A REVIEW OF LARGE-SCALE WIND GRID INTEGRATION IN THE UNITED STATES

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I. Introduction

With over 25 GW of installed wind capacity, the U.S. currently leads the world in the amount of wind capacity. Just 1-2% of U.S. electricity generation comes from wind power, but more and more utilities are also adding significant amounts of wind to their systems, measured both by capacity and by estimated wind energy penetration (see Table 1).[1]

Table 1. The Top 20 Wind Power Utilities in the United States (by Capacity and Energy)

Table 3. Top 20 Utility Wind Power Rankings

Total Wind Capacity (end of 2007, MW)		Estimated Percentage of Retail Sales (for utilities with > 50 MW of wind)	
Xcel Energy	2,635	Minnkota Power Cooperative	11.2%
MidAmerican Energy	1,201	Empire District Electric Company	10.2%
Southern California Edison	1,026	Last Mile Electric Cooperative	10.0%
Pacific Gas & Electric	878	Xcel Energy	9.3%
Luminant	704	MSR Public Power Agency	8.4%
American Electric Power	543	Public Service New Mexico	7.5%
CPS Energy	501	Oklahoma Municipal Power Authority	7.2%
Puget Sound Energy	428	CPS Energy	7.1%
Alliant Energy	378	Northwestern Energy	7.0%
Exelon Energy	342	Austin Energy	6.6%
Austin Energy	274	Otter Tail Power	6.4%
Portland General Electric	225	Great River Energy	6.3%
Great River Energy	218	Nebraska Public Power District	6.0%
Last Mile Electric Cooperative	205	Puget Sound Energy	5.2%
Public Service New Mexico	204	Seattle City Light	5.0%
MSR Public Power Agency	200	MidAmerican Energy	4.7%
Reliant Energy	199	Alliant Energy	4.2%
Seattle City Light	175	Western Farmers' Electric Cooperative	3.8%
Oklahoma Gas & Electric	170	Luminant Energy	3.6%
Empire District Electric Company	150	Minnesota Power	3.5%

This paper examines and summarizes the experience with wind integration in the United States. The rapid growth in wind power capacity in the United States, with wind capacity having nearly tripled since 2005, means that cumulative operating experience is relatively limited. That said, several utilities, states and regional transmission organizations have conducted wind integration studies to determine the feasibility of incorporating wind, large amounts of it in some cases, onto their grid before actually taking the step of adding significant wind capacity. Over a dozen such studies have been conducted since the late 1990s, and more are planned or underway. To date, all of the wind integration studies have been prospective— modeling a potential future power system with wind—rather

[1] American Wind Energy Association. "Wind Energy Grows by Record 8,300 MW in 2008." January 27, 2009. http://www.awea.org/newsroom/releases/wind_energy_growth2008_27Jan09.html. (Accessed March 14, 2009).

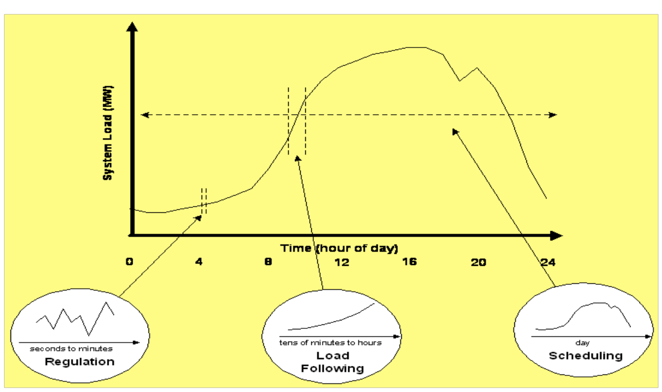
than retrospective—observing what has actually happened. The studies have evolved from focusing on whether it is possible to incorporate wind onto the grid (i.e., is one-for-one back-up capacity needed for wind power) to discussing how to incorporate wind and at what cost. In addition, the wind integration studies (as well as the accumulation of greater operating experience with wind generation) have also led to consideration and discussion of potential solutions for successfully incorporating higher levels of wind generation.

This paper begins with a description of the different time scales of grid operation; describes the estimated grid impacts that were found in wind integration studies and from operating experience; summarizes the estimated wind integration costs; considers the literature on how to determine the capacity value of wind; describes potential solutions and means of accommodating higher levels of wind power; discusses some recent grid outages where wind power has been involved; and closes with a summary. Not described in this paper are issues of expanding transmission to access wind resources in remote areas or to alleviate transmission congestion that prevents more wind generation from being loaded onto the grid.

II. Time Frames of Concern

Wind integration studies conducted to date in the United States have divided grid operations into time frames, and attempted to estimate the impacts of higher levels of wind power during these time frames. Arranged from shortest to longest, the time scales are system stability, regulation, load following/imbalance, unit commitment/ scheduling, and resource and capacity planning. Figure 1 illustrates the key time frames addressed in this paper and the wind integration studies; resource and capacity planning is also addressed in this paper, but to a more limited degree, and is not always addressed in wind integration discussions.

Figure 1. Time Frames for Wind Impacts



Source: National Renewable Energy Laboratory, 2008.

System Stability
System stability is the shortest time scale, ranging from milliseconds to seconds, and addresses the need for both voltage and frequency to be held within close tolerances at all times.

Regulation
The regulation time frame covers the period during which generation automatically responds to minute-by-minute deviations in load. Typically, a system operator will send signals to one or more generators to increase or decrease output to match the change in load. The regulation covers a time scale ranging from about several seconds to 10 minutes. Changes in load during the regulation time are typically not predicted or scheduled in advance and must be met with enough generation that is online and grid-synchronized to ensure the changes in load are met.

Load Following
The load following time scale covers longer periods ranging from 10 minutes to a few hours during which generating units are moved to different set points of capacity, subject to various operational and cost constraints and in response to increasing load (in the morning) or decreasing load (late in the day). Load following is typically provided by generating units that are already committed or from generating units that can be started quickly, subject to operating constraints specific to the unit.

Unit Commitment/Scheduling
Unit commitment covers several hours to several days, and concerns the scheduling and committing of generation to meet expected electric demand. Generation in this time frame may require several hours, even days, to start-up and increase to the preferred operating level. Similarly, taking a unit off-line may require several hours or days, and the unit may need several hours of cooling before restarting. Therefore, planning the "right" level of unit commitment is important. Scheduling too much generation may needlessly increase system operation costs, while scheduling too little generation may also increase costs by requiring the purchase of power at high market prices or running expensive, quick-start units. There may also be reliability issues if sufficient generation is not started or is not available on short notice.

Resource and Capacity Planning
Resource and Capacity Planning is the longest time frame of all, covering at least one year and typically multiple years into the future. This time frame encompasses the long-term forecasting of future load and load growth, and the projected availability of generating capacity to meet projected peak electric demand.

III. Physical Impacts

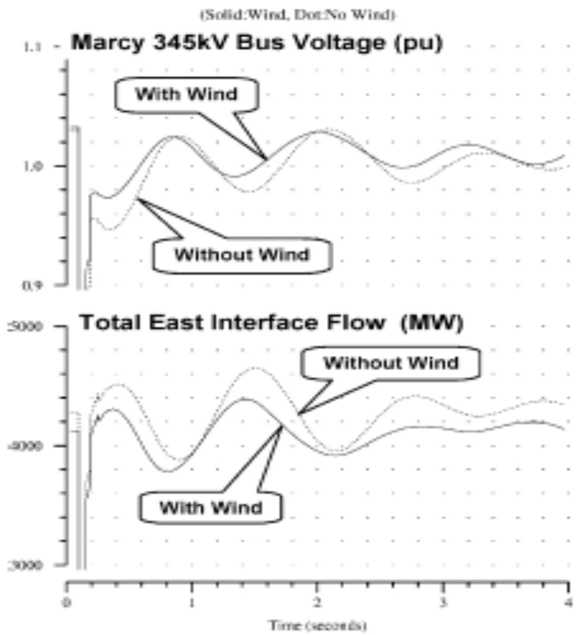
Because wind output is variable, adding wind generation increases the net variability of the system. In general, U.S. integration studies have found that the impacts of wind tend to increase with the time frame.

