Wind Energy Delivery Issues

Transmission Planning and Competitive Electricity Market Operation

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THE RAPID INCREASE IN WIND GENERATION IN RECENT YEARS has raised the visibility of an issue that has been troubling power grid planners and operators for years: how to deal with large amounts of intermittent generation resources connected to the grid. Grid planning and operating practices, including the structure of the electric power market, are largely based on dispatchable generating resources (i.e., generators capable of producing power up to their full rating whenever the system operator schedules them to do so). A typical system-operating scheme follows this sequence:

1) *Day-ahead forecast:* Market participants forecast system load for each hour of the following day. This is a sophisticated process involving historical information, weather forecasts, and time of day.
2) *Day-ahead market:* Generators and load-serving entities bid for producing and purchasing energy and operating reserves.
3) *Unit commitment:* System operator schedules an appropriate mix of generating resources to serve the load recognizing factors such as bid prices for energy, generator start-up and maneuvering constraints, and transmission congestion constraints.
4) *Real-time operation:* System operator adjusts generating resources to match actual system load in real time during the day of operation.
5) *Market settlement:* Actual power generated and consumed is logged, and imbalances from scheduled values are financially settled, following a prescribed set of market rules.

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Wind generators introduce new challenges due to their intermittent nature. The amount of power a wind generator can produce depends on the wind conditions at the time. Although wind generator output can be forecast a day in advance, forecast errors of 20–50% are not uncommon. These characteristics of wind generation increase the levels of variability and uncertainty in power grid operations.

Transmission system planners are faced with a related set of challenges. Renewable portfolio standards (RPSs) that set minimum requirements for renewable energy are being adopted worldwide. In the United States, production tax credits are (sometimes) available to encourage development of new generating resources. As a result, new wind generation projects are numerous and increasing. Wind capacity in the United States is expected to exceed 9,000 MW in 2005, up from about 6,800 MW in 2004. New York State presently has about 50 MW of installed wind generation and over 4,000 MW of new projects in the queue—and this is not unique.

Many of the best wind resources are remote from load centers or existing transmission corridors. In most areas with deregulated power markets, existing planning practices do not look ahead towards expanding the transmission grid to serve such resources. Individual wind projects cannot afford to pay for such major transmission expansion on their own, so the wind resources may remain stranded and undeveloped.

What can be done to address these issues? Should regional transmission operators take on the responsibility to install transmission in anticipation of new generation resources? Should traditional system operating practices be changed to accommodate intermittent generating resources without compromising grid reliability? Should power market rules be changed to accommodate the nondispatchable nature of wind generation, and could this be done while maintaining a fair and competitive market?

Midwest Independent System Operator Transmission Planning Process and the Implications for Wind Generation

The potential for wind generation within the Midwest Independent System Operator (ISO) footprint is significant. As Table 1 shows, there is more than 500,000 MW of potential wind generation capacity in the Midwest ISO and neighboring areas. A 10% renewable energy objective for the entire Midwest ISO footprint today would require about 19,000 MW of wind generation, but that represents only 4% of the total potential wind generation capacity available. The Midwest ISO has 5,800 MW of wind capacity in the Generation Interconnection Queue as of February 2005, and an additional 5,000 MW of wind generation under study for the Midwest ISO transmission expansion plan (MTEP) exploratory studies. The current level of installed wind network resource generation on the Midwest ISO system is 860 MW.

Most potential wind generation is in remote locations, as shown on the map in Figure 1. Wind generation constitutes 65% of the total number of requests in the Midwest ISO Generation Interconnection Queue. Class 4 (good) or higher wind development areas were the primary location of the wind generation in the queue last year, but Class 2 (marginal) queue entries have been occurring more frequently this year.

The Midwest ISO planning process is an open, collaborative process with the transmission owners and other stakeholders. Inputs are obtained from a wide range of stakeholders from the Midwest ISO advisory groups and from various meetings. That input is then studied using multiple methods to resolve the problems of providing adequate transmission for all the transmission system requirements, including wind generation.

Bottom-up transmission studies compile the individual requirements for transmission into one system. That system is then tested and adjusted to meet planning criteria. Examples include the reliability portion of the MTEP (which assembles all the transmission owners plans into one master plan), the interconnection queue sequential studies under FERC processes, and the transmission requirements to serve load in the Midwest ISO. One such bottom-up study, the Buffalo Ridge study, is determining the short-term need for transmission to serve wind generation in the particularly congested area of southwestern Minnesota. Multiple study groups have studied problems and recommended local solutions. The local solutions are incorporated and tested, and reliability violations are resolved in the MTEP process.

Top-down transmission studies are based on generation scenarios that are formulated in an open, collaborative process by stakeholders for some specified future period. Top-down processes only provide information and do not determine the transmission that must be built. An example of such a study is the MTEP 03. It included a study of 10,000 MW of wind generation to determine the transmission

table 1. Potential wind generation in MISO region.

	Wind Power (MW)	
State	Existing MW[1]	Total Potential MW[2]
Illinois	50	6,980
Iowa	471	62,900
Minnesota	563	75,000
Nebraska	14	99,100
North Dakota	66	138,400
South Dakota	44	117,200
Wisconsin	53	6,440
Total	1,261	506,020

Notes:

[1]Nameplate MW (American Wind Energy Association, Jan. 2004, http://www.awea.org/)

[2]Average MW, circa 33% of nameplate capacity (from "An Assessment of Windy Land Area and Wind Energy Potential," Pacific Northwest Laboratory, 1991) .

