# Wind Plant Integration

## Costs, Status, and Issues





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INTEGRATION OF WIND POWER PLANTS INTO THE ELECTRIC POWER SYSTEM presents challenges to power-system planners and operators. These challenges stem primarily from the natural characteristics of wind plants—which differ in some respects from conventional plants—and from the fact that wind is a relatively new power source with a much shorter track record than conventional fossil or hydro power plants. Wind plants operate when the wind blows, and their power levels vary with the strength of the wind. Hence, they are not dispatchable in the traditional sense, which lessens the ability of system operators to control them. This leads to a concern among operators unfamiliar with wind power about wind's impact on the real-time process of maintaining the system's balance between load and generation.

The lack of dispatchability also limits wind generation's ability to serve new system load. Indeed, as discussed in the following, capacity credits for wind plants rarely, if ever, approach nameplate ratings. Traditionally, this has caused concern; however the level of concern diminishes as power-system personnel view wind more and more as primarily an energy source—and one that generally has some capacity value as well. The key integration question then becomes how the variations in wind plant outputs affect the operation of the power system on a day-to-day basis and what the associated costs are. As discussed below, these costs are lower than initially expected by some utility engineers. The main reason for this is that wind tends to behave more like negative load than traditional firm-block generation, and the power system has been designed to handle significant load variations on a routine basis.

## Key Wind Integration Issues

Wind's natural variability gives rise to a number of questions important to power system operators and planners. Key among these are the following:

- ✔ How does wind generation affect net load (i.e., load minus wind) variability?
- ✔ To what extent are dispatchable generation reserves required and under what circumstances?
- ✔ Will system reliability be compromised?
- ✔ What are the system operating cost impacts of wind's variability?
- ✔ How should wind plant capacity credit be determined?
- ✔ What is the role and value of wind forecasting?
- ✔ How do impacts vary with wind penetration?
- ✔ How has wind affected system operating strategies in practice so far?

In aggregate, the wind integration studies conducted to date have addressed most of these questions, although none has addressed them all. We summarize below the key results and insights from the individual studies, and then draw overall conclusions. All of the studies present simulations of system operation that employ well-established production-costing and unit-commitment computational tools. Most have benefited from peer review by industry experts.

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The last question on the above list was outside the scope of the existing studies. Therefore, we have attempted to glean related insights through discussions with personnel involved in the operation of utility systems that include significant amounts of wind in their generating mix.

## Some Popular Misconceptions about Wind Power

Concerns arising from wind's variability have spawned a number of misconceptions that are often voiced by utility engineers unfamiliar with wind power and by individuals wishing to impede wind power expansion. Each of these has been dispelled by either deliberate, careful examination or by actual practical experience. We discuss four of the most prominent misconceptions here, with additional detail in subsequent sections. First is the notion that every megawatt of wind generation must be backed up by approximately 1 MW of conventional dispatchable generation. Actually, the great majority of wind generation has been added to power systems as an energy source rather than a capacity source, so the generation needed to maintain system demand-generation balance is already present as part of the system. As discussed further below, a small amount of additional regulation or load-following capability is generally needed, but that is most often provided by existing units. And as a practical matter, with over 6,000 MW of installed wind power generation so far in the United States, not a single conventional unit has been installed as a backup generator for wind.

A second popular notion is that wind plant output can (and often will) drop to zero in a few seconds. In fact, individual turbines in a wind plant experience different winds at any given moment, leading to substantial spatial smoothing of the output from the entire plant. Additional smoothing occurs as more plants are added in different locations. An informative study of these issues has been carried out by Y. Wan of the National Renewable Energy Laboratory (NREL). These findings have been corroborated by several of the studies discussed in this article. A third notion—closely related to the second—is that wind plants will cause the entire power system to collapse. But again, because abrupt wind-related changes in plant output do not occur, this fear is unfounded. If an entire plant trips off because of a plant-level failure such as the loss of a step-up transformer, then the situation is no different than a similar problem with a conventional plant. Finally, as shown in the GE Energy study discussed below, a modern wind plant will actually help a power system handle a major outage or contingency elsewhere on the system. Reactive-power control and low-voltage ride-through capabilities of modern wind plants actually improve system stability.

