Operational Analysis and Methods for Wind Integration Studies

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***Abstract*—Wind integration studies are increasingly important tools to estimate the impacts that the addition of large amounts of variable and uncertain generation will have on the electricity grid. As the number of these studies has increased in recent years, the sophistication of the methods and assumptions utilized has also increased. These methods have had to evolve with increasing penetration rates and to study changing research questions. In this work, the authors report on the state of the art in this area and make suggestions for improving the methods and assumptions used for cases with high levels of wind power.**

***Index Terms*—Power system operations, power system planning, stochastic systems, wind power generation.**

I. Introduction

With the dramatic growth in wind power installed in the United States over the previous ten years, it is no surprise that a number of wind integration studies have been conducted in order to gauge the effect of adding significant amounts of this intermittent resource into the electricity grid. These studies have built on the results of previous studies and progressively have become more sophisticated, not only in the modeling techniques employed, but also in the types of questions answered. The previous state of the art in wind integration has been described in [1] and a review of recent studies can be found in [2]. The United States Department of Energy sponsored two large integration studies recently completed by the National Renewable Energy Laboratory (NREL): the Western Wind and Solar Integration Study (WWSIS) [3] and the Eastern Wind Integration and Transmission Study (EWITS) [4]. These two studies have produced considerable insights into different areas of integration studies including both methods and data. However, wind integration is still a relatively young field and there are significant areas where new methodologies are needed to explore new aspects of the problem. In this paper, we discuss some of the key technical areas of wind integration studies, focusing on operational aspects in systems with high levels of wind penetration and the calculation of wind integration costs. We also discuss other factors that influence the ability of the system to absorb high wind penetration levels, such as baseload turn-down levels, and the complex topic of the interaction of wind with various types of reserves.

We start with a section on operational analysis. Recent wind integration studies in the United States have utilized electricity production simulation models and market models to analyze the impact that wind will have on unit commitment decisions and operating reserves. Standard production models may not have the ability to correctly manage commitment and dispatch efficiently with high levels of wind, so separate statistical analysis of wind and load data is typically used to help develop operating reserve levels that are dynamically determined based on actual operating conditions (e.g., wind and load levels). In Section III, we more fully define and develop concepts related to operating reserve and discuss the impact of wind power integration on this ancillary service. In Section IV, market considerations of the inclusion of large amounts of wind power are considered. In Section V, we discuss integration cost analysis and describe some of the evolution in methods of assessing integration cost. Early methods were developed to allow the side-by-side comparison of costs between wind and other generation technologies. We show some of the issues and shortcomings of these approaches, and suggest possible paths forward. Section VI concludes the paper.

II. Operational Analysis

Early integration studies focused on single utilities and modest wind penetration rates. As interest in wind energy has grown and wind energy has been adopted into the generation mix around the United States, larger study footprints accompanied higher penetration analyses. For example, Xcel Energy in Minnesota was the subject of two early integration studies [5] which were eventually followed by a statewide study that analyzed wind energy penetration of 25% of annual electricity demand [6]. The larger the system sizes and wind energy penetrations become, the more difficult it is to accurately model the impact of the large amount of wind power output on the power system.

Before the modeling of the power system begins, there are a number of assumptions that must be made on the state of the system to be modeled. Assumptions on the generation mix, transmission expansion, and locations and amounts of the wind in the scenario have to be agreed upon. Operation of the power system, however, also depends on the market structure assumptions. The first is that the study system is usually optimized in its entirety. For large regional studies, this is somewhat different than today's actual operations. Many small balancing areas (BAs) currently operate their own system individually, and power transfers between regions may not be

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fully optimized based on economics. Sometimes special techniques are used to replicate this behavior. However, with very large penetrations of wind power, it has been found that the seamless coordination of BAs and rational economic operation between them is essential to fostering an efficient integration of wind power. This is why many studies perform the simulations based on operation of the power system by an integrated whole, assuming greater BA cooperation.

Other assumptions regarding operations are made before the simulations are performed. Many studies assume that the areas operate with day-ahead and real-time energy markets (or economic dispatch). They also assume that the energy and ancillary services markets are cooptimized to find the most efficient solution. Many studies also assume that subhourly energy markets or scheduling exist in the study area and this assumption helps drive the operating reserve analysis. Most studies assume that the market participants will offer into the energy market with bids based on their marginal cost. Lastly, and most importantly, most of the studies make the assumption of keeping the power system at the same level of reliability with added wind generation.