System Stability
The development of large grid-connected wind projects in the United States occurred first in California in the 1980s. Typically during those early years, wind projects were disconnected during a grid disturbance, and wind projects were not brought back on-line until the grid was brought back to a normal state of operation. As wind projects began being developed outside of California to Texas and the Upper Midwest on relatively weaker grids, and the wind projects became larger in capacity, voltage stability issues arose, aggravated by the use of direct-connected induction generators.

These grid concerns, plus the development of grid codes in Europe and the United States (discussed later in the paper), led to advances in wind turbine technologies that make wind projects more grid-friendly. While wind power plant behavior is different from that of conventional generation, it can still be compatible with grid design and operation. Grid code requirements can either be met directly by wind turbines or through the addition of on-site equipment. Other requirements that can be met when requested include voltage control, output control and ramp rate control.

Because of these advances in wind turbine technologies and the development of grid codes, some system stability studies have demonstrated that modern wind turbines with power electronic controls and dynamic-voltage support capability can enhance grid performance by damping power swings and supporting recovery of the grid after a fault (see Figure 2).

Figure 2. Impact of Wind Generation on System Dynamic Performance



Regulation

Because the variations of load and wind tend to be uncorrelated in short time scales, most U.S. wind integration studies have found that only modest amounts of additional regulation are necessary with more wind. In two studies conducted in Minnesota[2] and New York[3], the addition of 1,500 MW and 3,300 MW of wind increased the regulation requirements by 8 MW and 36 MW. The amount of wind energy studied represent 15-percent and 10-percent of each respective system peak load. One exception is a 2007 study by the California ISO, which assessed the feasibility of incorporating 6,000 MW of wind in the Tehachapi Pass Region in Southern California. The California ISO determined that regulation requirements would increase by nearly a factor of two, from 100 MW to 170 MW, for "up" regulation (for generation to provide regulation when frequency is decreasing) and from 100 MW to 500 MW for "down" regulation (when generation must be ramped down because frequency is increasing and needs to be decreased). The California ISO attributed this difference with other wind integration studies as representing more accurately the time lag in the generator's response to dispatch commands.

Load Following

Loads and changes in loads may be forecast with a reasonable amount of accuracy in systems with little or no wind. When these forecasts are wrong, the system operator must

[2] EnerNex Corporation and WindLogics, Inc. "Wind Integration Study – Final Report," Prepared for Xcel Energy and the Minnesota Department of Commerce, September 28, 2004.

[3] GE Energy, Energy Consulting. "The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations," Prepared for the New York State Energy Research and Development Authority, March 4, 2005.

deal with the resulting system imbalance. In systems with a significant amount of wind capacity there is an increase in forecast uncertainty and the associated costs in addressing them through system operations. Beyond the maximum and minimum generation constraints that exist in every system, ramping constraints may also be affected by significant wind generation on the system.

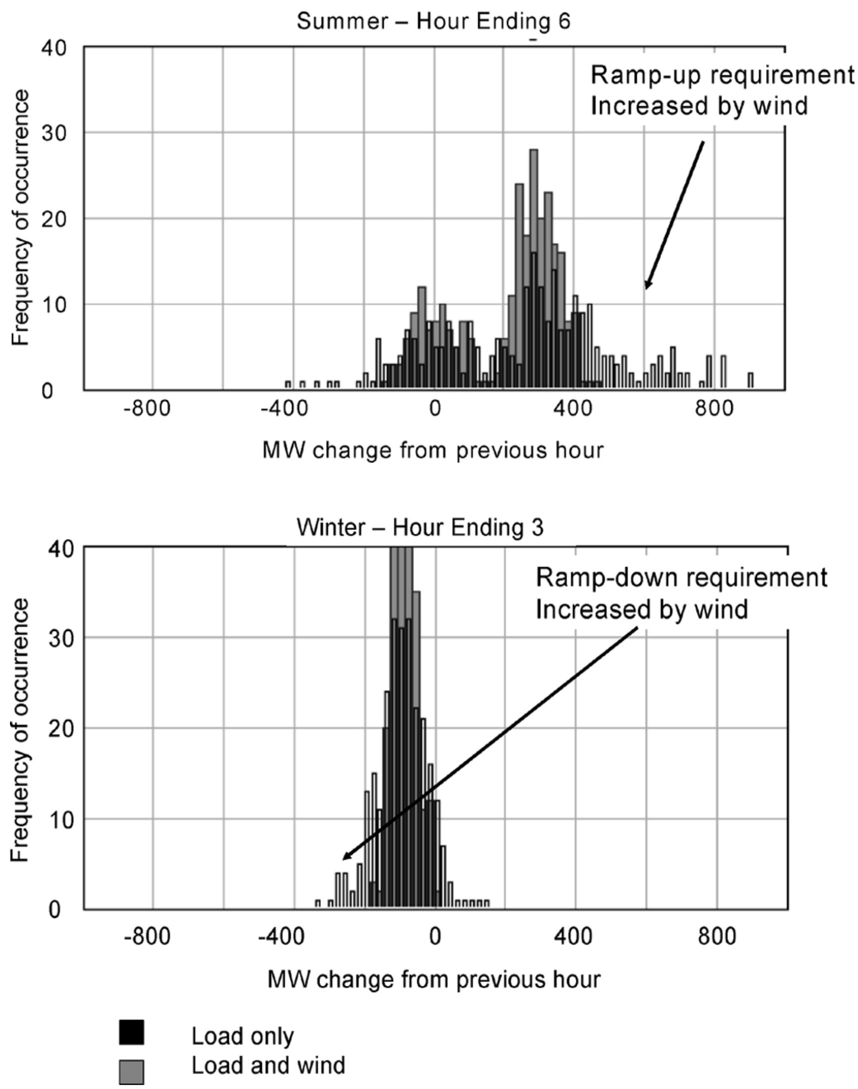
U.S. wind integration studies have typically found a larger increase in the need for load following with higher levels of wind generation. This is due in large part to wind's diurnal output, which in many cases may be opposite of the peak demand period for electricity. For instance, wind output may fall off in the early morning hours when load is increasing, increasing the need for generating resources to ramp up to meet the increasing electric demand. Conversely, wind production may be higher during off-peak hours when load is decreasing or at minimum levels, increasing the need for generating resources that can ramp down. Therefore, adding wind generation will typically require more active load following, or more load management capability to counteract the combined net variability of load and wind.

U.S. wind integration studies have also determined that certain periods will pose particular stress on grid generators: the morning load pick-up, when wind generation is typically ramping down while load is picking up, and times of low or minimum load, when wind production may be high when load is low. In a California study that assessed the feasibility of incorporating up to 33% renewables, wind provided almost 30% of energy under light load conditions in a scenario with 12,500 MW of wind. Because some of these potential impacts may be more pronounced by season, some grid operators such as the California ISO are contemplating varying their regulation and load-following reserve requirements at different times of the year, in anticipation of different levels of wind output, as opposed to procuring a flat amount annually.

As illustrated in Figure 3, the distribution of changes in net load flattens and broadens with large-scale wind added to the system, with more "tail events," i.e., more instances of higher hourly changes in load, both positive and negative. The two graphs illustrate an increase in ramping-up and ramping-down requirements with wind compared to the case without wind.

Figure 3. Load Following Impact of Wind

(Black shows no-wind case; gray shows net load and wind.)



Source: EnerNex Corporation and WindLogics, Inc., September 2004.

Unit Commitment

At the day-ahead or multi-day-ahead time frames, the uncertainty of wind production may result in higher variable costs through increased fuel consumption and increased operating costs. This may occur if too much generation is committed due to an underestimate of actual wind production, or if not enough generation is committed, necessitating the use of quick start units or short-term market purchases.

