed to being on line; also, it is not probable that 500 MW of wind generation could be built by the summer of '06. However, 2006 was chosen as the study year because load and system conditions could be modeled with relative certainty, and the objective of the study was to understand the value that CAES could create when integrated with wind under various conditions, rather than to do a formal planning study. It was expected that the methodologies and approach used in this study would define how and why the CAES plant creates value and would create a template for more detailed analysis of CAES and wind in the Panhandle area should initial results look promising.

Equipment

Dresser-Rand was the equipment vendor whose equipment was modeled for this study. Their scope included the compressor trains, generation trains and the recuperators. The cost of balance of plant (BOP) components such as substation, switchgear, controls, cooling towers, etc were selected from data compiled by Ridge Energy in association with prior project development activities.

Operating Parameters

The following table summarizes the key operating parameters that have been used for modeling CAES operations in this study. Appendix C defines and describes the operating parameters in greater detail.

CAES Operating Factors & Ranges

Factor	Value
Minimum generation	67.5 MW
Maximum generation	270 MW
Average heat rate	4,500 Btu/MWh
Average energy ratio	0.8 kWh in/kWh out
Startup time for generation	10 minutes
Generation ramp rate (per unit)	4.5 MW/second
Minimum compression	60 MW
Maximum compression	200 MW
Startup time for compression	12 minutes
Compression ramp rate (per unit)	20 MW/minute
Reactive capability – Generation mode	-112 MVar to 132 MVar
Reactive capability – Compression mode	-96 MVar to 96 MVar
Reactive capability – Synchronous condenser mode	-47 MVar to 122 MVar

Cost Parameters

Cost assumptions were developed for the capital and operating costs of the CAES facility modeled in this study. Estimates were developed from equipment quotes from Dresser-Rand – the major equipment provider for a CAES project – and from prior work that Ridge Energy has performed in estimating the economics and performing development work for CAES projects. The following table summarizes the main cost parameters that were fed into the project finance model and economic analysis.

Estimated CAES Capital Costs

Parameter	Value (270 MW)
Overnight Cost – above ground equipment	$504/kW
Overnight Cost – cavern development	$101/kW
Total Overnight Cost	$605/kW
Development Cost	$28/kW
Annual FOM	$14.07/kW
Inflation/Escalation	1.5%
VOM	$1.50/MWh
Heat Rate	4,500 Btu/kWh
Energy Ratio	.8

Overnight cost for above ground equipment includes all equipment costs, engineering, procurement and construction, spare parts, interconnects for gas, air, water, and electricity, and contingency. Costs are included to enable one of the generators to be disconnected from the turbine via a clutch so that it can operate as a synchronous condenser.

Cavern development costs include all the costs associated with acquisition of the land and mineral rights, solution mining of the caverns, well drilling and completion costs, and piping and casing costs.

Development costs include expected costs for permits, transmission and engineering studies for interconnect agreements, legal costs, and fees.

Annual FOM (fixed operations and maintenance) cost includes plant personnel and major maintenance accrual associated with start costs, as well as ancillary costs such as auxiliary power and water treatment.

VOM (variable operations and maintenance) cost mostly consists of accrual for major maintenance based on utilization of the turbines.

SECTION IV – WIND MODELING

WIND DEVELOPMENT STATUS IN REGION OF STUDY

At the time we started this study, SPS had one wind farm operating in its control area, the 80 MW Llano Estacado project at White Deer, near Amarillo in Texas. Another 80 MW wind farm was under construction in Quay County, New Mexico called the Caprock Wind Ranch. Furthermore, Xcel Energy had made an announcement that SPS was going to contract for additional wind purchases from a 120 MW wind farm being developed by Padoma Wind Power near Elida, New Mexico, and from a 160 MW wind farm being developed by Cielo Wind Power near Wildorado, Texas. Due to time pressures imposed by the uncertain future of the federal production tax credit, currently set to expire at the end of 2005, it was expected that all 440 MW of wind projects will be online by the end of year. For purposes of this study, all of these projects are considered to be existing projects.

Further wind development activity may slow until SPS can integrate the existing 440 MW of wind. SPS is unlikely to contract for additional wind energy until it can swallow the whole 440 MW it has already contracted for and it develops an appetite for additional wind resources. The wind resources are of excellent quality, and wind developers continue to hold leases on promising land in expectation of future wind development opportunities.

SCENARIO ASSUMPTIONS

We selected three additional sites, one in Oklahoma, one in Texas, and one in New Mexico, that represented reasonable locations for a total of 500 MW of new, hypothetical wind projects. Based on knowledge of developer activity and wind resource quality, Dalhart, TX, Guymon, OK, and Frio Draw, NM, were selected as the locations for further study. Wind monitoring stations with accessible data were in place at those locations.

We also had to gather data from wind monitoring stations that would allow us to understand the wind resources for each of the existing wind projects. We selected monitoring stations as a data source that were close enough to each project location that they would provide a reasonable approximation of what wind conditions were like at the existing sites. The following table lists the wind projects we modeled in our Base Wind and Study Wind Scenarios and identifies which wind monitoring station was used to provide data or proxy data for the project. In the remainder of this chapter, the names of the wind monitoring stations are used to refer to the project, not the official project name.

Wind Project Status and Capacity

Wind Project Common Name	Status	Wind Monitoring Station	Modeled Capacity (MW)
Llano Estacado	Existing	White Deer	80
Caprock	Existing	Mesa Redondo	80
Padoma (Elida)	Existing	San Juan Mesa	120
Wildorado	Existing	Wildorado	160.5
New TX Farm	Hypothetical	Dalhart	167.4
New OK Farm	Hypothetical	Guymon	166.5
New NM Farm	Hypothetical	Frio Draw	166.7

The following map illustrates the approximate locations of the wind farms modeled in this study with respect to the transmission grid. The CAES plant is modeled as interconnecting into the Tuco substation.

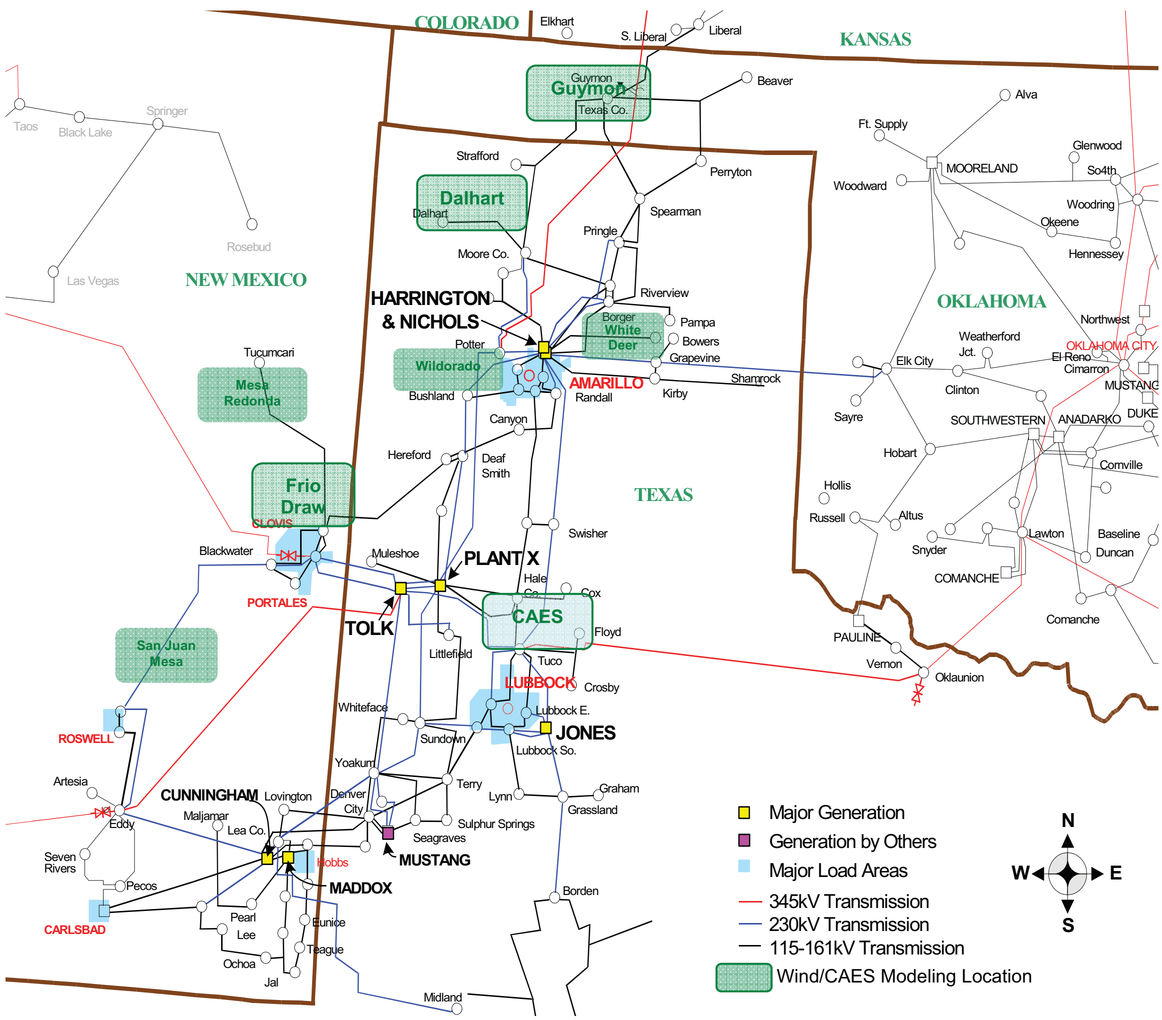


Figure IV-1: Study Area Map

ANALYSIS METHODS AND TECHNIQUES

Data gathering

The data that needed to be accessed for the wind resource analysis was historical data on hourly average wind speeds that has been collected by a variety of wind monitoring stations throughout the area. Three different places, the New Mexico Energy, Minerals and Natural Resources Department (EMNRD), Alternative Energy Institute at West Texas A&M University (AEI), and Oklahoma Wind Power Initiative (OWPI) have compiled wind data from various wind monitoring stations, and we used the data that they have gathered as the information resource for this study.

Originally, for the Texas and New Mexico cases, wind data has been generated and acquired from the field sites by using the equipments from NRG [Systems.

The data was transmitted once a week from each wind measurement site, however for the manual exchange of data chips, the time period for some sites was typically one month. The data in this study has been collected by the NRG 9300 series logger.

The raw data from each logger are in binary code and the data need to be converted into proper formats such as database format or text file format. This procedure is called importing and is done by using MicroSite and BaseStation, which is software distributed by NRG Systems. After importing, the software generates the "hour averaged" database, which contains one average and one standard deviation value per sensor, per hour. After generating hourly averages of wind data, it was carefully inspected by following AEI quality control procedures and stored into an Excel spreadsheet database.

Selection of time period for analysis

All the data used in this study have been selected for the same time periods for comparison reasons. Turbine types were selected for each wind farm in order to estimate wind energy production from wind speed data. For the existing projects where we knew what turbine was being used, we modeled that same turbine. However, for the hypothetical projects and the projects under development, we assigned a turbine type based on the desire to get roughly equal representation of the three main turbine manufacturers; GE, Mitsubishi, and Vestas/NEG Micon. The wind turbines and time periods that we used for each project site are listed in the following Table IV-1.

Table IV-1. Wind turbines and time periods for each site

State	Project	Data Period	Turbine Type	Total MW & #of Turbines
NM	Frio Draw	7/01/99 00:00~6/30/01 23:00	Micon 1.65	166.7 (101)
NM	Mesa Redondo	7/01/99 00:00~6/30/01 23:00	Mitsubishi 1.0	80 (80)
NM	San Juan Mesa	7/01/99 00:00~6/30/01 23:00	Mitsubishi 1.0	120 (120)
TX	Wildorado	7/01/99 00:00~6/30/01 23:00	GE1.5	160..5 (107)
TX	Dalhart	7/01/99 00:00~6/30/01 23:00	Vestas 1.8	167.4 (93)
TX	White Deer	7/01/99 00:00~6/30/01 23:00	Mitsubishi 1.0	80 (80)
OK	Guymon	7/01/99 00:00~6/30/01 23:00	GE1.5	166.5 (111)

Methodology for patching

Due to conditions such as severe weather, sensor failure and logger failure, the data can have some missing or invalid data range. Data points are considered invalid if they do not present the actual wind conditions at the site [1] . In this study, the data has been validated and patched when possible to create a corrected data set.

Basically all analyzed sites have the same patch criteria. In the case where only a few hours are missing, the average of the hour before and the hour after the outage is used to replace the invalid data. When a longer period of data is affected and another wind speed sensor is operating at the same site, the data are filled in based on a correlation between the sensors. When all sensors are affected by an outage a correlation is developed to a nearby reference site that has data concurrent with the affected hours. If there's no reference site data available, the missing data are replaced with the average diurnal values of valid data from the same site in the same month [1] .

Based on the criteria, all the data used in this study have been patched up to 100%. The amount of patched data information is listed on Table IV-2 on the next page.

Table IV-2. Amount of patched data

Average of 2 years	Frio Draw	Mesa Redondo	San Juan Mesa	Wildorado	Dalhart	White Deer	Guymon
Original (%)	100%	?	?	79%	93%	83%	?
Patched (%)	NA	?	?	22%	8%	17%	?
Recovery Rate	100%	100%	100%	100%	100%	100%	100%
1st year	**Frio Draw**	**Mesa Redondo**	**San Juan Mesa**	**Wildorado**	**Dalhart**	**White Deer**	**Guymon**
Original (%)	?	?	?	83%	96%	96%	?
Patched (%)	?	?	?	17%	4%	4%	?
Recovery Rate	100%	100%	100%	100%	100%	100%	100%
2nd year	**Frio Draw**	**Mesa Redondo**	**San Juan Mesa**	**Wildorado**	**Dalhart**	**White Deer**	**Guymon**
Original (%)	?	?	?	74%	89%	70%	?
Patched (%)	?	?	?	26%	11%	30%	?
Recovery Rate	100%	100%	100%	100%	100%	100%	100%

Methodology for calculation electrical power

Only part of the available wind power can be converted into useful power. On an annual basis the amount can vary from 10 to 45% depending on the regional wind resources and the types of wind turbines. The typical industry values are 35-40% for a good wind resource site.

To calculate wind power from the wind speed, elevation of the site, its air density, wind shear value, numbers of turbine and manufacturer's power curve have been considered. There are several mathematic formulas that are used to predict wind power and correct the factors used for this power estimate. These equations are listed below.

Equation 1) Air density ρ

$$\rho = 1.225 - \left(1.194 \times 10^{-4}\right) \times Z$$

Where,
Z= Elevation of the site

Equation 2) Electrical power (MW)

MW = P× N × (1.225 + (Elevation × (-0.00012))/1.225)

Where,
P = Turbine power from the power curve lookup table
N = Number of turbines
Elevation = height above sea level in meters

Wind Shear

Wind shear, a change in wind speed or direction over some vertical distance, is an important factor in estimating wind turbine energy production. Since the wind power varies as the cube of the wind speed, an increase in wind speed with height will strongly affect energy production and the economic feasibility of wind farms.

The amount of wind shear is characterized by the exponent in the power law formula and represents the degree to which wind speed increase with height in the lower boundary layer. The need for this model is that having a measured wind speed value at a reference height and knowing the wind shear exponents, a, allows for calculation of expected mean wind speed at a new height. In general this new height is hub height and hub plus blade radius height. The exponent is calculated from Equation 3 and measured wind speed levels at two known heights.

Equation 3) Wind shear value

$$a = \frac{\ln\left(\frac{V}{V_0}\right)}{\ln\left(\frac{h}{h_0}\right)}$$

Where V = wind speed at height H

V_o = measured wind speed at height H_o

α = wind shear exponent

In this study, wind shear values are used to calculate target wind turbine hub height, mainly 60 m from data heights, 10, 40, and 50meter.

Power Table

The wind turbine power curve is the quantitative relationship between the electric power output and the incident wind speed. Together, the wind speed distribution and the wind turbine power curve determine the annual energy production.

As listed in Table 1, four different types of wind turbine have been used in this study. However, the power curves from manufacturers are based on the standard air density of 1.225 kg/m^2 which is different from actual conditions at these sites. Under this condition, original wind power curve tables are slightly modified to satisfy the actual site elevations and predicted air density.

Number of Wind Turbines

In this study, wind plant locations and numbers of wind turbines for each site can be divided by three conditions: current, planned/under development, and hypothetical sites. Number of wind turbines used (actual, planned or predicted) at each site are listed on Table 1.

ANALYSIS RESULTS

Wind generation profiles and trends

In order to ascertain the values for the wind power production in individual months, capacity factor has been used (presented in Figure 1). Figure 1 illustrates the average of all sites, using two years of data (July, 1999 – June, 2001).

According to the analyzed data in this time period, the highest average capacity factor occurs during April and August has the lowest. It is also noted that highest capacity value, 60% observed at any site, was Mesa Redondo in April 2001 and lowest, 13% at Frio Draw, in August 1999.

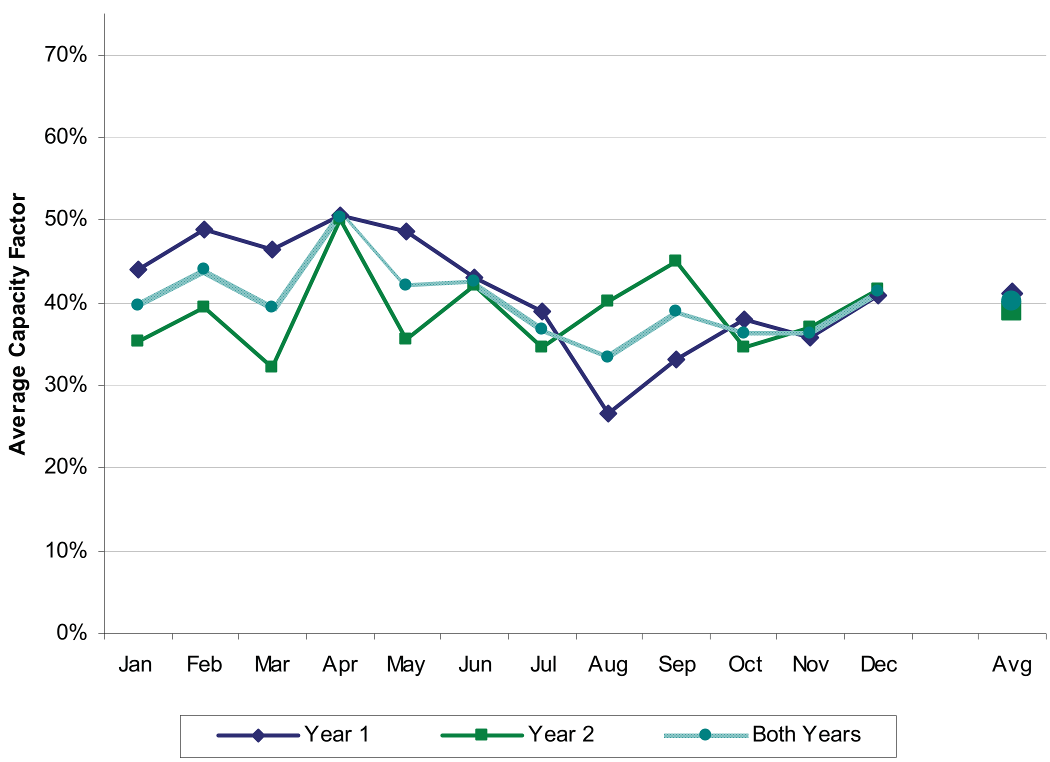


Figure IV-2: CF of Selected Data Sites

Diurnal power production estimates were made for the daily pattern of wind turbine performance. Figure 2 shows the diurnal pattern of the performance of the existing wind plant at the Wildorado site in August 1999. This is the typical shape observed at all seven sites. Capacity is fairly low in the middle of the day and highest at night. The deviation about the mean monthly value is also typical, with less deviation in the daytime and more spread in the data at night.

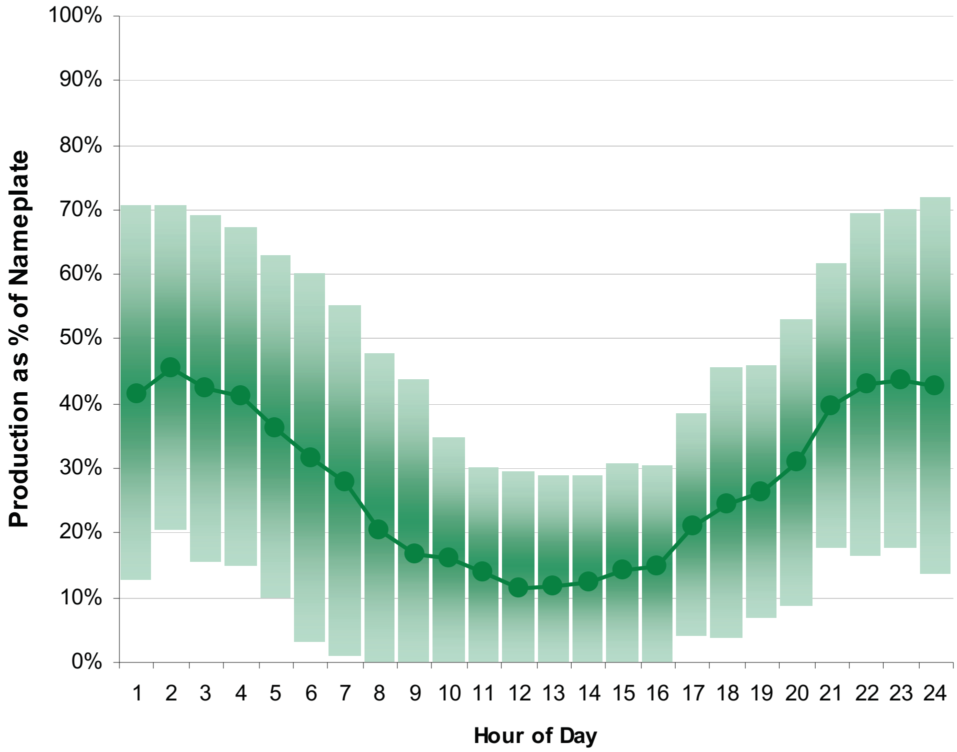


Figure IV-3: Diurnal Pattern Data for Wildorado

Capacity characteristics

To precisely estimate the performance of wind turbines, it is important to know not only the average wind speed at a particular site, but how wind speed varies over time. By comparing the sites, Frio Draw and Wildorado, it is easy to spot the difference in capacity factors, due to the different wind speed distribution characteristics. During our analysis, we noticed that Frio Draw had low wind resources, so we changed the expected model of wind turbine, Mitsubishi 1.0 to a Micon 1.65, a turbine which has been designed for the lower wind speed sites. Before changing the turbine, the capacity factor was below 30%.

In this study, year 1 (July 1999 to June 2000) and year 2 (July 2000 to June 2001) show a typical difference in terms of annual wind energy and capacity factor. According to the data in Table 3, differences in capacity factors ranged from 0.2% to 6.5%. Wind energy production during year 1 is mostly higher except at Mesa Redondo where 2.3% more production was predicted in year 2.

Table IV-3 Summary of power, wind speed, and capacity factor

Average of 2 years	Frio Draw	Mesa Redondo	San Juan Mesa	Wildorado	Dalhart	White Deer	Guymon
Project Output (MW)	64	33	43	70	69	33	67
60m Wind Speed (m/s)	7.7	9.0	8.5	8.2	8.3	8.8	8.1
Capacity Factor (%)	38%	41%	36%	43%	41%	41%	40%
Average 1st year	**Frio Draw**	**Mesa Redondo**	**San Juan Mesa**	**Wildorado**	**Dalhart**	**White Deer**	**Guymon**
Project Output (MW)	66	32	47	70	72	34	67
60m Wind Speed (m/s)	7.8	8.8	8.8	8.2	8.6	8.9	8.2
Capacity Factor (%)	40%	40%	39%	44%	43%	42%	40%
Average of 2nd year	**Frio Draw**	**Mesa Redondo**	**San Juan Mesa**	**Wildorado**	**Dalhart**	**White Deer**	**Guymon**
Project Output (MW)	61	33	39	70	65	32	66
60m Wind Speed (m/s)	7.6	9.1	8.2	8.2	8.1	8.7	8.1
Capacity Factor (%)	37%	42%	33%	43%	39%	39%	40%

General discussion of results

As a result, the turbine performance is neither totally independent nor totally synchronized with wind speed. Table 3 shows Mesa Redondo has the highest average 60 m estimate wind speed, but Wildorado shows the highest average capacity factor.

To analyze the relations among studied sites, correlation analysis was performed. As shown in Table 4, three of the Texas sites and one of the Oklahoma sites have strong positive correlation coefficients. In correlation between Texas and New Mexico, only White Deer and Frio Draw, and Dalhart and Mesa Redondo have around 0.61 correlation coefficients. A correlation coefficient of 1.0 shows a perfect lockstep in wind pattern, when one site speed increases the second would increase in the same relative amount. A correlation coefficient of -1.0 would show a complete inverse in wind pattern.

It is also observed that San Juan Mesa and Mesa Redondo have a low correlation coefficient, 0.462, even though they are alike in elevation, topological characteristics, and average wind speed.

Table IV-4. Correlation coefficients for daily energy production

Project	Frio Draw	Mesa Redondo	San Juan Mesa	Wildarado	Dalhart	WhiteDeer	Guymon
Frio Draw	1	0.711	0.714	0.585	0.596	0.616	0.500
Mesa Redondo		1	0.462	0.597	0.615	0.586	0.601
San Juan Mesa			1	0.358	0.434	0.408	0.328
Wildarado				1	0.688	0.910	0.723
Dalhart					1	0.737	0.802
WhiteDeer						1	0.730
Guymon							1

SUMMARY AND CONCLUSIONS OF WIND SCENARIO ANALYSIS

The collection and analysis of the wind data, predicted output of the modeled distributed wind plants, and the discovered changes in daily and hourly production, do nothing to diminish the potential for wind power on the existing utility grid. All the factors do point out that the successful inclusion of a properly sized and placed CAES plant would enhance the value of the wind power. The wind pattern, coupled with the broad change in daily wind shear values, also points to the added value of a CAES plant when the opportunity to shift the greater than expected night time energy to periods during the daytime when the utility needs that energy. The overall value for this type operation of the CAES in cooperation with the dispersed wind plants would do much to mitigate the intermittency that is the common complaint against wind alone, and the CAES plant could improve reliability for the local area.

The Panhandles of Texas and Oklahoma, coupled with the far Eastern New Mexico region, have a known proven resource for wind energy. The land area, natural gas resources and the underground formations that lend themselves to reduced CAES costs are in place. This combination of the two different power production methods (wind and natural gas) will prove to be a way to extend existing natural gas supplies, while utilizing all the energy that comes from the wind plants at the delivery times that best assist the utility.

References

[1] New Mexico EMNRD, New Mexico Resource Assessment Program Annual Report, 2000
[2] Tae Hee Han, Wind Shear and Wind Speed Variation Analysis for Wind Farm Projects for Texas, Master's Thesis, West Texas A&M University, May 2000.

Appendix
Wind Turbine Brochure (PDF version)

1. Vestas 1.8
2. GE 1.5
3. Mistubishi 1.0
4. Micon 1.65

SECTION V – CAES DISPATCH SCENARIOS

CAES/WIND HYBRID DISPATCH MODEL

How it Works

Ridge Energy's wind shaping models have been used to simulate the output of a CAES plant that is operated specifically to balance and shape energy from a wind farm or group of wind farms. While the wind farms and the CAES plant do not need to be collocated, we assume that communications exist between the plants such that the CAES plant can respond in real time to the output of the wind farm. Another key underlying assumption is that energy is delivered according to a combined schedule, and that it doesn't matter whether the energy is coming from the wind farms, or from storage. The important factor is the net energy delivery to the grid. Effectively, the wind shaping model assumes that operations of the CAES plant and the various wind farms are *hybridized*, in other words, that the output is co-dispatched to meet a common schedule.

Hourly wind energy production profiles for an entire year are entered into the windshaping model, along with assumptions regarding the CAES configuration and incremental heat rate and energy ratio. On a monthly basis, the user defines the target shape for the net firm energy output from the wind/CAES plants. This occurs by specifying the number of megawatts of energy to deliver in various shapes. For example, a user could specify the delivery of a 100 MW block of 7x24 energy, supplemented by a 100 MW block of 5x16 energy to meet energy needs during the peak period. Alternatively, the user also could select a "shaped" on-peak block, which provides for a graduated delivery of energy over the peak period, ramping up and down in rough proportion to load. Finally, a user can also enter a manual schedule, which can be used as a proxy for additional firm deliveries of energy to be provided based on short-term forecasts of wind availability.

