Reserve requirements for primary frequency control increase sharply at high levels of wind penetration

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Abstract

Power system stability following a fault is protected by primary frequency control and also by the inertia of heavy generator rotors like those found in conventional power plants. Because non-hydro renewable resources provide the power system with much less inertia and frequency response, a large fault could induce damaging oscillations in a system with a high penetration of renewables, resulting in lost load.

Time-domain simulations on a fully dynamic modified IEEE 14-bus test system were conducted to measure the effect of a fault on metrics for system stability with varying quantities of wind power and wind interconnection locations. In response to model uncertainty, a probabilistic metric resembling loss-of-load-probability (LOLP) was ultimately chosen. Scenarios vary wind power penetration from 0% to 28% of total installed capacity.

Primary frequency control rapidly damps transients; we find that its reserve requirements increase sharply at high levels of wind penetration. Although these experiments should be run on a validated model of a major US interconnection to ascertain whether the observed trends are general, we find a sharp increase in LOLP as wind penetration nears 20% unless new primary frequency control resources (that can include energy storage) are added.

Keywords: Power system transient stability; Primary frequency control; Wind power integration; Inertia; Reliability; Energy storage

1. Introduction

Renewables Portfolio Standards in the majority of the United States are directing system operators and load-serving entities towards the inclusion of large fractions of energy from renewable sources. At the same time regulations set by the Environmental Protection Agency (EPA) on conventional pollutants such as mercury, SO_2 and particulates, as well as regulations on cooling water intake and effluents, are expected to result in the retirement of at least 64,000 MW of coal generation – 7% of US generating capacity – by 2017 [1,2].

The replacement of this capacity by renewable resources presents a challenge to power system transient stability[1] because renewable energy sources like wind and solar differ fundamentally in their control, generation and size from most of the generators in the US power system. Those generators that produce most of the energy in the US use steam to rotate a large field coil electromagnet (rotor), which induces an electrical current in stationary copper windings (stator) surrounding the rotor. The power output of these generators is controlled by adjusting the amount of steam driving the rotor, and may be sized at 800 MW or larger. Frequency-sensitive governors are found on the majority of these conventional power plants that can adjust real power output in response to changes in frequency within milliseconds. Wind generators also produce electricity through a rotating magnet inducing an electrical current in a stator coil, but this is done on a much smaller scale, meaning that wind turbines contribute much less inertia to the power system. Unlike the generators in thermal power plants, wind turbines consume reactive

[1] Transient stability is defined as the ability of a power system to remain in a state of equilibrium under normal operating conditions and to achieve equilibrium after undergoing a disturbance [3]. It will be further elaborated in section 2.

power to induce a magnetic field in the rotor. Lastly, wind turbines produce power only when the wind blows, so they are not as easily controlled.

The Federal Energy Regulatory Commission (FERC) has directed the North American Electric Reliability Corporation (NERC) to promulgate a more rigorous standard for frequency response [4]. Specifically, Balancing Authorities will need to comply with a standard that dictates not only its level of secondary frequency control, but also primary frequency control[2]. The new standard, which is expected to take effect in 2012, also allows for less flexibility in the procurement of frequency response reserves, and sets out more rigorous rules for compliance with more frequent checks. While NERC expects that "most, if not all BAs should have no trouble meeting" the standard under current conditions [5], increased wind penetration could place upward pressure on the need for frequency response reserves.

The theory of the transient stability problem and why it will become of greater concern as conventional power plants are replaced by renewable resources is presented in section 2. Then, we review the literature on renewable resource integration, highlighting the dearth of research on the effects of renewable integration on power system transient stability, especially in comparison to the heavily studied areas of economics and balancing. In section 4, we present our hypotheses and approach. In section 5, we discuss our results: 1. power system operators do not face much risk from the fact that renewable resources will displace inertia, but rather because they will displace resources capable of primary frequency control; and 2. the relationship between the megawatts of

[2] Primary frequency control rapidly damps transients but may stabilize the system at a lower or higher frequency than desired, while secondary control acts more slowly to return the system to the desired frequency (e.g. 60 Hz).

resources capable of primary frequency control displaced by renewable resources and probability of lost load is non-linear. These results are then viewed through the lens of energy storage applications. We posit that as primary frequency control becomes scarce, due to displacement of conventional generation by renewable resources, it will become a more valuable service. In becoming more valuable, we suggest that energy storage devices, which already have the physical capability of providing primary frequency response, will also have a price incentive to do so above a threshold level of wind penetration.