IV. Cost Impacts

In general, U.S. wind integration studies have found that the costs of wind integration will generally be less than $5.00/MWh for wind capacity penetration levels of up to 20%. Most of the costs are in the unit commitment time from under or over-committing generating plants (see Table 2, and Figure 4). These findings may need to be reassessed as the results of higher wind penetration studies (e.g., 25-30% of peak demand) become available. Some wind integration studies have found higher wind integration costs approaching $10/MWh. These studies are mostly in the Pacific Northwest and reflect in part the lack of sub-hourly scheduling or markets in the West; the reliance on persistence wind forecasts which is satisfactory in the one hour to two hour time frame but may lead to large errors in longer time frames; and the reliance on more costly reserves such as regulation as compared to spinning or non-spinning reserves.

That said, the costs to integrate wind are dependent on a number of factors:

- The size of the balancing area. A large balancing area will make it easier to integrate a fixed quantity of wind, as there will be a deeper stock of flexible generation to draw from. Conversely, smaller balancing areas will have more difficulty managing wind variability.
- Resource mix. A resource mix with more flexibility in ramping up and down and operating at different dispatch points will make it easier to integrate wind than if the resource mix is comprised of generating resources that have more limited ability to move.
- Depth and type of ancillary services. Wind integration costs will be lower if there is a well-functioning and deep market for ancillary services (such as present in most RTOs) as compared to a relatively thin and more bilateral-based market for ancillary services, as is the case in the Western United States.
- The geographic concentration of wind projects—greater spatial diversity of wind projects can lessen the fluctuations in wind output and therefore lessen wind integration costs, whereas greater concentration of wind projects in a geographic area will have the opposite impact.

In some cases, utilities have subtracted wind integration costs from power purchase rates, or have charged wind generators either a wind integration rate or regulation rate.

- Idaho Power subtracts between 7% and 9% from payments it makes to wind generators under contract, up to a maximum of $6.50/MWh.
- The Bonneville Power Administration charges wind generators a wind integration cost of $0.83/kW-month and is seeking to increase it to $2.33/kW-month.

Table 2. Comparison of Cost-Based U. S. Operational Impact Studies

Date	Study	Wind Capacity Penetration	Cost ($/MWh) Regulation	Load Following	Unit Commit.	Gas Supply	TOTAL
2003	Xcel-UWIG	3.5%	0	0.41	1.44	na	1.85
2003	We Energies	29%	1.02	0.15	1.75	na	2.92
2004	Xcel-MNDOC	15%	0.23	na	4.37	na	4.60
2005	PacifiCorp	20%	0	1.60	3.00	na	4.64
2006	Calif. (multi-year)*	4%	0.45	trace	trace	na	0.45
2006	Xcel-PSCo	15%	0.20	na	3.32	1.45	4.97
2006	MN-MISO**	31%	na	na	na	na	4.41
2007	Puget Sound Energy	10%	na	na	na	na	5.50
2007	Arizona Pub. Service	15%	0.37	2.65	1.06	na	4.08
2007	Avista Utilities***	30%	1.43	4.40	3.00	na	8.84
2007	Idaho Power	20%	na	na	na	na	7.92
2008	Xcel-PSCo****	20%	na	na	na	na	8.56

* Regulation costs represent 3-year average.

** Highest over 3-year evaluation period.

*** Unit commitment includes cost of wind forecast error.

**** This integration cost reflects a $10/MMBtu natural gas scenario. This cost is much higher than the integration cost calculated for Xcel-PSCo in 2006, in large measure due to the higher natural gas price: had the gas price from the 2006 study been used in the 2008 study, the integration cost would drop from $8.56/MWh to $5.13/MWh.

Figure 4. Comparison of Cost-Based U. S. Operational Impact Studies

V. Capacity Value of Wind

As noted at the beginning of the paper, resource and capacity planning represent the longest time scale for grid planning and operations. While these issues are important, they are not always included in the definition of grid integration issues for wind. As such, we touch on these issues here, but in a cursory manner.

The capacity planning piece represents resource planners' estimates at how much generating capacity will be available at peak demand, discounted to reflect the potential for planned or unscheduled outages (sometimes known as the forced outage rate). In addition, because electric demand is uncertain and varies over time, and generation and transmission are subject to planned or unplanned outages, grid planners maintain a reserve margin, expressed as a percentage over peak demand (e.g., 15%).

Wind generators typically have very high mechanical availability, exceeding 95% in many instances; i.e., the forced outage rate is often below 5%. However, because wind generators only generate electricity when the wind is blowing, the effective forced outage rate for wind generators may be much higher, from 50% to 80%, when recognizing the variable availability of wind.

Some areas have experienced low wind capacity values during summer or winter high-pressure weather patterns that correlate with system peak demand. For instance, during a 10-day heat wave in California in 2006, aggregate wind generation output during peak demand hours of each day ranged from 5-10% of nameplate capacity. However, wind generation may have higher output during shoulder months (i.e., spring and fall) that may be helpful for system operators, since generators may be off-line for scheduled maintenance during those periods of time.

Two approaches to determining the capacity value of wind are utilized currently:

- Determining the Equivalent Load Carrying Capability (ELCC) of a wind plant as compared to a benchmark conventional unit; and

- Estimating the capacity factor of the wind project during specified time periods (typically peak demand hours)

Estimating ELCC involves a database that contains hourly load requirements and generator characteristics such as rated capacity, forced outage rates, and maintenance schedules for conventional generators. For wind generators, at least one year's worth of wind data is needed, although because wind resources can vary from year to year, more data is better. The wind data can be actual output from wind projects, although that can be difficult to obtain. An alternative approach is an hourly time series from numerical weather prediction models, synchronized to hourly load.

Although there are some variations in the approach, ELCC is calculated in several steps. Most commonly, the system is modeled without the generator of interest, e.g., a wind generator. The loads are adjusted to achieve a given level of reliability, typically a one-day-in-10-year probability of no electric service, otherwise known as loss of load expectation (LOLE).

Once the desired LOLE target is achieved, the wind generator is added to the system and the model is re-run. The new, lower LOLE (higher reliability) is noted, and the generator is removed from the system. Then the benchmark unit is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the renewable generator. The capacity of the benchmark unit is then noted, and that becomes the ELCC of the renewable generator.

Because ELCC is data intensive, and it can be difficult to collect and compile the data, interest in approximation methods has emerged. Broadly speaking, the approximation techniques fall into two categories: risk-based or time-period-based. Risk-based techniques develop an approximation to the utility's LOLP curve throughout the year. Time-period-based methods attempt to capture risk indirectly, by assuming a high correlation between hourly demand and LOLP. Although this relationship generally holds, it can be compromised by scheduled maintenance of other units and hydro conditions (i.e., hydro production may be lower because of low water levels). A further limitation of time-period-based methods is that all hours considered by the method are generally weighed evenly, whereas ELCC and other risk-based methods place greater weight on high-risk hours, and less weight on low risk hours. However, time-period based methods are simpler, and easier to explain in regulatory and other public proceedings. Earlier research also suggests that measuring the capacity factor of wind for the top 10% or more of the load hours will be within a few percentage points of ELCC.[4]

Table 3 presents a summary of study results and market rules that illustrate the range of capacity values found to apply to wind, and some of the methods used to calculate those values. Note that, in general, the capacity value data presented in Table 3 is typically lower than the average capacity factors of wind plants.

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[4] Milligan, M. and B. Parsons (1999), "A Comparison and Case Study of Capacity Credit Algorithms for Wind Power Plants. Journal of Wind Engineering. Multi-Science Publishing Co. LTD. Brentwood, Essex, United Kingdom. Vol. 23, No. 3, 1999.