A. Production Simulation

To get a realistic view of how the system operates in these studies, detailed simulations are run with the system conditions modeled. Production cost simulation tools are commonly used when simulating the power system behavior of the generating units and the power flows on the transmission system. These tools are very popular in use by utilities, independent system operators (ISOs), and others when evaluating profit outlooks based on locational marginal pricing (LMP), financial transmission rights price forecasting, and transmission planning, among other applications. Wind power integration studies are a new application of these models and challenges arise because these models were not built with this goal in mind. That being said, their use of security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) show great realizations of how the system may behave with high wind power penetrations. A very large portion of the analysis on steady state operations can be seen by the use of these powerful tools.

SCUC solves an optimization problem to determine the least cost selection of units that can meet the load and reserve demands while respecting limitations on the generation fleet, for example: minimum run times, ramp rate limits, minimum generation limits, and startup times. These are physical generator constraints that must be replicated in the simulation. The SCUC used in the production cost tools can also model transmission constraints, usually using a dc power flow. The solution creates power flows that are within reliable operation of the transmission system. In some cases, it also ensures that following "$N-1$" contingencies power flows are still within emergency limits. Commitments must be made well in advance since many thermal generating units need substantial time to start up.

In SCED, dispatch is adjusted to meet load while minimizing production costs and meeting all generator and transmission constraints. This is the second stage of the production cost tool. In most cases, quick start units are allowed to be turned ON and OFF, but all other thermal units must remain in their unit commitment status determined from the SCUC. Hourly costs and LMPs that come from the SCED are calculated.

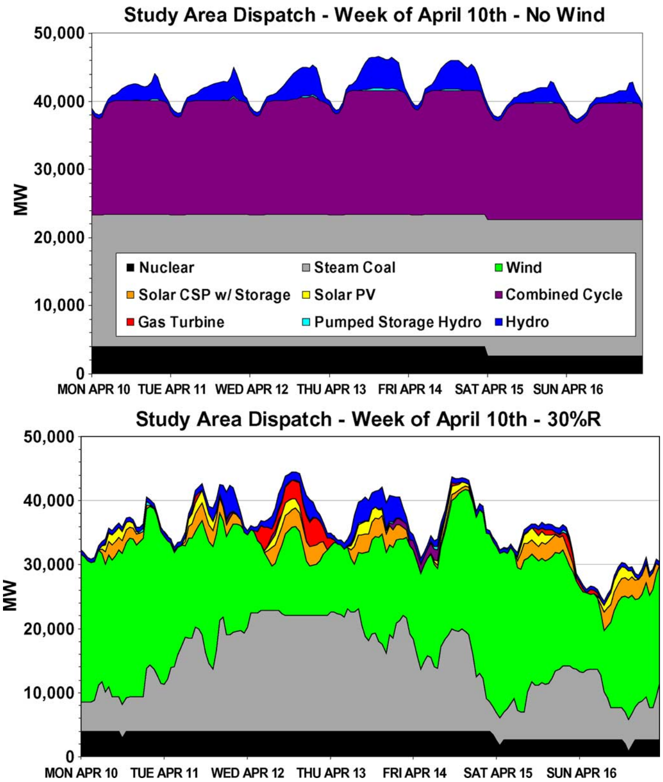

Fig. 1. Example dispatch when wind energy is added to the system. Top: no wind. Bottom: 30% annual wind and 5% solar penetration during low-load and high wind period.

The wind power forecast errors are very important when analyzing the operational impacts of wind. The simulations have to use the wind power forecasts in a way that represents how BAs are planning on using them or should use them. Generally, this means that the wind power forecast is used in SCUC and the actual wind power production is used in SCED. Load forecasting is treated similarly, and both usually use the day-ahead forecasts. The result is that unit commitment is made with consideration of the forecast, while the actual dispatch is made using the actual production. A larger forecast error will lead to a more inefficient unit commitment decision and higher production costs.

Fig. 1 shows an example of the types of outputs that are created from typical integration studies. Fig. 1 [7] shows one day in April with no wind with a typical dispatch—nuclear, coal, combined cycle, and hydro generation that meets local load within WestConnect and some exports. When the 30% annual wind energy plus 5% solar penetration is added, the dispatch changes significantly, as seen in the bottom portion of Fig. 1. Combined cycle generation is reduced significantly, and hydro is moved around somewhat. There is even an impact on the coal stack. This particular week is the most challenging of the 3-year study period, so it is not representative of typical operation. Detailed simulation of multiple years is a valuable way to find rare situations that may be very challenging for system operations.