Source: Wind on the wires presentation on net environmental impacts of transmission systems in the Midwest.

needed to deliver the wind energy without undue transmission constraints. The interconnection queue was used as an input, but the generation scenario was also formed by stakeholder input. MTEP 05 further refined the exploratory plans for combinations of wind generation and coal in the Dakotas and Minnesota and additional plans for northern Iowa, southern Minnesota, and Wisconsin. One use of the information from the top-down processes is to provide realistic examples for regulatory and legislative processes. Generators may use the information to plan their interconnection queue entries.

CAPX is an integrated top-down capital expenditure study of generation options for Minnesota and the surrounding states for horizon year 2020. CAPX also addresses the transmission necessary to serve those options. The 10% renewable energy objective for Minnesota is modeled in the studies. The Midwest ISO transmission owners have worked with the State of Minnesota on the study and on deriving the legislative requirements to implement and recover costs. The Midwest ISO is participating in the economic studies for CAPX, which should result in a recommended blueprint for future options for transmission and generation development for the area. The results of CAPX will then be included in the MTEP process when appropriate.

In summary, the study process and associated regulatory and legislative process are still evolving. Progress is being made and methods are being formulated and exercised to resolve the issue of providing transmission on a regional basis for generation that includes wind in the Midwest ISO footprint. Similar efforts are underway in other ISOs across the country.

Integration of Wind Generation into the California ISO Markets and Operations

California is a leader in the United States in the development of renewable resources including wind, solar, geothermal, biomass, and small hydro generation resources. In September 2002, the state passed legislation (SB 1078) that created the California Renewables Portfolio Standard (RPS). This law requires the investor-owned utilities (IOUs) to increase their procurement of renewable energy to 20%, based on the total energy they deliver to customers by 2017. The new energy action plan for the state accelerated this goal to 20% by 2010.

Wind generation will supply a major part of the renewable energy required to meet the RPS goal. Wind is forecasted to increase from 4,000 GWh of energy in 2004 to over 15,000 GWh by 2010. The installed capacity is forecasted to increase from 2,100 MW in 2004 to 7,500 MW in 2010. This forecasted increase in wind generation requires solutions to a number of issues:

- ✔ market integration
- ✔ real-time grid operations
- ✔ calculation of the capacity value of wind generation
- ✔ solutions for environmental impacts

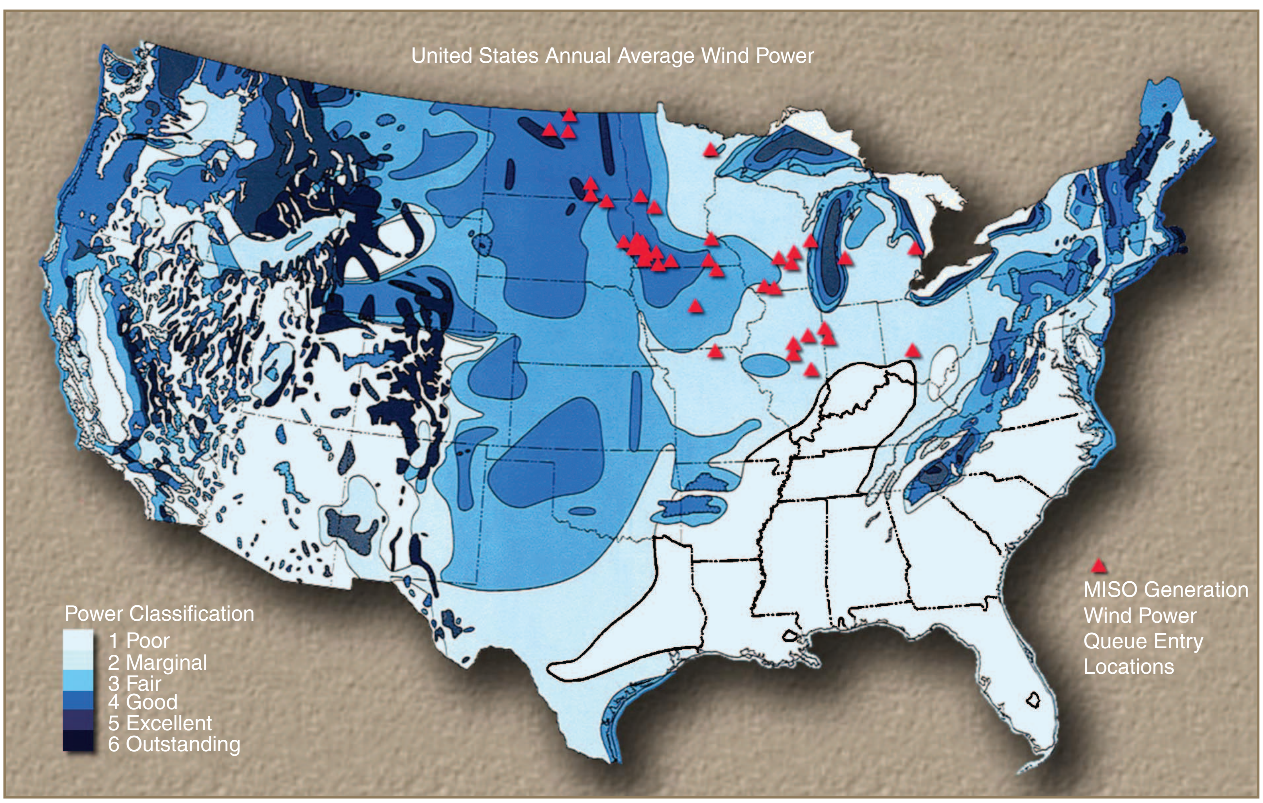

figure 1. Wind resource map showing locations of planned wind projects in Midwest ISO region. (The map is from the U.S. Department of Energy and the National Renewable Energy Laboratory; the queue overlay is from Midwest ISO.)