Based on the firm, target schedule, the wind-shaping model determines how to dispatch the CAES facility in conjunction with the wind in order to meet the firm schedule desired by the user. Basically, CAES compression and CAES generation are both used to decrement or supplement and balance wind production to meet the desired net dispatch profile. The model takes into account minimum load requirements on the turbine and compressors. Cavern "inventory" tracking formulas ensure that the model doesn't dispatch CAES generation if there is no stored air in the cavern, and that it doesn't dispatch CAES compression if the cavern is at maximum pressure. Therefore, the model predicts some variance from the target schedule. The user can modify the desired schedules for firm energy deliveries to minimize the negative variance; the underlying assumption being that for reliability purposes, it is better to under predict the amount of firm energy delivered rather than over predict and suffer the consequences of negative variance.

Summary Assumptions

The following table summarizes the main assumptions about the CAES plant that are relevant for use in the wind-shaping model.

CAES Plant Details

Factor	Value
Generation units	2
Minimum generation per unit	67.5 MW
Maximum generation per unit	135 MW
Compression units	2
Minimum compression per unit	60 MW
Maximum compression per unit	100 MW
Cavern storage capacity	10,000 MWh
Heat rate	4,500 Btu/MWh
Energy ratio	0.8 kWh in/kWh out
Variable O&M cost	$1.50/MWh

For the Base Wind Scenario, the following table summarizes what was defined as the target monthly schedule of firm energy delivered for the hybridized dispatch of CAES and 440 MW of wind.

Base Wind

	Schedule (MW)											
Firm Product	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*
5 X 8	0	0	0	0	0	0	0	0	0	0	0	0
Peak Shaped	50	50	130	140	120	130	100	70	110	50	50	70
5 X 16	50	80	20	20	60	40	60	80	40	15	50	75
7 X 16	0	0	0	0	0	0	0	0	0	0	40	0
7 X 24	90	80	90	120	70	100	70	80	120	70	80	105
Total Firm Schedule	190	210	240	280	250	270	230	230	270	135	220	250

Note that the firm schedule for April totals 280 MW, which is higher than the nameplate capacity of the CAES plant of 270 MW. However, because April is such a high wind month, the maximum firm schedule could be set a little higher than 270 MW with an implicit forecast of 10 MW of wind availability around the clock.

For the Study Wind Scenario, the following table summarizes what was defined as the target monthly schedule of firm energy delivered for the hybridized dispatch of CAES and 500 MW of wind. In other words, CAES was modeled as managing only the Study Wind, not the existing 440 MW of wind.

Study Wind

Firm Product	Schedule (MW) Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
5 X 8	0	0	0	0	0	0	0	0	0	0	0	0
Peak Shaped	60	70	130	160	120	130	120	90	110	95	95	70
5 X 16	60	60	20	0	60	40	60	100	40	15	100	95
7 X 16	0	0	0	0	0	0	0	0	0	0	0	0
7 X 24	100	95	90	130	90	100	70	70	120	70	75	105
Total Firm Schedule	220	225	240	290	270	270	250	260	270	180	270	270

Because more wind is being managed in the Study Wind Scenario, the firm dispatch schedule for hybrid CAES/wind output is set higher than for the Base Wind Scenario. Again, due to the high winds in April, we assumed that a forecast of 20 MW of wind around the clock would be very reasonable, allowing us to define a maximum firm schedule of 290 MW rather than being limited to the CAES plant capacity of 270 MW.

MODEL OUTPUT

The graphs below show output from the CAES/wind dispatch model. The scenario shown here is for the Study Wind Scenario, and output is shown for the month of April.

The V-1a graph shows the total wind production for the three Study Wind farms totaling 500 MW. April is a high wind month, and the green block shows the quantity of wind power that would have been delivered to the grid over the month. Note that while there are several occasions where total wind power delivered approaches 500 MW, there are also several occasions where the total wind power delivered is close to zero. Note that the graph only shows the total wind production for the 500 MW of Study Wind. When coupled with the wind deliveries from the 440 MW of SPS wind that is already assumed to be on the grid, some of the fluctuations in delivery quantity will be dampened, but not by much. (See below for more details.) Furthermore, wind power deliveries definitely display much higher variability than the patterns associated with load, shown in the orange line, and show low propensity to arrive at times coincident with grid needs.

The V-1b graph provides a visual indication of what is happening with the operations of the CAES plant. The shaded green blocks that are still visible on the second graph now represent wind energy that has been stored via compression. Blue or purple blocks above the dark green outline of the original wind deliveries represent power that is being generated by the CAES plant.

The V-1c graph shows the net deliveries to the grid after hybridization with a CAES plant. The purple blocks represent a schedule that was committed to as a firm delivery. A supplemental schedule, shown as the dark blue block starting on April 9th, represents additional firm power that was promised based on a reasonable assessment of availability of wind or excess inventory of stored energy. The light purple block represents energy that was delivered when in excess of the firm delivery requirement. The excess energy exists since it is impossible to perfectly shape the wind energy using a month-ahead type of approach, which is effectively what this model does. Also, the model takes into account factors such as minimum load on the generation and compression trains, and therefore cannot assume a perfect shaping. Nevertheless, it is useful to see that the net energy delivery is targeted to a shape that matches the patterns seen in actual load.

The V-1d graph tracks the inventory of stored energy in the cavern over time. Following the graphs tells a story of how wind/CAES work together. Over the first two weeks of the month, a considerable amount of wind energy is produced, more so than is required to deliver energy in the targeted profile. Inventory of stored air builds up in the cavern, resulting in the cavern's fill limit being reached by April 9 and 10th. In recognition of the fact that there is ample stored energy, and also because of the need to reduce inventory in the cavern, an upward adjustment is made to the firm delivery schedule. However, it is not quite enough to empty the cavern, and on two occasions on April 10th and April 11th, cavern storage limits are reached, which means that some excess wind energy that would have been taken off the grid is allowed to flow onto the grid. Cavern inventory slowly declines over the rest of the month as the stored energy from the first two weeks is released onto the grid in a net shaped delivery. As wind energy production lulls from April 24th to April 28th, more energy is pulled out of storage, and cavern inventory levels drop rapidly from April 24th to April 28th. However, an increase in wind speeds in the last few days of the month results in greater wind energy available for the grid, and allows for cavern inventory to be replenished to meet the shaping needs for the following month.

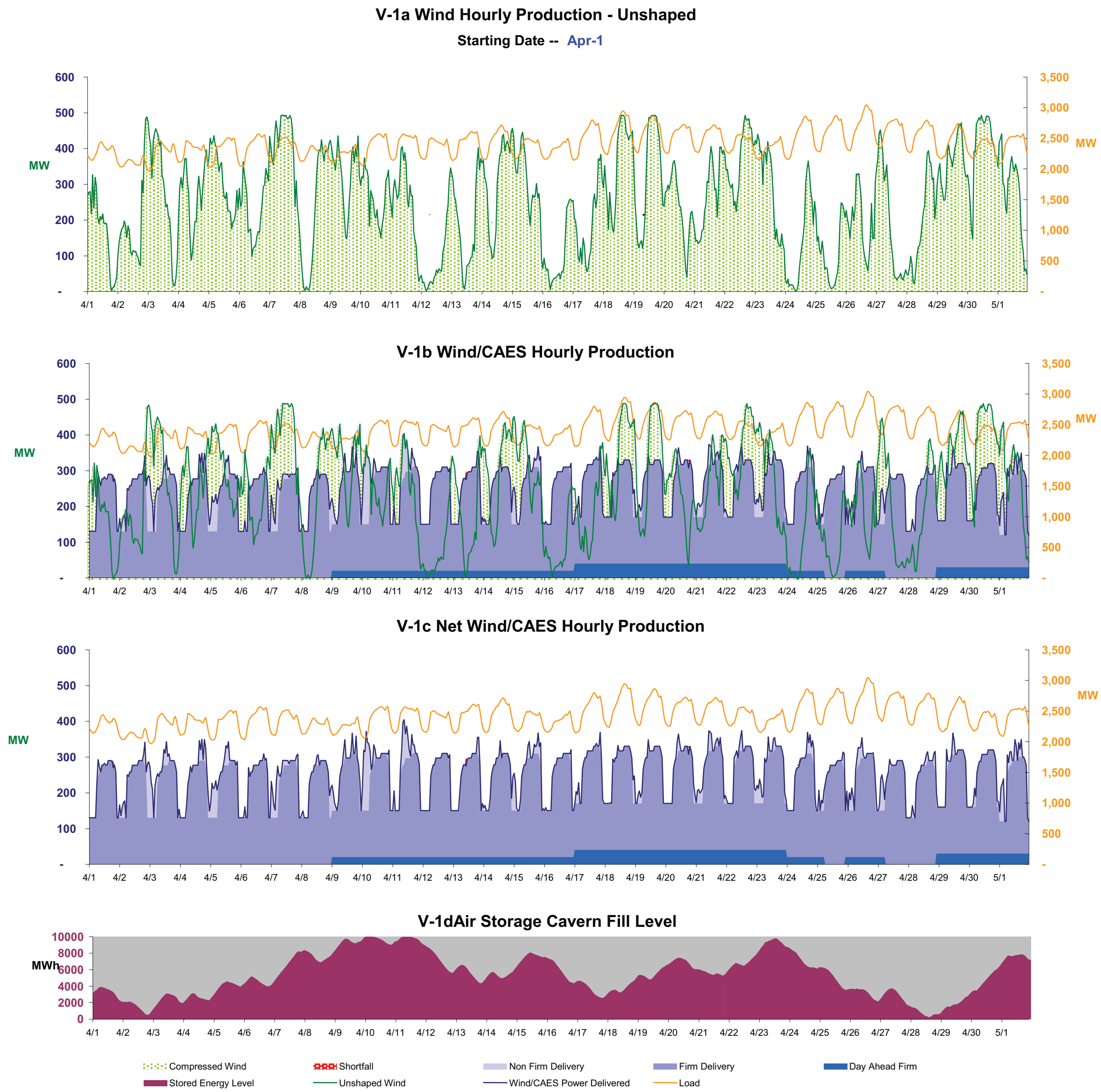


Figure V-1: (Study Wind Scenario) CAES/Wind Dispatch Graphs - April

We have also provided the hourly dispatch graphs for the month of April for the Base Wind Scenario. Comparing the graphs with the output for the Study Wind Scenario, one can see that while the wind patterns are not perfectly alike, they show similar energy delivery trends which will be reinforced when the energy production from the two sets of wind farms are added together. It is not surprising that they are similar – the wind patterns are for the exact same time period.

The targeted schedule for firm energy deliveries for the Base Wind Scenario is very similar to the targeted firm schedule for the Study Wind Scenario. Refer back to Tables on pages 32-33 to see what the actual schedules were. So it is not surprising, with similar wind patterns, that one would see that the projected use of the CAES energy storage cavern also exhibits strong similarities from scenario to scenario.

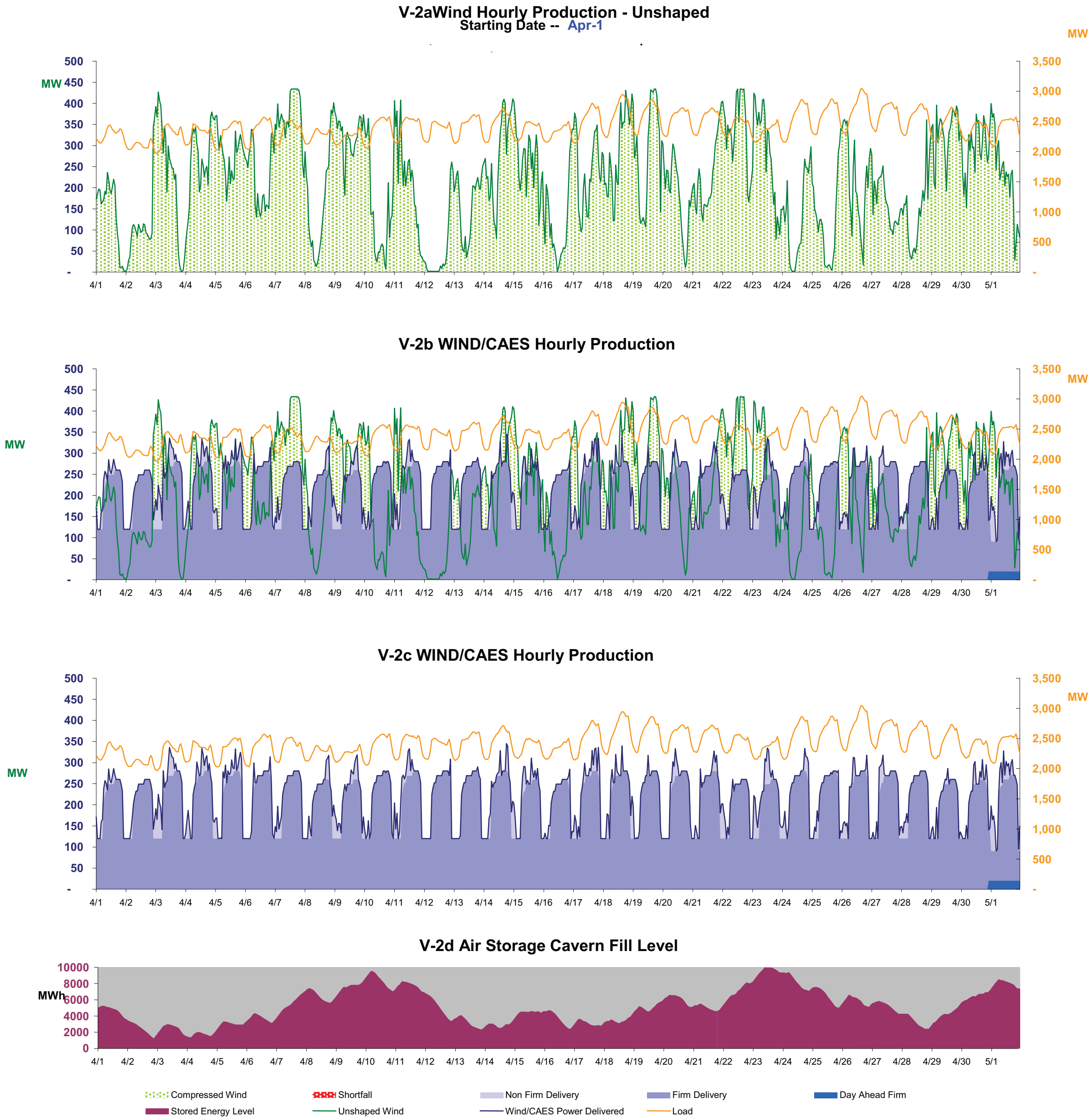


Figure V-2: (Base Wind Scenario) CAES/Wind Dispatch Graphs - April

Below are shown the hourly dispatch graphs for July, which is when SPS can experience its annual system peak, while wind capacity factors tend to be comparatively low. However, on July 8th in the Study Wind Scenario, we see an example of running out of room in the storage cavern and therefore losing the ability to provide shaping through compression for a few days.

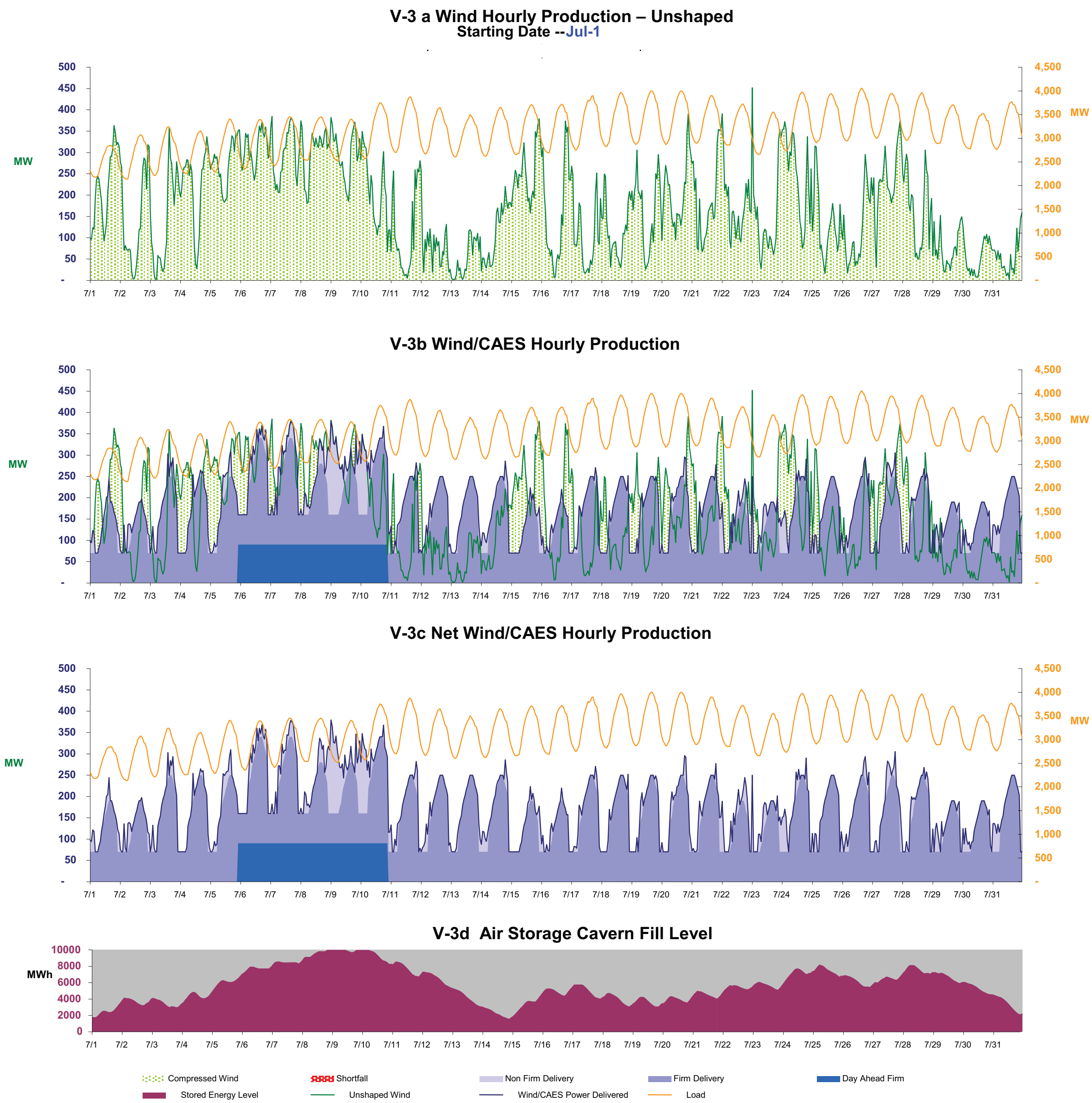


Figure V-3: (Study Wind Scenario) CAES/Wind Dispatch Graphs - July

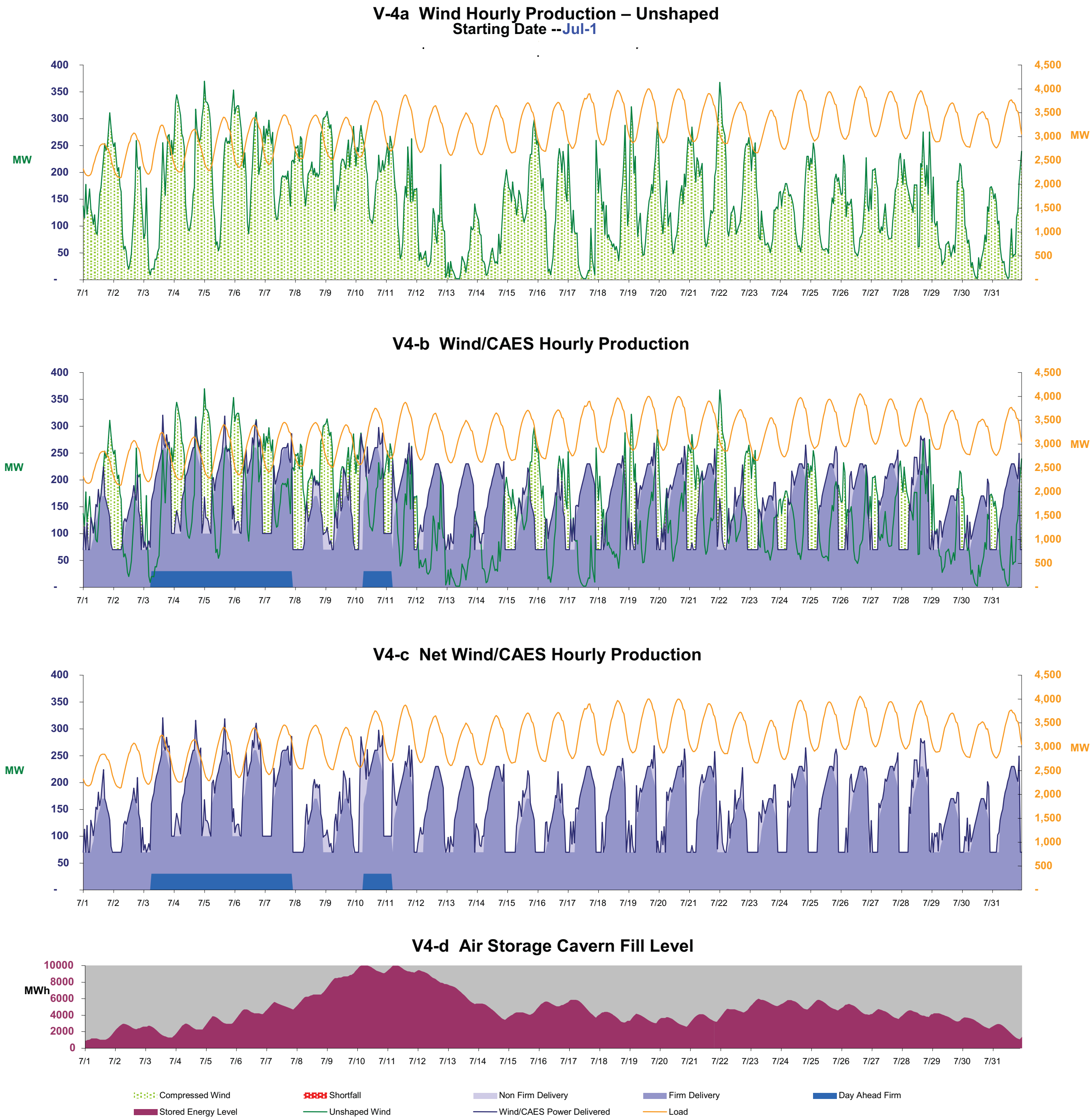


Figure V-4: (Base Wind Scenario) CAES/Wind Dispatch Graphs - July

The hourly dispatch graphs for January show a completely different load profile with a pronounced wintertime double peak. The net wind/CAES graphs show how the wind can be shaped into a profile to match the double peak.

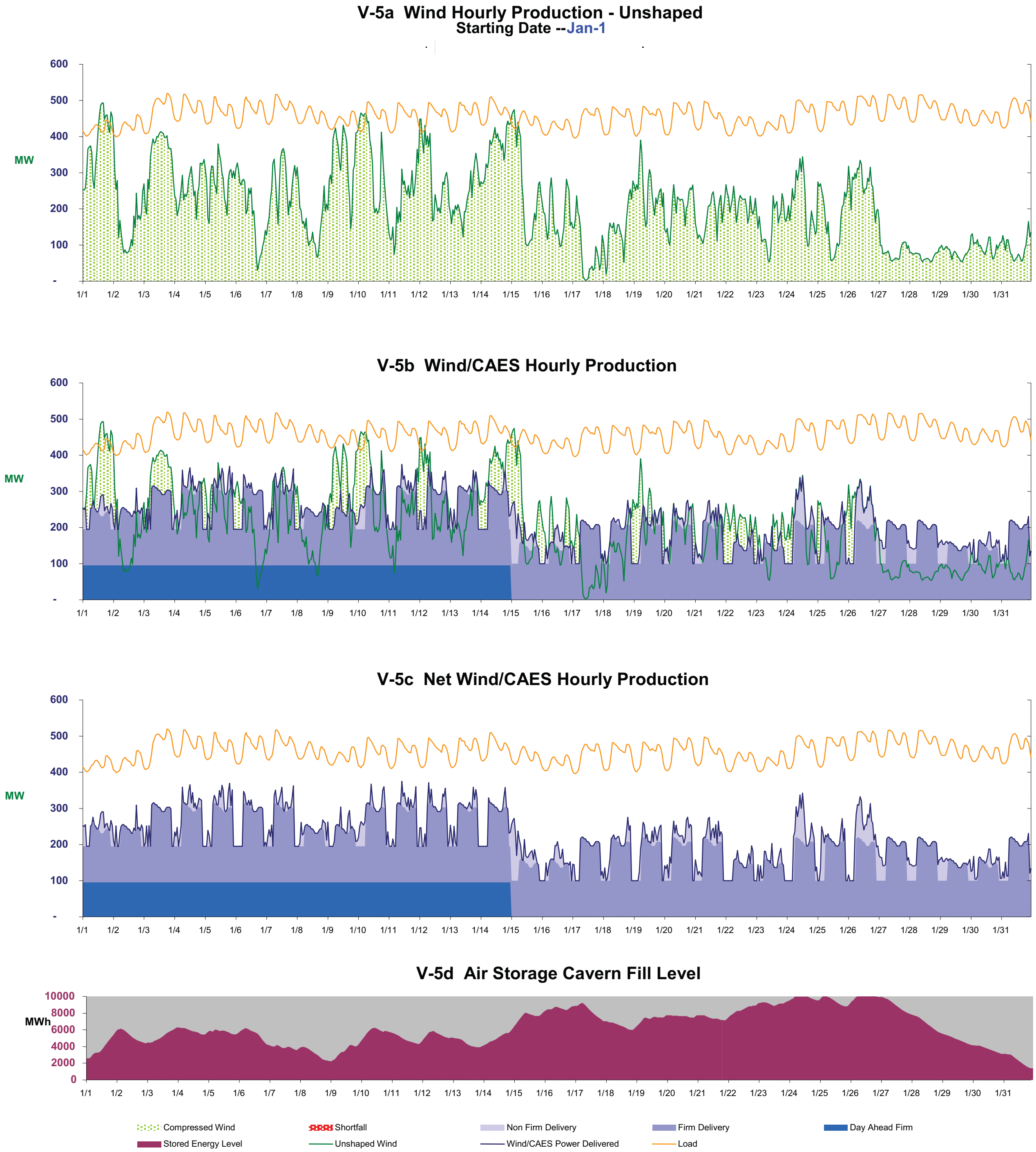


Figure V-5: (Study Wind Scenario) CAES/Wind Dispatch Graphs - January

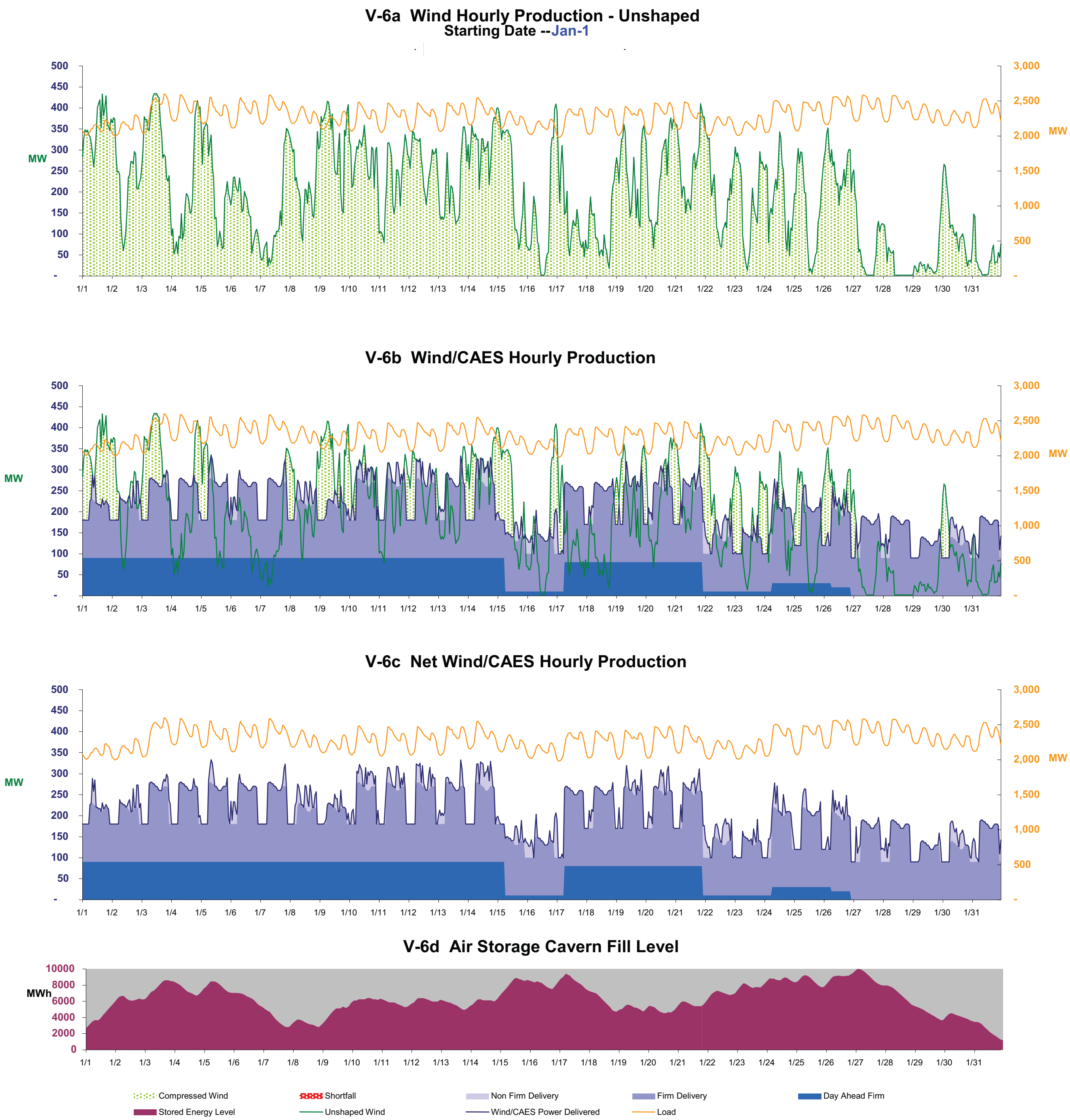


Figure V-6: (Base Wind Scenario) CAES/Wind Dispatch Graphs - January

WIND/SHAPED WIND COMPARISONS

Profile Impacts

Graphs of average diurnal delivery profile have been compiled by month. In each of the months, the green line, which represents the unshaped wind, shows an average diurnal profile that does not follow load, the red line, very closely. In fact, in the peak electricity months of July and August, the wind energy shows a pattern that is strongly opposite to that of load, with energy deliveries highest at night, and dropping significantly during the day when electricity demand peaks.