A common goal of wind integration studies is to examine how production costs change as wind is added to the system. Production costs consist primarily of fuel cost, and are a function of the unit commitment and dispatch schedules. Because wind is assumed to have a zero marginal cost, the economically optimum situation is usually to use all the wind that is available, unless there is a reliability concern. This will displace other fuels, reducing production costs.

B. Stochastic Unit Commitment

The traditional SCUC used in both day-ahead markets and in production cost simulation tools is deterministic. In other words, uncertainty in day-ahead predictions against real-time outcomes is not modeled explicitly. Instead, operating reserves are used to cover any uncertainty associated with loss of generation or load forecast error. The probability of outages occurring is fairly constant at all times, and system operators will carry enough reserves to cover the largest credible contingency. With current levels of wind penetration net load forecast errors are often insignificant compared to contingency reserves and large errors can be accommodated with existing operating reserves or system flexibility in real-time. With high wind power penetrations, the uncertainty is more complicated. A number of recent studies have examined stochastic unit commitment programs that solve the unit commitment towards a robust set of resources being able to meet multiple possible scenarios [8]–[11]. This creates an efficient solution that, in the long term, is both more economic and more reliable.

The objective function of a deterministic SCUC can be written as

$$\text{minimize } \mathcal{L} = \sum_{h=1}^{\text{NH}} \sum_{i=1}^{\text{NG}} P_{ih} * c_i + u_{ih} * \text{NLC}_i + z_{ih} * \text{SU}.$$

The objective function of the stochastic SCUC differs

$$\text{minimize } \mathcal{L} = \sum_{s=1}^{\text{NS}} \pi_s * \sum_{h=1}^{\text{NH}} \sum_{i=1}^{\text{NG}} P_{ihs} * c_i + u_{ihs} * \text{NLC}_i + z_{ihs} * \text{SUC}_i$$

where: h = hour index; NH = number of hours; i = generator index; NG = number of generators; P = power schedule; c = variable energy cost; u = unit status; NLC = no load cost; z = unit startup indicator; SUC = startup cost; s = scenario index; NS = number of scenarios; and p = probability.

Stochastic unit commitment minimizes the expected cost based on weighting its solution on the probability of events. Therefore, it is more important to reduce costs for more likely scenarios. Stochastic unit commitment represents a two-stage process where the first stage ensures a unit commitment and the second is a scenario tree of possible real-time outcomes. The unit commitment must be followed regardless of the scenario outcome since it must be made in advance.

The constraint is specified as

$$u_{ihs} = u_{ih} \quad \forall s \in \text{NS}; \quad \forall i \in \text{NGLS}$$

where NGLS is the set of generators with long start times. This ensures that one single-unit commitment solution is made robust toward multiple solutions. When different outcomes occur in real-time, the system is already built to meet these conditions reliably and efficiently.

The main issue with stochastic SCUC is its computation times. For increases in the number of scenarios, computation times increase as well. Scenario reduction techniques have been researched to help reduce computation times. However, reduction in scenarios may cause a reduction in accuracy and efficiency. Research continues in this area and advanced algorithms will likely soon be able to solve the stochastic unit commitment problem in reasonable computation times.

C. Rolling Unit Commitment

Generally, in the U.S. market regions, there is a day-ahead market and a real-time market. The day-ahead market runs the SCUC program and the real-time market runs the SCED program. Unit commitment is considered fixed after the day-ahead market solution is completed. This is identical to how production cost simulation models are run for most wind power integration studies. However, many resources have start times of only a few hours and, therefore, would be able to change the commitment decision any time throughout the day.

As one would guess, forecast errors are generally higher as one looks further ahead. When decisions are made closer to real-time, those decisions may be more efficient than if they were made further in advance. Some research has looked at using rolling unit commitment strategies, where the unit commitment solution can be adjusted at frequent intervals throughout the day. The unit commitment process would have the opportunity to change the previous commitment decision for any one generator if it does not violate the units' physical constraints. This strategy could further facilitate the integration of wind power by increasing the efficiency of unit commitment and reducing integration costs. One example of the application of rolling unit commitment is a recent study [12] performed on the Eastern Interconnect using the WILMAR model [11].