- ✔ interconnection standards
- ✔ planning and construction of new transmission
- ✔ transmission availability and utilization.

California has addressed the first problem: the integration of wind generation into the energy markets. The California ISOs Participating Intermittent Resources Program (PIRP) went into operation in August 2004. The PIRP lowers the risks for wind generators of bidding into forward energy markets without incurring 10-min imbalance energy charges. Wind generators must schedule their energy in the hour-ahead market by using an advanced forecasting service, and this forecast becomes their deemed delivered schedule. Deviations between actual energy delivery and the scheduled amount are multiplied by the hourly price, and the total dollar amounts are collected in an account for settlement at the end of the month. An unbiased forecast of hourly energy production should result in a relatively small net energy deviation over the entire month.

There are currently ten participants with a total of 450 MW of wind generation capacity enrolled in the PIRP program. These generators produced over 530,000 MWh of energy in 2004. However, this only represents 20% of the total wind generation available. The other 80% is currently covered by qualifying facility (QF) contracts with local utilities, and the utilities have responsibility for forecasting and scheduling the energy. When the California ISO implements uninstructed deviation penalty charges, the utilities will have a greater incentive to schedule the wind generation energy through the PIRP program.

Although the existing 2,100 MW of wind generation in California has not resulted in serious operational issues, it does have a noticeable impact on operations. The most serious of these problems is over-generation during the night. Wind energy production is high during the late spring months, the same time hydro generation is at its peak due to the melting snow in the mountains. The load is low during this period, and the goal is to have other generation off line or ramped down. Ultimately, some wind generation may have to be curtailed during this period to mitigate the over-generation condition. There is also a need for new procedures and protocols for controlling large ramps both up and down during major storms that cause high wind variability.

Data from current operations is being used to assess future operational issues when the installed wind generation capacity increases to 7,500 MW or more. New methods are needed for calculating, on a seasonal and day-to-day basis, the amount of regulation and load-following resources that will be needed. Other areas requiring further exploration include new concepts for the automatic generation control and dispatch of controllable loads to assist with mitigating the impact of wind generation variability. The California ISO has established a working group to address these and other operational issues. The group includes participants from the California ISO, the wind generators, the utilities, and the California Energy Commission. The recommended solutions will be published by December 2005.

California's formula for calculating capacity value of wind generation is based upon three years of wind energy production data during the hours of noon to 6 p.m. for the months of May through September. The blue bars in Figure 2 show the average hourly wind energy production for 2004. The yellow bars show the average hourly energy production during the peak hours for these five months as well as a capacity percentage based on a total of 2,046 MW of available capacity. The amount of wind generation energy to meet summer peak loads declines significantly after June and, in fact, was less than 300 MW, or 15%, at the peak hours on the hottest days of August and September 2004.

Work is continuing on other issues such as interconnection standards and transmission planning requirements for wind generators. The Western Electricity Coordinating Council (WECC) has proposed a new low-voltage ride-through standard that is less restrictive than the standard FERC adopted. The transmission expansion plan for the Tehachapi region in Southern California will be the test for how to plan and finance the transmission network in order to move 4,000 MW of new wind generation to the California load centers. Transmission capacity upgrades take a lot longer to plan and construct than the corresponding time required to build new wind generation plants. If a transmission company builds a major transmission line to a wind generation area with the expectation that new

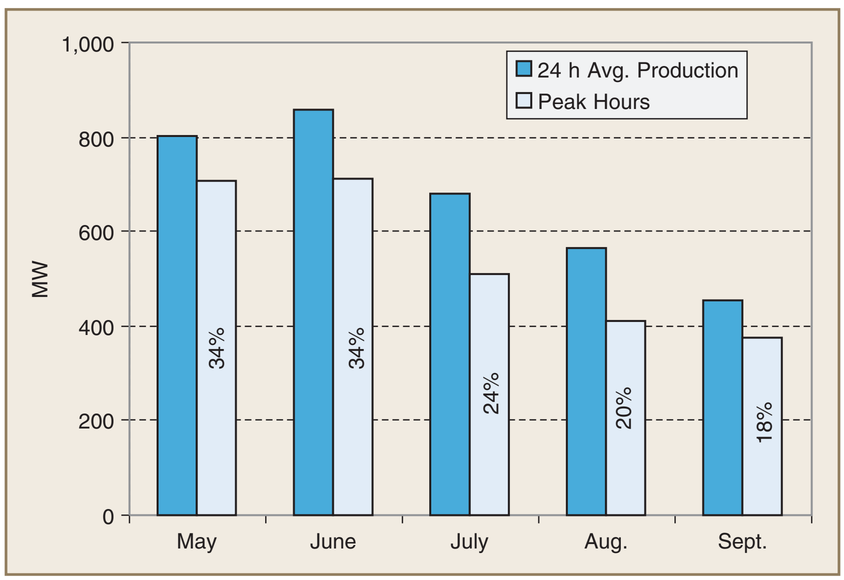

figure 2. Average hourly wind energy production during 2004.

wind generating facilities will be built there, can the transmission company be assured they will earn an acceptable rate of return on the investment? This question has been submitted to FERC, and California is awaiting a FERC ruling on a proposal for new transmission for the Tehachapi area.