The purple/light purple blocks show the average diurnal profile of net energy deliveries after the CAES plant has been dispatched to manage the wind. There is a significant shift in the timing and shape of how energy is delivered onto the grid. Not only does the timing of deliveries correspond better to electric load, but the profile of deliveries is also smoother. Visually, it is also possible to see that the amount of energy that can be pre-scheduled onto the grid is a very high proportion of total energy deliveries, in contrast to wind on its own.

Figure V-7: (Base Wind Scenario) CAES/Wind Dispatch Graphs - Monthly

Figure V-7 (cont'd): (Base Wind Scenario) CAES/Wind Dispatch Graphs - Monthly

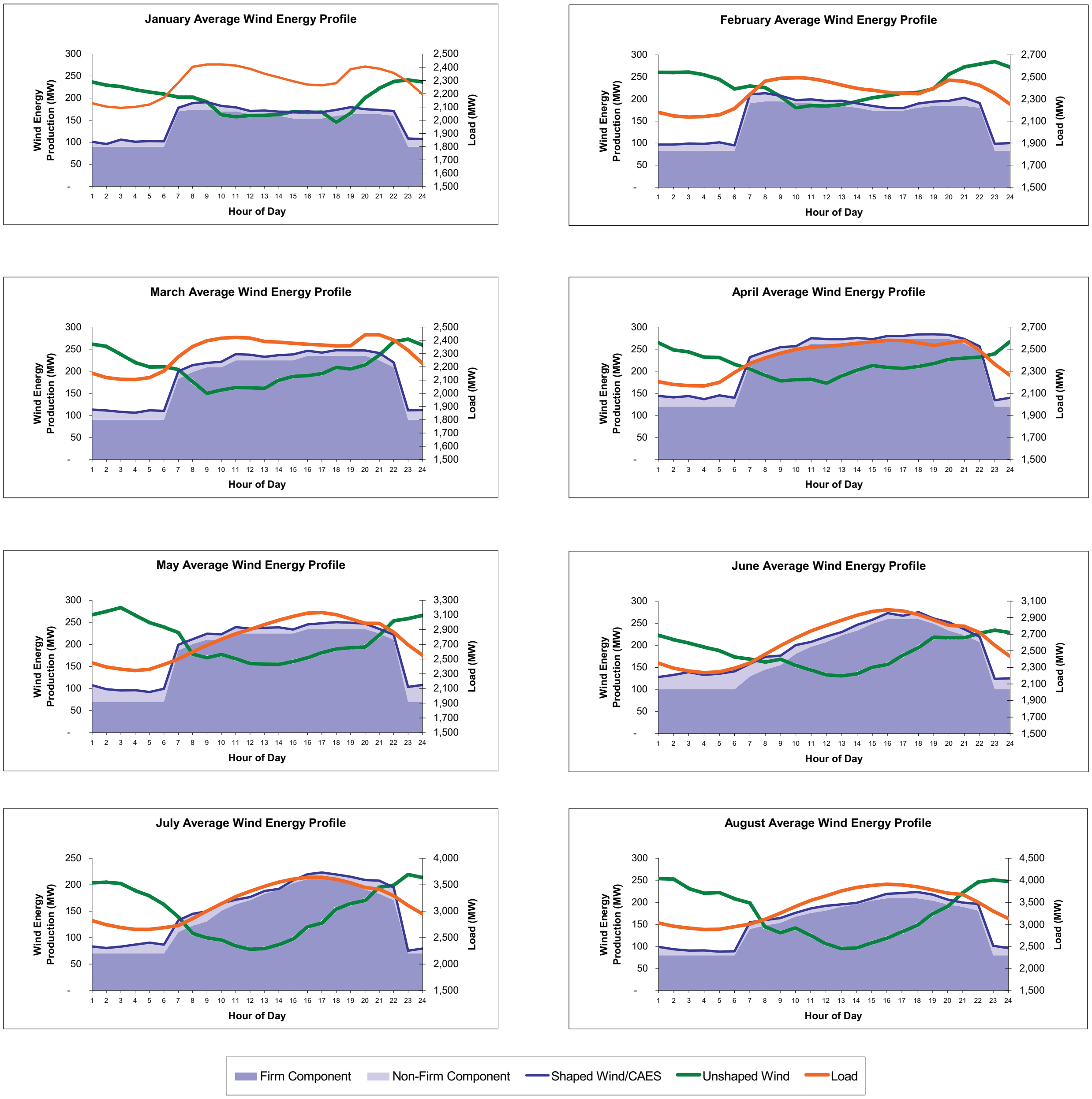
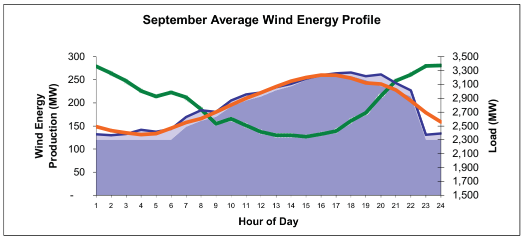
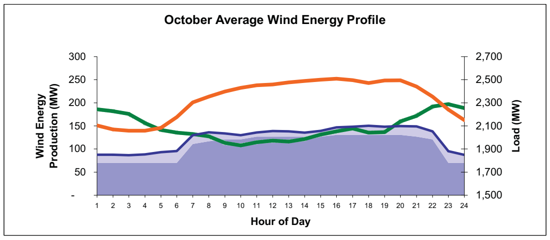
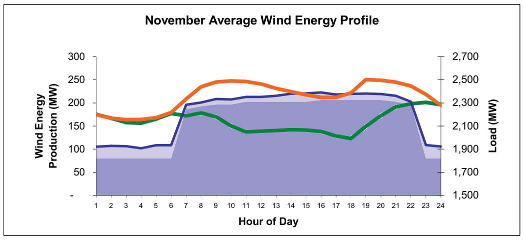
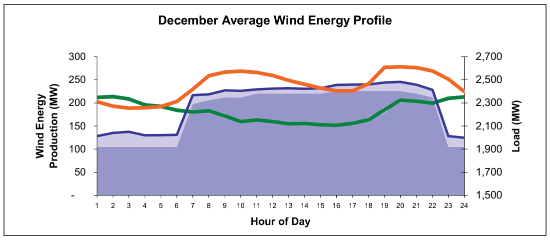


Figure V-8: (Study Wind Scenario) CAES/Wind Dispatch Graphs - Monthly









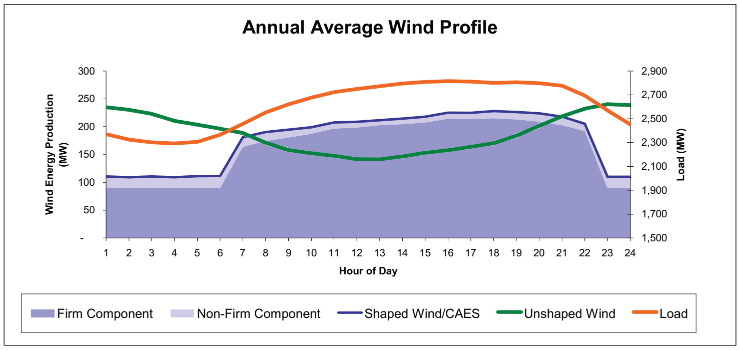


Figure V-8 (cont'd): (Study Wind Scenario) CAES/Wind Dispatch Graphs - Monthly

Hour-to-Hour Ramping

When examining the pattern of wind energy delivery onto the grid, it has already been noted that the wind tends to exhibit diurnal patterns that are opposite to that of load. On average, load is higher during the day than during the night, while wind energy deliveries are higher at night than during the day. This has important ramifications for unit scheduling because of the impact on unit ramping requirements. If wind is dropping while load is picking up, the generators on the system have an added ramping burden. Not only do they have to be able to ramp up to meet load, but they also have to be ramped up to make up for declining wind power. Additional ramping capability may need to be scheduled to ensure that the total ramping capabilities of committed generator capacity is sufficient to meet the requirement. On the other hand, if wind picks up while load picks up, it is possible that wind might reduce the ramping burden that is ordinarily borne by conventional generators.

In order to quantify this impact, we looked at the net hour-to-hour ramping requirement for the various cases and compared the distributions. We calculated the net ramping requirement by taking the projected load schedule and subtracting the amount of energy that would be delivered by wind or by wind and CAES together. The change from hour-to-hour represented the ramping requirement for the particular case we were evaluating, with 8760 points for the year. A simple histogram and distribution analysis shows the annual burden on ramping requirements for the system.

The following graph compares the Base Wind Scenario reference case (440 MW of announced/existing wind) to ramp requirements posed by net load on its own. (Refer to Page 42 for a refresher of the scenario/case descriptions.) Most of the hourly changes in net load (shown as the hollow red columns) are within +/- 200 MW. Once 440 MW of wind is integrated into the system, it significantly reduces the number of instances when hourly ramp requirements are very low. This is offset by an increase in the number of instances when system ramp requirements are relatively high. The integration of 440 MW of wind also slightly widens the distribution of ramp requirements, in other words, making it more likely that the system has to respond to an hourly ramp of greater than 200 MW up or down.

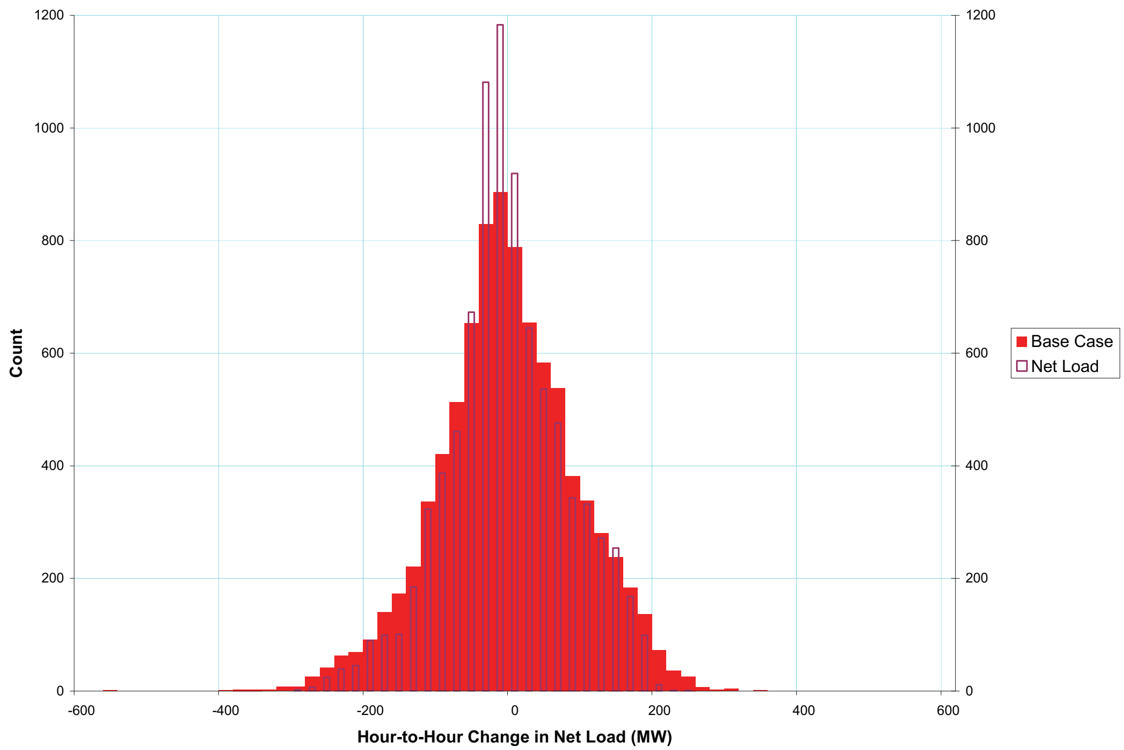


Figure V-9: Base Wind System Ramping Requirements

Let's look at how the system ramp requirements are impacted when we use a CAES plant to manage the 440 MW of wind. Using the net energy delivery profile that was developed for the Base Wind Scenario change case, and performing the same analysis, we show a marked improvement on system ramping requirements, compared to the reference case, shown in red. The results from the change case, graphed in blue, show a significant decrease in the number of times that the system has to respond to relatively high ramping requirements, while showing an increase in the number of hours when hourly ramp was rather low. Aggregate burden on system ramping requirements is clearly lowered with the use of a CAES plant to manage the wind.

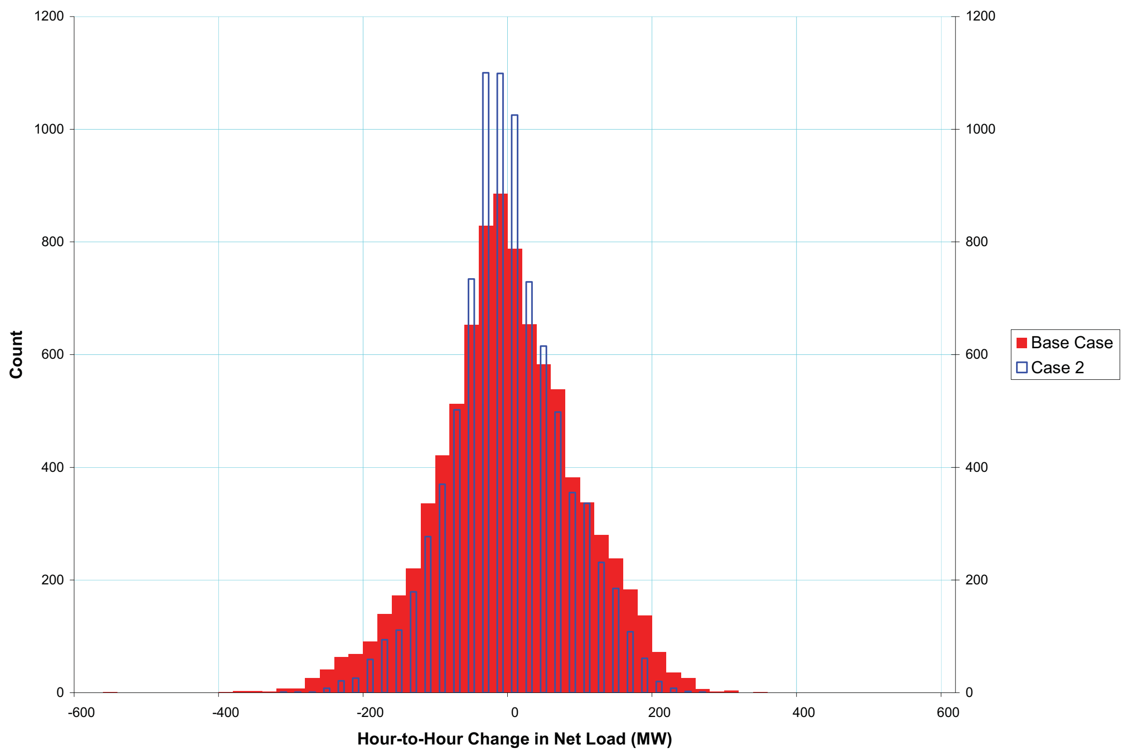


Figure V-10: Base Wind with CAES System Ramping Requirements

Next, we compared the Base Wind Scenario reference case to the Study Wind Scenario reference case, which is the addition of 500 MW of Study Wind on top of the 440 MW of wind embedded in the Base Wind Scenario. The distribution of hourly ramp requirements in the Study Wind Scenario, shown in green, is flatter and wider than for the Base Wind Scenario, indicating higher aggregate burden on system ramping requirements.

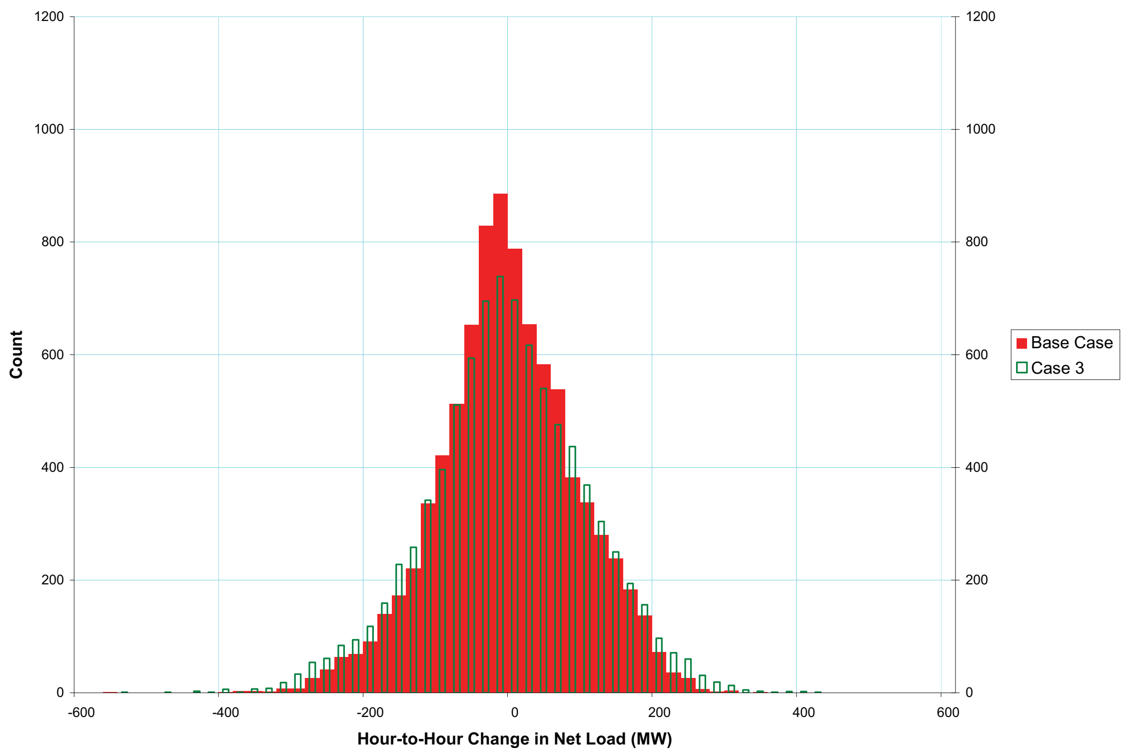


Figure V-11: Base Wind + 500 MW Study Wind System Ramping Requirements

Again, when we compare the results from using CAES to manage the wind according to the CAES dispatch profile developed for the Study Wind Scenario change case, we see an improvement compared to the reference case for the scenario. The reference case is still shown in green, though this time as a solid block, while the change case is shown in yellow. The distribution of hourly ramp requirements in the reference case is flatter and wider than for Case the change case, indicating that the change case (using CAES to manage wind) has a lower burden on system ramping and therefore integration requirements.

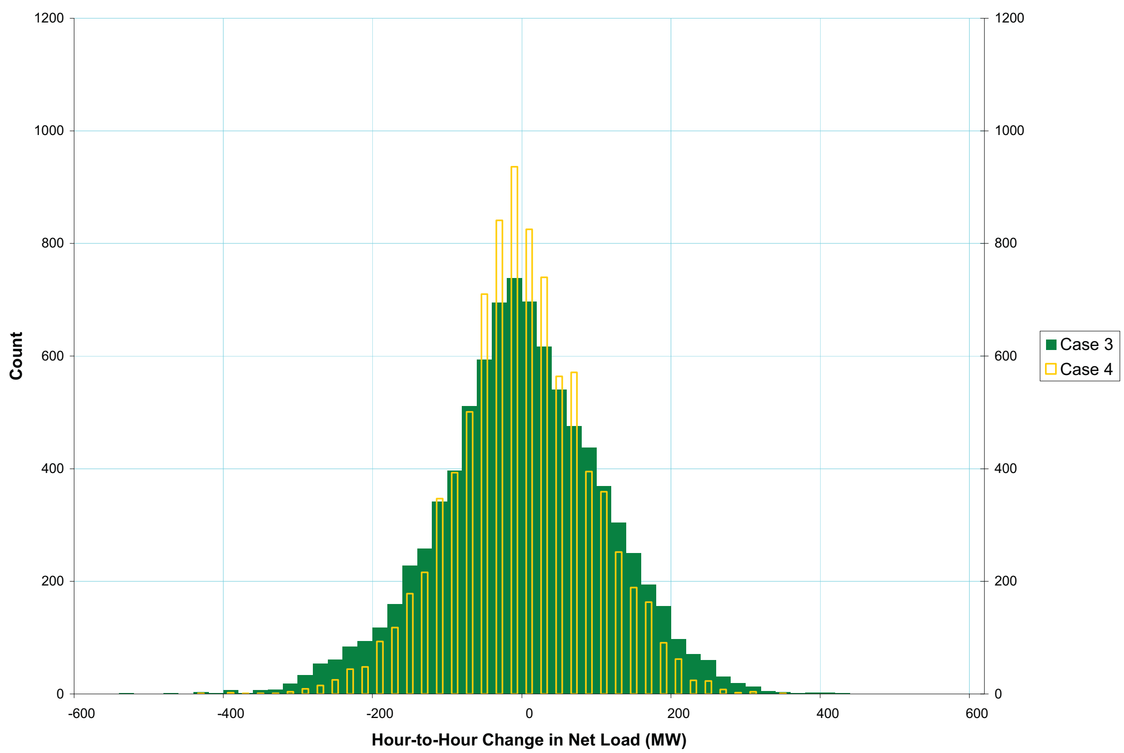


Figure V-12: 500 MW Study Wind System Ramping Requirements with CAES

Interestingly, when we compare the results from the Study Wind Scenario change case to the Base Wind Scenario reference case, we find that the distributions almost overlap. The conclusion is that CAES can be used to manage the integration of 500 MW of Study Wind into the SPS system without negatively impacting hour-to-hour system ramping requirements, and CAES can also be used to improve hour-to-hour ramping impacts associated with wind energy that Xcel Energy has already contracted for.

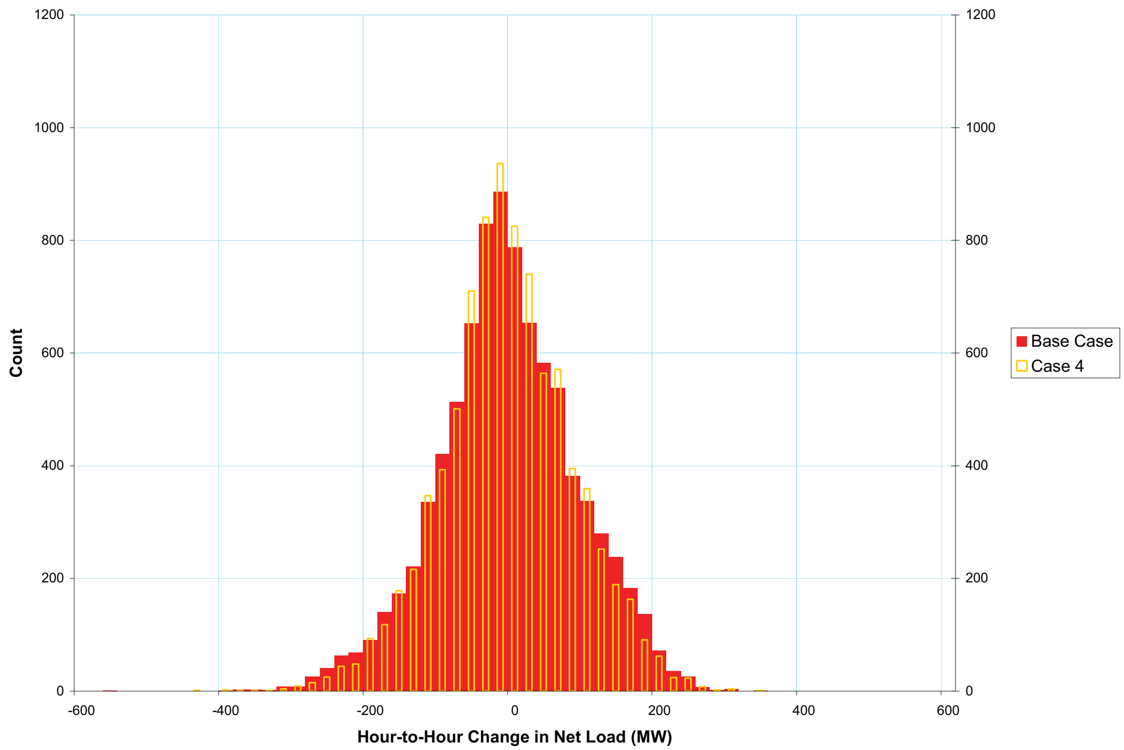


Figure V-13: Base Wind + 500 MW Study Wind System Ramping Requirements with CAES

To the extent that PROSYM accurately captures the costs associated with meeting system ramping requirements, the value of using energy storage to decrease the ramping burdens imposed by wind should be captured in the production cost analysis that we have performed. If the true costs of increased system ramping burden cannot be captured in PROSYM, for example, because of an incomplete understanding of additional O&M costs that are incurred when ramp rates are increased, then the value of energy storage in integrating wind will be underestimated.

Wind Energy Deliveries Versus Load

We have already seen graphs that show that on average, wind energy delivery profiles do not correspond closely to load profiles. Let's examine a 3-D chart to get deeper insights into how wind and load compare to each other. The chart below graphs the Base Wind Scenario reference case, in other words, 440 MW of nameplate wind versus load.