D. Subhourly Time Resolution

Production cost simulation tools have historically been applied with an hourly resolution. Hourly averages of wind generation and load were used and their hourly variability had to be met by the system resources. Within-hour variability and uncertainty were quantified statistically and added to the hourly reserve requirements. More research is required to determine if production cost modeling can be effectively implemented at the subhourly level.

III. Operating Reserves

Current practices for power systems operations involve carrying reserve capacity to ensure a reliable and secure system. In the United States, operating reserves are typically separated into contingency reserve and regulation reserve. Contingency reserve is generally used for system failures and usually a BA will ensure it can withstand the largest credible contingency. Regulation reserve is used to provide minute-to-minute balancing to control interchange flows and keep system frequency stable and minimize the area control error. The amount of regulation reserve usually carried is based on meeting NERC Control Performance Standards (CPSs) in North America [13]. These reserves are based on the current variability and uncertainty on the system. Most experts agree that the types and amounts of reserves will change with higher penetrations of wind power.

For instance, reliability events due to wind power changes do occur, but the speed is on a slower time scale than that of generation contingency. Some research on how to quantify operating reserve requirements with large penetration of wind power can be found in [14]–[17].

Most wind power integration studies attempt to quantify reserve requirement increases due to wind [18]. Methods are evolving with each study and with wind power penetrations of up to 30% of total energy, further improvements in methods will be necessary. One basic assumption is that the amount of operating reserves with higher wind penetrations must be made based on meeting the current level of reliability.

In the United States, the first two large-scale wind power integration studies were performed in New York State [19] and Minnesota [5]. Both of these had extensive analysis on determining operating reserve increases. In New York, the study evaluated 3300 MW of wind power on the 33 000-MW peak load NYISO system. The study concluded that no incremental contingency reserves would be needed since the largest single severe contingency would not change. The study then concluded that an additional 36 MW of regulating reserve was required on top of the current 175 to 250 MW procured today. This is a result of analyzing the standard deviation of 6-s changes in load net of wind compared with that of load alone. In Minnesota, the initial study evaluated 15%, 20%, and 25% wind energy as a percentage of total annual demand. This corresponds to 3441-, 4582-, and 5688-MW wind power on a system with a peak demand of roughly 20 000 MW. Similar to New York, it was concluded that there would be no impact on contingency reserve requirements with the added wind penetrations. The regulating reserve requirement similarly evaluated the added variability of wind, but calculated it to be a 2-MW standard deviation for every 100-MW wind plant installed. This calculation was based on operational data from existing wind plants. The ratio was used to calculate the regulating reserve requirement as seen in the following equation:

$$\text{Reg Req} = k\sqrt{\sigma_{\text{load}}^{\mathbf{2}} + N\left(\sigma_{W10\text{o}}^{\mathbf{2}}\right)}$$

where k is a factor relating regulation capacity requirements to the standard deviation of the regulation variations (assumed to be 5 in this study reflecting current practices); σ_{load} is the standard deviation of regulation variations from load; σ_{W100} is the standard deviation of regulation variations from a 100-MW wind plant; and N is the wind generation capacity in the scenario divided by 100. The Minnesota study quantified two other defined categories: load following and operating reserve margin. These categories are not usually defined in current system procedures and unique methods were used to determine how variability and uncertainty of wind impacted their results.

Most recently, three large regional wind power integration studies have been performed for the WestConnect footprint of the Western Interconnection [3], the Eastern Interconnection [4], and the Southwest Power Pool (SPP) [20]. Each of these used highly sophisticated engineering techniques to determine additional operating reserve needs on its system. We discuss each of these methods in more detail below.

TABLE I
WWSIS RESERVE RULES FOR 30% LOCAL PRIORITY SCENARIO

	Load Only (% of load)	30% LP Scenario		
		Load Term (% of load)	Wind Term (% of wind production)	up to (% of wind nameplate)
Footprint	1.3	1.1	5	47
Arizona	2.2	2.2	5.6	36
Nevada	2.1	1	10.7	54
Colorado East	2.4	2	5.7	68
New Mexico	2	3.1	3.5	70
Wyoming	1.3	2.7	8.7	33
Colorado West	1.8	3.1	7.3	100

In WWSIS, the team used the term variability reserve to note the capacity that must be available to meet the increased variability apparent from wind power. Ten-minute wind net load data was analyzed and its variability compared to that of load-only data. The team also investigated how different wind penetrations and load levels influenced the total net load variability on the system. Three standard deviations of this variability were used to create formulas to achieve the reserves needed based on wind and load levels. Table I shows these rules for the 30% wind, local priority scenario (which includes 5% solar). For each area, variability reserves were calculated based on a percentage of hourly forecasted load, plus a percentage of hourly wind forecast up to a maximum level of wind capacity. Once above that level of wind, the variability reserves did not need to increase with increased wind power. The project also examined nonlinear functions to represent the statistical distribution of variability.

