Impact of Variable Renewable Energy on US Electricity Markets

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INTRODUCTION

Competitive wholesale electricity markets followed the restructuring of the vertically integrated electric utility industry in the US in the 1990's. Considerable attention was paid to design and operation of markets centered around traditional forms of generation, including fossil, nuclear, and hydro. Little consideration was given to market design and operation under conditions of high penetrations of variable renewable generation, such as wind and solar energy, which had not yet appeared on the scene in any significant amounts. Some of the characteristics of variable generation which present a challenge to market design are the greater variability and uncertainty associated with plant output, due to the fact that its fuel supply cannot be controlled; the need to schedule additional reserve capacity to manage the additional variability and uncertainty; the practice of renewable energy dispatch with a marginal price of zero, and that the renewable generator may have a profit motive to continue operation during moderately negative Locational Marginal Prices (LMPs).

This article examines the design and operation of a cross-section of electricity markets in the US. Experience with the evolution of such markets in the recent past to accommodate limited amounts of variable renewable energy is discussed. Based on this experience, insights into the needs of markets necessary to accommodate significantly higher levels of variable renewable energy in the future are provided.

ALTERNATIVE US MARKET DESIGNS WITH VARIABLE RENEWABLE RESOURCES

The article begins with an overview of the design and operation of typical regional markets operating in the US, as well as a typical stand-alone balancing area, and reviews their performance from a variable generation point of view. Some common characteristics of the large regional markets are that they have sub-hourly energy markets that are co-optimized with ancillary service markets in which all generators and loads can participate. This provides access to the physical flexibility that exists in the power system. Sub-hourly energy markets and the associated sub-hourly energy scheduling also reduce the amount of regulation (the most expensive ancillary service) required for both conventional power systems and for systems with high penetrations of variable renewable generation. Each of these systems is fairly large and provides significant aggregation benefits for both variable generation and load.

Regional Markets

There are a number of regional multi-lateral markets operating in the US today, including the PJM Interconnection, operating across all or parts of 13 states and the District of Columbia in the mid-Atlantic region; the ISO-NE, operating in the 6 New England states; the New York ISO, operating in the State of New York; ERCOT, operating across 85% of the geography of Texas; MISO, operating in all or part of 14 mid-western states; SPP, operating in all or part of 9 states in the south central region; and the CAISO, operating in the State of California.

A variety of markets can be found in the organized market regions, including day ahead (forward) and real-time (balancing) energy markets. In the real-time market in most regions, Locational Marginal Prices are calculated at five-minute intervals based on actual grid operating conditions. Most regions also operate day-ahead and real-time markets for ancillary services including regulation, synchronized and supplemental reserves. Additional market possibilities include financial transmission rights markets, forward capacity markets, demand response, voltage support, and frequency response.

Many variations of the basic markets can be found in the different regions. For example, several of the market areas allow wind generators to participate in the capacity markets, with capacity values represented with capacity factors during peak hours and months during the summer and winter season. Wind generally does not participate in ancillary service markets. Some markets recognize the uncontrollable behavior of wind power during normal conditions and exempt it from under- or over-generation penalties.

For example, in CAISO, wind and solar energy production are currently forecasted and scheduled on an hour-ahead basis and settled financially in the real-time energy market (on a monthly averaged basis for net imbalances for most such resources), but the goal for the near future is to provide the right pricing incentives such that renewable resources will schedule in the day-ahead markets. One key element to achieve this goal will be more accurate day-ahead forecasts of renewable energy production.