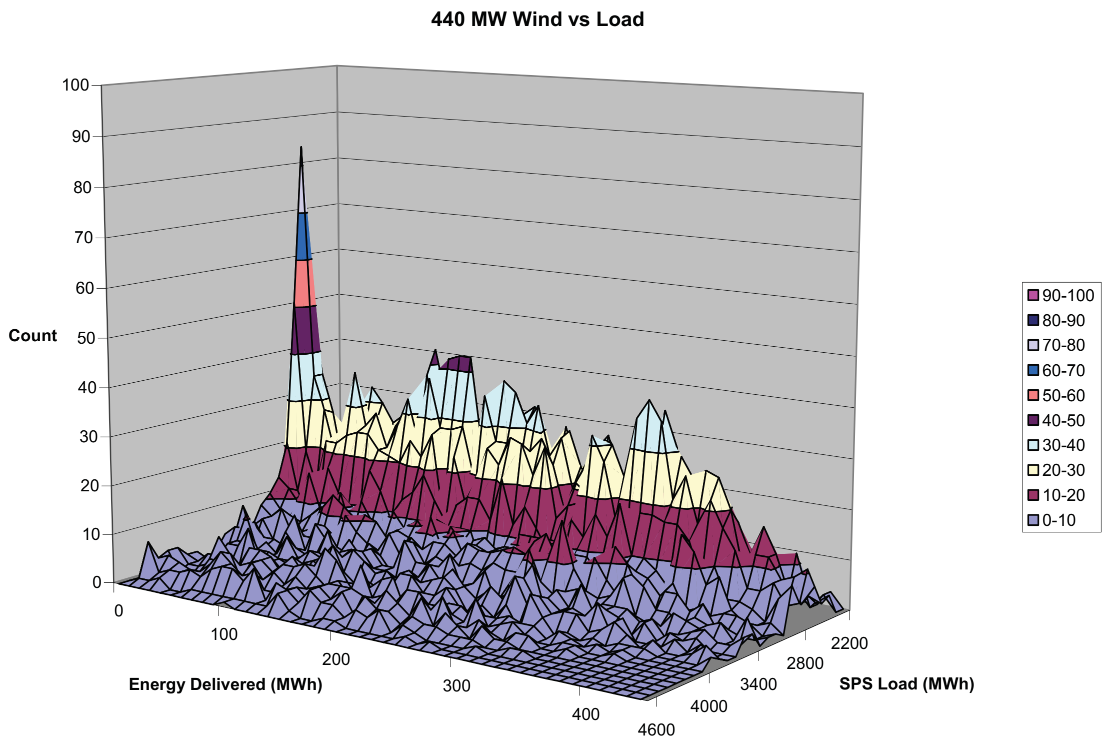


Figure V-14: 3D Base Wind Energy vs. System Load

As a 2-D graph, the above chart would be a scatterplot for one year comparing hourly wind energy to hourly load. However, as a 3-D surface chart, the graph provides more insight by showing the number of hours per year when wind energy and load are within certain ranges. For example, the spike shows that there were 84 hours in the year when wind production was less than 10 MWh, while load was between 2700 and 2800 MW.

When load is high, the graph shows that wind deliveries are likely to be a low percentage of nameplate wind. Note how most of the wind deliveries are less than 300 MW in volume when load is above 4000 MW. There are practically no hours when load is above 4000 MW and when wind is producing at a high percentage of nameplate capacity.

Based on number of occurrences, 440 MW of wind is most likely to be producing at 192 MW, which is 44% of nameplate. However, when load is between 4600 and 4700 MW, wind is most likely to be producing at only 100 MW, while it is most likely to be producing at 236 MW when load is between 2200 and 2300 MW. There is a negative correlation between the amount of wind produced and the amount of load, and the 3-D graph shows the variability around the trend. It is interesting to see that when the wind is producing at a high percentage of nameplate capacity, that load is very likely to be low.

The next graph plots the frequency of wind/CAES deliveries versus load. The net wind/CAES deliveries are calculated from the Base Wind Scenario CAES dispatch profile.

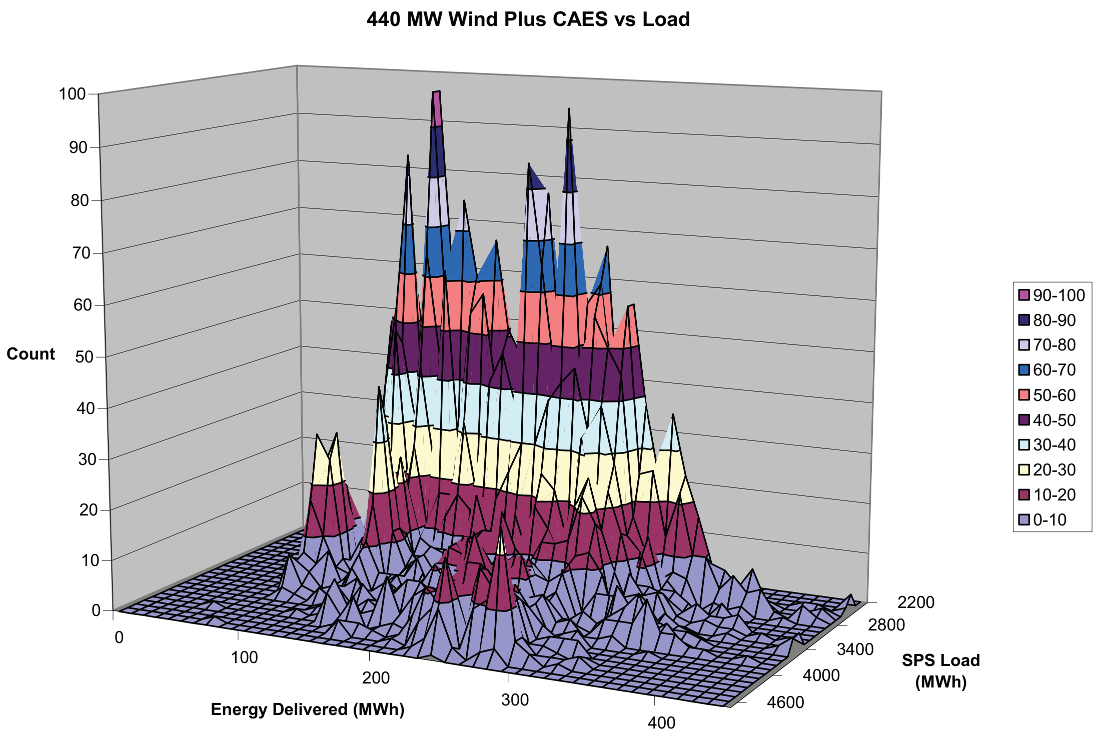


Figure V-15: 3-D Base Wind with CAES vs. System Load

There are several differences in the 3-D charts that depict the key impacts of wind hybridization with CAES. First, note that there are close to zero hours when less than 70 MW of energy is being delivered to the grid from the combination of wind and CAES. Effectively, CAES has baseloaded over 70 MW of the 440 MW of wind on the grid and turned it into a round-the-clock product. Next, note the dramatic reduction in the number of instances when energy deliveries are at a high percentage of nameplate wind while load is low. In fact, there are significantly fewer times when energy deliveries are above about 350 MW. Third, note the increased volumes of energy that are delivered during the peak demand hours compared to wind on its own. Finally, note that the frequency of energy deliveries within a certain range of hourly volumes has dramatically increased, implying greater predictability in long term planning for energy supplies due to the hybridization of wind with CAES.

Comparisons of the 3-D graphs for the Study Wind Scenario depict similar benefits from the use of CAES to integrate wind, but we have not shown those graphs here because it is hard to do justice to them in a printed version versus an interactive computer screen.

SECTION VI – TRANSMISSION LOADFLOW MODELING

OVERVIEW

The objectives of the transmission loadflow analysis were three fold:

- Pinpoint the transmission upgrades required to inject the additional wind power into the grid at the specified locations
- Determine if planned transmission upgrades could be delayed or replaced by the CAES plant
- Determine what transmission upgrades were needed if the CAES plant were interconnected at the specified location

No transmission loadflow analysis was performed to find the best location for the CAES plant, or to determine the best interconnection locations for the three study wind plants. The assumed locations of the wind plants and the CAES plant were determined prior to the start of the loadflow analysis.

THE THREE LOADFLOW STUDY SCENARIOS

The 2006 summer peak, April minimum and summer shoulder loadflow databases were used for the loadflow analysis. The databases are from the 2005 SPP "Update 1 Reduced Models" series created January 31, 2005. For those familiar with loadflow analysis, the term "loadflow database" is being used instead of "loadflow case" so there is no confusion with the word "CAES".

The loadflow databases contain the White Deer and Caprock wind plants, just two of the seven wind plants required for this study. The Wildorado and San Juan Mesa wind plants make-up the remainder of the "announced" wind, but were not included in the loadflow databases. The models (IDEV files) were provided by SPS planning personnel. The loadflow wind models for the Guymon, Dalhart and Frio Draw wind plants, which contribute the 500 MW of installed wind, were created for this study. The loadflow wind models were not based on any particular wind turbine manufacturer, model or technology, unlike the wind analysis study which did consider specific turbine models and manufacturers. The organization of the loadflow analysis was based upon the three various levels of wind capacity installed on the transmission system; PreWind, BaseWind and Study Wind

Table VI-1. Maximum Wind Plant Capacity for the Three Study Scenarios.

	White Deer	Caprock	San Juan Mesa	Wildorado	Frio Draw	Dalhart	Guymon	Total Wind
PreWind	80	80						160
BaseWind	80	80	120	160				440
Study Wind	80	80	120	160	166.3	166.3	166.3	940

PreWind

To begin the loadflow analysis process, the thermal overloads and voltage violations present in the "as published/delivered" databases were reviewed and documented. These unaltered loadflow databases are referred to as the "PreWind" scenarios. This process was carried out for both the intact (transmission system with no contingency conditions) and contingency conditions. Any system violations noted in this case are considered "acceptable" and are not flagged as violations due to the additional wind or CAES plant if they are noticed in the subsequent loadflow studies. The output of the two wind plants (White Deer and Caprock) included in the PreWind studies was not increased or altered in any way during PreWind scenario analysis.

BaseWind

The "BaseWind" scenario included the original White Deer wind plant and the three announced wind plants: (Caprock, San Juan Mesa, and Wildorado) for a total of 440 MW of installed wind. In this scenario the wind output was increased to the appropriate level for the study (typically 100%). BaseWind scenario violations were once again monitored and documented for both system intact and contingency conditions. System improvements which were necessary due to the injection of 440 MW of wind were made so that the violations did not appear in the subsequent 940 MW wind study.

Study Wind

The Study Wind ("Study Wind") analysis included the full 940 MW of wind plant capacity. This study model was used to investigate the interconnection requirements of the three individual wind plants, to better understand the impact of wind on the north-south constraint and to investigate the role of CAES in the compression and synchronous condenser mode. Any system violations noted in this portion of the study, which were not noted in the PreWind or BaseWind studies, were scrutinized and if transmission upgrades were necessary, they were modeled into the system before the CAES plant was studied.

THE SEASONAL TRANSMISSION LOADFLOW DATABASES

The transmission loadflow analysis primarily examined the transmission system under the "bookend" summer peak and spring minimum conditions, as is customarily done. These extreme conditions are useful to examine the impact of the wind injection on the local transmission system and to understand what problems might be lurking out there as the system is stretched to its load, congestion, and generation limit. It is very unlikely all of the wind plants will be operating at full capacity during summer peak, so the summer shoulder loadflow database was also examined. It is a better representation of a loaded transmission system that might also experience high wind injection Table VI-2 provides a summary of the PreWind loadflow databases utilized in this study. The total wind number is presented here just to show that the typical transmission analysis procedures hold the wind at a lower level. The number shown is for the 160 MW combination of White Deer and Caprock.

Table VI-2. Seasonal SPS Load.

	SPS Load	Total Wind
Summer Peak	100%	16 MW
Summer Shoulder	85%	58 MW
Spring Minimum	53%	80 MW

CONSIDERATION OF FUTURE TRANSMISSION UPGRADES

No future transmission upgrades were modeled into the loadflow databases. A list of proposed transmission upgrades, provided by SPS planning, was monitored to see if the CAES plant installation could delay or replace any of the projects.

As wind power develops in the wind rich regions of New Mexico, Oklahoma, Kansas and the Texas Panhandle a renewable highway will be needed to transport the power from the wind rich regions to the populated areas. SPP planning has been considering a renewable highway system that links the wind and load centers called the Kansas Panhandle Expansion Plan. They have analyzed 3 different new 345 kV transmission configurations. Two of the three configurations export the wind power from the Potter substation, the third configuration exports from Tuco, which is where the CAES plant is located in this study. Although the Expansion Plan was not the subject of this study, the CAES plant would be able to respond to markets outside the SPS territory in a similar fashion.

THE WIND PLANT MODELS

Wind plants are comprised of induction generators, which absorb reactive power (VARs) from the system. Historically, this leading power factor has been corrected by adding reactive compensation to the system in the form of fixed and switched capacitor banks. Wind plant manufactures have been working closely with the utility industry to develop wind plants which are more operationally friendly, including the capacity to provide a dynamic range of reactive compensation. This study did not attempt to analyze the reactive compensation needed for the interconnection of the various wind farms, and such information was not yet available from the studies in the generation interconnection queue. It is assumed that the wind plants will be responsible for providing an amount of reactive compensation to be determined in plant-specific interconnection studies.

Existing and announced wind plants

White Deer, which is rated at 80 MW and located northwest of Amarillo, has been in operation for a few years. Caprock (Mesa Redonda), also rated at 80 MW, is near Tucumcari and is just coming on-line. These two plants exist in the PreWind scenarios at various levels depending upon the seasonal load. Wildorado, located west of Amarillo, and San Juan Mesa, in south-central New Mexico, make up the remainder of the “announced” wind. Both the announced and existing wind that appear in the BaseWind studies were provided with additional reactive support for the loadflow studies.

Guymon

The Guymon wind plant is interconnected to the 115 kV transmission system at the Texas County Interchange. The Texas County Bus is capable of exporting power onto four 115 kV transmission lines, two of which lead to the north-south corridor in the Texas Panhandle. The Guymon wind plant is a North region wind plant and therefore contributes to the congestion on the north-south corridor. See Figure VI-1.

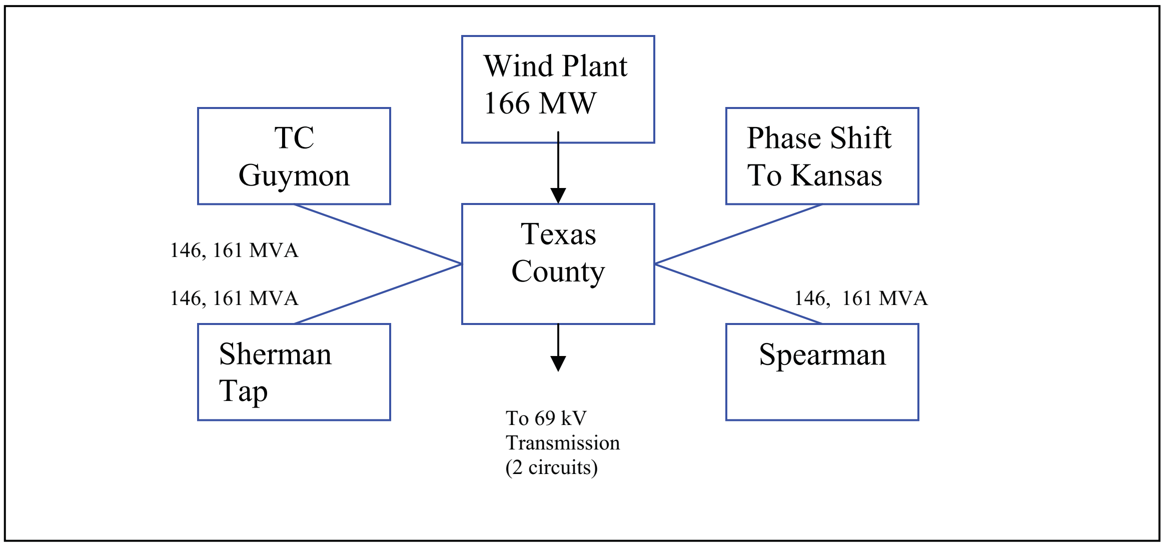


Figure VI-1: The Guymon Wind Plant Interconnection

Dalhart

The Dalhart wind plant is connected to a weaker grid than the other two plants. A 40-45 mile 115 kV loop extends west from the Moore County Interchange, and the point of interconnection, the Dalhart substation, resides at the westernmost edge of the loop. Whereas all of the conductor out of the Guymon interconnection was capable of handling plant output during contingency conditions, the Dalhart wind energy encounters conductor that can handle just over 60% of plant capacity. The Dalhart wind plant is also in the north region.

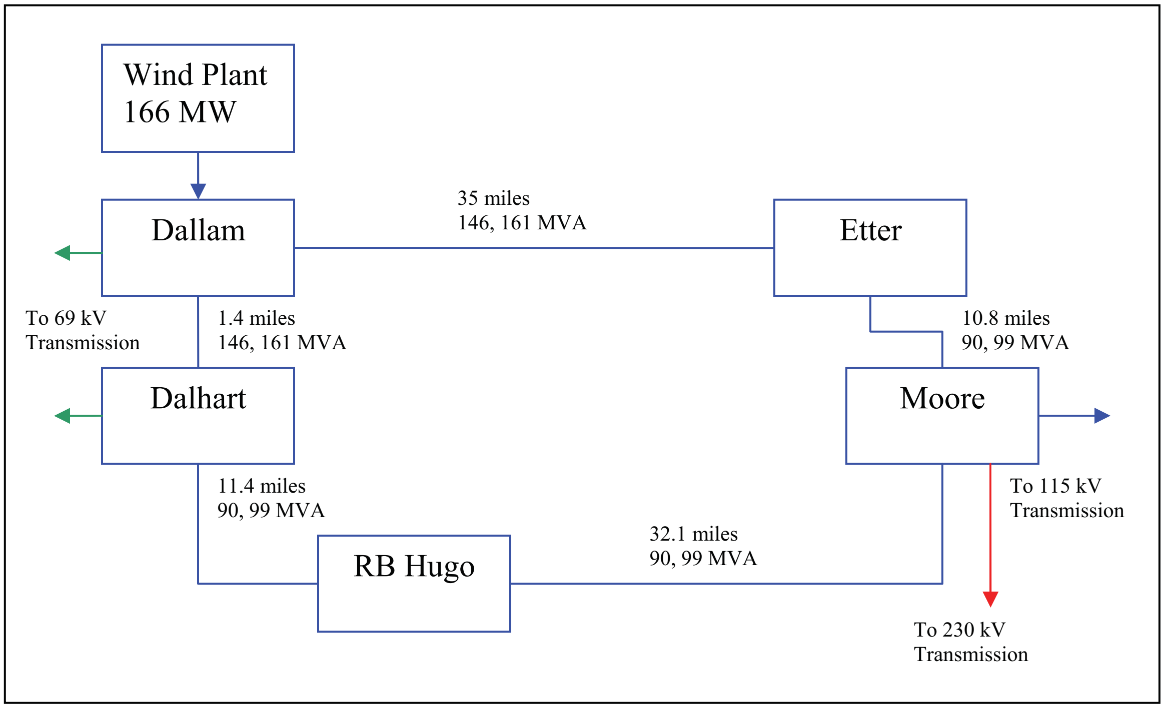


Figure VI-2: The Dalhart Wind Plant Interconnection

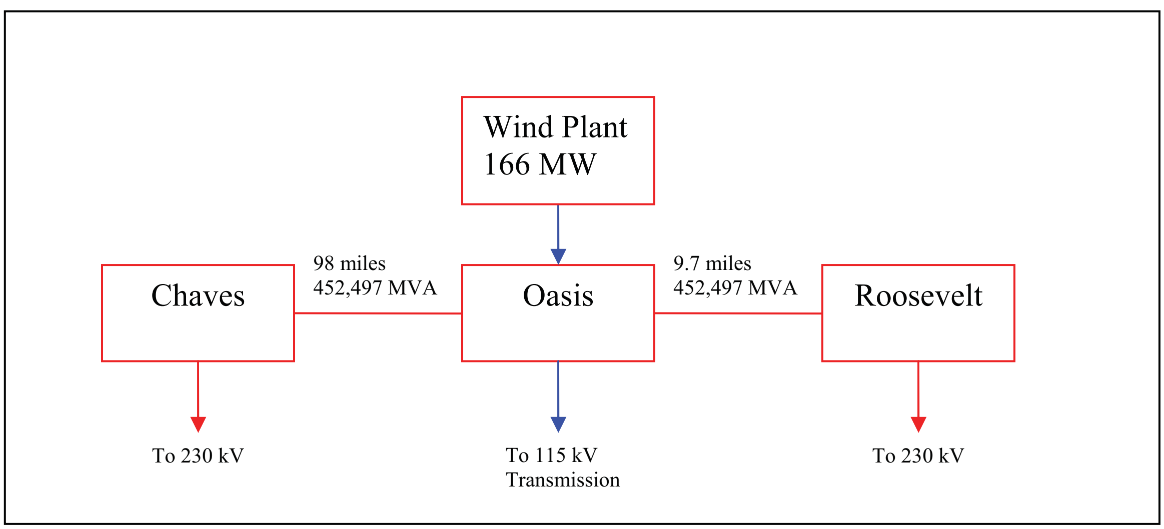


Figure VI-3: Frio Draw Plant Interconnection

Frio Draw

The Frio Draw wind plant is interconnected directly into the 230 kV transmission system near Clovis, New Mexico. Wind injection from the Caprock plant just to the north is injected into this portion of the transmission system as is the San Juan Mesa wind plant near Chaves. None of the wind plants in this region contribute *directly* to the north-south corridor congestion as they reside south of the corridor.

THE CAES MODELS

The CAES plant compression and generation models were interconnected to the 230 kV Tuco interchange as two separate entities for modeling purposes. The Tuco interchange is located just north of Lubbock and connects to the 345 kV transmission extending to Oklaunion. The CAES generator was modeled to provide 270 MW with a reactive range of -112 MVar to 132 MVar. The compression train was modeled at 200 MW with a reactive range of -96 MVar to 96 MVar. The CAES plant was also modeled as a synchronous compensator which can supply or absorb reactive power from the grid. Reactive limits for the synchronous compensator were set to -47 MVar and 122 MVar.

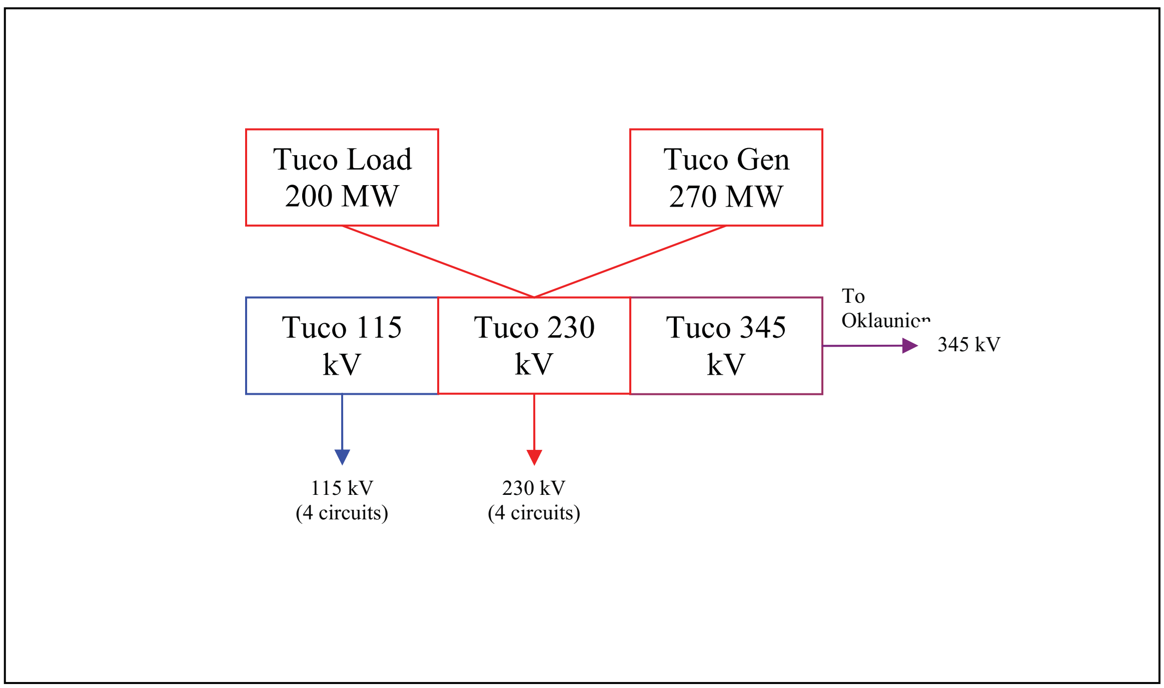


Figure VI-4: The CAES Plant Interconnection

TRANSMISSION ANALYSIS PROCEDURES

The loadflow analysis utilized the Power Technologies Inc. (PTI) Power System Simulator/Engineering (PSS/E) program, Version 30.1. Thermal ratings for normal system intact conditions were held to Rate A, and for contingency conditions, to Rate B. For system intact conditions, voltages above 1.05 and below .95 were monitored. For contingency conditions, voltages below .90 and above 1.10 were listed, though FERC Form No. 715 did not designate an allowable range. The SPS area was the only region which was monitored. Over 900 single contingencies and three multiple contingencies were investigated using AC Contingency Checking (ACCC) steady state analysis with a Fixed Slope Decoupled Newton-Raphson (FDNS) Solution . Only the Tolk and Jones generator contingencies were investigated.

FERC Form 715 states that the Tuco 230 kV bus is not allowed to go below .92 p.u. to minimize the risk of voltage collapse and separation from the Power Pool. It was monitored accordingly. But it was the FERC form 715 north-south flow criteria which had the greatest impact on the analysis. The north-south flow criterion states that there is an 800 MW north to south stability limit for the corridor. The corridor is comprised of three 230 kV and two 115 kV transmission lines as indicated in Table VI-3. With over 570 of wind installed in the northern region the challenge was monitor the corridor and adjust the Harrington-Nichols generation to levels suggested by the market analysis and still accommodate the wind induced flows.

Table VI-3. The Five North-south Corridor Circuits.

North-south corridor Line	Transmission Level
Nichols – Swisher	230 kV
Bushland – Deaf Smith – Plant X	230 kv
Potter County – Plant X	230 kV
Randall County – Kress – Swisher	115 kV
Osage – Canyon – Deaf Smith	115 kV

SECTION VII – TRANSMISSION LOADFLOW RESULTS

SUMMARY

The results of the loadflow analysis can be summarized as follows:

- Portions of the Dalhart Loop transmission system must be rebuilt to accommodate the Dalhart plant, but the other two plants need no additional transmission infrastructure.
- A new 122 mile 345 kV Potter – Tolk transmission line is needed to support full wind plant injection in the north.
- The CAES plant, when operated as a synchronous condenser, can defer or replace the need for dynamic reactive support needed in the Tuco area, and contributes to increased import (and possibly increased export) capability.
- A new transformer is needed at Tuco so that CAES plant generation is not limited during the highest peak hours due to transmission congestion in the area.

During each of the studies, the loadflow generation was set to match the generation stack as much as was reasonably possible given load and transaction level differences between the loadflow and market studies. Different generation and import/export patterns could yield very different results.

SUMMER PEAK LOADFLOW ANALYSIS

For the summer peak loadflow studies, the wind output at all of the wind generators was set to the maximum amount. Although wind analysis indicates that it is unlikely the wind will be operating at full output during the summer load peak, the studies are useful for indicating potential problems under high load scenarios. None of the 8760 data profiles matched this configuration, so final generation patterns for the summer peak did not match the generation stack. The Harrington-Nichols generation, which has the most impact on the North-south corridor, *was* set to reflect the generation stack.

Summer Peak - BaseWind

The original summer peak loadflow included only 16 MW of wind on the system. The Harrington-Nichols generation total was between 1500 and 1600 MW and the north-south corridor was under 500 MW, far below the 800 MW requirement. As BaseWind was added to the system, the SPS generation was scaled back. Wind north of the corridor increased by approximately 230 MW, but Harrington-Nichols generation was reduced, and the net effect was that the north-south corridor flows remained under 500 MW. There were no adverse affects on the transmission system.

Summer Peak - Study Wind

To accommodate 500 MW of additional wind, SPS generation was further reduced. Generators were turned down or off in a way that best reflected the generation stack given that there were significant load, export and wind injection differences between the market and loadflow studies. Although 320 MW of additional wind was added north of the corridor, the combined Harrington-Nichols generation remained above 1300 MW. Corridor totals remained within FERC 715 criteria at just under 750 MW, but several contingency violations were noted. Under system intact conditions, there were no thermal overloads, but low voltages were noted at Swisher and Cox. These buses are on the south end of the corridor.