2. The Transient Stability Problem

The vast majority of power produced in a system is from "synchronous generators," in which the frequency of the stator electrical quantities is synchronized with the rotational speed of the rotor. The magnetic field of the rotor induces an electrical current in the copper windings of the stator as it rotates. Those induced currents produce a magnetic field that lags slightly behind the rotor magnetic field during normal operation. The angular separation between those fields is referred to as the "rotor angle" [3].

A large disturbance in the power system has the effect of applying a significant electrical torque against the mechanical torque of the rotors of all interconnected synchronous generators, thus slowing them down or speeding them up. This behavior is known as the transient stability problem, a sub-set of the larger class of power system stability problems, broadly defined as the ability of a power system to remain in a state of equilibrium under normal operating conditions and to achieve equilibrium after undergoing a disturbance [3]. The mechanical torque and electrical torque oscillate against each other, and if sufficient damping (provided by inertia and primary frequency control) is present, will eventually stabilize. Inertia is supplied by the large rotating mass of conventional generator rotors. Primary frequency control is most commonly provided by conventional generators with frequency-sensitive operating governors. Following a large disturbance, primary frequency control will stabilize power system frequency by arresting its decline or rise within a matter of seconds. This is known as "frequency response." Stability will be realized only if there is sufficient generation capable of providing frequency response in reserve. One way of ensuring this sufficiency is by procuring spinning reserves. It is secondary frequency control, which is provided by Automatic Generator Control (AGC) action, that is capable of returning frequency from a stable level to the scheduled value (typically 60 Hz), usually within minutes. Power system operators can ensure that sufficient secondary frequency control exists by procuring the ancillary service known as regulation.

NERC standard BAL-003-0 presently defines the method of calculating balancing authority frequency bias, which ultimately determines the level of secondary frequency control through AGC action [6]. The method is designed to ensure that AGC action will be sufficient to provide effective secondary frequency control. The standard does not address balancing authority frequency response for primary frequency control. However, due to an observed decline in frequency response throughout the US since BAL-003-0 was made effective, FERC directed NERC to instate a new standard that would also include quantitative requirements for frequency response to provide effective primary frequency control [4]. This requirement, known as the Frequency Response Obligation, indirectly dictates the amount of generation capable of contributing to frequency response that must be held in reserve, and is expected to come into effect in 2012 under standard BAL-003-1 [7].

Wind turbines lack the inertia and control offered by conventional synchronous generators, and, as induction generators, impose much different voltage angle characteristics from the synchronous generators they are replacing. Because they displace generators that provide the inertia and frequency response needed to stabilize the system in the event of a large disturbance, a high penetration of renewable power could undermine the sufficiency of existing power networks to comply with NERC standard BAL-003-1.

3. Renewables Integration Literature

The literature on large-scale wind integration can be divided into two broad categories with little overlap: power system effects and wind turbine modeling. Power system effect studies typically cover economic and social effects, and the effect of renewables on grid operators' ability to match power generation with load.[3] Very few have examined the effects on voltage and transient stability.

Studying the challenge of matching power generation with load is not unique to renewables integration studies. It is a well-defined concept that falls under the mid- and long-term stability problem of the power system stability problem. Most of these studies address two questions: 1. How much wind generation can currently be accommodated by the existing system? 2. How must the system be modified to accommodate wind generation given its variability and intermittency? Conclusions from these studies typically indicate the level of renewable energy that can be accommodated under present

[3] These have used different metrics: regulating requirement; "frequency keeping" band; ACE; load following requirement; spinning reserve requirement.

system operations, as well as the necessary changes to the system to integrate a target penetration of renewable energy. Nearly all of these studies predict that more secondary frequency control will be necessary as the penetration of wind power grows because of its variable output [8-10]. For example, Enernex [8] estimates that ISO-NE will require anywhere from 197 to 1,587 MW of additional regulation reserve requirements under different scenarios in which wind power contributes 20% of electricity generation in the United States. Those increases represent 100% to 780% growth in regulation reserve.