Bilateral

Stand-alone transmission provider balancing areas still exist in many areas of the United States, and in many cases these areas have significant renewable resources such as wind and solar. As compared with the large regional markets, stand-alone balancing areas tend to saturate with renewables sooner. The stand-alone provider tends to have a smaller pool of dispatchable resources available to manage the renewable integration, is often limited by hourly scheduling protocols, and may not make full use of load response to provide ancillary services. To the extent the stand-alone balancing area does have enough resources, its costs for renewable integration tend to be higher than the regional market dispatch pools can provide because of the reduced efficiency associated with a smaller pool. Because a stand-alone balancing area reaches its saturation point sooner, they are making increasing attempts to develop wind integration charges which are allocated to the renewable provider. Some non-jurisdictional utilities have been successful with this at the Federal Energy Regulatory Commission (FERC), and some FERC-jurisdictional utilities have either filed requests to charge a wind integration rate or plan to do so.

As renewable penetration increases towards the significant levels of 20-30% there will be several areas of operational impacts for the stand-alone balancing areas and bilateral-only markets. The saturated balancing area will encounter the need to keep more expensive but more flexible dispatchable resources on-line during periods where previously the slower-ramping and lower-cost dispatchable resources were sufficient to comply with balancing standards. This dispatch trend is likely to increase the desirability of instituting sub-hourly scheduling for all generation (utility owned and IPP) and consolidating energy imbalance provisions across balancing area boundaries. There are many examples already of sub-hourly scheduling and cooperative energy balancing dispatch in real-time that transcend the balancing area boundary. But for some areas of the United States, these concepts are still viewed with a great deal of skepticism.

A second impact of the increasing penetration involves reliability coordination. The traditional advance reliability evaluation of the scheduled resource plans of load-serving entities within the balancing area becomes less certain with the increased variability and uncertainty associated with variable generation. This in turn increases the need for improved tools and more efficient and cooperative congestion management methods that transcend the balancing area boundary. In some stand-alone provider areas, most congestion management is a local-only problem and the recourse to broad, efficient resolution of congestion is quite difficult. The increasing uncertainty of the sources of energy flow, including broad regional variability from renewables, will likely spell the end of local-only congestion management methods for the stand-alone providers.

Operating Challenges with high Renewable Penetration

Power system operation with variable renewable generation presents a number of challenges to system operators. The major difference between variable renewable generation and conventional thermal generation is the additional variability and uncertainty associated with the plant output. The uncertainty can be managed with better forecasting, but even if the forecast is perfect, there is still additional variability which must be managed. Additional flexibility is required from the remaining portfolio of plants to maintain schedules and keep the load and generation balanced under the conditions of higher variability.

Large balancing areas, geographic diversity of the wind resources, and fast markets (i.e., 5-minute dispatch) all help mitigate the operational impacts associated with integrating large amounts of variable output resources. Nonetheless, additional steps are being taken to mitigate potential impacts on operations, including centralized wind power forecasting. The wind power forecast can be used in day-ahead transmission analysis and security-constrained unit commitment programs to ensure that sufficient generation resources are scheduled to meet forecast load, transaction schedules, and reserve requirements.

Recently, several of the market operators implemented changes to improve wind resource management by allowing generating resources to submit negative price offers, which enables wind resources to submit flexible offers that better reflect the price at which they are willing to reduce output. Under this modification, wind resources are no longer considered “price takers” in the real-time market. Instead, wind plants participate in the market by providing a dollar per MWh bid below which they are no longer willing to generate. In the NYISO, when the price is below this bid, the wind plant will generally be directed to reduce its generation to the optimal schedule produced by the real-time market. Failure to respond to the directed schedule and over-generation above 3% of the upper limit during these times will result in financial penalties to the wind plant. The NYISO also uses a blending of wind power forecasts provided by the forecast provider and a persistence forecast based on the last actual power output reading of wind plants for the real-time energy markets.

Steps are being taken by the wind plant designers to enable greater flexibility in operation of the wind plants themselves. An active power control algorithm to limit wind plant output can be implemented. This capability is already being called upon during wind curtailment events, which can be caused by either transmission congestion, or a minimum load situation.

The ability to enable a limit in the “up” ramp rate is also possible during normal operation. For example, when a rapidly moving weather front passes through a heavy concentration of wind plants, the ability to limit ramping of the wind plants, and thus reduce the amount of ramping required from conventional generators, has proven to be very helpful in maintaining reliable operation.