ACCC contingency analysis pinpointed the need to reconductor the Dalhart Loop. Over 50 miles of looped conductor is rated below 100 MVA, and when a section of the south side of the loop is outaged, conductors on the north side of the loop overload. Similarly, conductors on the south side of the loop overload when the north side is taken out. The smaller conductors were replaced by larger conductors in the loadflow database for all subsequent studies and a transmission improvement value of $2,100,000 was incorporated into the financial analysis. Note the one time transmission improvement is required whether or not CAES is installed on the system, so the additional transmission costs, in effect; cancel out in the market analysis calculations. The Dalhart wind plant is far removed from the CAES plant location, so adding CAES to the system does not remove this transmission upgrade requirement. It is solely associated with the Dalhart wind plant.

Table VII-1. Dalhart Loop Conductors Included in Construction Estimate

From Bus	To Bus	Length (miles)
Moore 50668	Etter 50650	10.8
Moore 50668	RBHugo 50640	32.1
RBHugo 50640	Dalhart 50648	11.4

ACCC contingency analysis also indicated overload conditions on several sections of the north-south corridor lines. The overloads occurred during more than one contingency on the line segments which were rated below 100 MVA. More than 55 miles of 115 kV lines were affected.

Table VII-2. North-south Corridor Contingency Violations

Lines	Emerg Rating	Contingency	Length (miles)
Osage-CanyonNE-CanyonNW	99 MVA	Open Bushland-Deafsmith 230kV	19.4
Randall-Palodu-Happy	99 MVA	(Several)-Amarillo/Kress/Swisher 115 kV and 230 kv	35.3

ACCC contingency analysis also pinpointed low voltage problems in the Swisher area during loss of the Swisher 230/115 kV transformer. The low voltage problems experienced during outage of the Tolk generator were even more significant, falling to below .90 in some areas including the main artery Tuco 345 kV bus. When half of the lost generation was accounted for with SPS generation, rather than relying on the ties importing from neighbors in the SPP, the voltages at Tuco improved, but were still low.

The final contingency which appeared in the Study Wind scenario but not the PreWind or BaseWind scenarios was an overload of the Sundown 115kV/230kV transformer for loss of the Lambco-Hockley 115kV line. Sundown is directly connected to PlantX, and when generation was adjusted at PlantX, the overload condition went away.

Summer Peak - CAES Synchronous Condenser

Adding the CAES plant in the synchronous condenser mode supported the voltages in the region which were low during loss of a Tolk unit. The graph below indicates the level of support as compared to other scenarios. The 50% Tolk imported scenario assumes 50% of the generation which replaces the Tolk unit comes from within the SPS system. The scenario which is labeled "7.2 MVar at Cox" examines the results of installing reactive in the problematic area. As the graph indicates, the CAES Synchronous Condenser raises the Tuco 345 kV and 230 kV above the 0.95 level and also raises the Swisher and Cox voltages (a .95 value is .95 *or* above).

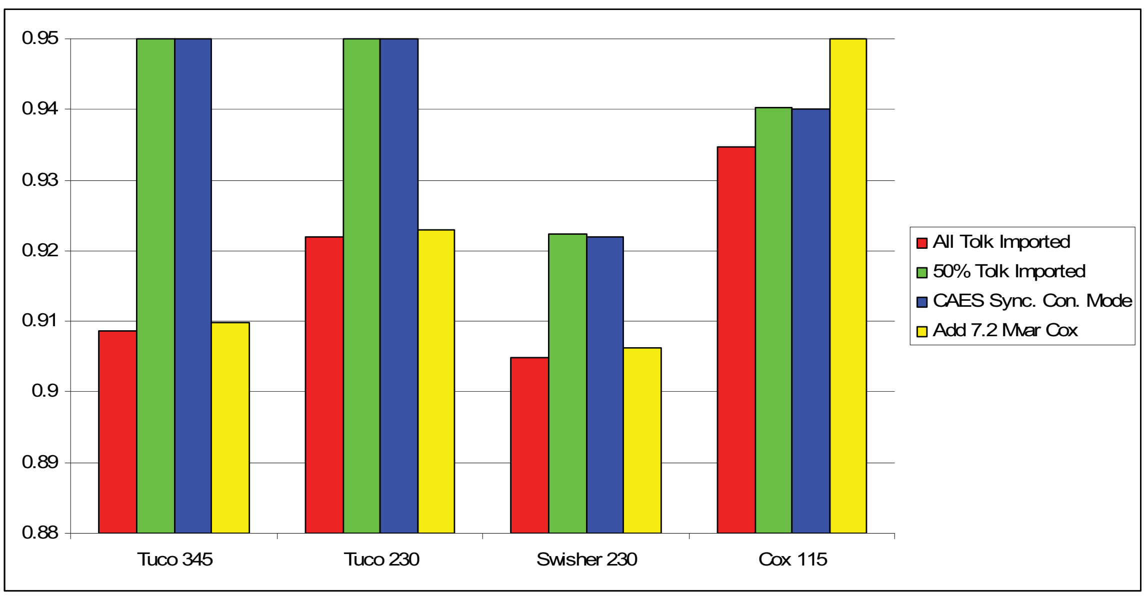


Figure VII-1: Tolk Outage Bus Voltages

The SPP ran a simplified transfer capacity study to evaluate the impacts of a CAES plant running in synchronous condenser mode at TUCO Interchange (TUCO) located north of Lubbock, Texas on the SPS power system. The CAES plant was modeled as a static var controller (SVC) type device. It is common knowledge that SPS has a voltage stability limit associated with the 230 kV bus voltage at TUCO. SPP performed a quick transfer study on the 2006 Summer Peak model out of the 2005 SPP series to determine the transfer impacts with and without an SVC at

TUCO. Their choice of software for the PV analysis was PowerWorld, and the graphs identified in this section were generated from this software package.

For the transfer analysis, a transaction was set up between SPS and the eastern interconnections outside of SPP. All of the SPS units were utilized in the transactions. From previous studies, it has been determined that the most critical contingency in an import scenario was the loss of a Tolk unit at 540 MW, and the most critical contingency in an export scenario was the loss of the Finney to Holcomb 345 kV circuit. Using these as the critical contingencies for comparison purposes, SPP performed the PV analysis and monitored known limiting bus voltages. These buses included the Moore County 230 kV bus, the Potter County 345 and 230 kV buses, the TUCO 230 kV bus, and the Oklaunion (OKU) 345 kV bus. The study was performed without the SVC at TUCO, and then with a +122/-47 MVar SVC and two-50 MVar fixed capacitor banks to help regulate the SVC. The results are summarized with the graphs below.

1) The following chart shows Tolk Outage import scenario without SVC and indicates that the TUCO bus voltage limits the transaction to approximately 880 MW.

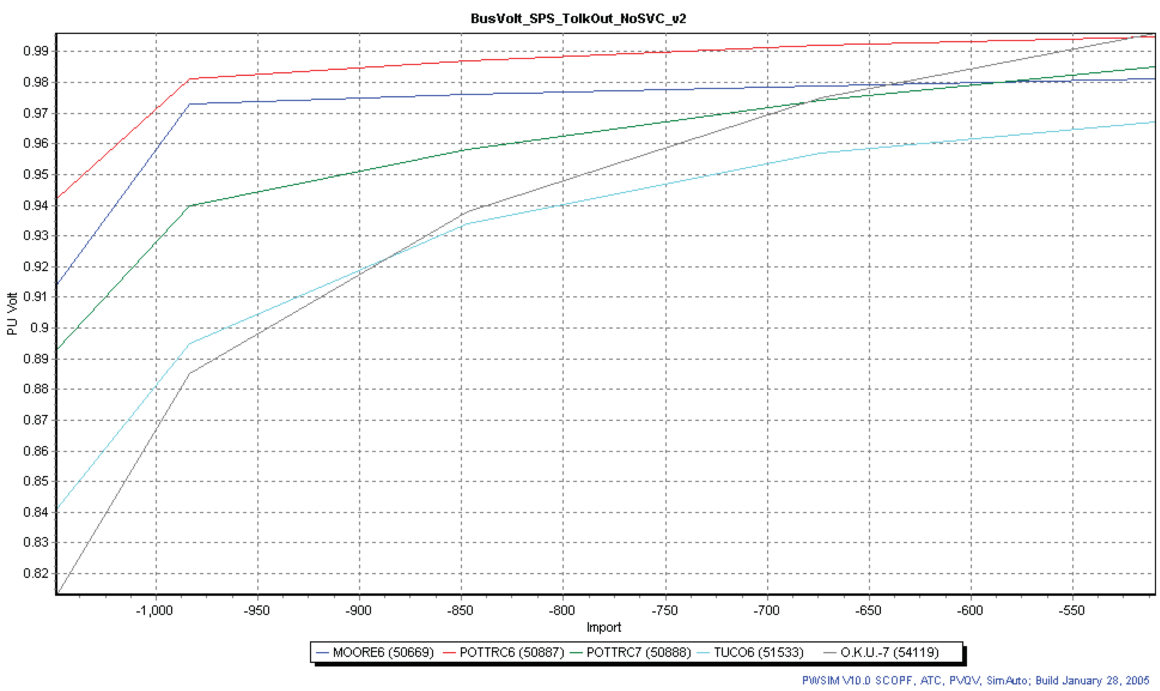


Figure VII-2: Tolk Outage Import Without SVC

2) Import scenario with the SVC and Tolk Outage scenario. Graph shows bus voltages at TUCO and OKU and indicates that the OKU bus voltage limits the transaction to approximately 1030 MW. **Total capacity increased by approximately 150 MW for the import scenario with the CAES plant acting as an SVC.**

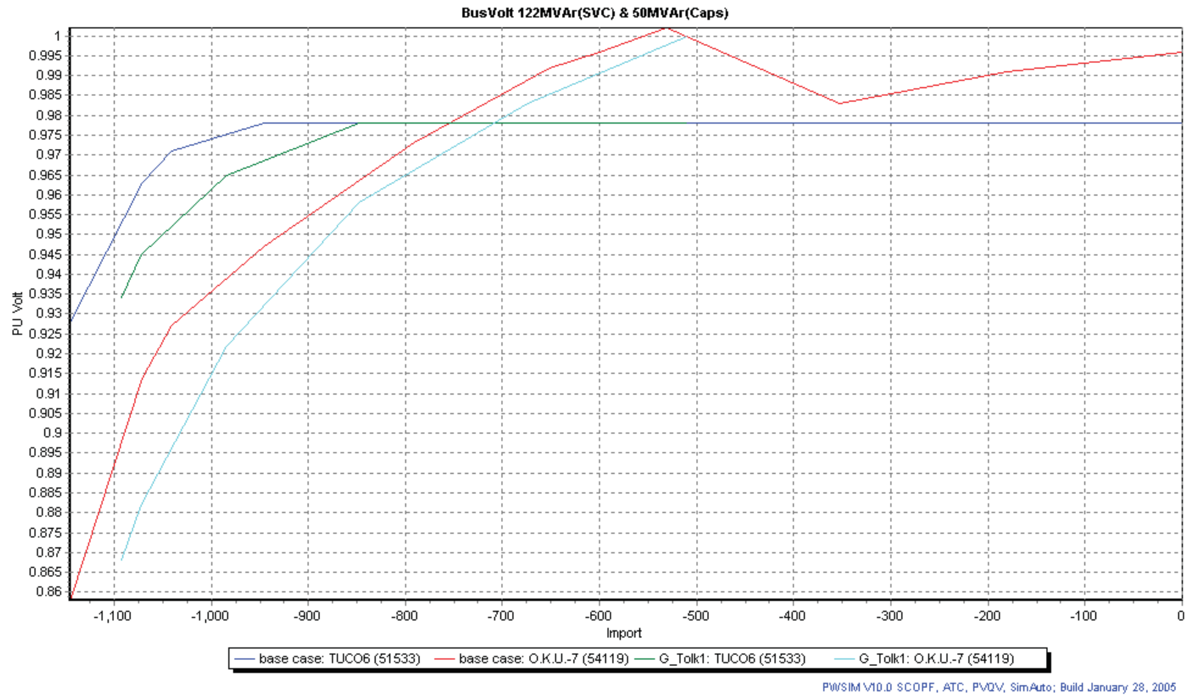


Figure VII-3: Tolk Outage Scenario With SVC

3) Export Scenario – Finney to Holcomb outage without SVC. Figure VII-4 indicates that the TUCO 230 kV bus voltage limits the transaction to approximately 920 MW.

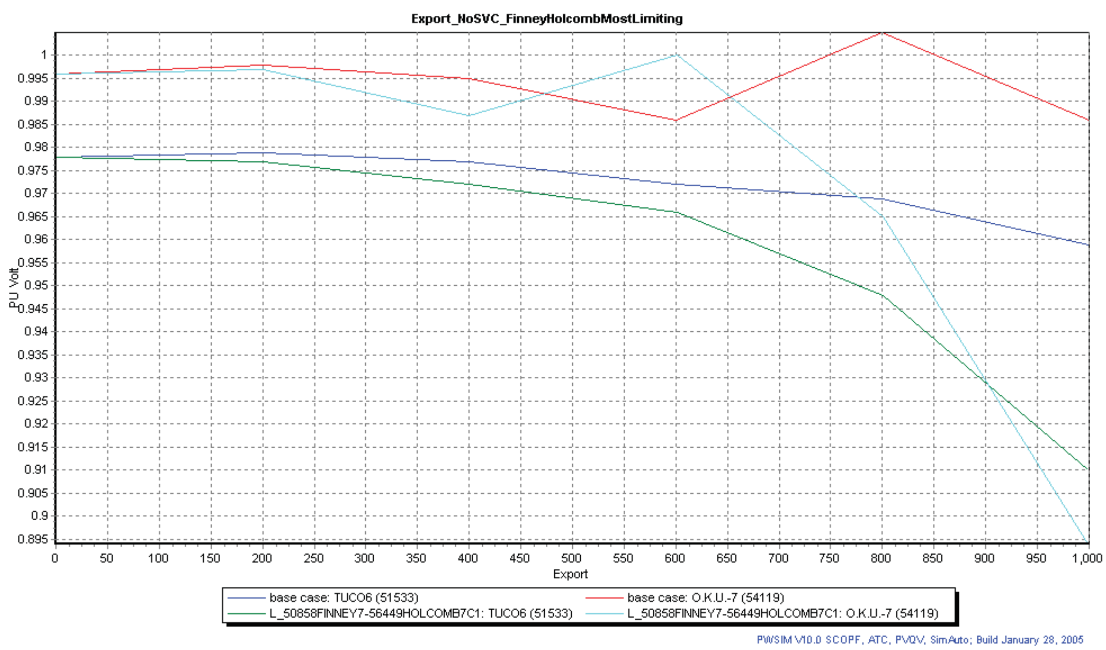


Figure VII-4: Finney to Holcomb Outage Without SVC

4) Export Scenario – Finney to Holcomb outage with SVC. Figure VII-5 indicates that the OKU 345 kV bus voltage limits the transaction to approximately 1035 MW.

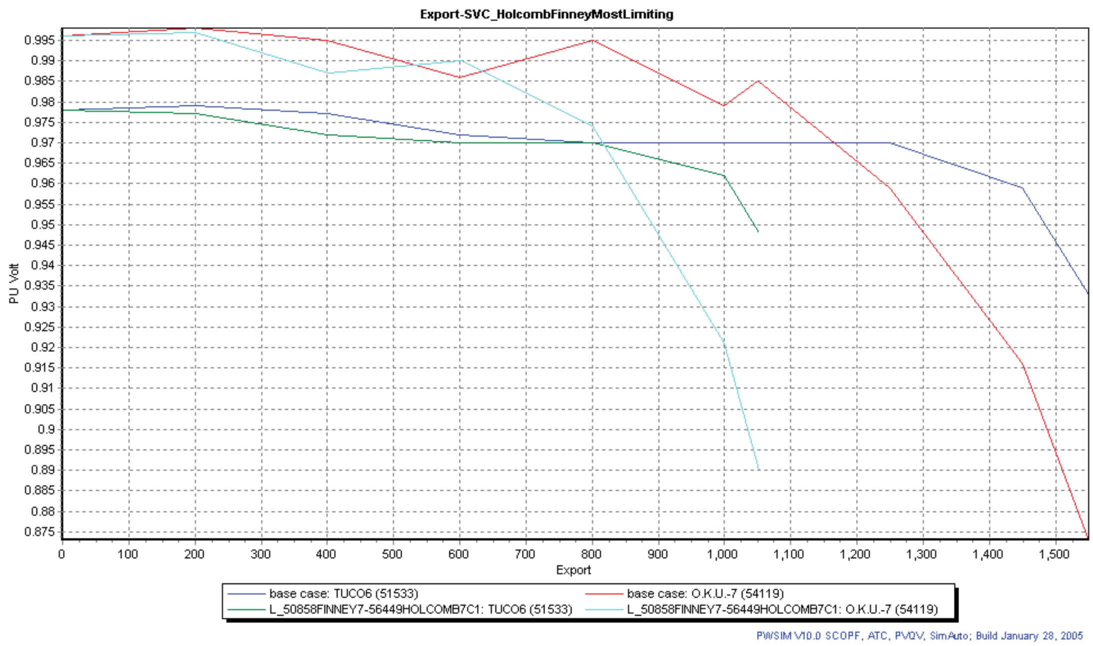


Figure VII-5: Finney to Holcomb Outage Scenario With SVC

Total export capacity appears to have increased by 115 MW with the SVC. Unfortunately there are thermal limits that occur prior to the voltage limits. This comparison does indicate that the CAES plant would have a positive impact on the export scenario.

Summer Peak - Potter to Tolk 345 kV

Although the CAES Synchronous Condenser was beneficial in aiding the low voltage violations noted in high load/high wind conditions, the north-south corridor contingency thermal overloads did not improve. A new 345 kV transmission line from Potter to Tolk was included in this scenario to reduce the corridor congestion. The new 122-mile 345 kV transmission line has been under consideration for some time. The one time construction cost for this line, including substation upgrades, is approximately $36,739,000.

When the Potter to Tolk 345 kV transmission line was included in the summer peak Study Wind analysis, system intact and contingency conditions remained within their compliance values. Specifically, studies indicate the system intact low voltage problems on the corridor at Swisher and Cox were eliminated. The 115 kV north-south corridor lines which were overwhelmed under contingency conditions by the combination of power from the Harrington-Nichols generators and the northern wind plants were no longer overloaded (there was one small infraction of 101% for loss of Amarillo-Swisher 230 kV but the overload responded to minimal north region generation adjustment). Finally, the voltage in the Tuco area during loss of the Tolk generator was greatly improved. During the Tolk outage the 345 kV allowed additional power to flow on the northern SPS ties to the pool, easing the burden on the local ties to the east.

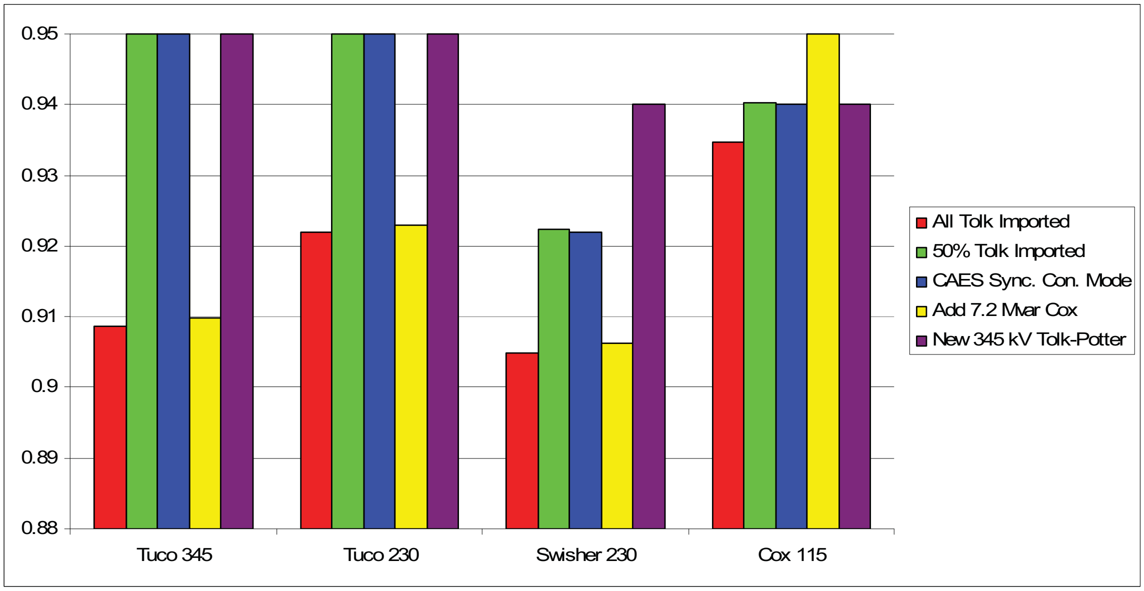


Figure VII-6: Tolk Outage Bus Voltages (New 345 kV Included)

Summer Peak - CAES Plant Generation

The summer peak study scenario pinpointed the probable need for a second Tuco 115/230 kV transformer to support CAES generation during the highest load conditions. Under the single contingency loss of the Tuco – Jones 230 kV transmission line, power from the CAES generator is limited to the two remaining paths: the Tuco to Carlisle 230 kV line and the 230/115 kV Tuco transformer. The Tuco 115/230 kV transformer is rated at 252 MW for both normal and emergency conditions, and the 115 kV transmission line between Tuco and Carlisle is rated at 452 MVA. Transmission flow into the 115 kV transmission system overloads the transformer to 110% of its emergency rating. This contingency overload condition appeared under very specific generation stack, wind injection, SPS export and system load conditions.

In the 8760 dispatch dataset used in the market analysis, there are about 20 hours where the CAES generator is at full output and the load is above 91%, the transformer problem was not noted in the summer shoulder case (91% load) A generation pattern different from the one used to replicate the 8760 data may not require the transformer, but to be conservative in the analysis, a one time cost of $3,500,000 for the new transformer and related work was incorporated into the financial analysis as a cost for the interconnection of the CAES plant.

SUMMER SHOULDER LOADFLOW STUDY RESULTS

The summer peak was appropriate for finding local congestion limitations caused by the addition of the wind plants and monitoring the capabilities of the north-south corridor with wind injection under high load conditions. But another loadflow configuration that was a better match to the

8760 dispatch data was required to look at the CAES plant since its operational characteristics are defined by the wind output and the market conditions. CAES compression at very high load conditions is unreasonable because the wind power would better serve the market. An 8760 dispatch datapoint that represented high wind (approximately 700 MW) at 91% system load was chosen for the CAES operation study. Load in the summer shoulder loadflow was increased from 85% to 91% (scaled proportionally across the SPS system) and the loadflow generation was manipulated to resemble the generation stack. As with the other scenarios, the PreWind intact system and contingency conditions were recorded and the Study Wind case was then developed (though this time with less than the 940 MW of wind).

Summer Shoulder - CAES Compression

The impact of the CAES compression plant was neutral. No system intact or contingency problems which were noted in the PreWind cases were improved by the CAES installation, and no additional problems were noted. A transformer in the Lubbock region appears to overload under several contingency conditions in the PreWind loadflow case. When the CAES plant was operating in the compression mode, the Lubbock transformer overload was worse.

Summer Shoulder - CAES Generation

As with CAES in the compression mode, the CAES generation plant had no effect on the reliability of congestion on the transmission system. The Tuco transformer overload problem noted during the Jones-Tuco 230 kV contingency did not appear in the summer shoulder study.

SPRING MINIMUM LOADFLOW ANALYSIS

The spring minimum loadflow database represents a 53% load situation. Wind analysis indicates that high wind penetration is far more likely under these low load conditions. Once again, it may be unreasonable to expect the wind output to be 100% at the very lowest load hours of the year, but because there is a possibility of such an occurrence the system impacts were analyzed with full wind injection. As with the previous scenarios, the PreWind loadflows were analyzed, followed by the BaseWind loadflows. The Study Wind loadflow results were then compared to the lower wind output study results and problems pinpointed and corrected. Finally, the CAES compression operation was examined. Only the compression mode was studied, the CAES generation plant would not be operating in such low load conditions.

Spring Minimum - BaseWind

The results of the BaseWind Scenario are highly dependent upon how the Harrington-Nichols units are operated. If all of the coal is coming out of Harrington and all of the northern wind is injected into the system, the north-south corridor section from Osage-Canyon will overload during loss of the Bushland-Deafsmith 230 kV line. North region power production exceeds 1300 and this contingency occurs even though total corridor flows remain under 800 at 687 MW.

Changing the loadflow minimum generation to more closely match the generation stack introduced some contingency overload conditions into the Lubbock area. A check of the areas effected show that they are at the most limiting end of the Available Capacity Table with only 14-20 MVA available before the loadflows are altered. The situation was not investigated further, just documented for comparison to the Study Wind scenario

Spring Minimum - Study Wind

The north-south corridor contingency overloads noted in the BaseWind configuration were not noted in the Study Wind scenario. This is because additional Harrington-Nichols units were removed from service to accommodate the Northern region wind, actually decreasing the Northern generation from that seen in the BaseWind study and unloading the corridor slightly (80 MW), but apparently just enough to keep the contingencies from being flagged. A review of the Available Capacity Table does indicate that each problem segment of the three north-south corridor lines (Randall/Palodu, Osage-CanyonE, and Palodu-Happy) have less than 9 MVA available during a limiting contingency event. Because the corridor is so heavily loaded under the high wind conditions, and the summer peak studies indicate a need for the 345 kV line, and any additional generation adjustment at Harrington-Nichols involves backing down cheap coal, the 345 kV line from Potter to Tolk was included in the subsequent analysis.

Spring Minimum - CAES Compression and Synchronous Condenser.

There are no additional transmission compliance problems noted when CAES is operated at a 200 MW compression level. The Tuco transformer contingency is no longer flagged and all other contingencies are comparable to the PreWind and BaseWind analysis. Corridor flows remain well under 800 MW around 500 MW. .

TRANSMISSION STUDY LIMITATIONS

The transmission analysis is based on a very limited investigation of the transmission system; a series of snapshots that may or may not actually represent operation of the transmission system with the specified wind penetration and CAES operation. Studies were limited to replicating a few data points from the 8760 dispatch data, and did not consider altering the generation pattern or transactions in and around the SPS area (i.e. Lubbock). The transmission analysis also did not monitor areas that were outside of SPS.

CONCLUSIONS

The transmission loadflow analysis results indicate the need for transmission improvements to accommodate the additional 500 MW of wind at the designated areas, primarily the need for a new 122- mile 345 kV transmission line. At the location selected for modeling, the CAES plant installation does not mitigate the need for these or other planned transmission improvements, but in fact requires an additional 115kV/230 kV transformer at the Tuco substation. The CAES plant does increase import capability by approximately 150 MW and may increase export capability as well.

SECTION VIII – ECONOMIC VALUE ANALYSIS

INTRODUCTION

The primary method for quantifying the value of storage to wind was the use of production cost analysis. By simulating unit commitment and hourly dispatch decisions, a chronological production costing model is able to calculate the value of various generation options based on avoided cost to SPS.

Avoided cost provides a good proxy for net value of various generation options, though it does not necessarily need to correspond to transfer price. For example, the avoided cost of a block of energy might be shown to be $60/MWh, while the cost to produce that block, including the minimum required rate of return on investment, might only be $40/MWh. The avoided cost does not imply that the fair market value of the block of energy is $60/MWh; it merely indicates that there is $20/MWh of value that can be shared between the buyer and the seller.

The production cost modeling was done with PROSYM. PROSYM is a chronological electric power production costing simulation computer software package produced by Global Energy Decisions and used by several utilities and wholesale power producers all over the country for planning and operational studies. As inputs, the model accepts data on generating units such as fuel costs, heat rate, variable operating and maintenance costs, and startup costs, as well as operating constraints imposed on individual units such as minimum up/down times and maximum ramp rates. Then, based on a weekly projection of hourly loads, the model simulates the unit commitment and hourly dispatch decisions that would have been made to meet the forecast. The most economic hourly dispatch is determined based on operating constraints and the set of generating resources that are specified to be online at that time. The unit commitment module utilizes a sophisticated economic merit ordering routine that stacks the units with lower operating costs with higher priority and iterates to find a unit commitment solution that results in minimized total operating costs. Despite PROSYM's many features, it does have some drawbacks that limited its usefulness for certain areas of our analysis. In our discussion, we have noted those limitations and tried to find other ways to quantify areas of value that we could not model in PROSYM.