In EWITS, reserve requirements were determined slightly differently. The study showed increases in two types of operating reserves, with contingency reserves determined by the largest single contingency for each region. For regulation reserves, the minute-to-minute variability of wind was deemed to be insignificant because of the geographic diversity of resources in the large study area. However, because economic dispatch signals that are created and sent to generating units every 5 or 10 min cannot be changed inside the same time frame, any forecast errors made with each dispatch signal must be met with regulation reserves. It was noted that these errors were larger at different percentages of wind power output, mainly in the middle 50% of capacity range, and a function was used that was calculated based on three standard deviations of the variability of the hourly forecast wind production. The totals were statistically added to the regulation required due to load, because of the lack of correlation between wind plant locations. Lastly, an additional reserve requirement was used for the hour-ahead forecast errors. This was also an hourly function of wind, but only one standard deviation was required to be spinning reserve due to its slower response requirement. The calculations from EWITS can be found in Fig. 2.

In the SPP Wind Integration Task Force (WITF) Integration Study [20], the reserve determination methodologies were once again unique. The study evaluated reserve requirement needs for regulation reserves, load following reserves, and contingency reserves. For regulation reserves the NERC-CPS2 standard was used to determine the increases. Therefore, to equate to the 90%

Reserve Component	Spinning (MW)	Nonspinning (MW)
Regulation (variability and short-term wind forecast error)	$3\cdot\sqrt{\left(\frac{1\%\cdot HourlyLoad}{3}\right)^2+\sigma_{ST}(HourlyWind)^2}$	0
Regulation (next-hour wind forecast error)	$1\cdot\sigma_{NextHourError}\,(PreviousHourWind)$	0
Additional Reserve		2 × (Regulation for next hour wind forecast error)
Contingency	50% of 1.5 × SLH (or designated fraction)	50% of 1.5 × SLH (or designated fraction)
Total (used in production simulations)	Sum of above	Sum of above

Fig. 2. EWITS reserve methodology overview.

compliance requirement of CPS2, the 5th and 95th percentiles were used as the requirement boundaries. Also, because the BA is out of compliance only if the 10-min average ACE is above the BA-L_{10}, this is taken into the overall equation of determining the requirement. The overall equations are shown as follows:

$$R_{\rm up} = \sqrt{(0.01 l_{\rm peak} + L_{10})^2 + \alpha \Delta W_{95}^2} - L_{10}$$
$$R_{\rm down} = \sqrt{(0.01 l_{\rm peak} + L_{10})^2 + \alpha \Delta W_{5}^2} - L_{10}$$

where $l_{\rm peak}$ = peak load; α is a calculated coefficient, and ΔW are the respective percentile of 10-min deltas. Similar to the other two studies, the project team proposes that regulation requirements be dynamic and time-varying based on system conditions. The study also recommends the possibility of a load following reserve requirement and provides analysis on some of the ramping requirement increases in this time frame. Lastly, the contingency reserve requirement was not changed for the study, but it was recommended that it be reevaluated if extensive high-voltage transmission expansion occurs.

These three studies have opened new doors on how system operators think about operating reserves. All propose time varying requirements and propose new reserve types, which differ from current system operating practices. Even though there are commonalities between the approaches, it is interesting to see where the methods differ. More work is needed to examine the strengths and weaknesses of the different methodologies. Simulations that model subhourly market operations, and replicate operator actions when deploying operating reserves with high wind penetrations, should help validate the various methods. Having enough reserves is normally not the issue since additional generation can always be committed, except in cases of constrained transmission. The real question is how to use the information available to determine the efficient amount of operating reserve for a given situation to keep a predefined reliability level. It is possible that the optimal standards to maintain a reliable system under these circumstances differ significantly from current standards.

A few examples of further research questions we recommend are listed as follows. An example of different operating reserves and how they interact is shown in Fig. 3.