A fourth notion is that the impacts of wind's variability on the operation of the rest of the power system will result in operating cost increases comparable to or even greater than the value of the wind energy. This misconception is the central focus of most of the studies discussed below. In most cases studied so far, the cost impact of wind's variability is about 10% of the wholesale value of the wind energy.

## Important Time Frames

Comprehensive investigation of wind power integration into electric power systems requires examinations covering time frames ranging from milliseconds to several years. System dynamic stability studies require modeling in the milliseconds to seconds time frame. Contributions to capacity expansion for meeting load growth are evaluated over periods of 1–10 years and perhaps longer. System operating cost evaluations require simulations over at least one year and generally cover several years of operation. The impacts of wind's variability on operating costs are captured by examining three different intermediate time frames: 1) frequency regulation (handled by automatic generation control and governor action without operator intervention) takes place in the time frame of a few seconds to about a minute; 2) load following (handled by economic dispatch and operator actions to deal with variations from load and generation forecasts and guided by the unit-commitment schedule for that day) takes place in the time frame of a few minutes to a couple of hours; and 3) unit commitment (handled by schedulers using load-profile predictions and characteristics of available generating units) deals with the time frame from several hours to one or more days into the future.

## Major Studies of Wind Integration into Electric Power Systems

Over the past four years, several thorough investigations of wind's impacts on power system operation and operating costs have been carried out. Most have involved utility systems that are still vertically integrated and have been conducted from a cost-of-service viewpoint. In contrast, one of the studies—a particularly comprehensive investigation of 10% wind penetration in the New York State power system (in all cases in this article, penetration is expressed as the ratio of nameplate wind generation to peak load served by the system; the New York study considered 3,300 nameplate MW of wind in a system serving a peak load of about 34,000 MW)—was conducted in the context of a large, fully functioning, statewide wholesale market for electrical energy, capacity, and ancillary services. This market is managed by the New York Independent System Operator (NYISO), which serves as the single balancing authority for the state.

A very important distinction exists between the cost-based and market-based studies. Most of the cost-of-service studies examine the costs of serving the portion of system load not served by wind. The energy from wind plants is assumed to pass through the power delivery system from wind generators to customers, and the associated payments are not considered. Rather, attention is focused on the costs of operating the nonwind portion of the overall system. In particular, these operating costs are estimated both with and without the effects of wind's variability. The difference in these two cost

estimates is ascribed to accommodation of wind's variability and uncertainty and is allocated over the total amount of wind energy generated. This yields a result expressed in terms of US$/MWh, which can be viewed as an equivalent reduction in the value of the wind energy. What is not captured—because it is not the focus of the studies—is the impact of the cost of the wind energy on customer payments. If the average unit of wind energy (after adjusting for wind's variability cost and any differences in transmission costs) costs more or less than the average unit of conventional energy, then customer payments will be increased or reduced, respectively.

In contrast, the New York market-based study captures the full range of impacts from the addition of wind. Included in the results are the conventional-plant operating cost increases attributable to wind's variability, the cost of the wind energy itself, and reductions in conventional plant operating costs stemming from displacement of conventional energy by wind energy. The actual costs of wind energy are established on an hourly basis through bids into the New York State wholesale power market; the wind generators—like all other generators—are paid what the market will bear for each hour. Unfortunately, it is not possible to separate the cost increases due to wind variability from the cost decreases due to fuel displacement. Hence the two types of studies cannot be directly compared. Nonetheless, they both provide essential insights into the impacts of wind generation on power system operation.

## *Xcel Energy North (Minnesota)*

Xcel Energy North serves parts of North Dakota, South Dakota, Minnesota, Michigan, and Wisconsin. The power system is summer peaking with a peak demand of approximately 8,000 MW in 2002, projected to rise to approximately 10,000 MW by 2010. Total system generation is approximately 7,500 MW with the difference made up by power purchases.

### Utility Wind Interest Group Study (May 2003)

The Utility Wind Interest Group (UWIG) completed an initial evaluation of operational impacts of wind generation on the Xcel North system in 2003. The work was done by Electrotek Concepts, Inc. The study estimated the incremental ancillary service costs incurred by Xcel North to accommodate the then existing 280 MW of Minnesota wind power.