Where power system simulations were used at all, none of these studies used an AC load flow model. As the authors of the Eastern Wind Integration Transmission Study (EWITS) concede, “For EWITS, the team conducted production simulations using DC power flow that does not consider the wide range of issues associated with voltage control and reactive power dispatch. An AC analysis would involve power flows that look at voltage and reactive compensation issues, dynamic and transient stability, and HVDC terminal control.”[8]

Several papers have focused on developing mathematical models for doubly fed induction generator (DFIG) wind turbines with particular attention devoted to their initialization in power system simulations and potential new control strategies to improve their performance [11,12]. Still other papers have focused on the stability limits of wind turbines themselves, rather than the system as a whole [13].

Fewer studies have addressed the power system angle stability and voltage stability problems wrought by large-scale wind integration. The dearth of such studies is likely due to the fact that transient problems are much more sensitive to the topology of the power system, cannot be modeled with DC power flows, and require that generators and loads be resolved into dynamic blocks at a more detailed resolution than that required for a mid- or long-term stability analysis. Furthermore, models of actual power system interconnections, such as the Western Electric Coordinating Council Interconnection, require a high degree of validation and are often not readily available to academic institutions.

These challenges aside, it is necessary to provide policymakers and power system operators with the results of angle and voltage stability studies to inform a more complete understanding of large-scale renewables integration. Ha and Saha [14] investigated the voltage stability of a sub-transmission network with a large wind farm interconnection. The study showed that the location of the interconnection bus of the wind farm affected system voltage stability, and that certain locations could mitigate the adverse effects of the wind farm on voltage stability. Jauch et al. [15] investigated the impact of large-scale wind integration on the transient stability of wind generators themselves and of a simplified network model of the Nordic Power System as a whole. The study concluded that larger, more persistent oscillations resulted from increasing quantities of wind energy. However, the simulations used fixed-speed wind turbines, which are much less frequently chosen for new wind power projects. The study also only qualitatively assessed the oscillations, and did not attempt to introduce a quantitative metric to elucidate the relationship between wind penetration and transient stability.

Quantitative metrics of frequency response were recently the subject of a major FERC-commissioned study led by Lawrence Berkeley National Laboratory [16]. The study defined quantitative metrics for transient frequency response and examined the effect of a large generation loss on those metrics. A major finding of the study was that the effect of lower system inertia on transient stability is minor compared to the displacement of primary frequency control reserves. This study was an important first step in examining the effects of wind power on transient stability, but the scenarios included only levels of wind penetration expected to be reached by 2012. Important questions therefore remain about these effects at anticipated levels of wind penetration by 2020 and 2030, which could be over 20% of total capacity, or five times higher than current penetration.[4]

4. Our Approach

Previous studies have made it clear that additional secondary frequency reserves will be required with increased wind penetration. In response, energy storage has emerged as a commercially viable solution to “smooth” the intermittent power generation of renewable resources, without sacrificing reduced emissions targets that would come with additional fossil fuel generation. The hypotheses we present are designed to shed light on whether the physical characteristics of wind turbine generators themselves (and not just the intermittent nature of the wind) poses a challenge to power system transient stability. They are further designed to establish whether it is generator inertia or primary frequency control that is responsible for maintaining transient stability with high wind penetration, as well as defining a quantitative relationship between wind penetration and stability. The results of the investigation will help to establish whether energy storage is a viable solution to mitigating decreased transient stability, and how much might be required.

The three hypotheses presented are:

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[4] Total US peak generating capacity is ~1,000,000 MW [17], and total wind capacity is ~40,000 MW [18].

Hypothesis 1: Increasing penetration of wind capacity will result in reduced transient stability.

Hypothesis 2: Changing the point of interconnection of the wind power will significantly affect power system transient stability.

Hypothesis 3: Increasing synchronous machine inertia will not improve transient stability with high levels of wind penetration.