Lessons Learned from NY State Study of 10% Wind Penetration

March 2005 marked the release of the final report on "The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations" of the New York State power grid. This 18-month study by GE Energy Consulting examined the addition of 3,300 MW of wind generation (approximately 10% of the system peak load). The overall conclusion was that the NY State Bulk Power System (NYSBPS) could readily accommodate this level of wind generation with only minor adjustments to the existing planning, operation, and reliability practices. Some of the key impacts on system operations and effective capacity are discussed below.

System Operating Costs

GE's Multiarea Production Simulation (MAPS) program was used to simulate the hourly operation of the NYSBPS for several years, with and without wind generation per the study scenario. The base approach involves using day-ahead wind generation forecasts for the unit commitment process, and adjusting the hydro generation after scheduling the wind output. Operating cost impacts, based on the 2001 historical hourly load and wind profiles, are summarized in the first column of Table 2. These are impacts for New York ISO (NYISO) only and do not include additional savings in New England and PJM. The total amount of wind energy generated in the 2001 simulation was approximately 8,900 GWh. Therefore, the NYISO variable cost reduction in US$/MWh was calculated to be US$350 million/8,900 GWhr = US$39/MWh. The simulation results also indicated a US$1.80/MWh average reduction in spot price in New York.

The operating costs depend on how the wind resources are treated in the day-ahead unit commitment process. If wind generation forecasts are not used for unit commitment, then too many units are committed and efficiency of operation suffers. The operating costs for this situation are summarized in the second column of Table 2. In this case, unit commitment was performed as if no wind generation was expected, and wind energy just shows up in the real-time energy market. The results indicate that energy consumers benefit from greater load payment reductions, but nonwind generators suffer due to the inefficient operation of committed units. In Table 2, the third column compares the two cases and shows

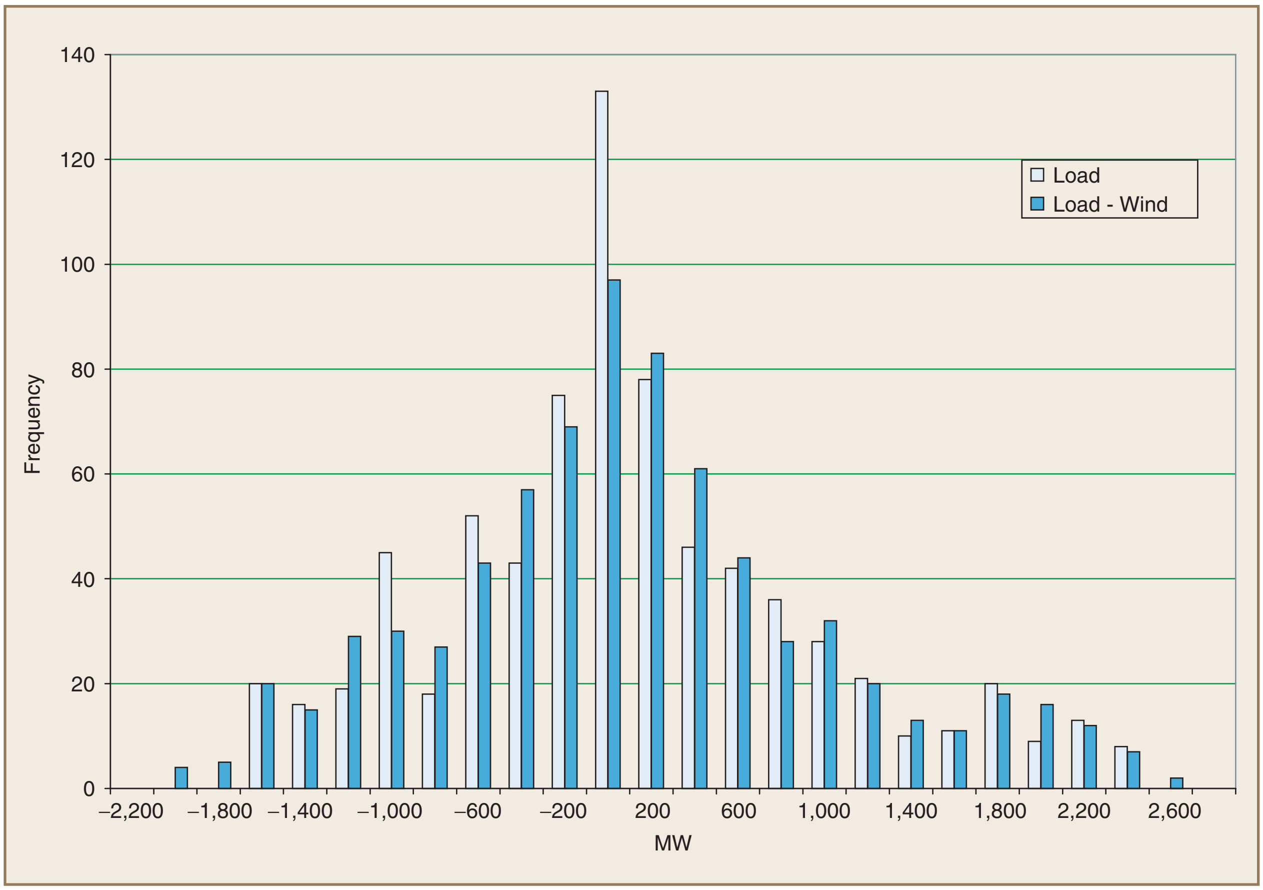

figure 3. Statewide hourly variability for January 2001.

table 2. Economic impact of wind generation.