In addition, a control algorithm to enable a wind plant to operate at a fixed level below its available output to enable spinning reserves to be carried and “up” ramp service to be provided has been implemented by several manufacturers, as well as the ability to enable governor and inertial response from units with the necessary control capability.

Reactive power control is also available to enable power factor control or voltage control of the plant output, even at no load in some cases. Low voltage ride through (LVRT) during power system faults is also required to help ensure system stability and can be provided by modern wind plants.

Market Design Considerations for Operation with High Penetration of Renewable Energy

A number of possibilities for increasing the efficiency and fairness of market design and operation to address the different characteristics and needs of variable output generators are discussed below. These ideas are being introduced and discussed at different rates in different jurisdictions, but are expected to increasingly occupy the attention of market design and operation and regulatory personnel.

Energy Market Prices and Price Volatility with Renewable Energy

One of the biggest issues related to variable renewable energy resources and competitive electricity market design is the potential impact of negative pricing on resource adequacy. Regions with high penetrations of variable renewable generation (e.g., wind) tend to have periods of low energy prices due to the fact that such generation has essentially a zero marginal cost (i.e., the fuel is "free") and is compensated for by the awarding of renewable energy credits. In fact, at certain times of the year, when renewable energy generation is high and loads are low, energy prices can and do go negative (i.e., a generator is willing to pay load to take its power). This also occurs when transmission constraints block the use of further downward control from flexible resources. The negative prices serve to establish a measure of the opportunity cost associated with a lack of dispatch flexibility.

Such a situation may lead to reduced resource adequacy and lower reliability in future years by its impact on the economic viability of existing conventional generation. If prices become too depressed, to the point that average prices do not cover the variable operating costs (e.g., fuel and maintenance) of a typical conventional generator, these resources will exit the market, jeopardizing resource adequacy and reliability.

The important price metric for flexible conventional generation is more complex: the average price and number of hours when price is above the generator's operating cost. Highly variable prices encourage investment in flexible conventional generation in place of inflexible generation with long start times and high minimum loads. In a market with significant renewable energy penetration, diurnal prices are likely to be more volatile, and high price periods are likely to result from changes in renewable energy availability (e.g., large wind ramps) rather than exclusively during peak load periods. Conventional energy resources that have sufficient flexibility to be available during these ramp periods are likely to be profitable and to contribute significantly to a market's ability to reliably integrate high levels of renewable resources.

Role of Capacity Markets - How to Keep Conventional Generators in the Market

For some time there has been a difference of opinion as to whether or not an energy-only market, or energy plus ancillary services market, can lead to stable prices and the ability of generators to recover fixed costs and provide sufficient capacity for adequate reliability. As pointed out in the previous discussion, there is concern that higher renewable penetrations will lead to depressed and highly volatile energy prices in energy markets. Volatile prices in a well run market can enhance reliability by showing market participants the type and location of response needed. Increasing price volatility is also expected to incentivize energy storage, price responsive load, and quick-start, fast ramping units, assuming proper market signals.

There is a growing body of evidence that a well designed forward capacity market operating in a parallel and coordinated fashion with an energy market can lead to a more stable market operation and reliable system operation in the long term. Due to the widespread differences in regulatory approaches to capacity adequacy, the jury is still out on this issue, which is still an active area of continuing study and research. This question will receive increased attention with the expected increase in penetration of renewable energy.

Role of Ancillary Service Markets – Do We Have What It Takes?

In order to cost-effectively integrate high levels of renewable energy resources, ancillary services requirements should be defined based on fundamental power system reliability requirements, not on the capabilities of the incumbent resources. For example, a strict interpretation of the current definition of spinning reserves would prohibit non-generation resources from supplying spinning reserve even if the response is faster and better for power system reliability. Responsive load, for example, can often supply faster spinning reserve response than generation. Ancillary service definitions should specify the system reliability requirements, not the technology for obtaining that response.