The cost of additional regulating reserves to accommodate the wind generation was found to be negligible. This finding is based on results of load frequency control simulations which showed essentially no change in the area control error standard deviation between scenarios with and without the wind generation. The cost of annualized intrahour load-following energy was approximately US$0.41/MWh, based on the evaluation of intrahour ramping and fluctuation of the wind generation with economic dispatch simulations. The cost of the reserve component of load following was found to be zero. The unit commitment cost incurred to reschedule units because of the inaccuracy of the wind generation forecasts used in the day-ahead scheduling was US$0.39–1.44/MWh for wind forecast errors ranging ±10–±50%, respectively.

The total incremental operating cost of integrating 280 MW of wind generation into the Xcel North system was US$1.85/MWh of wind generation for a wind forecast error of ±50%. The study methods and assumptions are considered conservative in the sense that wind's impacts are probably overstated.

### Minnesota Department of Commerce Study (September 2004)

In 2004, a follow-up study of the Xcel North system was completed by EnerNex Corporation on behalf of Xcel Energy and the Minnesota Department of Commerce (MN DOC). This study also focused on operating impacts but at the higher level of 1,500 MW of wind generation (15% penetration in 2010). Incremental costs resulting from plans and procedures needed to accommodate the wind generation while maintaining the reliability and security of the power system were determined.

Meteorological simulations were carried out by WindLogics and then combined with archived weather data to recreate the weather for use in the study analysis. Benefits of geographic dispersion of the wind plants and of wind forecasting were also demonstrated.

The costs of integrating 1,500 MW of wind generation into the Xcel North control area in 2010 are found to be no higher than US$4.60/MWh of wind generation and are dominated by costs incurred by Xcel Energy in the day-ahead time frame to accommodate the variability of wind generation and associated wind generation forecast errors. The total costs include about US$0.23/MWh resulting from an 8-MW increase in regulation requirements and US$4.37/MWh resulting from scheduling and unit commitment costs. The study characterized these results as conservative, since improved strategies for short-term planning and scheduling and the full impact of new regional markets were not considered.

## *California Independent System Operator*

In response to legislation in California that established a renewable portfolio standard, the California Energy Commission and California Public Utilities Commission established a team to examine the integration cost of all renewable power sources in the state. The analysis of wind generation was based on the three main California wind resource areas—Altamont, San Gorgonio, and Tehachapi—for 2002. The contribution that wind (and the other renewables) makes to system variability was estimated and California Independent System Operator (CAISO) regulation prices were used to provide a cost estimate of wind's regulation impact. The regulation costs were US$0.20–0.90/MWh of wind generation, depending on the resource area.

To estimate the impact on the load-following timescale, data on system load and renewable generation were analyzed. The energy market operated on a 10-min interval during the study period. The analysis focused on potential distortions to the dispatch stack resulting from swings in renewable generation. However, because of the depth of this stack, no measurable impact was found.

Unit commitment is not the responsibility of the CAISO. Once bids have been accepted, generators assume this responsibility, and associated costs are assumed to be reflected in bids. Hence, the impact of wind variability on costs in the unit commitment time frame was not assessed.

### *We Energies (Wisconsin)*

Operating in Wisconsin and the Upper Peninsula of Michigan, We Energies serves a summer peak load of 6,000 MW, with installed capacity of 5,900 MW of primarily coal and nuclear units. For wind penetration levels varying from 250–2,000 MW for a 7,000 MW peak load in 2012, the utility found ancillary service cost increases of US$2–3/MWh, with load and wind variations considered together. Sensitivity studies showed that the increase in regulation reserve for wind integration was small compared to the reserve carried for normal system regulation purposes associated with load variations and load forecast uncertainty.

### *PacifiCorp (Oregon—Wyoming)*

PacifiCorp, a large utility in the northwestern United States, operates a system with a peak load of 8,300 MW that is expected to grow to 10,000 MW over the next decade. PacifiCorp recently completed an integrated resource plan (IRP) that identified 1,400 MW (14%) of wind capacity over the next ten years as part of the least-cost resource portfolio. A number of studies were performed to estimate the cost of wind integration on its system. The costs were categorized as incremental reserve or imbalance costs.