Table 3. Wind Capacity Value in the United States

Region/Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s); 3-year near-match capacity factor for peak period used by CA PUC and CA ISO
CPUC	Peak Period	Three-year rolling average of the monthly average of wind energy generation between 12 and 6 p.m. for the months of May through September
PJM	Peak Period	Jun-Aug HE 3 p.m. -7 p.m., local time, capacity factor using 3-year rolling average (13%, fold in actual data when available)
MN 20% Study	ELCC	Found significant variation in ELCC: 4%, 15%, 25% and variation based on year
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26-34%)
NY ISO	Peak Period	Wind's capacity factor between 2-6 p.m., June through August, and 4-8 p.m., December through February
CO PUC/Xcel	ELCC	12.5% of rated capacity based on 10-year ELCC study. Load forecast algorithm compromised correlation between wind and load
PacifiCorp	ELCC	Sequential Monte Carlo (20%). Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
Idaho Power	Peak Period	4 p.m. - 8 p.m. capacity factor during July (5%)
Nebraska Public Power District		17% (method not stated)
Northwest Resource Adequacy Forum	Rule of Thumb	15%. Being studied further for potential revision
Tri-State	Peak Period	2-12%. Appears to be based on wind's contribution to monthly coincidental peak
SPP	Peak Period	Top 10% loads/month; 85th percentile
PNM	Peak Period	Capacity factor between 4-5 p.m. in July
ISO New England	Peak Period	For existing wind: wind's capacity factor between 2-6 p.m., June through September and 6-7 p.m. from October through May. For new wind: based on summer and winter wind speed data, subject to verification by ISO New England and adjusted by operating experience.

VI. Wind Integration Solutions

As wind capacity is added to the grid and more wind integration studies are performed, a variety of solutions are being considered in the U.S. to aid in integrating higher levels of wind generation. These potential solutions include the following:

- Grid codes
- Wind integration studies
- Flexible new generation
- Garnering more flexibility from existing generation
- More flexible markets
- Larger market operation areas
- Scheduling and dispatch rules
- Wind forecasting
- Responsive loads and real-time pricing
- Energy storage technologies
- Wind curtailment

***Implement Grid Codes*:**
When wind capacity began being installed in California in the 1980s, wind penetration was viewed to be small, and wind capacity was simply dropped from the grid during times of grid disturbances. As wind capacity began to increase and wind development moved beyond California to other states, the sudden loss of a large amount of wind capacity became more problematic for grid operators. Such a loss in wind capacity could lead to a fall in voltage and/or frequency. That, in turn, could contribute to other generators tripping off the grid and could result in not having enough generation to meet load.

In 2005, the Federal Energy Regulatory Commission issued Orders 661 and 661-A for interconnecting wind projects to the electrical grid in the U.S. As per those orders, wind plants are required to ride through low voltage events down to a zero voltage level for "location specific" clearing times up to a maximum of nine cycles (A cycle is equal to 1/60th of a second.). If the fault on the transmission system remains after the clearing time, the wind plant is permitted to disconnect from the system. Low-voltage ride-through is required for all new wind projects, and variations to these provisions are only allowed on an interconnection-wide basis, i.e., in the Eastern Interconnection, the Western Interconnection, or the Electric Reliability Council of Texas (ERCOT).

ERCOT established its own grid code for wind projects that encompasses both high- and low-voltage ride-through. ERCOT has also proposed that wind generators provide greater reactive power capability and limit ramp rates to 20% of nameplate capacity per minute. NERC has also proposed a high voltage grid code for wind projects, whereby wind projects are expected to stay on-line for a period of time should voltage on the grid exceed specified levels.

NERC is expected to soon release a report from its Integration of Variable Generation Task Force, or the IVGTF. Based on the findings and recommendations of the task force, NERC believes more work should be done on standardizing a grid code for wind projects, including the following elements:

- Power factor range (and reactive power capability)
- Voltage regulation
- Inertial response
- Control of ramp rates
- Providing frequency control

NERC recommends that any changes be phased in over time. The NERC Operating Committee plans to review its reliability standards to ensure adequate grid codes are in operation.

***Conduct Wind Integration Studies*:**
Early wind integration studies were conducted in the United States to address strong concerns that significant back-up generation would be needed to account for wind's variability; furthermore, that wind's variability could lead to grid disruptions and reliability failures. As noted earlier, these concerns proved to be overstated, and U.S. wind integration studies have now gravitated towards how to accomplish wind integration and at what potential cost. Sufficient general findings have emerged from the collective U.S. wind integration studies that can provide some basic guidance, but conducting a detailed wind integration study will address issues of concerns to a specific region, e.g., the interaction of the variability of load and of wind, ramping issues with and without wind, and minimum load with and without wind. Best practices of wind integration studies include matching the coincidence of loads and wind generation for specific time periods for multiple years (since load and wind generation can vary from year to year); constructing wind data from detailed, time-calibrated mesoscale metrological modeling; and having a technical review committee to review and assist study design, preparation and implementation.

***Add Flexible New Generation*:**
Adding variable generation sources will increase the need for generation resource flexibility, i.e., the ability for generation to move up and down in response to changing net load as opposed to baseload resources that have long start-up and shut-down times and are most cost-efficient and cost-effective when running at full output. Generation resource flexibility will be needed at different time-scales. The need for resource flexibility is more pronounced during times of minimum load, when generation that can be cycled down will be valued in order to accommodate higher levels of wind generation, as well as during times of low wind production, whereby generation that can ramp up will be needed.

At a minimum, the need for resource flexibility should be quantified and inventoried. More specifically, grid operators should strive to have generating resources or power agreements with neighboring grid operators that allow for assistance in grid operations at times of minimum load. Having higher levels of wind generation tends to result in lower levels of minimum load, as generation has to be de-committed or run at low levels to accommodate the wind generation. Similarly, having generation that can operate at lower minimum levels will also add flexibility and help with grid operations at minimum load. Another strategy is to add generation that can operate at diurnal cycling, such that the generation can operate at peak and shoulder loads but not have to operate at light loads.

Each operating grid will have differing characteristics and differing needs for flexibility, as well as different levels of available flexible resources. For grids with a high load factor, the generation resource mix may consist of more baseload resources with a smaller mix of flexible generation that can accommodate wind generation, absent a change in generation mix, operating practices, or access to transmission to import and export generation with neighboring systems.

Adding more flexible generation may be accomplished through incentives, mandates or through price signals. States or countries with integrated resource planning processes could incorporate resource flexibility as a criterion for resource evaluation and implementation. Capacity market auctions in the Northeastern US and other jurisdictions could also incorporate resource flexibility as a desirable operating characteristic, or perhaps hold separate auctions for flexible generating resources. Price signals could be utilized to signal greater need for load following or regulation up and regulation down services via ancillary service markets.

NERC is recommending in the IVGTF report that its Planning Committee should study potential changes to its annual resource adequacy assessment that consider ramping requirements and minimum generation levels, among other factors. NERC has also suggested that the electric power industry consider minimum requirements or market mechanisms such as price signals to ensure that non-renewable energy generation is flexible and can accommodate wind generation.[5]

***Garnering More Flexibility from Existing Generation through Contract Restructuring*:** Generators are typically reluctant to operate their generation at lower minimum turn-downs, or to ramp up and down more frequently, as such actions impose increased wear and tear on their units and incur direct costs such as increased fuel consumption with little or no compensation. Yet adding new generation resources of any type is capital-intensive and may be difficult to site from a political or regulatory perspective.

Acquiring more flexibility from existing generation, therefore, is a logical action. Inventorying and verifying the existing characteristics and capabilities of existing generation (e.g. minimum turn down, ramp rate capability) is the first step.

Relaxing or removing existing contractual obligations may also provide another source of flexibility. Certain existing contracts, notably some contracts under the Public Utilities Regulatory Policies Act of 1978 and contracts signed by the California Department of

[5] North American Electric Reliability Council. *Accommodating High Levels of Variable Generation*. Draft report, November 17, 2008. http://www.nerc.com/docs/pc/ivgtf/IVGTF_Reporta_17Nov08.pdf.

Water Resources during the California electricity crisis in 2000 and 2001, impose must-run conditions with operations around the clock. Such conditions can compound conditions such as minimum load by providing generation that cannot be ramped down and therefore makes the grid less flexible. New contracts, existing contracts considered for renewal, or any renegotiation of existing contracts should be evaluated with the view of at least maintaining, if not enhancing, grid flexibility. It should be noted that because of data constraints and market confidentiality concerns, U.S. grid integration studies are generally done without recognizing grid limitations that may be imposed by existing contractual obligations. Therefore, available grid flexibility, and the ability to incorporate higher levels of wind generation, may be somewhat exaggerated in these studies.