System reliability requirements are likely to change as additional renewable resources are integrated and additional ancillary services may be required as power system characteristics change. Load following, for example, is typically obtained at low cost through sub-hourly and hourly changes in the economic dispatch of the energy-producing generators and price responsive loads. There is typically sufficient depth in the energy market to accommodate the variation in net load. If high penetrations of variable renewable generation result in greater variation in net load than can be accommodated by the energy market itself, then a load-following ancillary service or a premium for faster ramping resources may be necessary.

Similarly, large wind ramping events such as experienced in Texas in February of 2007 and 2008 are too slow (as much as 1,500 MW decline over 2 hours) to qualify as contingency events. Contingency reserves are designed to respond to the sudden unexpected loss of generation and are expected to be fully deployed within 10 minutes. To accommodate such ramping events, an additional ancillary service, similar to but slower than supplemental operating reserve, may be required with high renewable penetration.

In addition, ancillary services procurement should vary by season and time of day in consideration of wind output patterns. Maintaining a constant amount of ancillary services annually will significantly increase the cost of wind integration. Rather, varying amounts of ancillary services should be procured for "high risk" periods such as when wind forecasts predict dramatic changes in wind energy output.

Co-optimization of Energy and Ancillary Service Markets

Co-optimization works by having generators submit offers to supply energy and each of the ancillary services. Co-optimization of energy and ancillary service procurement benefits the supplying generators and the power system. Generator revenue is maximized while power system costs are minimized through the most efficient allocation of all the offered products. Co-optimization requirements should be relaxed for emissions limited generation, storage, and responsive load, so these resources can offer response into the ancillary service markets without necessarily being co-optimized into energy supply. NYISO recently changed its market rules to exempt storage that is supplying regulation from having to be co-optimized into the energy market and MISO is in the process of changing its rules. Similar changes should be investigated for responsive load.

Improving Future Market Design

The role and challenge of market design will be to eliminate unnecessary barriers, create incentives that encourage the behavior and investment that will mitigate the impacts of variability, reduce the uncertainty that increases risk and therefore cost, and compensate resources fairly for the value of the service they provide, all within the legal and regulatory frameworks that have been established. The design process is guided by certain principals, including:

- level playing field, i.e. comparable treatment amongst all resource types
- pay for performance, not for promises
- put the risk and uncertainty with those best able to manage and control it
- incentivize compatibility, which in this context means a participant's best economic outcome should always be to follow dispatch instructions (no profitable opportunities to game the system)
- consistency with policy objectives established by the political and regulatory process
- market liquidity and transparency

Market design changes under consideration as potential solutions to foreseeable issues arising from high levels of wind resource penetration include the following:

- allow all resources to submit economic offers (including variable generation)
- create rules and infrastructure that encourage and facilitate the participation of price-responsive demand and storage resources in the market and consider their specific characteristics

Energy storage brings both an economic and a reliability value to power systems and wholesale power markets by withdrawing or consuming energy when there is more than enough available supply to meet demand (off-peak), and that energy is presumably less costly, and injecting the energy into the system when the supply/demand balance is tighter and energy is more expensive to provide. In wholesale markets with capacity and ancillary service market constructs, energy storage may also be able to capture cash flows from the reliability value and ancillary services which it provides, while contributing to reduced price volatility.

Demand response for peak reduction, ancillary service supply, and simply as price responsive load is a growing but still underutilized resource. In most regions, regulators will still not allow residential loads to be exposed to real-time electricity prices. This blocks loads from seeing and responding to prices which reflect power system reliability needs. Unlocking the full capability of load response will reduce costs and increase power system reliability. In regions with high penetration of variable renewable sources, the need for and benefits from load response are even greater.