NYISO Impacts Only	Recognizing Forecast in Commitment	No Recognition of Forecast in Commitment	Delta = Value of Forecast in Commitment
Total variable cost reduction (includes fuel cost, variable O&M, start-up costs, and emission payments)	US$350 million	US$225 million	US$125 million
Total variable cost reduction per MWh of wind generation	US$39/MWh	US$25/MWh	US$14/MWh
Wind revenue	US$315 million	US$305 million	US$10 million
Nonwind generator revenue reductions	US$515 million	US$600 million	−US$85 million
Load payment reductions (calculated as product of hourly load and the corresponding locational spot price)	US$305 million	US$455 million	−US$150 million

that there is a US$125 million (US$350 million−US$225 million) annual benefit in variable cost reductions to be gained from using wind energy forecasts for the day-ahead unit commitment. The results suggest that any economic incentives offered to wind generators should encourage the use of state-of-the-art forecasting and active participation in the day-ahead power market.

The existing day-ahead and hour-ahead energy markets in New York have sufficient flexibility to accommodate wind generation without any significant changes. However, it may be advantageous for the forecasting to be performed from a central location to ensure a consistent methodology and to ensure that changing weather patterns can be noted quickly. With these factors in place, wind generation can be held accountable to standards similar to those of conventional generation in terms of meeting their day-ahead forecast—with one exception. Specifically, imbalance penalties should not be imposed on wind generation. Wind projects would need to settle discrepancies between their forecast and actual outputs in the energy balancing market. However, because wind is largely nondispatchable, any additional penalties for imbalance should be eliminated.

FERC Order No. 888 allows imbalance penalties to be applied to generators that operate outside of their schedule. As can be applied in New York, any overgeneration can be accepted without payment and any undergeneration is priced at the greater of 150% of the spot price or US$100/MWh. While the penalties for undergeneration are not generally applied in New York, strict application of these policies in the analysis performed would result in the loss of roughly 90% of the wind generation revenue, which would be disastrous to their future development.

The intent of the penalties is to prevent generators from gaming the market, but their application to intermittent resources such as wind and solar would result in negative and unintended consequences. If a wind generator forecasts 100 MW for a particular hour but can only produce 80 MW due to a lack of wind, then no amount of penalties can get them to produce the remaining 20 MW. Their only option would be to bid less or zero in the day ahead market and possibly even bid low in the hour-ahead market. However, the analysis showed that as much as 25% of the value of the wind energy to the system could be lost if it is not properly accounted in the day-ahead commitment process. Any imbalance penalties for undergeneration would tend to encourage underbidding the day ahead forecast, to the detriment of the entire system. As of 13 April 2005, FERC has proposed new rules for wind generation which would relax these penalties.

Wind Variability

The NYISO was concerned that wind variations from hour to hour would cause too big of an impact to be easily absorbed by the rest of the generation system. Over the three-year period analyzed in this study, the hourly variations of the 3,300 MW of installed wind capacity ranged up to as much as 1,100 MW. However, large variations were rare, and 99% of the variations were 500 MW or less. Hourly variations in load are typically much greater. Figure 3 shows a distribution of the hourly variations in both "load" and "load minus wind" for January 2001. Although the addition of wind generation broadened the distribution slightly, there was no major distortion in the shape.

Energy Displacement and Emission Reductions

Energy produced by wind generators will displace energy that would have been provided by other generators. Considering wind and load profiles for 2001, 65% of the energy displaced by wind generation would come from natural gas, 15% from coal, 10% from oil, and 10% from imports. As with the economic impacts discussed above, the unit commitment process affects the relative proportions of energy displaced, but the general trend is the same regardless of how wind generation is treated in the unit commitment process.

By displacing energy from fossil-fired generators, wind generation causes reductions in emissions from those generators. Based on wind and load profiles for year 2001, annual NOx emissions would be reduced by 6,400 tons and SOx emissions by 12,000 tons, or 1.4 lb/MWh and 2.7 lb/MWh, respectively.

Because most of the wind generation is located in upstate New York, transmission flows increase from upstate to downstate with the addition of wind generation. Although there was some increase in congestion, most of the time the key interfaces were not limited, and increased flows due to wind generation were accommodated.

Effective Capacity of Wind Generators

Effective capacity is a measure of a generator's ability to deliver power when the grid needs it. This is most critical during peak load periods. The effective capacity of wind generation in the study scenario was quantified using rigorous loss of load probability (LOLP) calculations with the Multi-Area Reliability Simulation (MARS) program. The results show that the effective capacities, UCAP, of the inland wind sites in New York are about 10% of their MW ratings, even though their energy capacity factors are on the order of 30%. This is due to both the seasonal and daily patterns of the wind generation being largely out of phase with NYISO load patterns. Figure 4 shows the average wind patterns for three-month periods. Unfortunately, the daytime hours of the summer peak period are the lowest values. Figure 5 shows the average load and wind patterns for three selected months, demonstrating the difference in the patterns.