***Develop More Flexible Electricity Markets*:**
While operational flexibility is of high value to grid operators, it has correspondingly little value for power suppliers unless compensated, as deeper turnback, more rapid cycling and load following, and more frequent starts and stops all cause higher costs and revenue reductions for generation suppliers.

Market and policy changes will likely be a necessary feature of accessing greater flexibility from existing generation units, and that may take a combination of expanded ancillary service markets, incentives, and market requirements. For example, load following is not a compensated ancillary service in the United States, although it is recognized as essential for reliable grid operations. The cost of load following is implicitly included in the bids from generators.

Further market or policy changes may be necessary to accommodate wind ramps, which are relatively slow and infrequent and occur over several hours, as compared to a sudden generator trip. As such, wind ramps more closely resemble large load ramps than sudden unscheduled generator outages or trips. The ancillary service requirements from large wind ramps are more closely aligned with non-spinning reserves and supplemental operating reserve that are provided by generators and responsive loads that can respond within 10 to 30 minutes. Yet current reliability rules in the US require non-spinning reserves and supplemental operating reserves to only be in service for a period of time (usually 1-2 hours) that is shorter than the wind ramps that may occur over a longer period of several hours. Because of that, system operators may follow large wind ramps with regulation, at a cost that is 10 to 40 times that of non-spinning reserves and supplemental operating reserves. By way of comparison, non-spinning and supplemental operating reserves are estimated to cost about $1.50/MWh on average in California and New York in 2008, while regulation costs ranged between $33/MWh and $60/MWh.[6]

Fast, sub-hourly energy markets also aid in reducing wind integration costs. Sub-hourly energy markets can tap flexibility from existing generating units at little or no cost, and reduce the need for regulation, the most costly ancillary service. It also matches the timing of wind's variability in that wind output varies more in the sub-hourly to multiple-

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[6] Testimony of Brendan Kirby, Consultant to the American Wind Energy Association, to the Federal Energy Regulatory Commission, March 2, 2009.

hour time frame, not on a minute-to-minute basis that is characteristic of regulation. Fast, sub-hourly markets tend to be characteristic of ISOs and RTOs. Areas without ISOs and RTOs generally allow hourly generation schedules only, and most generators have to follow flat hourly schedules set one hour or more in advance. In these regions, changes in load or generation within the hour are met by generating units on regulation service. Regulation units receive signals every few seconds to change their output to balance load and generation.

As a consequence, wind integration costs for ISOs and RTOs are typically lower than for non-ISOs and RTOs. The integration costs for the two ISO and RTO studies range from near zero to $4.41/MWh of wind, while the integration costs for the two non-ISO or RTO studies range from $7.92 to $8.84/MWh (see Table 4). One reason for these results is that the two ISOs and RTOs operate subhourly markets (i.e., they dispatch generation on a five- to fifteen-minute timeframe), while the two non-ISOs or RTOs require generators to follow hourly schedules and obtain all subhourly balancing from regulating units.

Table 4. Wind-Integration Cost Study Results

Date	Study	ISO/RTO	Wind Capacity Penetration	Integration Cost: $/MWh of Wind Output	Energy Market Interval
3/05	NYISO	ISO/RTO	10%	Very low	5 minute
12/06	Minnesota/MISO	ISO/RTO	31%	$4.41	5 minute
3/07	Avista	No	30%	$8.84	1 hour
3/07	Idaho Power*	No	30%	$7.92	1 hour

* Reduced from $16.16 in September 2007 settlement proceedings.

A GE study for ERCOT recommended creating a new mid-term ancillary service. ERCOT currently employs Non-Spinning Reserve Service (NSRS) to cover unpredicted load changes over a period longer than 30 minutes. NSRS services are only procured for certain 'high risk' hours mainly due to weather or when spinning reserve procurement is projected to be less than the reliable minimum. The GE study recommended creating a mid-term ancillary service such as a 'quick-start non-spinning reserve' with a shorter start-up criterion (less than the 30 minutes currently required by NSRS) rather than relying on regulation to track wind's movements up and down. Regulation is a relatively expensive ancillary service, as both capital and fuel costs are accounted for, and the service must always be in operation, since it tracks movements in generation and load on a minute-by-minute basis. In contrast, providers of a mid-term ancillary service such as quick-start non-spinning reserves are only paid when the service is used, with no capital or reservation charge. The report also recommended that ERCOT modify its procurement of the NSRS to include 'high risk' times when wind energy changes are forecast to be dramatic. Wind movements tend to take place over hours rather than minutes and are more equivalent to anomalous load rises and therefore, can be tracked with less expensive non-spinning reserves. NSRS, both quick-start and the current 30 minute service, could cover much of the longer ramp changes presented by wind, can be procured on an as-needed basis, and reduce the requirement for procuring regulation and spinning reserve services.

***Operate Over Larger Market Operation Areas*:**
There are about 140 balancing areas (sometimes called control areas) in the United States with wide variations in size, generating resources, and load. As the term implies, each balancing area must balance load and generation within its area, and is responsible for meeting NERC reliability requirements. In general, larger balancing areas will have more ability to integrate more wind, as it can access more available generating resources that can provide ancillary services. In addition, a larger balancing area can take advantage of the geographic diversity of wind resources, thereby helping to smooth the variability of wind production.

Two different wind integration studies for the state of Minnesota provide an example. A 2004 study encompassing Xcel Energy (the largest utility in Minnesota) studied 15% wind penetration (about 12% by energy) and for that single control area, estimated that wind integration costs would be about $4.60/MWh. A 2006 Minnesota statewide integration study assessed the wind integration cost for up to 25% wind by energy but included the generation and transmission facilities in all of the Midwest ISO. The study determined that wind integration costs could be as high as $4.41/MWh, somewhat lower than the earlier analysis despite a much higher level of wind penetration. A separate analysis in New York showed large increases in hourly, 5-minute and six-second variability for New York if generation and load is balanced by individual zone rather than statewide.

Although ISOs and RTOs naturally capture the benefits of large balancing areas, these benefits can also be at least partially captured though sharing agreements among system operators. One example is the ACE Diversity Interchange that pools area control error (ACE) among utilities in the Pacific Northwest, and more recently, some utilities in the Southwest. ACE is the difference in planned and actual interchange within a control area. By sharing ACE among multiple control areas, diversity in load and generating resources can be captured. Early experience with the ACE Diversity Interchange indicated improvements in meeting ACE requirements and in other reliability performance measures.

***Develop Scheduling and Dispatch Rules that Accommodate Wind*:**
Wind generation becomes easier to forecast the closer the predictions are to real-time market operations, and correspondingly, more difficult to predict farther in advance. Therefore, submitting wind generation schedules closer to real-time market operations will allow for more accurate predictions of wind generation, although some trade-offs are involved. That said, having a shorter period of time before the start of real time market operations may contribute to a need for more reserves such as load following or perhaps higher costs from the increased starting and stopping of conventional units, as those

shorter periods of time will not allow sufficient time to change unit commitment decisions for conventional generating units.[7]

Final scheduling requirements are sometimes driven by regulatory requirements that do not have a technological or economic basis. FERC Order 888, issued in 1996, required FERC-jurisdictional transmission providers to offer open transmission access and is a case in point. FERC required transmission providers to offer six ancillary services, one of them being energy imbalance service to correct for hourly mismatches between the scheduled delivery and the actual delivery of energy to a load located within a control area. FERC also allowed transmission providers to apply a penalty if energy deliveries vary 1.5% or more (either higher or lower) from advance energy schedules (i.e., day-ahead). The imbalance penalties were typically not based on the cost incurred by the system operator, but instead were punitive to prevent strategic behavior by generators. Under this regime, typical penalties were either set at a utility's incremental cost of providing hourly energy plus an adder, or a pre-set price, such as 100 mills/kWh.

Absent waivers or special provisions, the FERC Order 888 energy imbalance essentially forestalled wind development, as it was impossible for wind generators to deliver wind energy within the 1.5% band included in the Order 888 tariffs, and the penalty provisions typically exceed the commercial value of the wind energy.