Role of Wind Forecasting in Markets

Another topic is the application of wind power forecasts into day-ahead markets and unit commitment. The general process that the ISO will follow is to first solve the security constrained unit commitment (SCUC) problem based on generator and load bids. This process is purely a financial way to establish prices and schedules for the day-ahead market. The ISO must, however, make sure whatever decision is made is also reliable and that enough capacity is committed to meet forecasted load and reserve demands with consideration of normal network limits and contingency condition limits. This process is usually performed with an additional SCUC and has been the natural fit for the use of wind power forecasts. Currently, however, since this process is solely for reliability reasons, there is no opportunity to decommit units, unless the decommitment is the only option for solving a reliability constraint.

Therefore, if the total offered energy of wind plant bids is much less than the wind power forecast, it is possible that over-commitment took place in the day-ahead market but cannot be adjusted even with the knowledge of the high wind power forecast. Using the wind power forecasts in the day-ahead market would generally produce a more efficient result with the negative effect that the ISO would be forcing units to bid specific quantities. Most arguments show that with the current process the prices would eventually incentivize wind generators to participate in the day-ahead market, and that where allowed, virtual traders will also take their place and make the process more efficient. In any event, it is likely that market operators will need to seek increased unit commit and de-commit authority in the future, and wind plant output forecasts will play an increasingly important role in that process.

The SCUC problem deals with a great deal of uncertainty, and wind power adds to this uncertainty. It may be necessary to adjust the current SCUC procedure to account for this added uncertainty. In previously reported work, a stochastic unit commitment was developed to account for wind power uncertainty. The unit commitment solves multiple scenarios of uncertain variables (in this case both the wind and load) so that one single unit commitment decision meets multiple scenarios and minimizes the expected costs. This creates a reliable system that is optimized towards all possible conditions and over the long run should be more efficient. The key disadvantage is currently the extensive computation time that is needed, that increases with the number of scenarios. The way this would function as part of the existing market design is also a very complicated task, and one which has not yet received sufficient attention or research.

Incentivizing Flexibility in Organized Markets – How Much is There and How Do We Access It

The operating results from the past decade have shown that well-designed organized markets provide reliable dispatch integration and financial transparency. As a result for areas of the country with these organized markets, the basic elements already in place provide financial signals necessary to address the value of flexibility. For most organized markets in the United States, the level of variable generation penetration is not yet near saturation and the existing aggregate ramping capability of the dispatchable regional fleet is sufficient to meet the flexibility needs. The best designed markets provide full access to responsive loads, allow them to supply ancillary services, to respond to real-time energy prices, and serve as capacity resources.

This sufficient level of flexibility will be challenged as variable generation saturation increases above some threshold. The threshold can be estimated as roughly correlated to the “traditional” variability inherent in the diurnal supply pattern. The flexibility challenges may lead stakeholders to establish some minimum aggregate flexibility measures and requirements. These steps will help manage costs and reliability as the percentage of variable generation increases.

The increased net variability of generation and load not correlated to the daily load cycle increases incentives to create an inventory for flexibility. There are two main components to this incentive. Firstly, long duration ramps can contribute to regulation scarcity pricing (i.e. very high administratively set prices due to lack of reserves). Secondly, excess generation during minimum load conditions can lead to negative prices, as previously discussed. Both of these economic signals can be used to evaluate potential responses by market designers as well as market participants. With this transparency, regional markets are well-positioned to adapt to increasing penetration of variable generation.

Lastly, many of these issues identified in organized markets are completely analogous to non-market or stand-alone balancing areas. The issues in the stand-alone case arise relatively sooner, because of the lack of a regional diversity benefit. The issues also tend to be masked by lack of price transparency in a non-market or stand-alone balancing area. To the extent the stand-alone balancing area has variable resources that only contribute to local supply for that utility, the transparency issues are moot due to vertical integration and cost internalization. But as stand-alone balancing areas gain increasing renewable penetration of resources selling to parties other than the stand-alone utility, the reduced integration efficiency and lack of price transparency will likely be perceived as less-than-acceptable for a competitive wholesale energy environment.