At wind penetration levels of 2,000 MW (20%) on the PacifiCorp system, the average integration costs were US$5.50/MWh, consisting of an incremental reserve component of US$2.50 and an imbalance cost of US$3. In the 2005 revision of PacifiCorp's IRP, the total estimated wind integration cost was revised downward to US$4.60/MWh.

### *NYISO*

This work, completed in early 2005, was conducted by GE Energy for the NYISO with primary support from the New York State Energy Research and Development Authority (NYSERDA). Wind resource projections were provided by AWS TrueWind. The project was motivated by a renewable portfolio standard in the state that may result in some 3,000 MW of new wind generation in New York within the next ten years. In light of wind's natural variability, NYISO wanted to understand the impacts of a substantial amount of wind generation on the operation of the New York electric power network. The study addressed 3,300 MW of wind in a system serving a customer load projected at about 34,000 MW in the 2008 study year. The key question was whether the system would be capable of handling 10% wind penetration without major difficulties.

This study is the most comprehensive wind integration assessment conducted to date in the United States. It encompassed all of the time frames discussed above. It estimated system operating costs, impacts on customer payments, reductions in emissions from conventional power plants, and the impacts of wind forecasting. The New York system is operated as a single, large balancing authority and has well-functioning hour-ahead and day-ahead wholesale markets into which generators bid energy. Bids are accepted until projected demand is met on an hour-by-hour basis, and all accepted bidders—including wind plants, which bid at zero price—are paid the highest accepted bid price.

As mentioned above, this study has estimated wind's total cost impact on the operation of the system. Increases in costs associated with regulation, load following, and generation scheduling that stem from wind's variability are combined with savings resulting from fossil fuel displacement. The wind resource was modeled from actual weather data for the 2001 through 2002 period and was combined on an hourly basis with corresponding coincident load and generation data scaled to the projected 2008 peak demand. Geographic diversity of the wind was captured by using wind data corresponding to a number of different locations in the state.

The overall conclusion from the study was that the New York State power system can reliably accommodate at least 3,300 MW (10%) of wind generation with only minor adjustments to its planning, operating, and reliability practices. No increase in spinning reserve would be required, and 36 MW of additional regulation would be needed to maintain CPS-1 at the no-wind level. The total impact on variable operating costs for the study year (including impacts of wind variability and fuel savings) was a reduction of US$350 million. The fuel displaced by wind was primarily natural gas. Of the US$350 million total, US$125 million, or approximately US$14/MWh of wind energy generated, was realized from the use of state-of-the-art wind forecasting techniques. In other words, if wind forecasts were ignored in estimating the net of load and wind for the next day, then the resulting bids and generation scheduling were suboptimal and the reduction in variable cost was only US$225 million. Remarkably, perfect forecasting provided an additional benefit of only about US$14 million.

Reductions in load payments amounted to US$305 million. This corresponds to savings to consumers of about 0.18¢/kWh on average. Revenue paid to the wind generators was US$315 million, or about 3.5¢/kWh. This amount is consistent with the terms of typical power purchase agreements between wind plant owners and purchasing utilities, implying that wind offers a viable business opportunity in New York.

**table 1. Wind impacts on system operating costs.**

| Study | Wind Capacity Penetration (%) | Regulation Cost (US$/MWh) | Load-Following Cost (US$/MWh) | Unit Commitment Cost (US$/MWh) | Gas Supply Cost (US$/MWh) | Total Operating Cost Impact (US$/MWh) | System Operating Cost Savings |
|---|---|---|---|---|---|---|---|
| Xcel-UWIG | 3.5 | 0 | 0.41 | 1.44 | NA | 1.85 | na |
| Xcel-MNDOC | 15 | 0.23 | 0 | 4.37 | NA | 4.60 | na |
| CAISO | 4 | 0.59 | 0 | na | NA | na | na |
| We Energies | 4 | 1.12 | 0.09 | 0.69 | NA | 1.90 | na |
| We Energies | 29 | 1.02 | 0.15 | 1.75 | NA | 2.92 | na |
| PacifiCorp | 20 | 0 | 1.6 | 3.0 | NA | 4.6 | na |
| Xcel-PSCo | 10 | 0.20 | 0 | 2.26 | 1.26 | 3.72 | na |
| Xcel-PSCo | 15 | 0.20 | 0 | 3.32 | 1.45 | 4.97 | na |
| GE-NYISO | 10 | na | na | na | NA | na | $350 million |