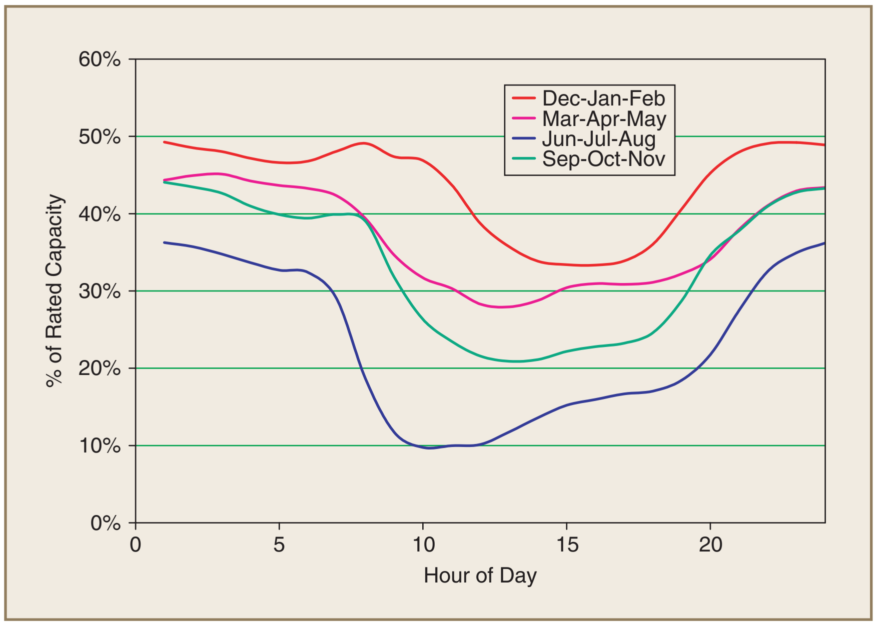

figure 4. Seasonal wind generation patterns.

All but one of the wind generators included in the study were land based. One offshore wind generation site near Long Island exhibits both annual and peak period effective capacities on the order of 40%—nearly equal to the energy capacity factors. The higher effective capacity is due to the daily wind patterns peaking several hours earlier in the day than the rest of the inland wind sites and, therefore, being much more in line with the load demand.

An approximate methodology for calculating the effective capacity of wind generation was demonstrated. A wind generator's effective capacity in New York State can be estimated from its energy capacity factor during a four-hour peak load period (1–5 p.m.) in the summer months of June, July, and August. This method produces results in close agreement with the full LOLP analytical methodology for New York.

The Role of FERC

The Federal Energy Regulatory Commission (FERC) administers the Federal Power Act (FPA) as amended by the Energy Policy Act of 1992. The core of the act ensures that transmission providers offer wholesale transmission service at rates that are just, reasonable, and not unduly discriminatory. In many cases, wind generators do not require wholesale transmission service because the generator sells to the local utility as part of its native load service obligation. In such instances, FERC-approved transmission tariffs are not required. However, any wind generator that wishes to sell to a neighboring utility must purchase transmission service under the FERC-approved transmission tariff. FERC rules are also relevant for all new generator interconnections, the amount of transmission capacity that is available as a result of the transmission planning, transmission pricing policies, and access to short-term spot energy markets.

Transmission scheduling methods under FERC tariffs have a significant impact on wind integration. Scheduling rules are different in areas operated by regional transmission organizations (RTOs). In these areas, the scheduling system typically allows all generators to sell into a large regional pool to serve all loads. Transmission rights are financial and, therefore, do not require separately fixed physical advance scheduling for every transaction. Wind resources can essentially just "show up" and sell to the real-time market. Outside of RTO/ISO areas, the physical transmission rights established in Order No. 888 of 1996 govern service. The need to schedule in advance often leaves capacity unused. FERC has encouraged the creation of RTOs to increase scheduling flexibility, eliminate the need to pay multiple or "pancaked" rates across each service territory, and broaden markets.

Imbalance penalties are a feature of many transmission tariffs. These apply to the differences, or "imbalances," between scheduled generation and actual production. The intent of such penalties is to prevent gaming and ensure that system operators have assurance that sufficient generation will be scheduled to serve the load. Wind generators are particularly burdened by imbalance penalties because of the difficulty of predicting wind output. Many tariffs have imbalance penalties of US$100/MWh, well above the reliability impact of these imbalances, and they can apply to generators that overschedule and those that underschedule at the same time so that charges can be assessed twice in an hour when the system overall is in perfect balance.

FERC proposed a rule to eliminate such imbalance penalties for intermittent generators, and this rule is pending at the time of this writing. FERC's proposal would eliminate the punitive penalty for failing to meet advance delivery schedules and would allow intermittent technologies a 10% dead-band from advance delivery schedules (with a minimum of 2 MW). Those exceeding the dead-band would be charged 110% of the transmission provider's incremental cost for underdeliveries, or be paid 90% of the transmission provider's cost for overdeliveries. FERC's proposed solution is similar to how the Bonneville Power Administration and PacifiCorp treat energy imbalances created by wind generation. This solution would mainly apply to non-RTO areas under Order No. 888 tariffs. FERC's proposed rule, if finalized in its current form, would remove what has been a significant hurdle for wind projects in non-RTO areas.

Transmission planning is a critical means of increasing grid capacity. RTOs serve that role in the regions where they operate. In other regions, the utilities and various public officials lead the planning process. The Rocky Mountain Area Transmission Study (RMATS) process, which has been led by certain governors' offices, has developed transmission plans that would help bring wind power out of the Rockies into load centers on the West Coast. FERC cannot require such activities but has encouraged them in the mid-1990s through regional transmission groups, RTOs, and various ad hoc groups. FERC required PJM to pursue economic planning—planning to build transmission to reduce congestion and not just for reliability purposes—as a condition of gaining RTO status. Such investment generally helps wind resources access a broad market.