These hypotheses are each tested with one experiment conducted on a modified version of the IEEE 14-bus test system, a standard power system model designed to provide a stable environment for simulations. In order to capture the effect on transient stability, AC load flow simulations must be conducted. To satisfy the requirements of AC load flow, the system must include fully dynamic generator models. DC load flow is unsuitable for this experiment because it does not include reactive power flows. All simulations were run over a period of 100 seconds with the fault occurring at t = 2s.[5] In order to isolate the behavior of the system with respect to transient stability, a fixed wind speed was chosen to drive the wind turbine. If real wind data had been used, this would obscure the effect of the wind turbine dynamics on transient stability by the added effect of the variability of the wind.

A schematic of the system is shown in Figure 1. The red-colored buses (numbered 1 – 5 and 15) indicate the high voltage transmission system while the blue-colored buses (numbered 6 – 14) indicate the low-voltage distribution system where most of the loads

[5] A fault refers to an incident that causes an undesired flow of current in a power system, such as a short circuit or open circuit. We simulated a short to ground that lasted 100-600 msec, as described below.

and no generators are found. The system was modified from the IEEE standard to include a 15th bus for the wind farm.

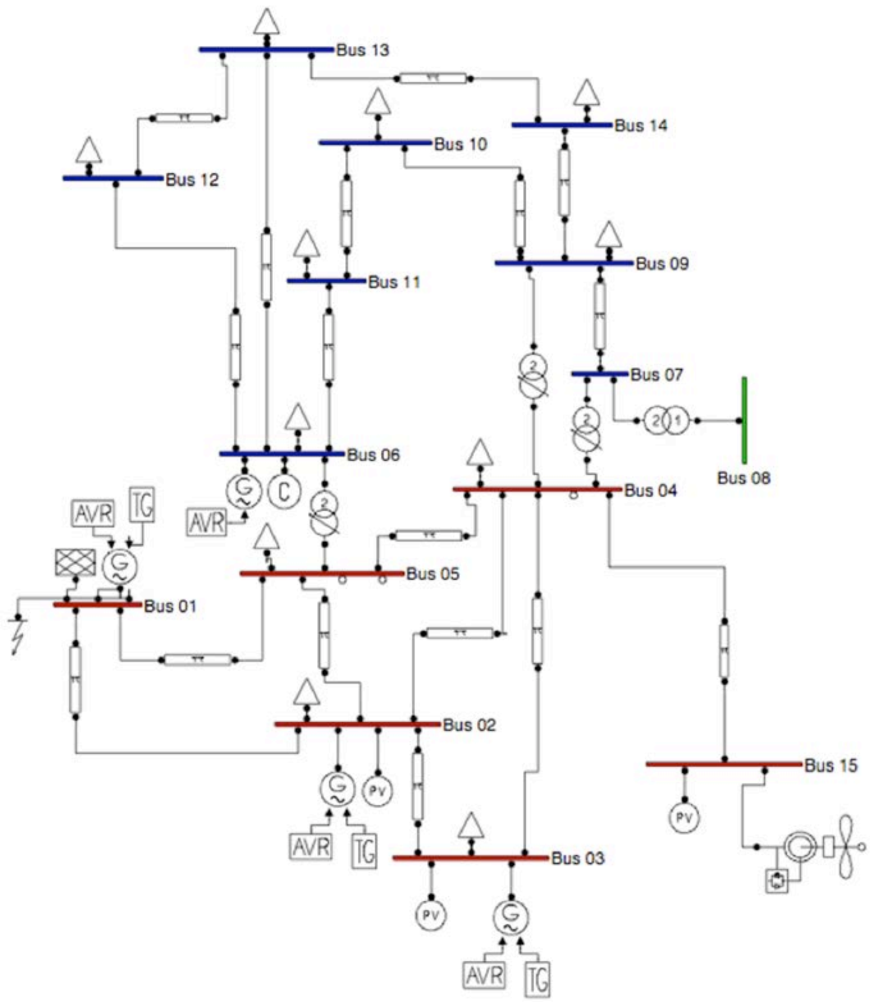

Figure 1: Schematic of the IEEE Dynamic 14-Bus Power System, Modified to Include a 15th Bus for Wind Power.[6]