To obtain the most effective use of resources allocated to this study, we chose to focus our analysis on a single year, examining in detail the impact of CAES on production costs. We did not have the scope or the resources to do a detailed evaluation of the power system several years into the future, so we started with the assumption that a single year's analysis would provide a reasonable approximation of annual benefits that could be achieved from a CAES plant. We then compared the annual benefits to the annualized cost of a CAES plant to determine whether and in what circumstances an investment in a CAES plant would make sense.

ANNUALIZED CAES COSTS

First, let us establish what it would cost for the envisioned Panhandle area CAES plant. The production cost analysis already incorporates any variable operating costs, such as fuel and variable O&M, so we want to focus strictly on what it would cost to have the plant online and the capacity available for use. The annualized cost includes debt service, fixed O&M, insurance, property taxes, and minimum return on equity investment, after income taxes, including the value of tax breaks on depreciation and interest payments. In order to calculate this annualized cost, we used a cash flow model to solve for the levelized annual capacity "fee" in real dollars that would cover all of the fixed costs and meet the minimum internal rate of return (IRR) targets appropriate for such an investment. We calculated the capacity cost under two sets of ownership assumptions. Under the first set of assumptions, the CAES plant is an IPP financed under a project finance agreement. Under the second set of assumptions where SPS is the presumed owner of the facility, the annualized cost is lower due to access to lower cost debt both during construction and during the project life and lower cost of equity for SPS than for an IPP.

Key Assumptions

Table VIII-1: Capacity Cost Models

	IPP Ownership	SPS Ownership
Overnight Cost	$605/kW	$605/kW
Total Capital Cost (including IDC, financing, development, contingency, working capital)	$765/kW	$744/kW
FOM	$14.07/kw-year	$14.07/kw-year
Inflation/Escalation	1.5%	1.5%
Debt/Equity ratio	70/30	50/50
Project life	25 years	25 years
Debt term	15 years	15 years
Interest Rate	6.5%	5.5%
After Tax Cost of Equity (IRR target)	15%	11.5%
Annualized cost $000's	$30,369	$28,472
Annualized cost $/kw-month	$9.37/kw-month	$8.79/kw-month

PRODUCTION COST MODELING ASSUMPTIONS

Xcel Energy's production costing models were used as the starting point for the production cost analysis. These models were already populated with information about the various types of generating assets, heat rate curves and operating constraints. We added profiles for wind, replaced the profile for load, and set various assumptions for the CAES analysis.

We chose to focus on 2006 as the model year. Although it would not be possible to have a CAES plant online by January 2006, 2006 was a year where the system conditions would be able to be modeled with some certainty. Keep in mind, we were also modeling 500 MW of additional wind in two of our cases, which also would not be developed and constructed by January 2006.

The wind datasets we developed covered the two year time period of July 1999-June 2001. We selected the data for calendar year 2000 as the data we were going to use in production cost modeling and assumed the same profile for 2006. We obtained SPS hourly load data for the matching time period. We then grossed up the load data by 2% per year to account for load growth by year 2006. Finally, we deleted 24 hours of data from the datasets, since 2000 was a leap year, and 2006 is not. We thus created an hourly wind profile dataset that corresponded to the hourly load dataset. By using a grossed up version of 2000 load data rather than Xcel Energy's 2006 forecast, we were able to ensure that any correlations between wind energy and load would be preserved in the data. Contracted power purchase and sale transactions had already been modeled into Xcel Energy's production costs, so those assumptions were left unchanged. No additional off system sales or purchases were allowed in the initial runs, unless they were needed on an emergency basis.

SPS's system is typically modeled using multiple transmission areas to account for a transmission constraint between the north and the south areas of the system, import/export capability, and loop flow. Since we were evaluating transmission congestion in a separate series of load flow analyses which would have its own assessment of congestion costs, we elected to model the SPS system as a single transmission area. However, to make sure that PROSYM dispatched the system in a way that would not compromise voltage or VAR stability, we added unit commitment logic that ensured that certain power plants, which were known to be needed for stability purposes, were committed and online under certain system conditions.

Delivered gas prices were set to \$6.00/MMBtu for all gas plants. For the coal plants, an assumption of \$1.20/MMBtu was used as the fuel price assumption. There were no other material fuel price assumptions.

For the Base Wind Scenario, the impact of the 440 MW of existing/announced wind projects had to be incorporated into the dispatch that was modeled in PROSYM. Generation plants on the system would have to be dispatched to meet the amount of load that was not being served by wind power for each particular hour. We modeled the 440 MW of wind by inputting the 8760 profile of hourly wind energy deliveries and asking PROSYM to treat the wind as a must take, non-firm purchase transaction. This meant that there would be no choice whether or not to accept the wind, and for any hour that wind was being delivered, PROSYM would reduce the dispatch of a power plant or reduce the amount of another dispatchable purchase transaction. Although we modeled the wind as a purchase, we did not assign a price to the wind. The profile for the 940 MW of wind in the Study Wind Scenario was modeled the same way.

For the change cases including CAES, the wind profiles were replaced with the net energy delivery schedules developed with the wind/CAES hybrid dispatch model. The schedules consisted of a "firm" schedule, which was modeled as a must take, firm purchase transaction with no price, a "variance" schedule, which was modeled as a must take, non-firm purchase transaction with no price, and two schedules for operating and spinning reserve provided by the CAES plant. For the change cases, we also modeled CAES using an alternative approach. For the alternative, we modeled CAES using PROSYM's pumped storage module. Rather than providing a schedule for wind/CAES deliveries, we defined the key characteristics for the CAES plant, and the PROSYM model figured out how to dispatch the CAES plant to optimize the system, not just to balance the wind.

RESULTS

Shaping Value

The shaped profiles developed in the wind/CAES dispatch model provided energy that was more valuable to SPS on average than unshaped wind power for both the Base Wind Scenario and the Study Wind Scenario.

Table VIII-2: Value of Shaped Energy Delivery

	Base Wind Scenario	Study Wind Scenario
Increased avoided cost from respective reference case	$14,413,000	$25,792,000
Energy delivered (MWh)	1,744,000	3,561,000
Added Value ($/MWh)	$8.26	$7.24

However, the operating costs (fuel and O&M) for the CAES plant need to be netted out against the production cost savings. When we do this, we found the dispatch strategy chosen for the Base Wind Scenario cost more in gas to the CAES plant than was saved by SPS. However, for the Study Wind Scenario, the net savings from CAES are substantial. CAES becomes more valuable when there is greater wind penetration on the system.

The reason for this is straightforward. Without CAES, more wind would be delivered during off peak or low cost hours than during on peak or high cost hours. Therefore, the more wind that is added to the system, the more likely that off peak prices will be depressed more than on peak prices, resulting in wider spreads between on and off peak prices. Since CAES adds shaping value by moving off peak wind and delivering it on peak, CAES will create more value as those on/off peak spreads widen with increasing penetration of wind.

For each of the cases, we have also compared the results to the alternate approach in which PROSYM developed the dispatch for the CAES plant. Results for the PROSYM module are better than for the defined CAES dispatch strategy in both cases. A graph is shown below summarizing the results for the base gas price assumption, $6/MMBtu, as well as sensitivities of +/- $1.00/MMBtu.

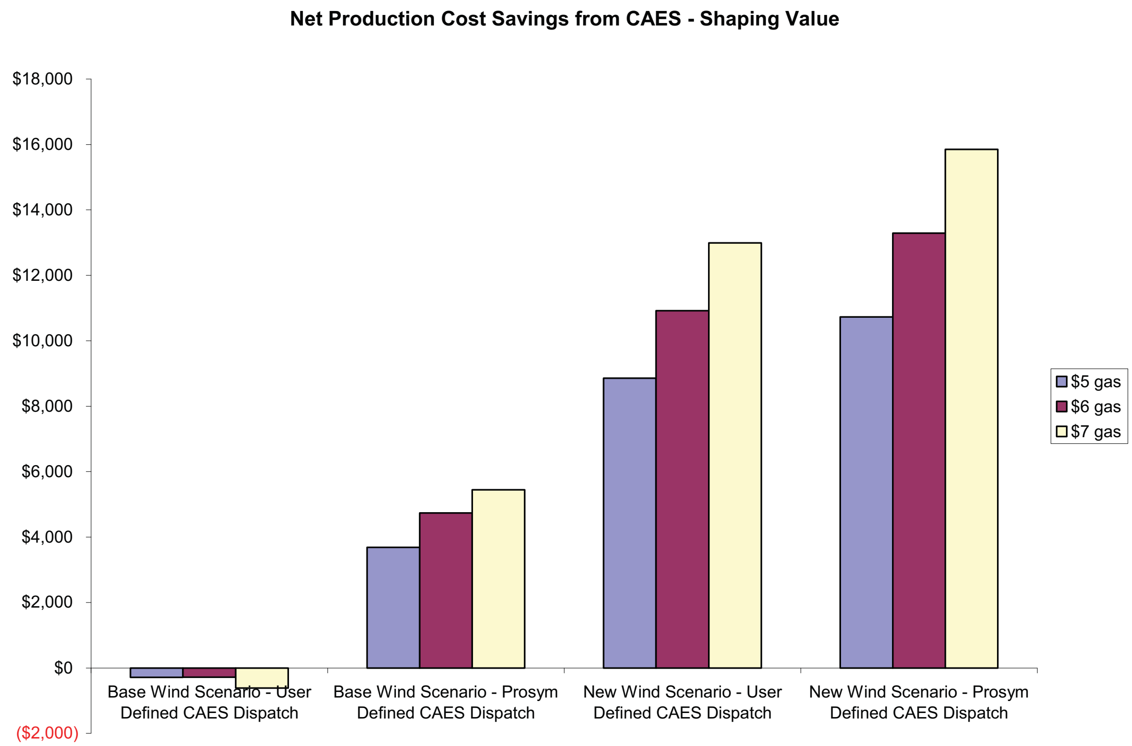


Figure VIII-1: Net Production Cost Savings from CAES – Shaping Value

The production cost savings calculated in PROSYM were higher for the cases where we let PROSYM define the dispatch of the CAES plant. There are several factors for why this is so. First, PROSYM modeled the dispatch of the CAES plant against the entire system, not just the wind. Therefore, if there were on-off peak arbitrage opportunities that had nothing to do with wind, PROSYM was able to model the CAES plant operating to capture those opportunities. The user defined dispatch strategy for the CAES plant was limited to managing wind patterns to fit average load patterns. Furthermore, PROSYM was able to optimize the CAES dispatch on a daily basis, whereas the wind/CAES hybrid model is not as sophisticated and is not able to refine the CAES/wind schedule based on prices or occurrences in the real-time market.

In the Base Wind Scenario with only 440 MW of wind, the PROSYM CAES dispatch was able to show $5 MM more in savings over the user defined CAES dispatch. However, in the Study Wind Scenario, the PROSYM CAES dispatch was only able to show an average of $2.3 MM more in savings than the user defined CAES dispatch. The reason PROSYM is able to do so much better in the base case is that the user defined dispatch limits the CAES plant to managing only 440 MW of wind, as opposed to the incremental 500 MW of wind in the Study Wind case. The CAES plant is thus underutilized in the user defined dispatch for the base case, and the PROSYM dispatch finds additional uses for the CAES plant than just managing the wind.

However, because PROSYM cannot take into account some of the costs associated with forecasting errors with wind (see the next section for the explanation), we built our total economic value analysis for CAES with wind based on the savings from the user defined CAES dispatch rather than the PROSYM CAES dispatch. We presented the results above to show that our analysis probably leaves some value unaccounted for by only focusing on using the CAES plant to manage wind and ignoring additional non-wind related arbitrage opportunities.

Firming Value

One of the shortcomings of PROSYM was that it could not distinguish between forecasted energy and actual energy in determining what the dispatch should look like on the rest of SPS's system. Once a schedule was input into PROSYM for wind deliveries, PROSYM would take that schedule as a definite schedule, and it would plan unit commitment decisions around it. For example, if the schedule said that 100 MW of wind was supposed to be online for the next several hours, PROSYM might not commit a fossil unit to be online for that period that would otherwise have been needed to serve load. The base assumption was that without a forecasting protocol, unit commitment decisions would be made to have enough plants online to serve load without considering the wind. If the wind showed up, then it would back down plants from how they would have been dispatched, but it would not result in taking thermal units offline that have already been committed. If the wind did not show up as planned, then the system would be dispatched as normal. Without some way of firming the wind, this method would result in overcommitment of units. The problem is that PROSYM can't model the overcommitment of units.

The firm/non-firm distinction PROSYM makes in modeling transactions only defines whether or not the transaction can count towards system operating and spinning reserves. A non-firm designation does not make PROSYM commit extra units to serve as backup should the wind not show up. We spot checked several hours in detail to see how PROSYM was dispatching the system. In the example below (for hour ending 6 on 3/8/06), one can see how the system is dispatched to meet a projected load of 2,461 MW. In the Base Wind Scenario reference case 432 MW of wind is being delivered on a non-firm basis. In the change case for that scenario, the CAES plant is being used to back up and guarantee 280 MW of that energy on a firm basis. Despite the change in designation of 280 MW of energy from non-firm to firm, there has been no change in the unit commitment or dispatch for that hour between the two cases. PROSYM does not capture the costs of backing up non-firm wind in its production costing algorithms, thus, PROSYM cannot give a fair accounting for the value that CAES can provide in performing this service.

Table VIII-3: Dispatch Generation Used in PROSYM Model

Base Wind Scenario Genstack No CAES 3/8/06 hr 6		Base Wind Scenario Genstack With CAES (user defined dispatch) 3/8/06 hr 6	
440 MW of wind only		440 MW of wind with CAES, RES dispatch	
aName	**Gen (MW)**	**aName**	**Gen (MW)**
CC 3	80	CC 3	80
CC 4	80	CC 4	80
		Firm Wind/CAES	280
Non firm wind	432	Non Firm Wind/CAES	152
Misc unit 1	11	Misc unit 1	11
Misc unit 2	26	Misc unit 2	26
Gas unit 1	56	Gas unit 1	56
Coal unit 1	333	Coal unit 1	333
Coal unit 2	332	Coal unit 2	332
Coal unit 3	331	Coal unit 3	331
Gas unit 2	24	Gas unit 2	24
CC 1	217	CC 1	217
CC 2	136	CC 2	136
Gas unit 4	57	Gas unit 4	57
Purchase 1	18	Purchase 1	18
Sale 1	(40)	Sale 1	(40)
Sale 2	(35)	Sale 2	(35)
Sale 3	(122)	Sale 3	(122)
Coal Unit 4	525	Coal Unit 4	525
Total	**2,461 MW**	**Total**	**2,461 MW**

In order to assess the firming value of CAES, we had to look at wind integration studies that have tried to estimate the impact on system costs of having suboptimal unit commitment decisions.

NYSERDA's recently published Phase 2 study of wind integration provides an interesting example. The draft report presents results from production cost analysis of the system using GE MAPS. Total reduction in variable system costs, including fuel cost, variable O&M, start-up costs, and emission payments were calculated for an assumed 10% penetration of wind into the system under various sets of unit commitment assumptions.

In one, unit commitment was performed on a day-ahead basis without considering potential wind deliveries, and wind just showed up in the real time markets and backed down units. In another scenario, wind generation forecasts were taken into account in the unit commitment process, and actual wind was modeled in the real time markets. The difference in results was $95 MM in annual system operating costs, or the equivalent of $10.67/MWh of wind energy delivered. While the results are focused on showing the benefit of highly accurate forecasting for firming wind, the numbers do show an example of significant costs that are incurred from using suboptimal unit commitment processes to back up non-firm wind energy.

In contrast, the EnerNex/Wind Logics wind integration study for Xcel Energy's Northern States Power System demonstrates only $4.37/MWh in wind integration costs from modeling day ahead unit commitment decisions that are based on a forecasted wind profile that is very different from the actual wind profile. Upon closer examination of the methodology, however, EnerNex's estimates blend in the costs of forecast error along with the "cost" of having a wind profile that is something other than flat. Since we have already accounted for shaping value in the PROSYM analysis, we cannot use the full $4.37/MWh as a proxy for the value of firming.

The results of these studies are shown below:

Summary table from *WIND POWER IMPACTS ON ELECTRIC POWER SYSTEM OPERATING COSTS: SUMMARY AND PERSPECTIVE ON WORK TO DATE*, presented at AWEA conference, March 2004

Table VIII-4: Wind Integration Cost Estimates

		$/MWh			
Study	Rel. WindPen.(%)	Regulation	Load Following	Unit Commitment	Total
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	0	2.50	3.00	5.50
BPA	7	0.19	0.28	1.00 - 1.80	1.47 - 2.27
Hirst	0.06 - 0.12	0.05 - 0.30	0.70 - 2.80	na	na
We Energies I	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92
Great River I	4.3	3.19			
Great River II	16.6	4.53			
CA RPS Phase I	4	0.17	na na	na	

With a projected value of over $10/MWh from the NYSERDA study, a value less than $4/MWh from the EnerNex/Wind Logics study, and unfortunately, none of our own analysis to make our own projections of firming value, we are forced to pick an arbitrary value as a placeholder for a future analysis. We picked $2/MWh as a conservative estimate of the benefit of firming, which is in line with estimates of wind integration costs associated with unit commitment from other studies.

We assume that the $2/MWh unit commitment savings value applies to all of the energy that is scheduled as firm from the wind/CAES dispatch model.

Table VIII-5: CAES Firming Values

	Base Wind Scenario	Study Wind Scenario
Firming value estimate/MWh	$2	$2
Firm Energy Delivered (MWh)	1,611,000	1,776,000
Total Firming Value	$3,222,000	$3,552,000

Capacity Value

As discussed earlier, the CAES plant provides 270 MW of firm capacity to SPS's system. The value of this capacity can be measured by using the annualized cost of a gas peaker. We used the following assumptions to calculate the cost of a gas peaker, many of which mirror the assumptions used by SPS's sister company, Public Service of Colorado in its 2003 Least Cost Resource Plan. We used a cash flow model similar to what we had used to calculate the annualized cost of a CAES plant to come up with the annualized cost of peaking capacity.

Table VIII-6: Simple Cycle GT Costs

	Conventional Gas Turbine SPS Ownership
Overnight Capital Cost	$430/kW
Annual FOM	$10.74/kw-year
Inflation/Escalation	1.5%
Debt/Equity ratio	50/50
Project life	25 years
Debt term	15 years
Interest Rate	5.5%
Cost of Equity (IRR target)	11.5%
Annualized cost $/kw-year	$75.95

At $75.95 per kW, 270 MW of CAES should have a capacity value of $20.5 million.

Transmission Value

The results from the load flow analysis did not show a benefit from marrying CAES with wind in this particular situation. With the Base and Study Wind Scenarios having diversified wind farm locations over a wide geographic area, and without having a cluster of wind creating significant problems on the grid, the location we picked for the CAES plant did not provide any strategic benefit to the wind farms.

However, the capabilities of the CAES plant were shown to have positive impacts on the grid in general. Specifically, the ability of the CAES plant to operate in synchronous condenser mode and provide reactive power to the grid was shown to be beneficial in increasing SPS's capability to import power from the rest of SPP by 150 MW. The reactive capabilities of the CAES plant were also shown to have potential to increase export capability from SPS to the rest of SPP, but the analysis was not confident enough for us to include the benefits of any increased export.

This increase in import capability was valued through a PROSYM sensitivity. In order to calculate the benefits of allowing 150 MW of additional economy purchases from the rest of SPP, we had to create a new base case since our original assumptions did not allow SPS to make any economy purchases. We created a new reference case for each of our wind/CAES scenarios allowing economy purchases up to the existing transmission limits already built into the model. Then we defined the transmission limit as being 150 MW greater than before, and performed a sensitivity allowing economy purchases to be made up to the new transmission limit. The model already had a market price forecast for SPP built in, so we just used the existing market price forecast to determine when the economy purchase transactions would occur. The difference between the sensitivity and the new base cases provided the value of improved transmission flow from the rest of SPP to SPS.

Table VIII-7: Import Energy Value (000's)

	Base Wind Scenario	Study Wind Scenario
Savings from add'l imports	$5,778	$4,282

Note that the savings from additional imports were lower in the Study Wind Scenario than in the Base Wind Scenario. The reason for this is that the 500 MW of additional wind in the Study Wind Scenario pushes SPS's system production costs lower down the generation stack. Since average generation costs are lower in the Study Wind Scenario than in the Base Wind Scenario, there is less benefit from being able to purchase from the market when market prices are lower than SPS's system costs.

The loadflow analysis also indicated the potential need for a second transformer at the Tuco substation to support CAES generation during high load conditions. The transformer would cost SPS as the transmission utility about $3.5 MM to construct. For transmission improvements, a recent SPS cost of service study indicates that the annual revenue requirement tends to be approximately 14% of the initial capital investment. Using the 14% capital charge, the new transformer would translate into an annual system cost of $.49 MM. While it is unclear whether or not those costs would be direct-assigned to the CAES plant, we have included the whole amount as a reduction to the total transmission related benefit. If a study of CAES were to move further to the detailed investigation and optimization of potential CAES sites in the SPS control area, it may be possible that alternate siting would result in different transmission upgrade costs associated with CAES.

Table VIII-8: Import Energy Savings Adjusted for Transforma (000's)

	Base Wind Scenario	**Study Wind Scenario**
Savings from add'l imports	$5,778	$4,282
New transformer	($490)	($490)
Net Transmission Benefit	$5,288	$3,792

Net CAES Value

The total economic benefit for using a CAES plant in conjunction with wind is tallied in the tables below. For the net shaping value, we have used the savings estimates that came from the defined CAES dispatch, not the PROSYM dispatch. As discussed in the section on shaping value, this approach probably leaves some savings unaccounted for by ignoring additional non-wind related arbitrage opportunities that could be captured by CAES.

Table VIII-9: IPP Ownership CAES Value (000's)

	Base Wind Scenario	Study Wind Scenario
Net Shaping Value	($283)	$10,918
Firming Value	$3,222	$3,552
Capacity Value	$20,507	$20,507
Additional Imports	$5,778	$4,282
New Transformer	($490)	($490)
Total Annual Value	$28,734	$38,769
Annual CAES Capacity Cost (IPP ownership structure)	($30,369)	($30,369)
Net CAES Value / year	($1,635)	$8,400

While the saving for both cases are significant, only in the Study Wind case do the annual estimates of value and savings exceed the annualized cost of the CAES plant. However, when we look at the results using the annualized cost of a CAES plant assuming SPS ownership, the story looks different.

Table VIII-10: SPS Ownership CAES Value (000's)

	Base Wind Scenario	Study Wind Scenario
Net Shaping Value	($283)	$10,918
Firming Value	$3,222	$3,552
Capacity Value	$20,507	$20,507
Additional Imports	$5,778	$4,282
New Transformer	($490)	($490)
Total Annual Value	$28,734	$38,769
Annual CAES Capacity Cost (SPS ownership structure)	($28,472)	($28,472)
Net CAES Value /year	$262	$10,297

The savings that SPS could obtain from the use of a CAES plant to manage the 440 MW of wind that it has agreed to buy is enough for SPS to pay for a CAES plant, earn a fair rate of return on the investment, and still have some value left over to deliver net rate reductions to its customers. If SPS were to look at purchasing an additional 500 MW of wind, the value proposition for using CAES to integrate the wind would be even more compelling.

Comparison of the results under different CAES ownership assumptions clearly indicates that SPS would have lower costs of ownership for a CAES plant than an IPP would have, and therefore SPS would have greater ability to generate net savings from a CAES plant through ownership of the facility rather than through contracting with an IPP. On the other hand, a contract with an IPP for a CAES plant would allow SPS to shed some of the technology and operational risks onto a third party, similar to what it is currently doing with its wind contracts.

For the Base Wind Scenario, IPP ownership of a CAES plant to manage the 440 MW of wind is not expected to be economic, while SPS ownership of a CAES plant is expected to generate net savings for ratepayers. In the Study Wind Scenario, the value to be gained from using a CAES plan to integrate 500 MW of Study Wind is large enough under both SPS and IPP ownership structures that there is room to consider laying off risk onto an IPP that owns the CAES plant.

Comparison to Alternative Resources

So far, the economic analysis has focused on comparing production cost and other benefits of CAES, and comparing them to the annualized cost of building the CAES plant itself. Another approach focuses on the Study Wind Scenario – the integration of CAES with 500 MW of Study Wind resources. We have shown that, operationally, CAES can be dispatched with wind such that the net output imposes few integration issues with the rest of the grid. So, if one could put wind and CAES in a black box and sell the output as a combined product, one could create a virtual, dispatchable power plant, that happens to have renewable characteristics. What happens when we attempt to value and cost out the wind and CAES together, rather than just focus on the added value of CAES?

The Study Wind Scenario involved the operational integration of 500 MW of wind in three wind farms with 270 MW of CAES in a central location. If an investor were to construct the 500 MW of wind along with 270 MW of CAES and sell the output under one contract, pricing for the energy and capacity delivered would need to reflect return on investment in the capital costs of the wind farms and of the CAES plant, as well as variable costs associated with the wind farms and particularly with the expected operations of the CAES plant to deliver the type of shaping services that would be necessary.

In today's environment, pricing for wind power reflects the benefits of a federal production tax credit. Anecdotally, for the quality of the wind resources available in New Mexico, Texas, and Oklahoma, pricing for wind contracts has ranged from \$20 to \$30/MWh on a take-or-pay basis for all the energy produced by the wind farm as well as any associated environmental attributes such as renewable energy credits. We assume that at \$30/MWh, an investor in the 3 wind farms in the Study Wind Scenario would be able to finance the wind farms and get a minimum return on investment in the project, also assuming that the federal PTC gets extended into the future.

Operationally, the CAES plant is expected to cost \$14.873 MM per year to cover the variable O&M and fuel costs at \$6.00/MMBtu to shape the 500 MW of wind into an acceptable product. The CAES plant would also require \$30.369 MM to cover annual fixed costs and to provide a return on debt and equity investment in the project (under an IPP ownership structure). The combined CAES/wind project would produce a total of 1,924 GWh of energy. Of the energy produced, 1,816 GWh would have been the annual production from the wind farms alone – the production of an additional 108 GWh of energy is due to the use of natural gas in the CAES regeneration process.

Under these assumptions, the output of a combined CAES/wind project would cost \$51.83/MWh of delivered energy, or a \$21.83/MWh premium over the base pricing for wind. However, in contrast to wind only, the delivered energy from the CAES/wind project would be firm, be shaped to meet load profiles, have long term capacity value, and would cause less burden on system costs for integration, ramping, and other ancillary services.