na=not available
NA=not applicable

### *Xcel Energy West (Colorado)*

This study is being conducted for Xcel Energy's Public Service of Colorado unit by the Enernex-WindLogics team. Wind penetrations of 10% and 15% have been studied, and a 20% case is in progress. The methodology is similar to that employed in the MN DOC study, although an additional element was required to assess the impacts on gas purchases, consumption, and storage. Traditionally, gas decisions must be made—and lived with—on a daily basis. As a result, higher penetrations of wind are likely to require additional gas storage, resulting in an additional cost impact stemming from wind's variability. As in the Minnesota study, the intra-hour load-following cost was found to be negligible, and the major impact was related to differences between the hour-by-hour commitment schedule and the net of load and wind. Results are shown below for the 10% and 15% cases.

## Results Summary and Discussion

Key results from these studies are summarized in Table 1. The 2004 Xcel North/MN DOC wind integration study contains significant advances in the cost-based analysis of operating impacts. The use of sophisticated, science-based atmospheric models is a large improvement over previous methods. The resulting numerical model of wind generation accurately characterizes both the variability of wind generation in the Midwest and the geographic diversity of multiple wind plants. Sensitivity runs indicated that emerging day-ahead and real-time regional markets can reduce integration costs by providing access to additional resources for the balancing of wind generation.

The GE Energy-NYISO integration study provides additional important results and insights beyond those discussed above. For example, system stability was examined using stability simulations of major disturbances, such as a forced outage of a large generating unit. Comparisons of cases with and without wind generation on the system showed improved stability when wind plants are part of the generating mix. Modern wind plants have reactive power control and low-voltage ride-through capabilities either at the individual turbine or wind plant level. As a result, the wind generation actually helps the system recover following a major disturbance. The study also showed the benefits to wind integration afforded by a large balancing area. The ease of accommodating 10% wind penetration is clearly aided by the NYISO's access to a large number of generating units with significant ramping capability.

The Xcel Energy West study provides additional useful insights relative to natural gas supply and management. The additional gas storage required to accommodate wind's variability and uncertainty would actually provide a winter-summer seasonal hedging benefit to the system of about US$1/MWh of wind energy at 15% penetration. In a much more extensive assessment of wind's role in hedging against swings and spikes in natural gas prices, researchers at Lawrence Berkeley Laboratories find hedge values of about US$5/MWh of wind.

All of these studies have led to important insights relative to methodology. For example, to develop an accurate picture of wind impacts, it is critical to consider wind variations along with load variations. If the latter are ignored, then wind impacts will be substantially overstated. Capturing the spatial variations of wind—both within an individual wind plant and across the entire region considered—is also important, since these variations afford significant mitigation of impacts.

## Capacity Value of Wind Plants

As discussed above, most wind generation has been added to power systems as an energy rather than a capacity source. Although the addition of a wind plant will generally decrease the statistical loss of load probability (LOLP)—or, alternatively, allow additional load to be served—system reliability is maintained primarily by the existing dispatchable generation. Nonetheless, some wholesale power markets include a capacity component with associated payments to generators. In those cases, it is important to have an equitable approach

for calculating wind capacity credits. Looking into the future, after wind has developed a substantial track record as a generally accepted element of the generating mix, some fraction of a new wind plant's nameplate rating will be relied upon to serve new load growth. Again, an equitable approach for determining this fraction in actual power systems is needed.

It is important to draw a distinction between capacity contributions toward planning reserves and operating reserves. For planning reserves, system planners look several years into the future and deal with all generating units and loads on a statistical basis, since it is not possible to know exactly what the situation will be at any moment in the future. The system is designed so that if a single plant is expected to be operating at some time in the future but is not when that time comes, then another plant will fill the resulting need. The established measure for estimating capacity contributions for system-expansion and resource-adequacy planning over periods of months and years is the effective load-carrying capability (ELCC), which is discussed in more detail below.