In 2007, FERC adopted Order 890 that, among other things, replaced the penalty-based energy imbalance charges with imbalance charges based on costs. Specifically, FERC adopted a tiered approach used by the Bonneville Power Administration, a transmission and wholesale power operator in the Pacific Northwest. Tier One imbalances of less than or equal to 1.5% of scheduled energy, or up to 2 MW (whichever is greater), would be netted monthly and settled at the incremental or decremental cost. Tier Two imbalances of between 1.5% and 7.5% of scheduled energy, or between 2 and 10 MW (whichever is larger), would be settled at 90% of decremental costs and 110% of incremental costs. Tier Three imbalances of over 7.5%, or greater than 10 MW whichever is greater), would be settled at 75% of decremental costs or 125% of incremental costs. Intermittent resources are exempt from the Tier Three imbalance charges.

Different system operators have implemented different provisions for scheduling wind that were not affected by Order 890, as discussed below:

- *California ISO*—For wind generation that participates in the California ISO's wind forecasting program (described more below), positive and negative scheduling deviations from intermittent renewable energy generators are netted on a monthly basis. Penalties associated with energy imbalances are waived.

[7] Gul, Timur, and Till Stenzel. *Variability of Wind Power and Other Renewables: Management Options and Strategies*. Paris: International Energy Agency. 2005. http://www.uwig.org/IEA_Report_on_variability.pdf.

- *ERCOT*—Wind generation is allowed a 50% deviation from schedules (50% under schedule or 50% over schedule). Load serving entities absorb any energy imbalance costs.

- *ISO New England*—Depending on the size of the facility, ISO-NE schedules intermittent power producers differently:

  - Wind capacity under 5 MW is treated as a "settlement-only resource." These resources do not have to bid in the day-ahead market; instead, they generate into the grid at real-time and get the real-time nodal price. The capacity value of these resources is considered the same as the capacity factor of the project, minus forced outages.

  - Wind capacity over 5 MW is considered an "intermittent power resource." These resources can submit bids into the day-ahead market, but if they do not, they must self-schedule into the reoffer period. As with settlement-only resources, the capacity value of these resources is considered the same as the capacity factor of the project, minus forced outages.

- *Midwest ISO*—MISO does not schedule wind in the day-ahead market but instead takes wind generation in the real-time market.

- *New York ISO*—The New York ISO settles schedule imbalances in real-time, without penalties, with generators being paid the real-time price for energy deliveries over schedule, and conversely, paying the real-time price if energy deliveries are below schedule. Up to 3,600 MW of wind generation is exempt from paying under- or over-scheduling penalties.

- *PJM*—As with the NYISO, PJM settles schedule imbalances in real-time, without penalties, with generators being paid the real-time price for energy deliveries over schedule, and conversely, paying the real-time price if energy deliveries are below schedule. PJM takes wind as a price taker in the real-time market and does not require wind generators to bid into the day-ahead market, except for wind generation that is an installed capacity resource, whereby these wind generators must bid into PJM's capacity auction known as the Reliability Pricing Market. PJM imposes an operating reserve charge for differentials greater than 5 MW to recover the costs from decommitting already committed generators. On average, the operating reserve charge is about $2–$3/MWh.

***Implement a Wind Forecasting System*:**
Because of the variability and uncertainty of wind production, a common practice for grid operators and utilities historically in the U.S. has been to simply take the wind generation on an as-available basis and back off other generation that has been committed in order to incorporate the wind generation. In general, such practices are acceptable for installed

wind generation amounting to small percentages of peak load, as the variability of the wind generation is swamped by load variability and could be easily absorbed.

Similarly, taking wind in when it shows up becomes untenable at higher levels of wind penetration, as it imposes operational inefficiencies and increased fuel consumption that becomes significant as wind penetration increases. The GE New York study determined that variable operating cost savings from 10% wind penetration increase from $335 million to $430 million when state-of-the-art wind forecasting is used, with another $25 million in benefit when perfect wind forecasting is used. The Intermittency Analysis Project conducted by GE for the California Energy Commission demonstrated a benefit of $4.37/MWh with state-of-the-art wind forecasting and another $0.95/MWh for perfect wind forecasting. Therefore, recent U.S. wind integration studies have strongly recommended that grid operators adopt and implement centralized wind forecasting that include all wind projects.

Wind power forecasting relies on three interrelated steps: 1) Numerical weather predictions (NWP) that include wind speed forecast and other meteorological parameters are used to, 2) forecast wind farm power output that can be, 3) scaled-up to regional forecasts using data from representative wind farms. There are two primary forecast horizons—the day-ahead and the real-time. For the day-ahead forecast, the preparation of the forecast starts 48 hours ahead (counted from the start of the NWP model); however, if there is no trading on weekends and public holidays lead time for the day-ahead trading can be anywhere upwards of 96 hours. In contrast, the real-time forecast is primarily used for intraday trading and activation of operating reserves and is conducted using online data from measurements of actual power output and/or wind speed, leading to an increase in forecast accuracy.

Another factor that influences the accuracy of forecasting is spatial spread. It is possible to forecast for small regions or an individual wind plant (helpful when addressing grid operation and congestion management issues) or for an entire control area (useful for optimizing power plant scheduling and balancing). As might be expected, when a forecast is conducted for multiple wind farms, the forecast error decreases. If that approach is taken one step further and the aggregation of large regions is coupled with several gigawatts of installed wind energy capacity, the relative forecast error will decrease even further. Increasingly accurate forecasts result in more precise power plant scheduling, thus reducing the economic costs often associated with wind integration.
To further enhance forecast accuracy, there is a trend of moving away from the typical practice of calculating wind power using a single NWP model—due to the risk of high and costly errors in prediction—especially in the case of extreme events, where individual models can go wrong, a multi model approach is employed. This allows for a combination of the best performing weather models for the specific situation, leading to significantly improved wind power prediction.

Yet another approach involves the use of an ensemble prediction system that serves as a combined weather and wind power forecasting system. The results of one study analyzing approximately one year of data illustrated forecast improvements of 9 to 24 percent dependent on the location and size of the forecasted area. Combining the individual wind power forecasts derived from a physically consistent ensemble prediction system not only results in significant improvements compared to single forecasts, but also has an advantage as a more cost-effective alternative to the multi-model approach.

The California ISO became the first grid operator to adopt centralized wind forecasting when it implemented the Participating Intermittent Resource Program (PIRP). In PIRP, the positive and negative imbalances associated with the 10□minute schedules of wind power generators are netted out and settled on a monthly basis, with the notion that these imbalances will cancel out over the month. Any net imbalances at the end of the month, positive or negative, are settled at the weighted average zonal market clearing price. Wind generators that participate pay the CAISO a $0.10/MWh fee; agree to stay in PIRP for one year; install CAISO telemetry equipment; schedule consistently with the CAISO's forecast of wind generation; and do not make advance energy bids into the California market.

Much has been learned from the PIRP program. Because the California ISO wind forecasting contract had incentives to discourage positive or negative bias in the wind forecasts, the wind forecasts were sometimes skewed to avoid the bias and to drive the monthly deviation charges as close to zero as possible, affecting forecasting accuracy. Missing data and unknown unscheduled wind plant outages also negatively affected the wind forecast accuracy. As a consequence, the California ISO now requires wind generators to have at least two metrological stations reporting from each project and have dropped the minimum capacity required for reporting outages from 10 MW to 1 MW.

Both ERCOT and the New York ISO adopted centralized wind forecasting in 2008, and PJM and the Midwest ISO plan to incorporate wind forecasting in 2009. Xcel Energy is collaborating with the National Center for Atmospheric Research for developing high-resolution wind forecasts every three hours for wind projects in Colorado, Minnesota, New Mexico, Texas and Wyoming. The New York ISO's forecast consists of a day-ahead wind forecast that is integrated with the New York ISO's unit commitment process and a real-time forecast that is blended with persistence forecasts to develop wind plant schedules in real-time commitment (which looks ahead in 15-minute intervals for 75 minutes) and real-time dispatch (which looks ahead in 5 to 15 minute intervals for 60 minutes).