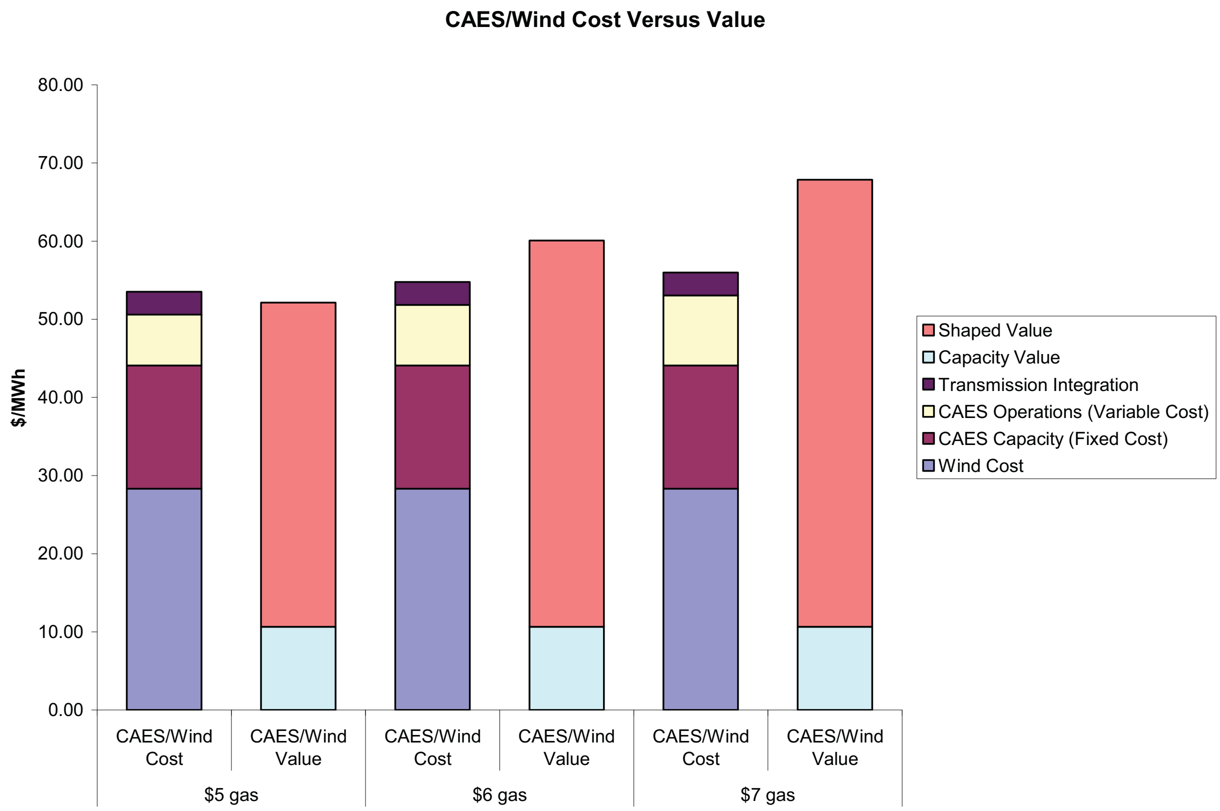
The loadflow analysis indicated that under the current planning criteria, a new 122 mile 345 kV transmission line from Potter Interchange to Tolk Station would be needed in order to integrate 940 MW of wind into the grid. At a construction cost of $36.7 MM, it is not the least cost solution; however, it seemed to be the most practical one since it was also needed to solve other problems existing on the grid that have nothing to do with wind. Unfortunately, the application of CAES was not shown to reduce the need for this line. At a 14% capital charge, the annualized cost associated with this line would be about $5.1 MM.

Since the line is needed for other purposes in addition to integrating the 940 MW of wind, it does not seem reasonable that all of the costs of that line would be direct-assigned to the 500 MW of Study Wind. However, we did just that in order to be most conservative. This along with the cost for the new transformer to support CAES, added a total of $2.93/MWh to the average lifecycle cost of a hybrid wind/CAES project.

Wind/CAES gen cost		Annual Cost ($000s)
Wind cost	@30/MWh	54,480
CAES Operations		14,873
CAES Capacity		30,369
Total		**99,722**
Average Cost - $/MWh		51.83
Premium over wind cost		21.83
Transmission Integration		Annual Cost ($000s)
Potter - Tolk 345 kV line		5,143
New Transformer		490
Total Transmission Integration		5,633
Total gen + trans cost		105,356
Average Transmission Cost - $/MWh		2.93
Average Total Cost $/MWh		54.76

Based on the avoided cost to SPS, the PROSYM analysis provides some insight into what the value of the integrated wind/CAES output might be. So far, our presentation of results showed the difference between the "no CAES" and "with CAES" cases for the Base Wind and Study Wind Scenarios individually. If we compare the Study Wind Scenario with CAES to the Base Wind Scenario without CAES, that should provide a measure of the value of adding 500 MW of Study Wind coupled with a CAES plant, compared to the assumed starting position, which is SPS with 440 MW of wind in its system. The PROSYM analysis showed $95 million of variable cost savings when 500 MW of wind and 270 MW of CAES were added to the system, or $49.41/MWh. The $20 million in capacity value from having a contract with the CAES plant is worth $10.66/MWh. So, only looking at shaping benefits and capacity benefits, we obtain a value of $60.07/MWh for the wind CAES production, a significant margin over the cost of

$54.76/MWh. Note that we have not included the value to SPS of the firming benefits or of the additional import capability, nor have we made any assessment as to any value associated with the renewable attributes of the wind itself, such as the value of any tradeable renewable energy credits or emissions reduction benefits. The graph below compares the cost of the combined wind/CAES output with the shaping and capacity value under a range of gas price assumptions.



Notes: CAES capacity cost assumes IPP ownership
Wind cost per MWh is equivalent to $30 base wind cost divided over total wind/CAES output (including incremental production from natural gas)

Figure VIII-2: CAES/Wind Cost Versus Value

It is useful also to compare the costs of the combined CAES/wind project with the costs of new thermal generation capacity. To evaluate the costs of various generation technologies, we used the following assumptions, many of which are the assumptions used by SPS's sister company, Public Service of Colorado in its 2003 Least Cost Resource Plan. In our models, we added estimates for development costs, working capital, financing and IDC costs, as well as for property taxes and insurance. The financing assumptions for the thermal generation assets are based on SPS ownership, though the cost of the CAES/wind project is based on IPP ownership. The table below shows the main assumptions which were originally in 2003 dollars – we have assumed that the numbers are still the same for 2005 dollars. The highlighted section of the table shows the results, which is the annualized cost of capacity in 2005 dollars.

Table VIII-11: Comparison CAES/Wind to Other Generation Options

	Conv. CT	Conv. CC	Adv. CT	Adv. CC	IGCC	Pulv. Coal
Overnight Capital Cost ($/kW)	430	563	483	639	1,800	1,400
Annual FOM	10.74	12.28	8.58	10.74	35.43	25.76
Inflation/Escalation	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Debt/Equity ratio	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Project life	25	25	25	25	35	35
Debt term	15	15	15	15	20	20
Interest Rate	5.5%	5.5%	5.5%	5.5%	5.8%	5.8%
Cost of Equity (IRR target)	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Annualized cost $/kw-year	75.40	96.30	80.20	104.96	300.00	233.50
VOM	4.30	2.14	3.23	2.14	2.14	3.23
Fuel Cost $/MMBtu	6.00	6.00	6.00	6.00	1.20	1.20
Heat Rate at 100% output	10,450	7,000	8,550	6,350	8,500	9,500

The lifecycle cost per MWh can be calculated by taking the annualized capacity cost, dividing by an assumed capacity factor, and adding the variable costs for fuel and variable O&M. The following graph compares the net costs for the various generation technologies, assuming an 80% capacity factor, to the costs for the combined wind/CAES project. To compare apples to apples, in this analysis, we have not included transmission integration in the wind/CAES project costs, because we do not have transmission integration costs for the thermal generation technologies we are comparing to.

Even at $6 gas, the wind/CAES costs are less expensive than other gas fired technologies, and it beats IGCC, and is only about $4 more per MWh than a conventional pulverized coal plant. No assumptions are made for carbon taxes or emissions costs, which would change the relative cost positioning of wind/CAES against coal.

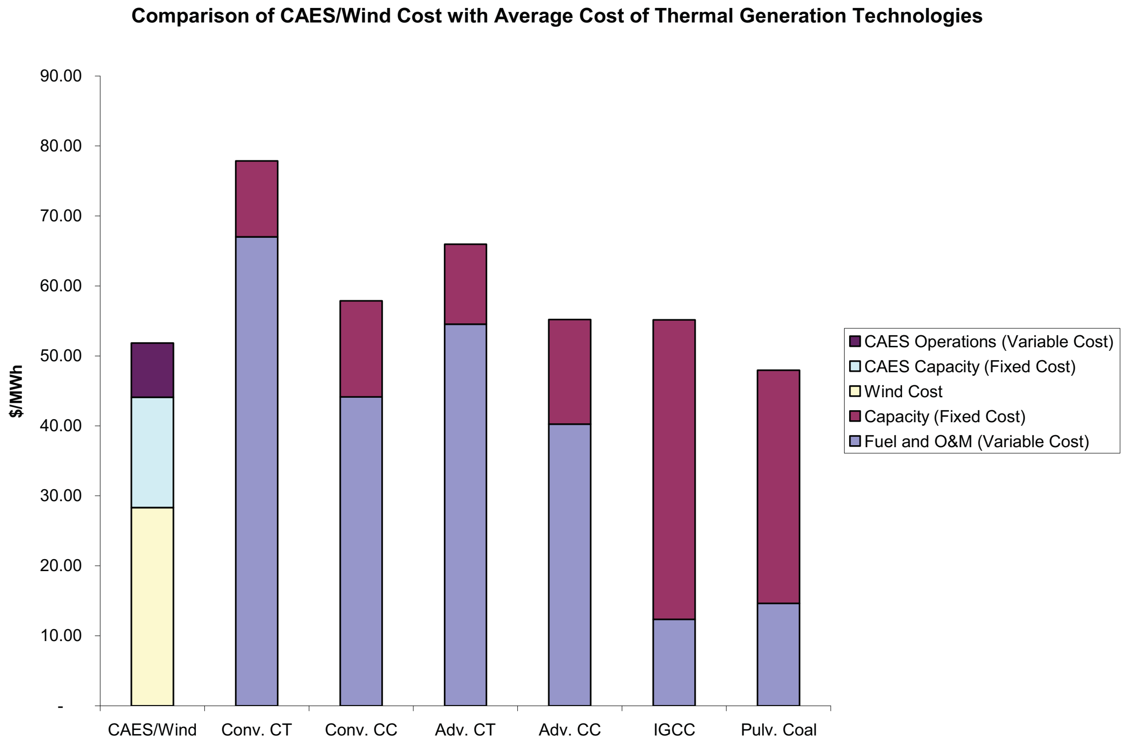


Figure VIII-3: Comparison of CAES/Wind Cost with Average Cost of Thermal Generation Technologies

When comparing CAES/wind costs with lifecycle costs from plants running at a 60% capacity factor, which is perhaps more realistic for the combined cycle plants, CAES/wind appears even more competitive compared to conventional generation. No adjustments were made to heat rate to account for degradation associated with running the plant at a suboptimal efficiency.

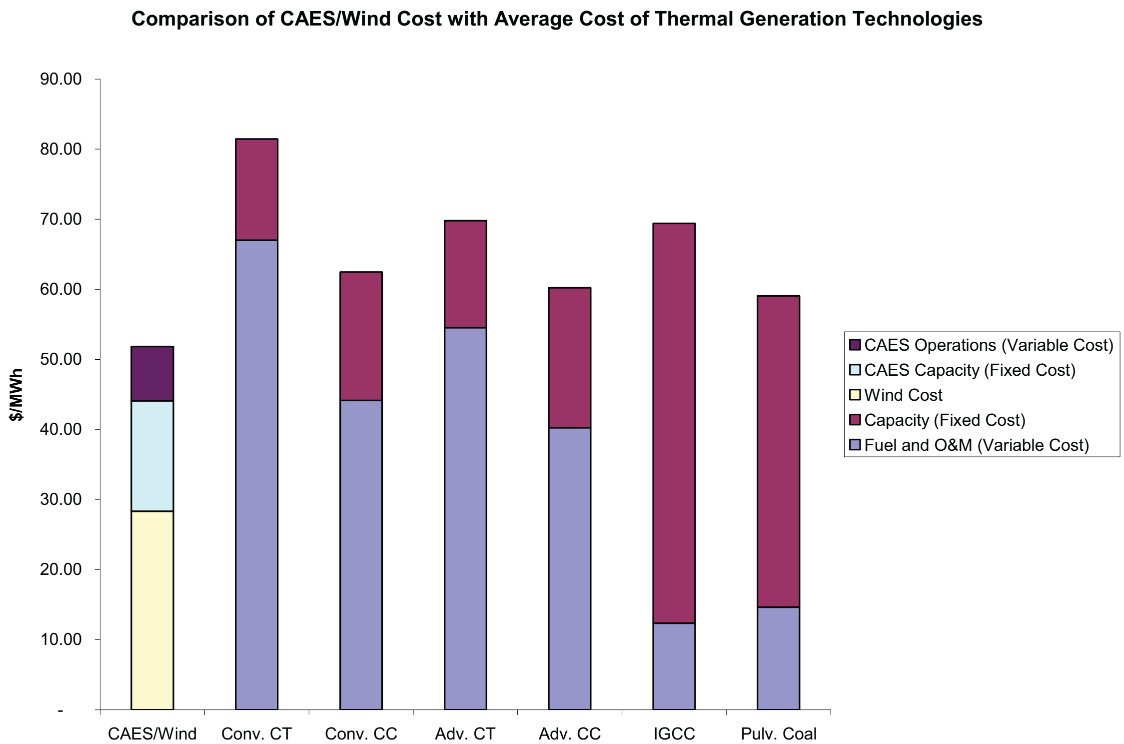


Figure VIII-4: Comparison of CAES/Wind Cost with Average Cost of Thermal Generation Technologies

In a $5/MMBtu gas price environment, and again assuming 80% capacity factors on the traditional thermal generation technologies, the costs of wind/CAES converge with the cost of a brand new conventional gas-fired combined cycle plant. However, 80% capacity factor assumptions might not be realistic for a new gas-fired plant.

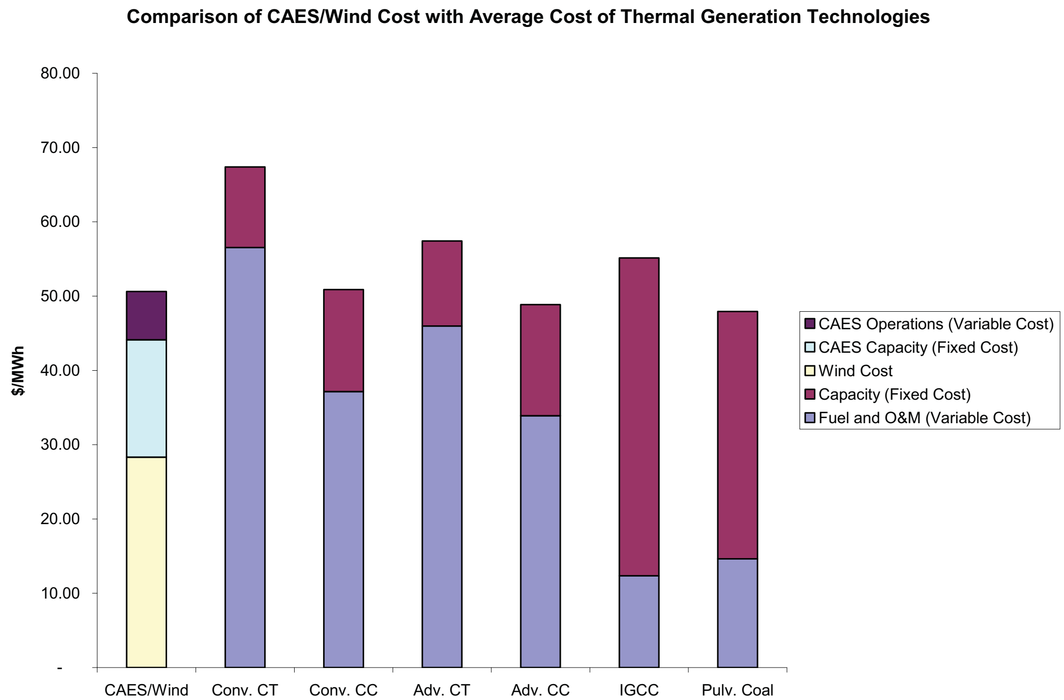


Figure VIII-5: Comparison of CAES/Wind Cost with Average Cost of Thermal Generation Technologies

CONCLUSION

In summary, the economic analysis shows that there is value to be generated from using energy storage in conjunction with wind resources in the Panhandles of Texas and Oklahoma and the eastern plains of New Mexico. Value can be created by a 500 MW CAES plant by providing firming services, shaping services, long term capacity benefits, and improved transmission flows in two scenarios: first, where the CAES plant is being used to manage 440 MW of wind that SPS has agreed to contract for; and second, where the CAES plant is being used to facilitate the integration of an additional 500 MW of Study Wind. In the first scenario, however, the annual benefits provided by the CAES plant only justify the investment cost in a CAES facility if SPS can leverage its low cost of capital by actually owning the plant. However, in a scenario where the CAES plant is coupled with 500 MW of Study Wind, the benefits provided by CAES can allow for third party ownership of the plant under an IPP financing structure. By treating the CAES plant and Study Wind as a single project, it is also possible to compare the per MWh costs of the net delivered energy to the costs from conventional thermal generation and show that a combined wind/CAES project would be a highly competitive alternative to consider when adding new physical generating resources to the grid.

SECTION IX – INSTITUTIONAL BARRIERS AND OPPORTUNITIES FOR ENERGY STORAGE

INTRODUCTION

Regulatory issues have been a key driving force for the development of wind across the country. Regulations and market rules serve both to encourage and to discourage the development of wind power resources and may have similar impact on the development of complementary energy storage.

National level, state level and NERC level rules and conditions have the most impact on encouraging and discouraging wind development in the region of focus.

NATIONAL FACTORS

The key factors encouraging the development of wind resources in the region of study are the quality of wind resources together with a high gas price environment, and a federal production tax credit (PTC) that makes wind power a competitively priced generation resource. SPS has already committed to purchase the output of 440 MW of wind, approximately 10% of its system measured as a percentage of peak load. This amount is significantly higher than any regulatory requirements to do so – they now have economic reasons to get ahead of the game.

The viability of energy storage with wind is very strong when one considers the addition of additional wind and storage at $51/MWh versus the addition of alternative fossil fuel generation at $48 to $80 per MWh. The $51 pricing assumption is dependent on the continuation of the federal PTC. Without a corresponding reduction in the cost of wind turbine equipment, therefore, it is likely that the PTC would have to be extended for energy storage to be viable as a complement to wind in the Panhandle area.

STATE INCENTIVES FOR WIND DEVELOPMENT

Texas

Texas has a renewable portfolio standard that was put into place as part of Senate Bill 7, the law that deregulated the retail electricity market in most parts of Texas. According to the standard, Texas just have 2,000 MW of new renewable generation in place by 2009. The Texas Public Utilities Commission (PUC) translates the renewable MW requirement into an annual MWh requirement already using a capacity factor based on the actual capacity factor of renewable facilities on the grid. The PUC then allocates the requirement to Load Serving Entities (LSEs) based on their load ratio share. A number of entities, such as municipal power providers, are not opted into competition, and thus are not subject to the renewable requirement; however, many of them have voluntary renewable programs and are significant purchasers of wind energy.

A system of tradeable renewable energy credits (RECs) allows LSEs to meet their renewable requirements without having to contract for wind power directly. This system also creates additional business opportunities for entities that can contract for more wind than they need and sell the extra RECs into the marketplace. In the deregulated retail market for electricity, voluntary green pricing programs create a demand for RECs above and beyond the regulatory requirement.

Currently, three bills have been introduced in the Texas legislature to increase the renewable portfolio standard, however, any additional requirements would not change the current schedule.

Oklahoma

At this time Oklahoma does not have a renewable portfolio standard (RPS). Renewable energy proponents supported an RPS bill in 2003 and 2004, but neither was successful in gaining even committee support. A RPS is supported by renewable energy producers and manufacturers as a means to ensure a renewable energy market in Oklahoma. However, there are adamant opponents to a RPS. Utility companies argue that without an adequate and reasonably priced transmission system a RPS is prohibitive. Traditional energy proponents are unfriendly to mandated market changes. And, many Oklahoma politicians are not supportive of government interference in the free market. Near future energy policy will unlikely contain an RPS, but may include a variety of renewable energy incentives for production.

As of this current legislative session, state government incentives are minimal for wind development, production and use. Oklahoma does have a state production tax credit for large wind farms, over 50 MW. It is an excellent means to encourage large-scale production, but does not promote small wind development. Further, term limits for state representatives and senators came into effect for the first time this past election resulting in a very large turnover of legislators. It is yet to be seen how this will affect future policies. Currently in committee is a bill from Representative James Covey, a leading proponent of renewable energy in Oklahoma, which would create the Renewable Energy Electric Generation Cooperative Act. This act would allow small farmers to form renewable energy cooperatives and sell wind energy. While passage of the act is unlikely, this bill is an example of the emerging interest and support of small communities to support wind energy production.

Another driver for wind developers comes from local economic development councils in the form of tax credits or incentives. These incentives are locally determined and vary to the size and impact of a potential farm.

Despite the lack of a state RPS, the Oklahoma Corporation Commission has supported the development of green pricing programs to encourage utilities to contract for wind and other renewable energy on a voluntary, market-driven basis.

New Mexico

New Mexico has several incentives in place to encourage the development of wind power and other renewable energy. The Public Regulation Commission (PRC) adopted Rule 572 in December 2002 which contained RPS provisions. The rule requires investor owned utilities to procure or generate an increasing percentage of their total retail electricity sales from renewable energy. The RPS Standard is 5% by 2006, increasing by 1% per year until the standard hits 10% by 2011.

In addition to the RPS, New Mexico offers a renewable energy production tax credit. The state tax incentive is in the form of a corporate tax credit of one cent for each kilowatt-hour of renewable energy generated. The statute providing for the tax credit was amended in 2003 to increase the total amount of credit available from 800,000 MWh to 2 million MWh per year; to include biomass as a qualifying form of source material, and to lower the minimum size of eligible projects from 20 MW to 10 MW to allow smaller wind, solar, and biomass projects to qualify.

PRC Rule 572 also contains a provision requiring public utilities to offer customers an opportunity to voluntarily purchase renewable energy in addition to what the utility may be providing under the RPS. Utilities must file the proposed tariff with the PRC for review and approval. This type of program provides another mechanism through which to create market demand for renewables, including wind.

While state incentives play a role in encouraging wind development, other regulatory and market structure barriers serve the opposite role. Key barriers include rules regarding transmission and treatment of purchase power contracts.

TRANSMISSION ISSUES

Transmission issues represent a significant challenge to wind development. In the SPS control area, transmission is governed by the open access transmission tariff common to entities in SPP. In order to finance a wind farm, a developer needs to have a long-term power supply agreement for its power, which includes firm long-term transmission to transmit the power to the buyer. The main choices for transmission service are point-to-point and network integration service.

There are several challenges with obtaining firm point-to-point service. First, firm service is often not available due to lack of excess capacity on the transmission line. If it is available, it is typically prohibitively expensive due to expected imbalance penalties for schedule deviations. Network integration service is the only reasonable option for transmission service, which implies that the wind farm needs to be directly interconnected into the control area of the buyer. Obviously this severely hinders wind development since the amount of wind power that can be developed in a particular area is limited.

Another problem with point-to-point service is that the typical utilization of that capacity will be no higher than the expected capacity factor of the wind farm. Thus the transmission demand charges are very high when amortized over expected wind productions.

Finally, the rules about how transmission upgrades are paid for in SPP represent another barrier to wind development. The cost of required network upgrades for a generator is allocated to load, i.e., spread out across the users of the system if the generator represents firm capacity. If the generator does not represent firm capacity, then the costs of those upgrades are allocated to the generator, and in turn, passed onto the customers of that generator. Currently in SPP, a capacity credit of about 5-8% of nameplate is being discussed for wind, which would effectively mean that wind would bear the majority of costs to upgrade transmission to accommodate wind.

PURCHASE POWER CONTRACTS

Another challenge for wind development is that the output of the wind farm is typically sold under a long-term power purchase agreement (PPA) to a buying utility. For an investor owned utility, its ability to earn value for its shareholders is contingent on its ability to invest in generating assets and earn its allowed regulated rate of return on the investment. PPA costs are generally treated as "pass-through" costs by the local public utility regulatory body, and thus the utility cannot earn a return on the PPA, even though the utility's balance sheet and credit rating are put at risk by signing a long-term contract.

However, utilities have little incentive to own a wind farm, since they then accept more of the risk of a technology they may have little experience with, and they also view wind as providing little value to contributing to capacity requirements. The first priority of the long-term generation planners is to ensure that capacity requirements are met; therefore, in planning for development of new power plants, planners are more likely to be focused on traditional thermal generation assets.

ENERGY STORAGE IMPACTS ON BARRIERS

Energy storage can help alleviate many of the regulatory barriers facing wind. Energy storage can be used to guarantee a schedule so that imbalance penalties can be minimized or even eliminated.

Also, energy storage would allow more cost effective procurement of transmission capacity. For example, for 500 MW of wind with 270 MW of CAES, perhaps no more than 300 MW of firm point-to-point long distance transmission capacity would need to be purchased, since dynamic scheduling with the CAES plant, coupled with wind forecasting, could ensure that no more than 300 MW of net energy would go onto the grid at any time. The designation of the generation capacity as firm may also allow the costs of transmission upgrades to be spread out over the system rather than being allocated to the wind customers.

Energy storage can mitigate many of the barriers of the current transmission rules to wind development; however, it cannot make up for the lack of firm point-to-point transmission service in SPP. To facilitate exports of wind, wind/storage, or conventional electrical energy, new transmission will be needed. However, as new transmission is being planned, an understanding of how storage works may help to optimize the development of new transmission that is built to accommodate wind.

The bias of investor owned utilities against PPAs and for ownership of generation assets would prove a challenge to the development of a CAES plant as an IPP. However, as a project coupled with wind, CAES removes some of the scheduling uncertainty and adds value in meeting capacity requirements. Energy storage might thus encourage a utility to take another look at owning its own wind generation, easing the way for development of additional wind projects.

SECTION X - CONCLUSIONS

This project had the following main objectives with specific application to CAES and wind in the SPS control area:

- Assess the ability of energy storage to affect positively the dispatch of renewable resources.
- Assess and quantify the economic benefits of using energy storage to improve reliability issues associated with renewable energy.
- Determine the economic advantage of using storage to firm and shape renewable energy sales.
- Determine institutional barriers and opportunities for energy storage combined with renewable energy facilities.

DISPATCH IMPACTS

In the scenarios we examined, 270 MW of CAES with 440 MW of wind projects online (Base Wind Scenario) and 270 MW of CAES with a total of 940 MW of wind projects online (New Wind Scenario), CAES was found to have the potential to improve the dispatch profile of the wind energy delivered onto the grid. The benefit was seen on a number of fronts.

First, modeling of CAES operations with wind showed that CAES can improve the shape in which energy is delivered onto the grid. Dramatic improvements in the hourly delivery profile were seen on a daily basis, where CAES operations could be customized such that the net deliveries from wind and storage could better match the load shape. The shaping is not perfect, since minimum and maximum loads on the CAES turbines and compression units limit how finely a certain amount of wind can be shaped on an hour-to-hour basis. In addition, the finite amount of energy storage capacity can lead to situations in which CAES is unable to provide shaping in high wind periods due to the cavern being full, or in which CAES is unable to supplement low wind production because the cavern is empty. However, even after allowing for these events to occur, modeling shows that the hourly delivery profile, averaged by month and by the whole year, can be very close to the average hourly load profile.

Second, modeling of CAES with wind was shown to positively impact ramping requirements. Because wind speeds tend to be higher at night in the region of study, wind energy profiles are seen to be opposite those of load. As a result, our analysis shows that hour-to-hour ramping impacts imposed by a significant amount of wind can negatively impact system ramping burden. The same type of analysis performed when CAES is modeled together with wind shows that CAES can mitigate the negative impacts that wind has on system ramping requirements.

Finally, depending on the exact operating strategy for the CAES plant, CAES can essentially “base-load” a certain portion of the nameplate wind capacity, allowing new wind/CAES resources to defray the development of some amount of base-load generation. Similarly, CAES allows stored energy to be made available to serve peak demand, whether or not the wind is blowing. The addition of storage certainly improves the ability of intermittent wind to meet demand for electrical generation.

Due to limitations on scope of the study and resources, we were only able to address improvements in dispatch on a time period basis from hour-to-hour and longer. We were unable to examine the impacts of CAES on intra-hour variability in wind.

TRANSMISSION IMPACTS

The economic benefits of energy storage in improving reliability issues (transmission issues) associated with renewable energy can be quantified in one of two ways. First, least cost system dispatch can be simulated by taking into account constraints imposed by transmission limitations. System generation costs, after integrating wind only, can be compared to system generation costs after modeling CAES under various operating scenarios. However, this type of optimal load flow analysis is complex and difficult to conduct on an hourly basis for several years' worth of analysis. For this study, a simpler approach utilized traditional load flow analysis to identify transmission upgrades that would be needed to integrate wind, and then evaluated any changes in required upgrades as a result of adding CAES to the grid.

Based on the assumptions for where new wind farms would be developed and the location that was chosen for modeling the CAES plant, we did not find that the CAES plant would have mitigated congestion or curtailment issues experienced or caused by the addition of intermittent wind energy into the SPS grid. This shows that the ability of CAES to create economic value from mitigating congestion or curtailment issues is highly dependent on a few conditions.