Examples of further operating reserve analysis questions:

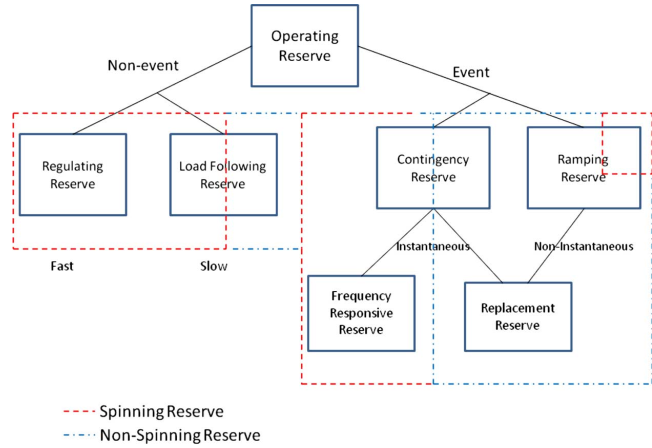

Fig. 3. Example of operating reserves on a system with high wind power penetrations.

1) What is the right level of spinning versus nonspinning reserve for the different categories?
2) Can certain reserves be shared or should specific causes trigger each reserve type?
3) What is the correct response time of nonspinning reserve?
4) How should a specific requirement for frequency responsive reserve be determined?
5) What are the true causes for regulation reserve utilization?
6) What are the appropriate standards for regulation reserve requirements?
7) Should ramping reserve requirements require a response time that is a function of ramping predictions or static responses?

IV. Market Considerations

Milligan and Kirby [21] analyze the role of energy markets in helping to integrate variable generation. It is worthwhile to extract key points and show the relevance to wind integration analysis. Fast energy markets, operating at 5-min intervals, allow variability in load, wind, and other variable generation to be managed with a potentially large fleet of generation. The economic dispatch calls upon units to move to new operating points, increasing or decreasing output as needed. At each of these time steps, units on AGC that are providing regulation can move back to their preferred operating points. Conversely, when the dispatch is changed only once an hour, the economic dispatch stack is constrained and all of those units will keep their position until the top of the next hour.

As shown in [21], fast energy markets can often supply needed ramping capability, which is a capacity service, at little or no cost. However, there are times that the units on economic dispatch may not have sufficient response capabilities to ramp quickly enough, and an out-of-merit dispatch of a fast-start unit may be required to supply the ramp. A simplified diagram appears in Fig. 4. The figure illustrates a case that has insufficient ramping capability online, causing a peaking unit to follow the ramp until the baseload capacity can catch up. The peaking unit sets the energy price for the hour. In such cases, it might be beneficial to design a load following market as a supplement to the energy market. It would not be necessary to invoke the load following market at all times, but in cases where ramping

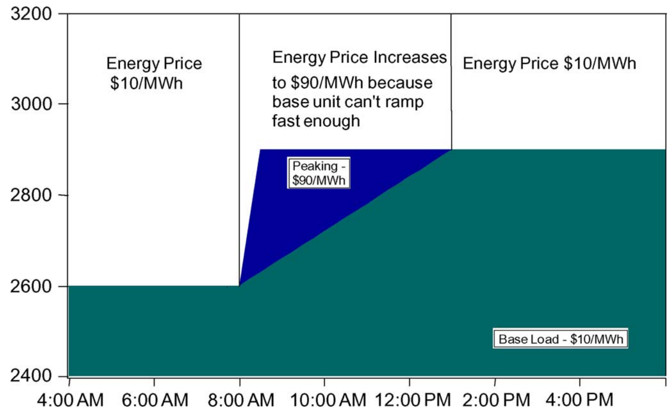

Fig. 4. Insufficient ramping capability from the dispatch stack may result in peaking response which could set the energy price for the period.

supply is limited, it could be used to procure more, without distorting the energy price.

Other concerns regarding the sustainability of existing energy markets at high wind penetration rates may be more important. The low LMPs that are often seen in wind integration studies are not due solely to wind; they are exacerbated by the inability of baseload units to move to a lower generation level or shut down. During high-wind and low-load times, this situation causes an excess of generation and consequently low or negative prices. With a different nonwind generation mix or transmission infrastructure, this situation might be alleviated.