The independent variables are the percentage of total generating capacity from wind power, the bus at which the wind farm is connected, and the bus at which the fault is induced. The obvious choice for a dependent variable is a measure based on the rotor angle behavior of the generators. However, as an induction generator, rather than a

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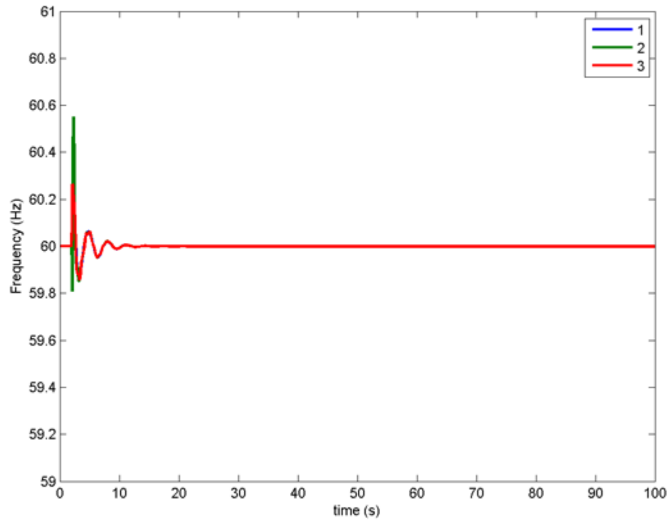
[6] Triangular symbols represent loads; AVR blocks represent exciters; G blocks represent synchronous machines; PV blocks represent fixed power & voltage buses for generators at load flow initialization; C blocks represent voltage compensators.

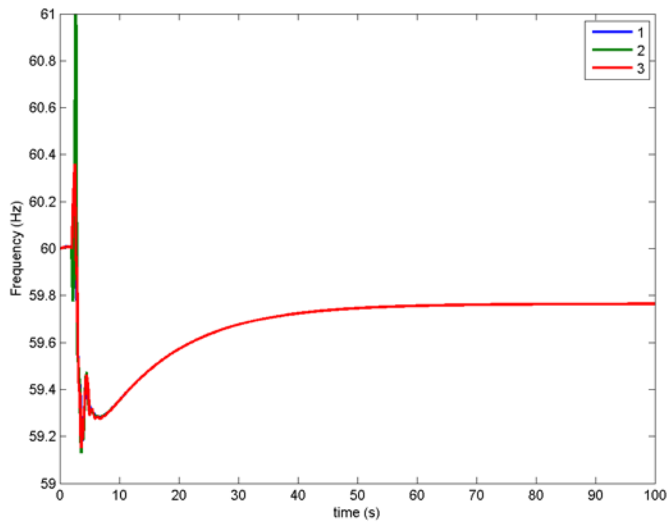
synchronous machine, a wind turbine does not have a "rotor angle" in the conventional sense. While Anaya-Lara et al. [19] proposes a method for deriving an analogue of a synchronous generator rotor angle for a doubly-fed induction generator (DFIG) wind turbine, it was found in the course of research that this quantity might not be suitable for an "apples to apples" comparison with synchronous generators. A more detailed discussion of this issue may be found in Appendix A.

Because rotor angle could not be used, a metric based on frequency – a closely related and relevant quantity – was chosen instead. Frequency deviation in response to a 100 ms fault was used as a qualitative indicator of power system transient stability by Jauch et al. [15]. More recently, Eto et al. [16] developed quantitative metrics of frequency response to assess the effect of wind power penetration on transient stability. However, that study used simulations run on validated models of the three major US interconnections, lending credence to the metrics as point solutions rather than probabilistic measures. Unfortunately, these very detailed validated models are difficult to acquire and use. Furthermore, they may be overly complex for the proposed experiment of characterizing the effect of wind power penetration and location on transient stability. Thus, a simple 14-bus IEEE system was run on the Power Systems Analysis Toolbox (PSAT), an open-source Matlab-based dynamic simulation program. Given model uncertainties, a probabilistic metric based on frequency response, Loss-of-Load Probability (LOLP), was chosen.