***Use Responsive Loads and Real-Time Pricing*:**
Demand response or load management is defined as the ability of end users of electricity to reduce load in response to price signals or other grid management incentives and regulations. As of 2008, the Federal Energy Regulatory Commission reports that 8 percent of energy consumers in the United States are in some kind of demand response program and the potential demand response resource contribution from all such U.S. programs is close to 41,000 megawatts, or 5.8 percent, of U.S. peak demand.[8] Shifting

[8] Federal Energy Regulatory Commission. *Assessment of Demand Response and Advanced Metering*, December 2008. http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf. (Accessed March 13, 2009).

load to correspond to periods with high wind production may help avoid curtailment of wind generation and help manage conditions of high wind generation of times of low or minimum load. To date, demand response programs have been designed for reducing peak electricity demand, or for allowing customers to self-generate using distributed generation, also during times of peak demand, not for aiding wind integration.

Real time pricing might also be used as a strategy for incorporating increasing amounts of wind energy into the electric grid. Research conducted by the Integrated Systems Engineering Department of Ohio State University found that the use of real time prices would reduce the wind integration costs as consumer demand would more closely follow the availability of low cost electricity supply. With real time prices, if available wind generation is less than forecast, the cost of deploying ancillary services to cover the generation shortfall will be passed on to consumers, thereby reducing electricity demand and the cost of serving the load. The results show up to a 7 percent increase in the use of wind generation, with a corresponding increase of approximately 10 percent in wind generation's contribution to load.[9]

***Research Energy Storage Technologies*:**
Researchers have been contemplating the best technologies and most cost-effective options for storing energy for several decades. Storage can be used to provide three varying support services:

1. Super-hourly or load shifting service, charging overnight and in off peak periods and discharging during peak afternoon and evening hours;

2. Shorter-term balancing service, where stored electricity is used to smooth variation of wind farm output thereby reducing the need for some spinning reserves;

3. Quick-acting instantaneous service, where storage systems provide immediate frequency and regulation products.[10]

That said, the U.S. Department of Energy determined that the U.S. can accommodate as much as 20% wind power generation without requiring storage. It will be many years before the levels of wind generation will be significant enough in the U.S. before storage may be needed, and in that time, changes in resource mix, market rules and the other factors discussed earlier may ease large-scale wind integration without the need for storage technologies. Consistent with this time frame, several of the storage technologies

[9] Ramteen Sioshansi and Walter Short, "*Evaluating the Impacts of Real-Time Pricing on the Cost on the Usage of Wind Generation,"* Integrated Systems Engineering Department, The Ohio State University, Columbus, OH, submitted to IEEE Transactions on Power Systems. Available: http://iwse.osu.edu/isefaculty/sioshansi/

[10] Patrick Sullivan, Walter Short, and Nate Blair, *Modeling the Benefits of Storage Technologies to Wind Power,* National Renewable Energy Laboratory, presented at the American Wind Energy Association (AWEA) Wind Power 2008 Conference, p. 4.

that will be discussed in this paper are at an advanced R&D or demonstration stage and are not available at a large scale currently.

Overall, storage should be used as a system resource, i.e., to help meet load requirements or to provide ancillary services, not to balance or "back up" individual generating plants. NREL determined there is an economic benefit for energy storage, finding that the price of electricity is $2/MWh cheaper in a scenario with storage as compared to a scenario without storage. The savings are effectively the avoided costs of not having to build as many conventional, natural gas-fired power plants.[11]

Pumped hydro, which generates electricity by reversing water flow between reservoirs, is the most widespread energy storage system on power networks. With an efficiency rate of more than 80%, pumped storage provides for approximately 20 GW of storage in the United States.[12] In one study, Public Service Company of Colorado found that its existing pumped storage hydro project offered a $1.30/MWh offset to wind integration costs at a 15% wind penetration level.[13]

Compressed air energy storage (CAES) makes use of natural and manmade (abandoned gas and oil wells) caverns to store compressed air and recover it for use in a turbine. Electricity is used to compress and pump high pressure air into an underground cavern during off-peak times when electricity prices are low. When electricity is needed, the air is released from the cavern, mixed with natural gas, and combusted leading to the air's expansion prior to running it through a turbine to generate electricity.[14] Presently, just two compressed air facilities exist: a 17-year-old, 110 MW facility in McIntosh, Alabama, and a 30-year-old plant in Germany, both in caverns in salt domes. The Iowa Association of Municipal Utilities plans to develop the Iowa Stored Energy Park (ISEP), whereby electricity output from a nearby wind power facility will be stored in an underground geologic structure using CAES technology to generate electricity during peak periods. The plant is expected to come online by 2011 and will provide 268 MW of wind/CAES electricity with 50 hours of wind power storage.[15]

The Federal Energy Regulatory Commission's (FERC) Order 890 allows for non-generation resources to participate in ancillary services markets. On January 6, 2009, FERC approved the Midwest Independent Transmission System Operator's (Midwest ISO) proposal to use stored energy resources for contingency reserves as well as regulating reserves.[16] Energy storage devices, specifically flywheels and batteries, are among the first storage technologies being integrated into regional regulation markets. Flywheel systems utilize a large rotating cylinder, and can be used for providing

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[11] Ibid., pp. 10-12.
[12] Sullivan, et al, p. 6.
[13] R.M. Zavadil. *Wind Integration Study for Public Service Company of Colorado*. May 2006. http://www.nrel.gov/wind/systemsintegration/pdfs/colorado_public_service_windintegstudy.pdf. Accessed March 14, 2009.
[14] Sullivan et al, p. 5.
[15] Website for the Iowa Stored Energy Park, http://www.isepa.com/index.asp
[16] *FERC authorizes Midwest ISO Ancillary services market for January 2009 startup,* FERC News Release, December 18, 2008, Available: http://www.ferc.gov/news/news-releases/2008/2008-4/12-18-08-E-3.asp

regulation services.[17] Flywheels are commercially available for development as "regulation power plants" providing up to 20 MW of up and down regulation for a 40 MW swing. Beacon Power has installed two 100 KW fly wheel demonstration projects for frequency control and load balancing in New York and California.[18] The New England ISO launched its "Alternative Technologies Regulation Pilot Program" on January 1, 2009. The pilot program allows for up to 13 megawatts of alternative technologies to be connected to the grid to provide regulation services. Beacon Power plans to connect up to five megawatts of energy storage flywheels.[19]

Battery storage systems are being evaluated for their ability to control and dispatch electricity as needed to meet demand or for system stability. Some lithium Ion batteries and Sodium Sulfur batteries are already in use to provide 15 to 60 minutes of energy storage as regulation services. A handful of energy companies are beginning to test the use of batteries for grid management and energy storage. AEP installed a 1.2 megawatt battery system in West Virginia in 2006 to test the storage technology and to help fill capacity gaps and flatten the load in the region.[20] Following their installation and observation of the 1.2 MW NaS battery, AEP installed an additional 6 MW, in three 2 MW sites. A unique feature of the battery storage systems is a triggered allows electricity discharge to provide load following service.[21] In Minnesota, Xcel Energy plans to use a 1 MW sodium sulfur (NaS) battery from NGK Insulators to test the battery's capability to store wind energy for eventual dispatch to the electricity grid.[22] The battery is capable of providing a constant power level of up to 1.2 MW for 6 hours and will store wind energy before being transmitted to the grid. Southern California Edison is supporting a research project, funded in part by the California Energy Commission, titled "SCE Storage Wind Research," a detailed feasibility and analysis study of existing wind-interconnection locations throughout the SCE system that may benefit from the use of storage devices.[23]Additionally, Altair Nanotechnologies Inc.'s 1 MW, 250 kWh Lithium-Titanate battery storage system recently received approval from PJM to provide grid regulation services as part of an AES technology validation effort in their Indianapolis Power & Light service areas in Indiana.[24]

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[17] Kevin Porter, Exeter Associates, Inc., and, Intermittency Analysis Project Team, *Intermittency Analysis Project: Final Report*, California Energy Commission, July 2007, p. 42.