However, the system operator has a very different perspective. He needs to maintain system reliability today and tomorrow, so he is reluctant to assume that a quantity derived on a statistical basis over a period of months will apply undiminished over the next 24 h. In the wind case, of much greater value to him is the wind forecast. Some system operators are considering alternative statistical measures suitable for periods of 24–48 h, but more experience is needed before such measures can be generally accepted.

It is common for utility engineers to think in terms of operating reserves when estimating a capacity value for wind plants, whereas wind developers are more likely to lean toward the longer-term statistically estimated planning reserves. This difference in perspectives has caused significant disagreements among utility and wind industry personnel.

### *ELCC*

ELCC is a rigorous, reliability-based method to calculate the capacity value of a generator. It can be applied to any generation type and has been applied to wind generation in many regions. The method estimates the equivalent capacity of a reference unit that would provide the same annual reliability level as the wind plant in question. Calculation of ELCC requires hourly wind generation data and a reliability model of the system to be evaluated. Because of its firm foundation in reliability theory and practice, this is the preferred method to measure capacity value. When applied to wind, multiple years of time-synchronous load and wind data will provide more robust results than a single year of data.

ELCC calculations for wind can have a wide range, depending on system details and the timing of wind generation. Results in California indicate capacity values in the range of 23–25% of rated capacity. The study carried out by GE Energy for NYISO-NYSERDA found the onshore capacity value in New York to be about 9%, whereas the offshore (Long Island) capacity value was 40%. The study conducted by Enernex for the Xcel/MN DOC found capacity values ranging 26–34% of rated wind capacity, depending on modeling method and specific locations. PacifiCorp found average capacity value to be 20% in their operating region. Figure 1 shows many of these results, along with results for an actual wind plant in Colorado (Colorado Green) that sells its output to Xcel Energy in Colorado.

Because of the rather extensive data and modeling requirements to calculate ELCC, there has been considerable interest in developing alternative approaches to measure wind capacity value. In some cases it is possible to perform an initial analysis of system LOLP to determine the times that the system is at highest risk. LOLP-measured risk is a function of planned and forced outages of conventional units, load shape, hydro operational characteristics and constraints, and off-system purchases, so it is reasonable to expect some variation from year to year based on these parameters. Once the relevant hours have been identified, the average wind production during the period can be calculated and will yield a result that approximates ELCC. This approach has the advantage of broad applicability to systems that have a bimodal load shape (summer and winter peaks that exceed most other hours of the year). In other cases, it may be possible to select a period that includes peak hours of the data and to calculate the wind capacity factor over that period.

Methods that attempt to calculate a percentile of wind generation during a peak period (for example, the level of wind generation that would be achieved at least 85% of the time) arbitrarily diverge from the large body of established reliability theory and practice. This, along with a number of the other issues raised here, is discussed more fully in a paper by Milligan and Porter presented at WindPower 2005.

## Wind Impacts on Power-System Operating Strategies

### *California*

The CAISO has developed an imbalance tariff for participating wind generators. In return for a small fee paid by the wind generators, a third-party forecast is developed and provided to the CAISO. In return, imbalances (differences between forecast and actual wind generation for the hour in question) are netted over the month. The forecast provides the system operator with information that can be useful for determining the extent to which dispatch instructions to marginal units should be changed. Given the extremely large system, relatively small wind penetration, and extensive potential dispatch stack, it is not clear that there are systematic operational changes during normal operating conditions.

While this approach seems equitable to the wind plant owners, it is likely that the use of wind forecasts in the day-ahead rather than hour-ahead time frame will result in greater overall system benefits, as demonstrated in the New York and Minnesota studies discussed above.