How Important Are Seams Issues, and What Can We Do About It?

It will be critical to address the issue of seams between balancing areas as wind penetration levels increase. Smaller balancing areas with more seams will increase system integration costs caused by the variability and uncertainty of wind generation. Seams also increase the cost of control actions needed to manage congestion on transmission facilities and maintain grid reliability. Transmission planning will be ineffective for large scale integration of wind without regional or interregional coordination.

Seams between energy markets can be mitigated or eliminated through consolidation of balancing areas, implementing procedures to share reserves, or dynamically scheduling energy between balancing areas with surplus power to those areas with more demand. Interregional transmission planning coordination as proposed by the Eastern Interconnection Planning Collaborative (EIPC) or the Western Electricity Coordinating Council (WECC) would address some of the deficiencies associated with a multitude of independent planning authorities, but cost allocation for transmission facilities that span multiple states or regions remains an unresolved question.

Will Current Congestion Management Techniques Be Adequate for a High Renewables Future?

Availability of sufficient transmission is currently a limiting factor in development of renewable generation. Transmission is required not only to deliver renewable generation to load centers, but also to allow system balancing across large regions so as to reduce the need for ancillary services within the hour. Analysis of transmission capacity improvements should account for the needs of both renewable generation, and of flexible generation and other complementary technologies required to cost-effectively maintain system reliability.

In order to better manage congestion in the future, wind plant output forecasts specific to nodal injection points will be required for the day-ahead SCUC analysis. In addition, changes will be needed to increase access to redispatch through participation in the economic dispatch in isolated balancing areas, which will greatly reduce the need for ancillary services within the hour. The use of LMP is generally considered as the most efficient means of managing transmission congestion.

CONCLUSIONS

Greater amounts of wind generation will likely prompt changes in how the power grid is operated, managed and planned. Several lessons can be gleaned from the experience in integrating wind to date. It is clear that integrating wind will be easier with a larger balancing area than with a smaller balancing area, as there will be a deeper stack of resources to draw from for balancing wind's variability, and the wind variability will be smoothed by geographic diversity, assuming adequate transmission. The development of sub-hourly energy markets also aid in wind integration. Sub-hourly energy markets can tap flexibility from existing generating units at little or no cost, and reduce the need for ancillary services.

The need for more flexible generation is a clear trend, not only for incorporating more variable renewable energy generation, but also to replace older fossil fueled resources that are retiring. Although there are grid benefits from having more flexible generating resources, all generators do not necessarily benefit, as some must cope with lower minimum load levels, faster ramping and more frequent starts and stops, all of which impose additional costs and revenue reductions. Market products to incentivize this flexibility service need to be developed to ensure continued resource adequacy.

Flexibility can also be obtained from demand. Demand response may play an important role in integrating more variable renewable energy generation by encouraging load to interrupt service when wind is ramping down and load is ramping up. Conversely, when wind output is high during times at low or minimum load, demand ultimately could be added through technologies such as plug-in electric vehicles.

A number of utilities and RTOs have either implemented or soon will implement central wind forecasting. Improvements in wind forecasting accuracy and the development of new wind forecasting services such as wind ramp forecasting are to be expected.

The current construct of required ancillary services under FERC Order 888 may need to be revisited. 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 of generators. Similarly, new ancillary services may need to be created, such as a new type of non-spinning reserve service, particularly to handle large multi-hour wind ramps.

FOR FURTHER READING

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J.C. Smith, Stephen Beuning, Henry Durrwachter, Erik Ela, David Hawkins, Brendan Kirby, Warren Lasher, Jonathan Lowell, Kevin Porter, Ken Schuyler, Paul Sotkiewicz. *Impact of Variable Renewable Energy on US Electricity Markets.* IEEE PES Annual Meeting, Minneapolis, MN, July 2010.

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