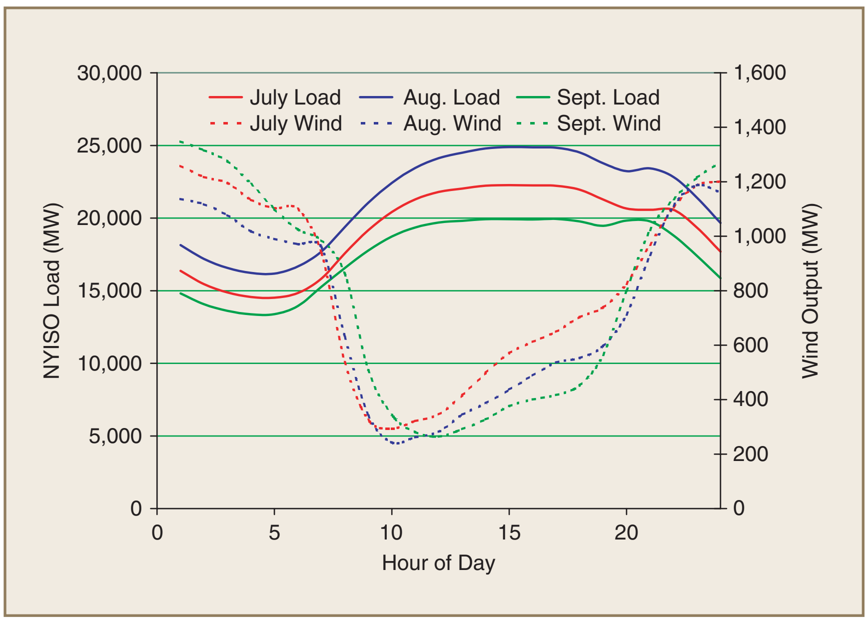

figure 5. Typical average monthly load and wind patterns.

Transmission pricing has a large impact on the development of the grid. Some areas like New England are building significant transmission by rolling in the cost of the investment to customers across the region. Other regions tend to prefer what is called *participant funding,* where costs of new investments are charged to each new customer. While FERC has not required any single form of transmission pricing along the spectrum between fully participant funded or fully rolled-in, FERC has raised concerns about the ability of transmission providers to discriminate against competitors through the use of participant funding. Participant funding can stifle wind development because there are many wind-rich areas that need a new transmission line to connect to the grid, but if the only way to pay for this line is to charge the first wind generator that interconnects, no generator will come.

Generator interconnection policy has been a critical piece of the regulatory puzzle for all types of generators, including wind. During the boom of merchant gas generation between 1998 and 2001, differences between transmission providers and generators led to hundreds of disputes that FERC had to resolve. To facilitate a speedier process and ensure fair and consistent treatment, FERC issued Order No. 2003, which included a standard interconnection agreement. To address technical and process issues of wind generators that were different from other generators, FERC issued a separate agreement called Appendix G, specifically addressing nonsynchronous generators such as wind. As noted earlier, wind projects are showing up in the interconnection queue in significant numbers, not only in NYISO and Midwest ISO, but also in PJM, ERCOT, and the Southwest Power Pool. If generator interconnection is done on a project-by-project basis, then the interconnection queue can become bogged down if projects are delayed for siting or financial reasons, yet other projects further down the list have to wait for these projects to be addressed before the transmission operator addresses them. Furthermore, the costs of any necessary transmission upgrades may be imposed on a small number of generators that may not be able to pay for them, essentially stranding not only the planned generation but perhaps the needed transmission

SB 1078—The California Renewables Portfolio Standard

- IOUs must increase the renewables portion of their energy mix each year by at least 1% of total retail sales
- The renewables portion must reach 20% by 2017.
- The governor's goal is to accelerate the program to reach the 20% goal by 2010.
- Renewables include wind, solar, geothermal, biomass, and small hydro energy.

upgrades as well. Grouping projects together in an interconnection queue can help with some of these issues and has been used successfully in PJM and in New York. To try to avoid project-by-project studies, Midwest ISO and the wind industry examined wind scenarios that assessed how to interconnect 10,000 MW of wind.

Corresponding with Midwest ISO's efforts was the increasing interest of FERC in transmission planning and expansion to not only protect reliability but also to enhance competition by building transmission to alleviate chronic transmission congestion and to access remote generating resources. Such economic transmission planning, called that because it refers to transmission not needed for reliability, typically looks at scenarios such as the 10,000-MW Midwest ISO wind scenario and incorporates load flow and dispatch models to measure the reliability impacts and the costs and benefits of the proposed generation and transmission additions. In addition to Midwest ISO, the Southwest Power Pool, PJM, NYISO, and the RMATs process in the West are all carrying out various forms of economic transmission planning. Such economic transmission planning represents an opportunity to access remote wind resources, and for this reason, the wind industry is keenly interested in it. Yet economic transmission planning faces at least three challenges.

1) Economic transmission planning is viewed separately from transmission planning for reliability, yet the two may be intertwined, i.e., certain reliability fixes may be necessary in order for an economic transmission addition to move forward.
2) These economic transmission studies may not result in any action; market participants are asked, rather than required, as is the case with reliability studies, to contribute financially to support any identified transmission upgrades or expansion.
3) Related to the previous point, economic transmission planning studies are time, labor, and cost intensive, and efforts to keep them going may fail without some sign of success.

Conclusions

Improving economics, environmental benefits, supportive state policies, and the rising costs of competing fuels are all contributing factors towards greater market and regulatory interest in wind energy. However, as noted in this article, wind energy poses several operational and planning challenges, some of which are beginning to be addressed. While the challenges are significant, they are not insurmountable.