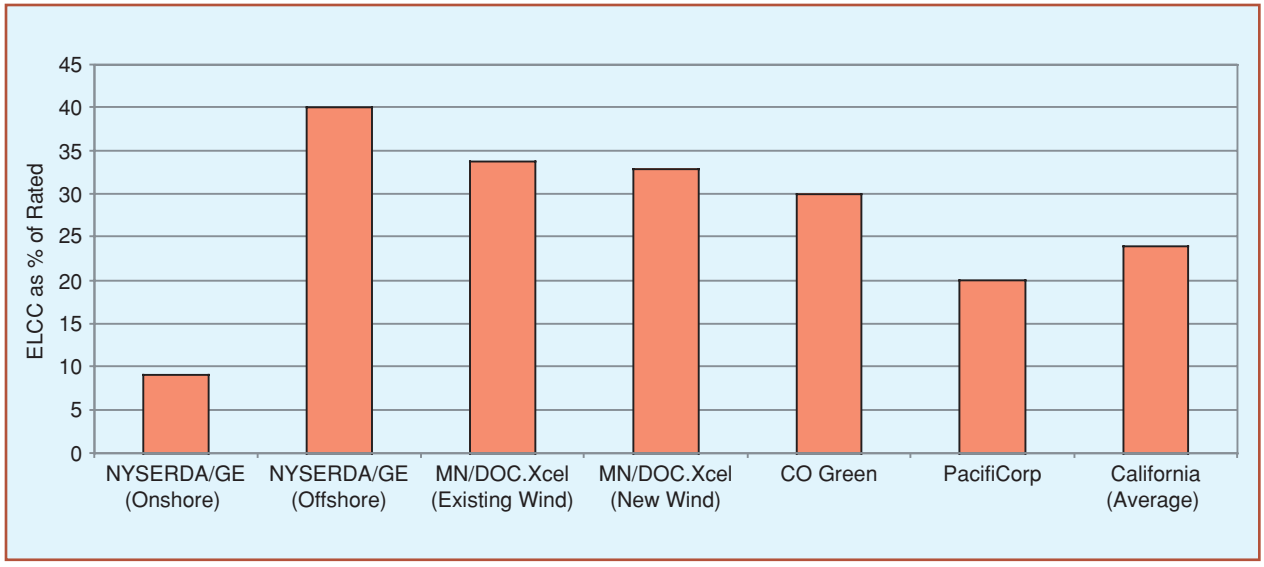


**figure 1.** Effective load-carrying capabilities from several recent studies.

### *Oklahoma*

The Western Farmers Electric Cooperative (WFEC) in Oklahoma has recently performed an analysis with NREL of the operational impact of wind on their system. WFEC has a peak load of 1,400 MW and installed wind capacity of 74 MW. Initially, the system operators were not able to maintain CPS-1 at its prewind level. With experience, they were able to gain familiarity with the wind system and were able to bring CPS-1 into its prewind range.

### *Colorado*

Xcel Energy West (PSCo) currently serves a peak load of approximately 6,400 MW. Approximately 200 MW of wind generation is interconnected to the system, and substantial wind expansion is planned.

In order to accommodate the intermittent nature of wind generation, the operator will utilize several different sources of information to help him determine the regulation requirements needed. An informational database is being used so the operator can trend the wind generation and track the instantaneous changes in the wind generation. This is also providing the ability to improve future forecasting by including historical trends.

PSCo has also subscribed to a weather service that provides real-time wind information to help the operator see real-time changes to the weather patterns. During periods when the wind is deviating enough to cause the operator concern about being able to match the generation with the load, the operator will increase the amount of regulating reserves he is carrying on the system. In extreme situations, PSCo will utilize its quick start capability (pumped storage hydro, fast-starting reciprocating engines, and quick-start gas turbines) to return to proper regulating ranges.

### *Future Prospects*

System operating experience with wind as part of the generating mix is at an early stage. It is logical to expect that operator accommodation of wind variability will improve with time and experience, even if no other changes occurred. The Oklahoma experience described above supports this view. In addition, as wind's role increases, the balance of the generation mix is likely to shift in favor of more units with increased ramping capability. In fact, at least one major gas turbine manufacturer has discussed plans for a new turbine product designed specifically to provide such capability. Also, the value of wind forecasting has been shown in most of the operating impact studies conducted to date—particularly the GE-NYISO study. But system operators have barely begun to factor wind forecast information into their daily operations. As this information becomes accessible in readily usable formats and as operators integrate it into their operating procedures, concerns over wind variability are likely to diminish substantially.