First, there needs to be significant congestion or curtailment being experienced or expected to be experienced from the addition of wind into the grid. For example, in McCamey, Texas, almost 800 MW of wind is clustered in a very small geographic area, resulting in significant curtailment issues because the wind energy production across the farms is highly correlated, and because there is inadequate transmission serving that location. Therefore, studies of CAES have shown significant economic benefit from reducing curtailments there. However, in the study in the SPS service territory, the wind farms were modeled as being rather geographically dispersed, resulting in much less congestion from the impact of wind alone.

In addition, the value of energy storage in mitigating wind related congestion is very dependent on the location chosen for the storage facility. In this study, it was anticipated that wind would exacerbate congestion along a north-south corridor, which would imply significant value for a load sink to be located in the north part of SPS's service territory. However, due to the size of the CAES plant being contemplated, we chose to model a location in the south part of SPS's service territory due to more suitable geologic features. Therefore, we lost the ability to show value from reducing grid upgrades that were required to solve north-south congestion issues. Furthermore, the CAES plant was determined to require additional upgrades in the form of a transformer at the Tuco Substation.

Nevertheless, in the location that we did choose for the CAES plant, we were able to show other transmission benefits that were not wind related. Due to the ability of the CAES plant to provide other critical transmission services such as VAR support, the CAES plant was shown to reduce limitations on imports from the rest of SPP into SPS's service territory, and potentially increase export potential as well. In further production cost modeling, the loosening of restrictions on imports was shown to provide a significant economic benefit in the form of reduced production costs for SPS. The annual value of these benefits was estimated to be 4 to 5 times as much as the annualized cost for the new transformer that would be required to support the CAES plant, showing significant net transmission benefits from the CAES plant.

FIRMING AND SHAPING ECONOMIC VALUE

Section XIII of this report details the economic analysis of CAES with wind projects in the Panhandles of Texas and Oklahoma and the eastern plains of New Mexico. The analysis shows that there is an economic value proposition to using a CAES facility to manage wind, both in the Base Wind Scenario (440 MW of wind) and the New Wind Scenario (500 MW of additional wind on top of the 400 MW of Base Wind). There are some key conclusions to be kept in mind.

First, the economic value proposition of energy storage with wind is built on a number of key elements of value, which need to be analyzed in concert since no one of them individually is large enough to show return on investment in an energy storage facility. Value elements include firming value, shaping value, capacity value, and transmission value. Arbitrage value (using CAES for non-wind related system arbitrage) was not modeled explicitly and was not included in the build-up of value. More detailed analysis could show additional value on this front.

Second, it is clear that the same amount of CAES adds more value when used to manage greater amounts of wind, both in terms of number of megawatts of nameplate capacity and in terms of penetration into the grid. 270 MW of CAES generates more value when matched with 500 MW of wind than matched with 440 MW of wind, but the bulk of the value increase between the Base Wind Scenario and the New Wind Scenario was that the CAES plant was modeled with a total of 940 MW of wind on the grid, even though it was only modeled as actively managing the last 500 MW of wind added to the grid.

Third, in comparing the value of energy storage with the cost of a facility, the ownership and financing structure can make a big difference in the economic viability of energy storage. SPS would have a cost of capital advantage if it owned a CAES plant as compared to an independent power producer or merchant energy player. In order to get appropriate return on investment, SPS ownership would be critical for a CAES plant if it were only to be used to manage the 440 MW of wind that SPS has currently planned for its system. However, the increased value that can be created by a CAES plant when managing an additional 500 MW of new wind is enough to create incentives for ownership of a CAES plant under an IPP type of structure.

INSTITUTIONAL BARRIERS/OPPORTUNITIES

Despite the favorable wind resource conditions in the area of study, the biggest hurdle faced by the wind industry in trying to increase the amount of wind development is the current state of transmission rules that create economic penalties for intermittent resources such as wind. By firming the resource and providing capacity value, CAES should be able to mitigate many transmission related costs that are currently seen as onerous for wind development. However, the biggest institutional barrier, or perhaps opportunity, for energy storage with wind project lies within the market structure. Without a liquid market for power contracts, the market for CAES as a wind power integration tool is limited to the utilities that serve the market. Thus, enlightened customers, who fully and fairly value the benefits that CAES brings in conjunction with wind power, will be necessary to create a true opportunity for energy storage.

FINAL WORD

This study has hopefully helped to quantify the economic benefits of using CAES to manage potential wind energy resources in the SPS service territory, while demonstrating to the reader how the impacts should be evaluated. As a final perspective, this study has concluded that under a range of scenarios, the combined cost of 270 MW of CAES with 500 MW of new wind would be competitive with conventional generation resources that might be considered as an addition to the grid, as long as the federal PTC for wind remains in place. This conclusion should highlight the opportunity for using CAES as a cost-effective way of encouraging further wind development in the SPS service territory, and also elsewhere in Texas, Oklahoma, and New Mexico. We hope that this study encourages utilities and developers to engage in dialogue about combining CAES with further wind development in the region.

APPENDIX A – CAES PLANT EQUIPMENT DETAILS

POWER ISLAND

High Pressure (HP) Air Turbine – The HP air turbine consists of a modified expander turbine section, which has been designed to accept the design flow rate of 400 pounds per second (lbs/sec) of 750 pounds per square inch gauge (psig) air. Prior to entering the HP turbine, air has been heated in the recuperator. The HP exhausts into the low pressure (LP) combustor duct. The HP turbine produces approximately 35 MW of the total 135 MW capacity. The HP air turbine reduces technical risk since it allows the LP combustion turbine to operate at exactly the same pressure, temperature, and airflow that it would experience if the unit still contained an air compressor.

Turbine - The LP turbine is a standard gas turbine from which the compressor section has been removed. The air from the HP expander enters the eight LP combustors, is fired to 1620ºF and enters the LP at 252 pounds per square inch absolute (psia). The heat rate is approximately 4,300 British thermal unit per Kilowatt Hour (Btu/kWh) (higher heating value). The LP turbine exhausts into the recuperator in which the SCR unit is installed. The LP turbine generates approximately 100 MW and the whole CAES train generates 135 MW. The installation of an identical and an additional CAES generation train allows the site to achieve the design output of 270 MW.

Recuperator - The recuperator in the CAES cycle is an air-to-air heat exchanger, which has been designed to handle the high volume of air required by the combustion turbine. The purpose of this exchanger is to increase the efficiency of the cycle by capturing the heat contained in the 664ºF exhaust of the combustion turbine and utilizing this heat to increase the HP air turbine inlet temperature from the 100ºF cavern temperature.

Electric Generator - The generator is rated at a nominal 135 MW with a 0.85 power factor.

Selective Catalytic Reduction - Selective Catalytic Reduction (SCR) units are incorporated into the design of the project. These units are fixed catalyst beds that convert NOx to nitrogen by introducing small quantities of aqueous ammonia into the gas turbine exhaust stream just upstream of the SCR unit. The SCR is built into the recuperator ducting.

COMPRESSION ISLAND

The purpose of the compression process is to provide the air volume necessary to increase the air pressure in the air storage system from atmospheric pressure to approximately 1250 psig. The air is subsequently used as expansion air by the HP air turbine and as combustion air by the gas turbine. The compression cycle for CAES consists of multiple compression trains made up of axial and centrifugal compressors. The compression train operates when needed to capture wind energy in excess of available transmission capacity and recharges the cavern to full pressure of 1250 psig.

In the compression cycle, ambient air is drawn into the LP compressor (a multi-stage axial compressor) and is discharged at 120 psig. The pressure is then boosted to 1200 psig in the HP compressor cases. The HP compressor has multiple stages of intercooling and an aftercooler, which allows delivery of air into the storage cavern at approximately 100ºF. Both the LP and HP compressors have electric drivers. Each compression train (LP plus HP) is sized to handle 400 lb./sec. of air. Typically, two compression trains would be installed to match the air requirements for 270 MW of power generation. The compression trains would be connected to the large underground salt cavern air storage system. For this study, 200 MW of compression has been selected in order to manage the wind resources and supply grid support in the area.

UNDERGROUND FACILITIES

The storage system is comprised of six air injection/withdrawal wells and storage caverns. Each cavern is capable of shut-in via separate closure valves and each cavern is connected via manifold piping arrangements to a header system that feeds directly into the discharge of the HP aftercoolers or the recuperator, depending on the mode of operation. During the storage mode, air leaving the HP compression aftercooler flows via the header piping and manifolding into the storage caverns. During the energy recovery mode, airflow via the header to the aftercooler is restricted via a shut-in valve; this results in air flowing via the header into the recuperator. The flow rate and pressure into the recuperator is controlled by the main airflow control valve resulting in a pressure of 800 psig at the recuperator inlet flange. The caverns are sized to provide up to 50 hours of storage and operate between 950 psig-1250 psig.

BALANCE OF PLANT

Most of the equipment in the balance of the plant, the cooling tower, the switchgear, the substation, the plant distribution and controls and the step-up transformers are similar to components typically used in many power plants. The main difference in the equipment at a CAES plant is the auxiliary transformer, which handles power coming into the plant from the grid. The auxiliary transformer in a CAES plant is sized to handle 200 MW of compression power. For a Panhandle facility, the step up transformers would be designed for 13.8 kV to 230 kV service. The balance of plant also includes the control room, maintenance facilities, fuel metering and control valves, water treatment and related facilities (such as pumps and tanks).

APPENDIX B – PANHANDLE GEOLOGY

The geology of Hale County in West Texas was reviewed using information from the U.S. Geological Survey, the Texas Railroad Commission, and the Bureau of Economic Geology at the University of Texas. From these published and archived reports, maps and well logs, contours were created for the top elevation of salt and salt thickness in the area around Lubbock and north towards Amarillo. This information was evaluated by a professional geologist to confirm that salt caverns could be solution mined at an appropriate depth to store adequate volumes of high pressure air for a CAES plant. A total of six caverns, each approximately 4-5 million-barrels, would be needed to achieve a total storage volume of 28.5 million barrels. This would allow the facility to store up to 10,000 MWh of energy.

While the current level of geological analysis suggests that air storage would be feasible in the Panhandle region, additional formation analysis would be required to optimize the exact location of a CAES plant if a project were to proceed.

Structure and Geologic Framework

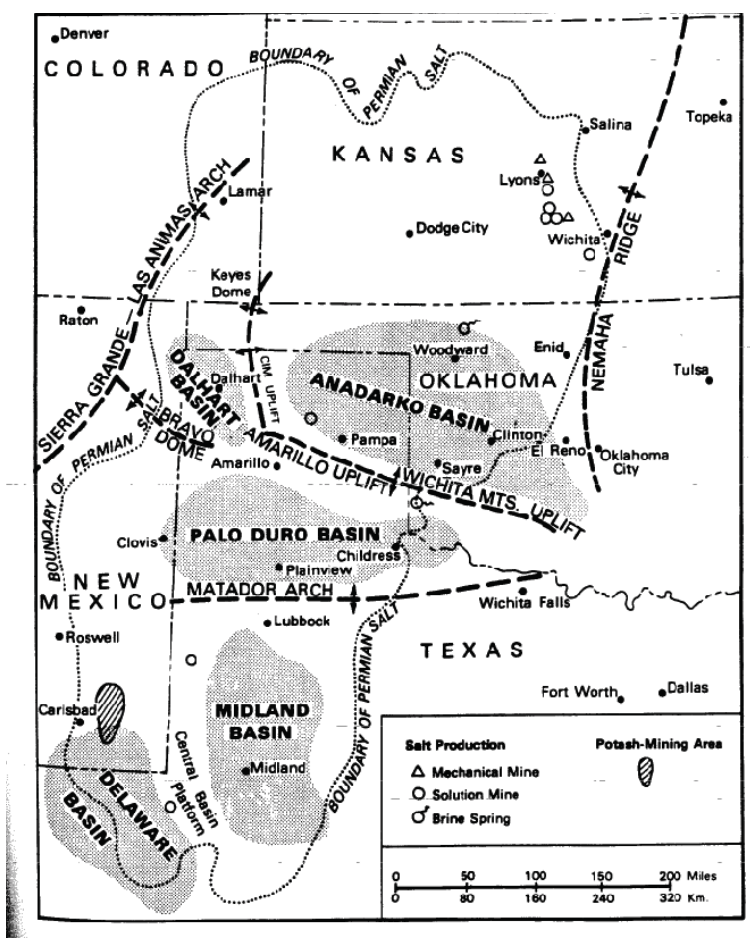


Figure B-1: Map of Permian basin salt area in southwestern United States showing principal tectonic provinces.

APPENDIX C – CAES PLANT OPERATING CHARACTERISTICS

CONFIGURATION

For study purposes, the configuration of the CAES plant is assumed to be as follows:

- 270 MW generation (2 X 135 MW generation units)
- 200 MW compression (2 X 100 MW compression trains)
- 10,000 MWh of energy storage capacity

OPERATING CHARACTERISTICS

With pressurized air feeding the combustion turbine, there is no loss of generating output, i.e. no "derate," as ambient temperatures increase. The CAES plant maintains its rated generating capacity throughout all the seasons of the year.

The gas-fired heat rate of the CAES plant is 4,300 Btu/kWh (HHV) at maximum load on the turbine. This is achieved by the installation of an 85% efficient recuperator on the exhaust of the LP expander. This configuration allows the plant to maintain a low heat rate with minimal degradation as the generating unit is turned down to 50% of capacity. Since we are modeling CAES plant operations in wind shaping mode, we expect that the CAES plant will often be operating at partial load conditions. Therefore, we have calculated that 4,500 Btu/KWh is a better heat rate to use for modeling fuel use in a wind shaping operating mode.

The energy ratio for a CAES plant is defined as the amount of compression energy required to produce one unit of energy with the generation equipment. The energy ratio for a plant operating the compression equipment at full output is 0.75. Again, however, we need to account for some efficiency penalty in wind shaping mode since the CAES plant would be operating at partial load conditions most of the time. Therefore, we used 0.8 as the energy ratio for modeling purposes in this study.

The physical separation of the generating and compression equipment allows both functions to operate simultaneously. This gives the operator a great deal of flexibility in managing wide variations in wind output.

Generation Mode

The minimum generation level for the CAES plant is determined by the minimum operating level for a single generation unit. The generation unit is flame stable at 11% (~15 MW), though the efficiency penalties for operating at this level are significant. Therefore, for modeling purposes, 50% of one unit (67.5 MW) is used as the working assumption for minimum operating level.

The CAES plant can economically operate anywhere in the range from 67.5 MW to the full output of the plant (270 MW) by having a combination of units on. Table C-1 provides examples of how the generation units would be deployed to meet various plant generation levels.

Table C-1: CAES Operating Range/Unit Commitment

Required Generation Level	Operating Unit Configuration
67.5 MW	One unit operating at minimum level of 67.5 MW
100 MW	One unit operating at 100 MW
135 MW	One unit operating at full output of 135 MW -or- Two units operating at 67.5 MW each
200 MW	Two units operating at 100 MW each
270 MW	Two units each operating at full output of 135 MW

The excitation on the generators can be adjusted to provide leading or lagging VARs as necessary to support the voltage level on the system. The maximum reactive capability of the generation units when operating in concert at various levels is described in the following graph:

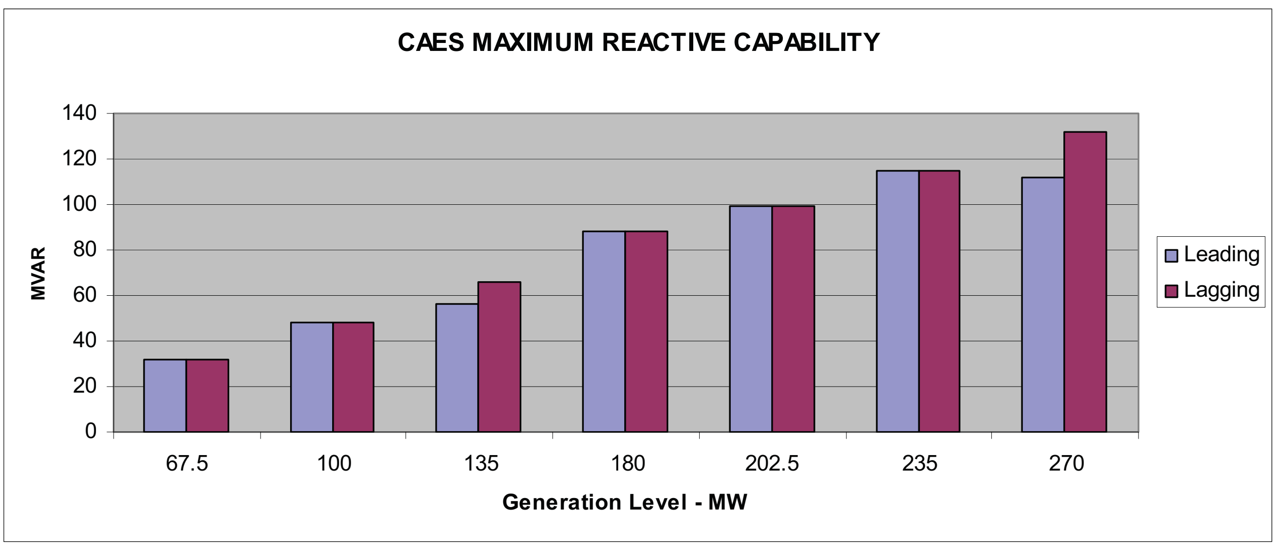


Figure C-1: CAES Maximum Reactive Capability – Generation Level

The generators can also be designed to operate independently of the turbines in synchronous condenser mode to provide VAR support. This would enable the CAES plant to provide reactive power to the grid when the plant is offline, and would also enable the provision of additional reactive power while the plant is in compression mode. Extra reactive capability is likely to be needed when wind is high and the CAES plant is taking power off the grid via compression, so it makes sense to use equipment that would have otherwise been idle, i.e. the generators, and create additional value from them. In our design, we have assumed that one of the generators has been configured to be able to be separated from the turbine via a clutch so that it can operate as a synchronous condenser.

The generation units are designed for rapid deployment and response. Under normal warm start conditions, a generation unit could be at full load in 10 minutes. Each unit has a ramp rate of 4.5 MW per second when online.

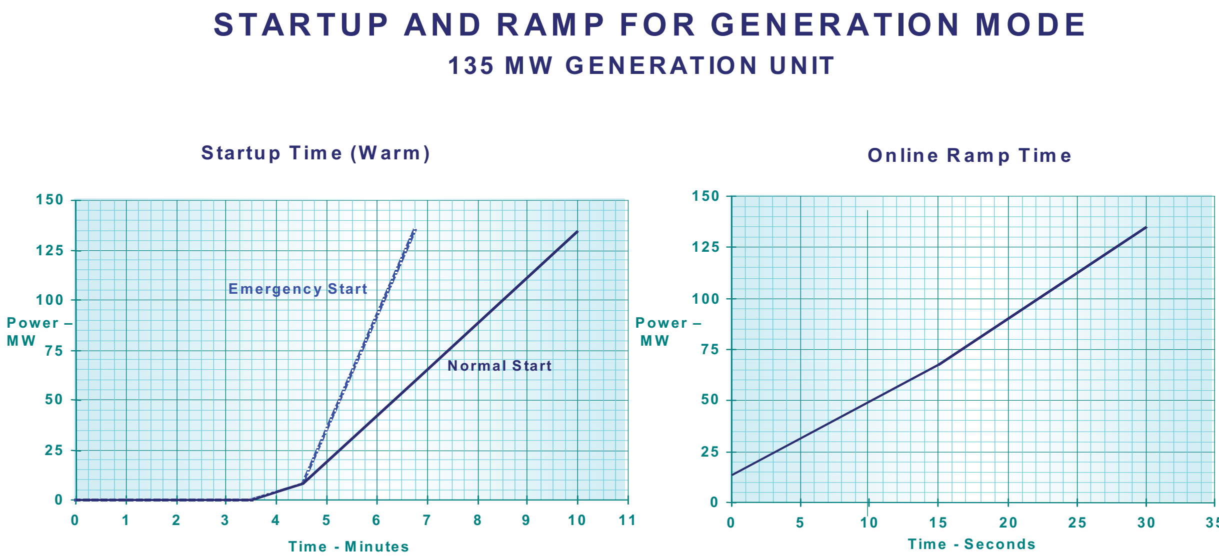


Figure C-2: Startup and Ramp for Generation Mode

Compression Mode

The minimum operating level while in compression mode is considered to be approximately 60% of a single 100 MW compression train, or 60 MW. Below this level, air would be recycled through the compressors in order to prevent compressor surge, resulting in an efficiency penalty. Therefore, this operating level is the minimum economical operating limit considered in this study.

The CAES plant can operate in compression mode anywhere in the range from 60 MW to 200 MW by varying the number of compressor trains that are online. Since there are two compressor trains, the configuration options are similar to those in the generation mode. While the compressor trains are in operation, the excitation on the motors driving the compressors can be adjusted to provide leading or lagging VARs as necessary to support the voltage level on the system. The maximum reactive capability of the motors when operating in concert at various levels is described in the following graph:

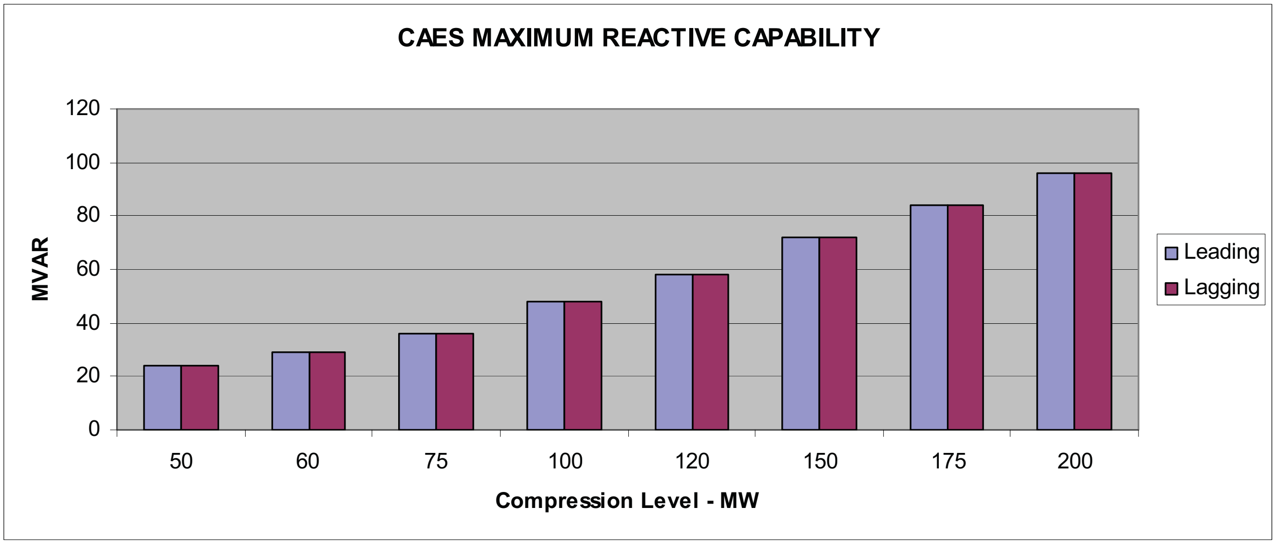


Figure C-3: CAES Maximum Reactive Capability – Compression Level

A compression train can be started and come to full load in 12 minutes. While operating, each train can move between minimum and maximum load at a rate of 20 MW per minute, or minimum to maximum (or maximum to minimum) in two and one-half minutes – 150 seconds.

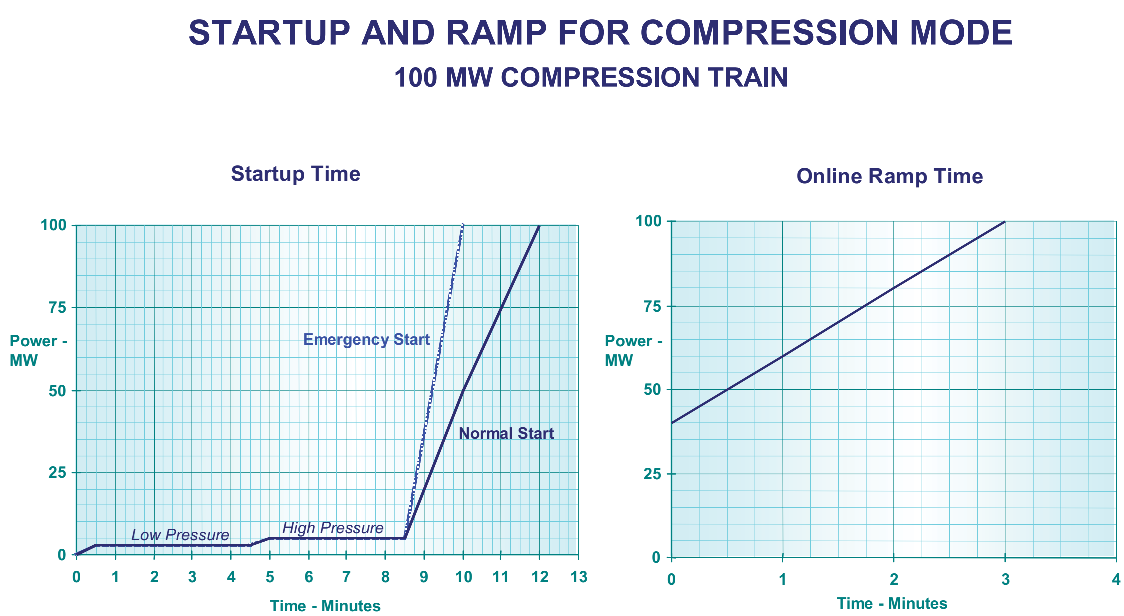


Figure C-4: Startup and Ramp for Compression Mode

APPENDIX D – CONSTRUCTION TIMELINE

Once a commitment for a CAES project is in hand, the remaining development and construction can be concluded within three years. This assumes that major project development tasks have already been completed prior to the commitment. These prior tasks would include equipment selection, preliminary engineering and permitting for air emissions and underground storage.

Preliminary notice to proceed is given to the equipment manufacturer in order to keep delivery of long lead-time items in line with the overall project schedule. Some of the above ground-supporting infrastructure for the air storage caverns is constructed while permanent financing is put in place for the project.

Once final notice to proceed is given, the schedule is driven by the delivery of the major equipment to the site and the solution mining and debrining of the air storage caverns. The project proceeds on a normal power plant construction schedule with the following assumptions:

- Major equipment is delivered to the site 15-18 months after the notice to proceed
- 15 months of field construction
- Startup occurs 7 months after major equipment is delivered to the site

The cavern leaching operation is the longest duration task. The impact of this could be initiated by starting up the project prior to completion of the mining thus operating at a reduced storage volume.

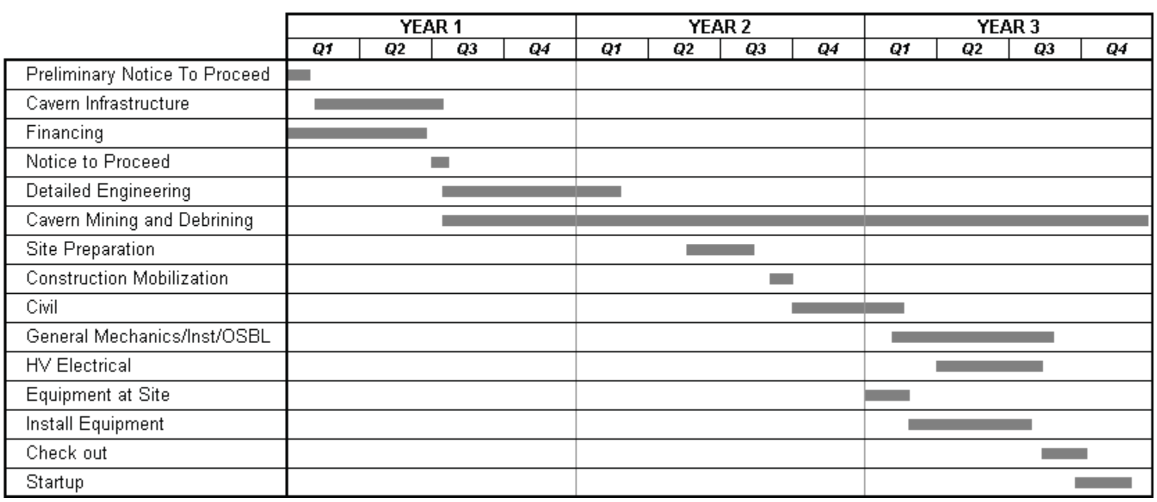


Figure D-1: CAES Plant Construction Schedule