In the course of the work, it was observed that simulation frequency response results fell into one of three categories: category 1 can be thought of as having sufficient primary frequency control and not requiring any secondary frequency control; category 2 as having sufficient primary frequency control but requiring secondary frequency control; and category 3 as having insufficient primary frequency control. Figure 2 shows examples of system behavior in categories 1, 2 and 3.



(a)



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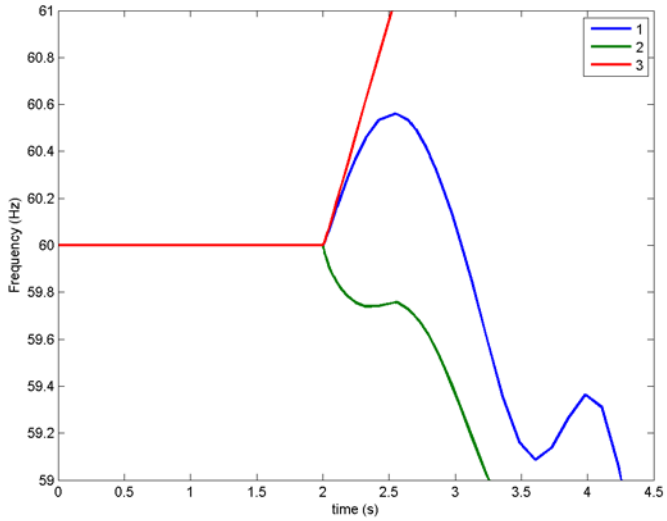


(c)

Figure 2: Example of (a) Category 1 Frequency Response; system returns quickly to stability at 60 Hz (b) Category 2 Frequency Response; system returns to stability, but not at 60 Hz and secondary control is required (c) Category 3 Frequency Response; system becomes unstable

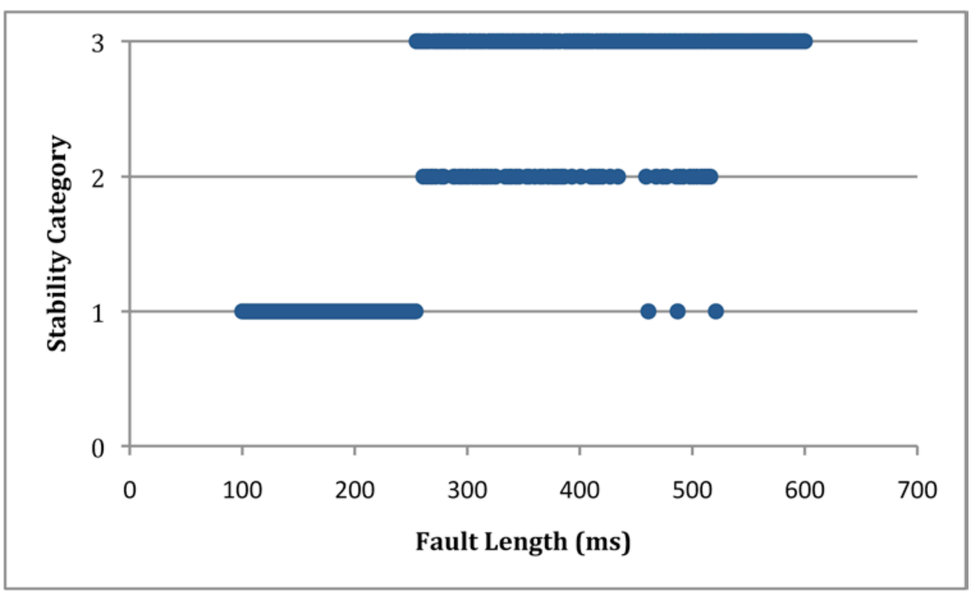


Figure 3: Power System Stability for Increasing Fault Durations

As fault duration is increased, the system does not remain in the non-convergence state (category 3) after transitioning from stable frequency response (category 1). Rather, the system oscillates between categories 2 and 3, with occasional instances of category 1, as the fault length increases. Thus, a probabilistic metric was devised. This metric can loosely be defined as loss-of-load probability (LOLP) over a range of fault durations. A point LOLP was assigned to each category: 0% for category 1, 10% for category 2, and 100% for category 3. A weighted LOLP for a given configuration of wind penetration, wind interconnection, and fault location was produced by averaging the point LOLPs over the range of fault durations for each set of simulations.