V. Integration Costs

Many wind integration studies have attempted to determine how the increased variability and uncertainty of wind translates into increased operating costs. Sometimes the objective has been to compare these costs to a benign generating unit that has neither variability nor uncertainty. Various types of theoretical benchmark units have been proposed, most of which have some form of flat energy blocks that are equivalent to wind energy over some agreed upon time period, such as a daily-equivalent block of energy. None of these proxy energy sources are entirely satisfactory for wind integration studies. In this section, we discuss the issue of integration cost, whether wind is the only technology that might impose additional variability or uncertainty on the power system, and also discuss shortfalls that have been identified in recent analysis.

A. Integration Costs Imposed by Nonvariable Generation

Wind integration operating costs generally consist of the cost associated with increased cycling, inefficient operation due to forecast errors, and additional reserves. For example, a thermal unit that increases its cycling to help accommodate the wind will typically perform less efficiently, using more fuel per unit of output. The additional cycling duty may also result in increased operations and maintenance cost, and potentially a shorter useful life.[1] Because of the many complex relationships between units in the commitment and dispatch stacks, and the requirement that load and generation must be balanced, any new entry into the generation fleet may change how the incumbent units are operated. This too may impose cycling costs in incumbent units. Consider the following simplistic example. A power system has two types of generators; one is base loaded and the others are cycling units. The baseload generation never changes its output, incurring no cycling costs or efficiency losses. If we now add a new baseload generator, that is less expensive than the incumbent baseload units, this changes the merit order in the economic dispatch stack. The new generation is dispatched first. This moves the incumbent units up the stack, forcing them to increase cycling, reducing the capacity factor (and revenue) and reducing efficiency.

[1]The wear-and-tear cost of additional deep cycling is widely acknowledged, but little public data is available to inform analysis.

B. Flat Proxy

Some integration studies that calculate wind integration cost use a flat-block proxy resource for the no-wind case. The method develops the proxy resource by calculating the wind energy-equivalent for each day of the study, and then inserting this block at zero cost into the dispatch stack. Since the block has no variability or uncertainty, it has been used for the no-wind base case. Integration cost is then the difference in total operating cost between the wind case and the flat-block proxy case, divided by the wind energy to get a cost per MWh of wind. Applying the flat-block proxy in EWITS revealed significant problems with that approach, and hence alternative approaches were used. To be fair, this method was developed to answer a particular question about wind integration: How much does incorporating wind's additional variability and uncertainty affect the system operations? The usefulness of this approach appears to have become limited with additional studies. In EWITS, there were extremely large transitions between days whenever wind output changed as a result of a large frontal passage or other significant change in daily wind energy.

Milligan and Kirby [22] analyzed the performance of alternative proxy resources, including various flat block durations, and found that at high wind penetrations they all imposed a significant artificial ramp during the intrablock transition. Wind integration studies often use 24-hour flat proxy blocks, which have extremely high intrablock ramps. Fig. 5 is adapted from that work, and shows that both the daily block and 6-hour block have much higher extreme ramping behavior than wind. Similar impacts are also observed with large negative ramps.

There are also concerns regarding the intermixing of value with cost. Because of the timing of wind energy delivery, it will likely have a different (lower) value than the proxy resource, as illustrated in Fig. 6. In that eventuality, part of the differential in production cost between the wind as-delivered and the proxy resource will be caused by this value differential, and is not the same as the cost of additional reserves or inefficiency.

A further concern arose during the EWITS. Because of the high penetration of wind analyzed, some regions found it economic to secure additional ancillary services from adjacent areas. This occurs often in areas that have electricity markets. But when integration costs are tallied across a multiregion footprint, there may be no recognition that one region benefited by making a sale, and the benefit from the revenue stream may not be counted in the integration cost.

For this and other reasons, it may be time to move in a new direction. Because of the complexity inherent in the system and

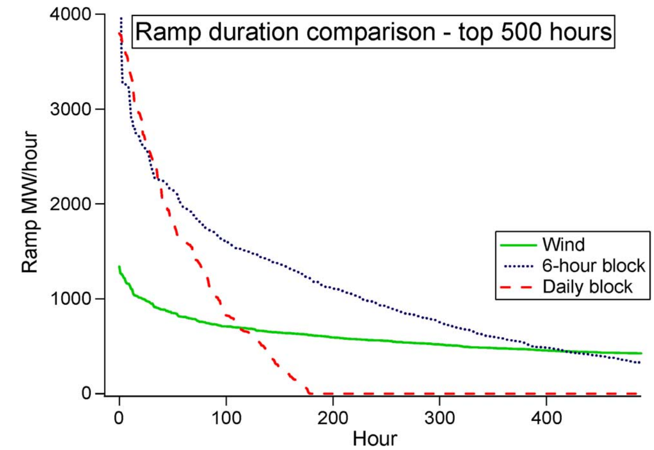

Fig. 5. Twenty-four-hour and six-hour flat blocks introduce large positive artificial ramps to the proxy resource.