Wind's intermittency is perhaps the best-known challenge. Initially, some utilities limited the allowable amount of wind on their systems until they learned more about integrating wind. Some utilities still do this—Nevada Power's and Sierra Pacific's 2005 renewable energy solicitations, for instance, limit the amount of wind to 50 MW per site for Sierra Pacific and 100 MW per site for Nevada Power. Other concerns are that wind energy could result in increasing the levels of regulation and reserves required to maintain reliability. Yet, as noted earlier, several studies have determined that wind energy, at somewhat modest penetration levels on the utility grid, will not have the significant impacts on regulation and reserves as feared. It should be acknowledged that these results could change at higher levels of wind penetration, and new studies are planned to examine this very topic.

Two important regulatory developments are FERC's proposal to change the energy imbalance penalties in Order No. 888 for intermittent technologies and its recent adoption of interconnection standards for wind generators (Appendix G of Order No. 2003). FERC's energy imbalance proposal would eliminate the punitive penalty for intermittent generators failing to meet advance delivery schedules and is similar to how the Bonneville Power Administration and PacifiCorp treat energy imbalances from wind. If adopted, FERC's energy imbalance proposal would remove a significant roadblock for wind generators, particularly in non-RTO areas. FERC's interconnection standards for wind turbines would require wind turbines to respond to voltage drops and to provide reactive power to the grid.

Improvements in wind forecasting will also be key to the future success of wind energy. Some parties use wind forecasting but are dissatisfied with high forecast errors, although the technology and science of wind forecasting is continuously improving. Although the N.Y. State Wind Integration Study illustrated the value of wind forecasting, only the California ISO currently has a centralized wind forecasting program. There is some debate as to whether an ISO-administered centralized wind forecasting protocol is better than what wind developers would deploy on their own, with some arguing that both may be necessary to cover the day-ahead and hour-ahead time frames.

Whether wind has capacity value also has been the subject of debate and analysis. The approaches in California and New York were discussed in this article. A range of methods are in place around the country, with some simply adopting the capacity credit of a wind generator (ISO New England and, for now, the NYISO), some adopting a proxy (RMATS), and some adopting the capacity factor of wind at certain times during the peak demand period (PJM). The capacity value of wind will vary across the country, depending on the quality of the wind resources. It also appears, at least preliminarily, that the capacity value of offshore wind resources will be better than for onshore wind resources, simply because of better and more consistent wind resources during times of peak demand.

Transmission for wind is another much discussed issue. Although not always the case, good quality wind resources are often located in remote areas with an undersized transmission grid. Obviously, the question is how to access those good-quality wind resources. Both reliability planning and economic planning processes for transmission are being pursued as part of the answer to this question.

In closing, good progress is apparent in the number of studies addressing the modest effects of wind on reserves and regulation, and new research will examine higher wind penetration levels. More remains to be done on transmission, and this mirrors the national situation, where it is widely acknowledged that more transmission is needed; however, consensus is elusive on how to do it and how to pay for it.

For Further Reading

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Biographies

Richard Piwko is a principal consultant with GE Energy in Schenectady, New York, where his responsibilities include management of large-scale system studies, power plant performance testing, control system design, and analysis of interactions between turbine generators and the power grid. He recently contributed to GE's development of the variable frequency transformer (VFT), a new technology for transferring power between asynchronous power grids. He is a Fellow of the IEEE and is chair of the new Wind Power Coordinating Committee. He has also served as chair of the IEEE HVDC & FACTS Subcommittee and as chair of the IEEE Transmission and Distribution Committee.

Dale Osborn is the transmission technical director for the Midwest Independent System Operator (ISO) in Carmel, Indiana. His responsibilities include the regional transmission exploratory expansion studies to define the possible development of transmission with various generation scenarios. Future generation scenarios for various levels of wind energy delivery are part of the scenario definitions that are explored. Both economic simulation and traditional transmission study techniques are used in the analysis of the exploratory expansion scenarios. He is also involved in the reactive power adequacy and voltage stability studies for the Midwest ISO. He is a Member of IEEE and vice chair of the new Wind Power Coordinating Committee.

Robert Gramlich has a B.A. with honors in economics from Colby College and a master's degree in public policy from the University of California, Berkeley. He is policy director of the American Wind Energy Association. In this capacity, he manages a group that performs policy analysis and advocacy, working with a number of regional renewable energy organizations. From 2001 until 2005, he was economic advisor to chair Pat Wood III of the Federal Energy Regulatory Commission, where he was involved in policy development on regional transmission organizations, market power, and transmission access.

Gary Jordan is a principal consultant with GE Energy in Schenectady, New York, where he is currently responsible for the technical content, training, and use of GE's detailed simulation programs covering multiarea generation reliability and production simulation. He has coauthored more than 20 papers in the field of generation and transmission planning and has coauthored a textbook on least-cost utility system planning.

David Hawkins is the manager of special projects engineering in the operations division of the California independent system operator. He is responsible for the assessment of new technologies, analysis of operating issues, and review of industry standards. This group has studied the impact of wind generation and other renewables on the California power grid over the past several years. He has served on many professional and industry committees and is currently chair of the Western Electricity Coordinating Council (WECC) Performance Work Group. He is a Member of the IEEE.

Kevin Porter is a vice president and principal at Exeter Associates, Inc., with 20 years of experience in renewable energy technologies, state and federal electric regulation, electric restructuring, and transmission access and pricing. He is considered one of the preeminent national experts on renewable energy and has advised state regulatory commissions, state energy offices, energy trade associations, the National Association of Regulatory Utility Commissioners, the U.S. Department of Energy, and several other organizations on renewable energy and electric power markets. At Exeter, he assists in green power procurement, transmission policies, energy analysis, and analyses of restructured electric markets.