[18] Website for Beacon Power, http://www.beaconpower.com/products.

[19] New England ISO, Alternative Technology Regulation Pilot Program, FAQs. Available: http://www.iso-ne.com/support/faq/atr/index.html#faq1; and *Energy Storage Pilot Program Approved in ISO New England; Beacon Power Eligible to Participate and Earn Revenue,* Beacon Power Press Release, August 7, 2008, Available: http://www.beaconpower.com

[20] Ali Nourai, Installation of the First Distributed Energy Storage System (DESS) at American Electric Power (AEP), Sandia National Laboratory, Albuquerque, New Mexico 87185 and Livermore, California 94550, Available: http://electricitystorage.org/pubs/2009/Sandia_First_Storage_AEP.pdf

[21] E-mail correspondence with Ali Nourai, Distributed Energy Resource, American Electric Power, February 13, 2009.

[22] *2007 Resource Plan, Appendix E: Wind Storage Research and Experiments*, Xcel Energy, Available: http://www.xcelenergy.com/SiteCollectionDocuments/docs/AppendixE.pdf

[23] Stephanie Hamilton, Southern California Edison, "Batteries are Key to Wind Integration," *Transmission and Distribution World*, December 1, 2008.

[24] " PJM Accepts First Grid-Scale, Battery Energy Storage System," *Transmission and Distribution World,* December 1, 2008. Available: http://tdworld.com/test_monitor_control/highlights/pjm-altair-battery-storage-1208/

Use of plug-in all-electric and hybrid vehicles for storage of electricity is another variation of battery storage. The idea of using the batteries of plug-in all-electric and hybrid vehicles as an energy storage resource is called Vehicle to Grid (V2G). The Mid-Atlantic Grid Interactive Car Consortium (MAGICC)[25] interconnected an AC Propulsion "eBox" (a converted Toyota Scion xB, fitted with an AC induction motor, AC-150 electronics and a custom built battery) to the PJM grid and used the control center of PJM to dispatch the battery-stored electricity as a regulation resource.[26] In addition to regulation, the V2G concept would have vehicles providing spinning reserves, back-up power supply service; and peak load management. According to MAGICC, a vehicle plugged in at home and driven sporadically for a total of 2.5 hours might provide regulation electricity services for more than 21.5 hours. In regulation down periods, the car takes in the excess electricity and stores it, in regulation up periods, the car discharges electricity.[27]

***Allow for Wind Curtailment*:**
Maximum wind production can be several times larger than average wind production, meaning that at 20 percent wind penetration by energy, wind production may equal consumer demand for some hours. Curtailment of wind generation may be necessary if the amount of wind generation at a specific time is more than what the grid can reliably handle. In fact, for grids with small control areas that are dominated by thermal generation that may not be very flexible, wind curtailments could occur at wind penetrations as low as 10 percent.

More recent U.S. wind integration studies have stated that at higher levels of wind penetration, wind generation may need to be curtailed during some portion of the year. The Intermittency Analysis Project report for California suggested that wind curtailment may be advisable at times of minimum load if there is insufficient down regulation. The GE study for the New York ISO and the New York Energy Research and Development Authority recommended that the New York ISO have the ability to limit or curtail wind generation for system reliability reasons, such as temporary local transmission limitations or if severe weather is expected. The curtailment would be imposed on a project basis, i.e., the wind operator could choose to meet the proposed curtailment through limiting production or by shutting down individual wind turbines, not the entire wind plant.

Some grid operators have proposed or are experimenting with implementing wind curtailment. In Texas, ERCOT assigns daily limits on wind generation because of transmission constraints. Between January and August 2008, ERCOT curtailed, on average, between 140 and 150 MW of wind.

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[25] Consortium including: Pepco Holdings Inc. (PHI), the University of Delaware, the PJM regional transmission organization, AC Propulsion, and Comverge.
[26] Willet Kempton, et al, *A Test of Vehicle-to-Grid (V2G) for Energy Storage and Frequency Regulation in the PJM System*, University of Delaware, November 2008, pp. 6-7.
[27] Ibid., pp. 23-24.

Separately, the New York ISO has requested that FERC adopt its wind curtailment proposal. Under the New York ISO's proposal, wind generators can move up and down freely during unconstrained hours. During constrained hours, NYISO will choose the most economic units to relieve the congestion, including directing wind plants to reduce their output if the clearing price drops below the wind plant's economic offer price. NYISO will send a signal to a wind plant when the clearing price is below the bid price and will impose penalties if the plant does not follow base point directions. The penalty would be set as the deviation over base point multiplied by the regulation clearing price, with a 3% bandwidth margin. PJM will likely adopt a similar proposal, although without penalties.

The Bonneville Power Administration and system operators in Hawaii are requiring wind plants to install and respond to automated wind energy management signals. BPA is adapting its wind generation interconnection procedures to require wind plants to install automated control systems. Variable generators must be able to accept electronic dispatch signals and comply with generation reduction orders within ten minutes (if required). The Hawaii Electric Company requires all wind plants in its control area to install grid operator-controlled curtailment interfaces that are designed with a set point that limits the output of the wind plant to an amount set by the grid operator.

VII. Role of Wind in Recent Electric Outages

From an operational perspective, there is relatively little experience in dealing with outages caused by too much wind on the system. Two examples, both from ERCOT in Texas, detail a large ramping event and a reliability event, both of which occurred within the past two years.

> *February 24, 2007: Texas Reliability Event*[28]
> On the morning of February 24, 2007, aggregate wind production in ERCOT was over 2,000 MW—about 70 percent of the total 2,900 MW state wind capacity. A strong weather pattern moving across the state increased the winds throughout the western part of the state forcing a number of the turbines to shut down. One 200 MW wind plant dropped 150 MW in 11 minutes. The total wind fleet dropped approximately 1,500 MW over an almost two hour time period; a dramatic drop in production, but because it occurred over hours rather sub-hourly, it was considered a large ramping event, not a contingency event.
>
> *February 26, 2008: Texas Reliability Event*[29]
> Because of a deteriorating imbalance between load and generation that led to a drop in system frequency, ERCOT called upon its commercial and industrial customers who participate in a load response program to curtail load. The event

[28] Milligan, M and Brendan Kirby, "Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration," Conference Paper NREL/CP-500-41809, June 2007.
[29] Ela, E. and Brendan Kirby, "ERCOT Event on February 26, 2008: Lessons Learned," Technical Report NREL/TP-500-43373, July 2008.

drew significant media attention because of what was perceived as wind's prominent role, but several factors contributed to the event. No load was involuntarily curtailed. Over the 40 minutes preceding the start of load curtailment, wind generation declined by 80 MW relative to its schedule, non-wind generation decreased by 350 MW relative to its schedule, and load increased by 1,185 MW above the forecasted value. Ironically, ERCOT was field testing but not relying upon a centralized wind forecasting system, which forecasted the event reasonably accurately. After the event, ERCOT accelerated incorporation of its centralized wind forecasting system.

Although much was made of the fact that ERCOT called upon commercial and industrial load to voluntarily curtail production, it is not unusual for ERCOT to do so. ERCOT called upon commercial and industrial load to provide non-spinning reserve 63 times in 2007, and load for spinning reserve about 10 times. The average load response was 1,137 MW and had a duration of about three-and-a-hours, as compared to this event that used 1200 MW of load response and lasted just under three hours.

VIII. Summary

Wind presently contributes just 1-2% to total U.S. electricity generation. That said, a number of utilities are adding significant amounts of wind capacity, and over a dozen wind integration studies have been conducted to assess the technical ability and feasibility to incorporate wind energy. In general, the wind integration studies have moved from "can it be done" to "how and at what cost." These studies have found that large interconnected power systems can accommodate high levels of variable renewable energy generation (wind and solar) generation but not by doing more of the same. Wind forecasting, acquiring flexible generating resources (from new or existing generating units), new operating strategies during minimum load hours or other high risk periods, larger balancing areas (or greater sharing between balancing areas) new market rules, and grid codes will be necessary to incorporate higher levels of wind generation.

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