## Conclusions and Perspective

Wind integration investigations conducted to date lead to several broad conclusions. First, all of the related work conducted so far indicates that the impacts of wind's variability on system operating costs are not negligible but are relatively modest. In most cases, the costs are less than 10% of wholesale energy value and in some cases are substantially less. For power systems with a substantial natural gas component, wind actually provides a hedge against fluctuations and spikes in gas costs. As shown by the New York integration study, systems with appreciable natural gas generation can expect to see electricity prices to consumers reduced by the addition of

wind, unless gas prices return to pre-2003 levels, which is not expected by anyone close to the natural gas industry.

Second, it is clear that wind forecasting (discussed in much more detail in another article in this issue) has substantial value. Its payoff is primarily in the day-ahead time frame through its influence on unit-commitment decisions. It is also significant that most of the value of forecasting—90% in the New York case—is already available through state-of-the-art capabilities already in use. What remains is to integrate these techniques into the day-to-day operation of power systems.

Third, the impacts of wind's variability on system operating costs are strongly related to the size (in MW) of the associated balancing authority. In general, the larger the balancing authority, the greater the access to generation options for accommodating wind variations. Needed regulation and ramping capability may be difficult to access within a small balancing authority with a relatively small number of generating units. But a large balancing authority with many more generating units will be much more accommodating to wind variations, unless access is hampered by transmission constraints.

Fourth, on any given power system, costs arising from wind variability are a strong function of the characteristics of the system, such as generation mix and fuel costs, and will increase with increasing wind penetration, assuming the nonwind characteristics of the system remain unchanged. As discussed above, the presence and size of a balancing market are also important factors affecting the costs arising from wind's variability.

Fifth, wind power plants in general have some nonzero capacity credit. ELCC is the preferred estimation method. Specific amounts depend on many factors. They are influenced primarily by wind energy availability during peak load hours, but other hours (such as those in off-peak periods with substantial scheduled maintenance activities) can also be important. However, ELCC applies primarily to system-planning activities and is not the appropriate metric for designation of operating reserves over the next 24–48 h.

Finally, as shown by the New York study, modern wind plants with low-voltage ride-through and variable reactive power compensation capabilities can actually improve system stability following a major power system disturbance.

## For Further Reading


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## Biographies

***Edgar DeMeo*** holds Ph.D. and Sc.M. degrees from Brown University, where he was an IEEE Fortescue Fellow, and is a graduate of Northeastern University's management development program. He managed renewable energy programs at the Electric Power Research Institute (EPRI) from 1976 through 1998. In 1999, he formed Renewable Energy Consulting Services, Inc., through which he provides program management and technology development support to national and state renewable energy programs. He is a strategic advisor to the Department of Energy-National Renewable Energy Laboratory (DOE-NREL) Wind Energy Program and the Utility Wind Interest Group. Before joining EPRI, he served on the engineering faculty at Brown University.

***William Grant*** is the director of power operations in the commercial enterprises business unit of Xcel Energy. He is responsible for the economic dispatch and real-time merchant and the short-term analytical functions for Xcel Energy. He has been employed in the electric utility industry for 27 years, with experience in power plant operations as well as bulk power operations.

***Michael R. Milligan*** received Ph.D. and M.A. degrees from the University of Colorado and a B.A. from Albion College. He is a consultant to the National Renewable Energy Laboratory, where he has worked on wind energy integration issues since 1992. He has authored or coauthored more than 60 papers and book chapters and has participated as a technical review committee member for Xcel Energy Wind Integration Studies in Minnesota and Colorado. Other recent projects include the Rocky Mountain Area Transmission Study and the California Renewable Portfolio Standard Integration Study for the California Energy Commission.

***Matthew J. Schuerger*** holds an M.B.A. Through Energy Systems Consulting Services, LLC, he is an independent consultant working on renewable energy planning and development. Recent projects include work as a technical advisor on the current Minnesota Wind Integration Study and on the 2004 Xcel-Minnesota Department of Commerce Wind Integration Study. He has over 20 years of experience in the utility industry, including senior positions in engineering, power plant operations, and business development. He is formerly the executive vice president of District Energy Saint Paul, Inc. and is a licensed professional engineer.