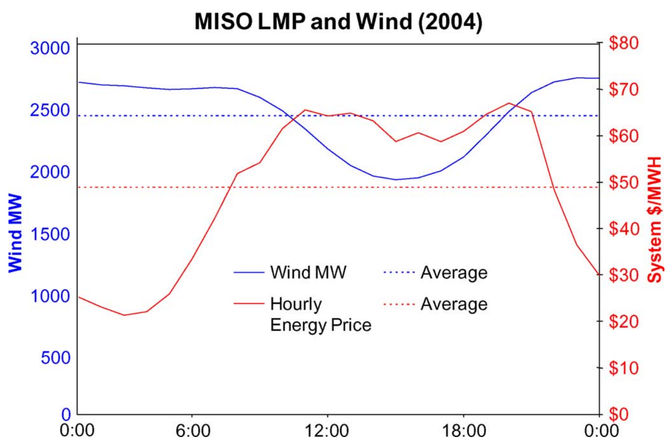

Fig. 6. Prices from the Midwest Independent System Operator and wind data show the average diurnal value swing of wind energy (Milligan and Kirby, 2009).

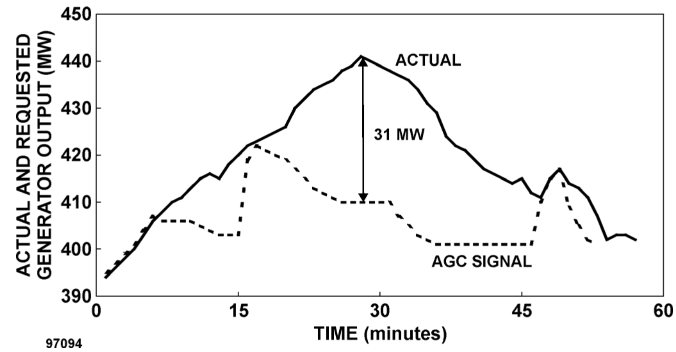

Fig. 7. Coal unit cannot follow AGC and imposes an additional 31 MW of regulation during this hour.

because it can be difficult to untangle costs from benefits, it may be time to assess total operational cost with and without wind. Of course, this comparison will be complicated in cases that have different generation mixes. The flat-block comparisons, although problematic, have provided significant insights into wind integration impacts and costs. A full accounting of all operating costs, assuring that the system is reliable and that the modeling is realistic, encompasses all such costs of integrating wind.

C. Conventional Generation and Control Signal Following

Some generators have difficulty following an automatic generation control (AGC) signal, which is sent to AGC units that provide regulation reserves. In cases like this, the generator can actually increase the need for regulation instead of providing helpful regulation. This imposes an integration cost on the system that is rarely assessed. Fig. 7 illustrates a coal unit in the Midwest where the unit imposes a 31-MW regulation burden for this hour because of its inability to follow the AGC signal.

VI. Conclusion

Wind integration analysis has progressed significantly in the last several years. Advances in wind data development, reserves modeling, operational analysis, incorporating subhourly information into hourly models, and performing unit commitment based on forecasts have all enhanced our collective knowledge about integration. New methods that include rolling stochastic unit commitment, and introducing additional constraints and other factors into simulation programs will further improve the quality of the analysis. Further work in operating reserves, incorporating subhourly constraints into hourly models, developing models with subhourly economic dispatch is needed. All of these improvements will greatly enhance resource development and better transmission planning. Further work is needed to either refine methods for integration cost analysis, or propose entirely new approaches with transparent accounting for the complex interactions among generating units. Additional work is also needed to understand the complex interactions between transmission build-out, resource mix, BA size, and markets.

Markets cover a large fraction of the U.S. power grid, and much valuable experience has emerged from operating the various markets over the past several years. However, questions remain about whether the markets in their current form will support needed services and provide market signals that will induce an economically efficient level of flexibility in the long-term. There may be a need for a supplemental ramp product so that energy prices are not severely distorted during fast ramps. Hypothetically, very low LMPs over a significant fraction of the year will induce generation developers to favor flexible units, with a disincentive to overly develop baseload generation. Whether this is realistic remains to be seen.

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