In total, 85 configurations were examined: [5 wind interconnection buses] x [5 fault locations] x [4 levels of wind penetration] + [5 cases of 0% wind for each fault location] – [20 cases where wind interconnection bus = fault location] = 85. Each was simulated with fault durations increasing in 501 increments of 1 ms, from 100 ms to 600 ms. The wind capacity as a percent of total generation varied from 0% to 28% (from 0 MW to 240 MW out of a total of 915 MW). Wind capacity was increased in increments of 7%, or 60 MW, for each set of scenarios. Tables 2 and 3 illustrate the configuration of generators for each of the scenarios.

Table 2. Generation Capacities of the 0% Wind Configuration

Generator Type	Capacity
Wind Farm	0 MW
Synchronous Generator	615 MW
Synchronous Generator	60 MW
Synchronous Generator	60 MW
Synchronous Generator	60 MW
Synchronous Generator	60 MW

Table 3. Generator Capacities of the >0% Wind Scenarios

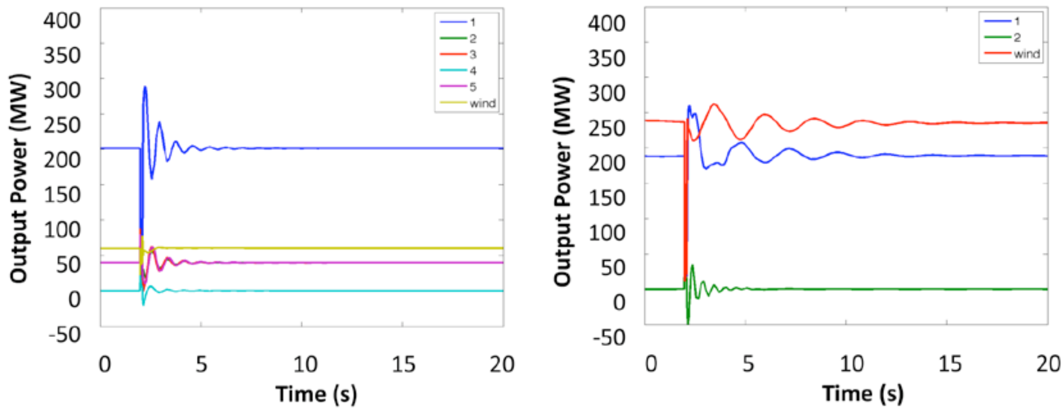
Generator Type	7% Wind Scenario	14% Wind Scenario	21% Wind Scenario	28% Wind Scenario
Wind Farm	60 MW	120 MW	180 MW	240 MW
Synchronous Generator	615 MW	615 MW	615 MW	615 MW
Synchronous Generator	60 MW	60 MW	60 MW	0 MW
Synchronous Generator	60 MW	60 MW	0 MW	0 MW
Synchronous Generator	60 MW	0 MW	0 MW	0 MW
Synchronous Generator	0 MW	0 MW	0 MW	0 MW

A total of 42,585 simulations were run for this experiment: [85 configurations] x [501 fault duration increments of 1 ms] = 42,585 simulations.

5. Results

5.1 Hypothesis One

As measured by the LOLP metric and visual inspection of synchronous machine frequency and power output plots, the power system transient stability deteriorated as more wind power capacity replaced synchronous generator capacity, supporting hypothesis one. Figures 4(a) and 4(b) show the real power outputs of the synchronous and wind generators where wind represents 7% and 28% of total capacity, respectively. The real power oscillations of the synchronous machines at 7% wind energy are large and short lived, and the oscillations are greatest for the large 615 MW generator. Also, the oscillations for the wind generators are comparable to the smaller 60 MW synchronous generators. At 28% wind capacity (Figure 4b), the initial real power excursion is equally large for the wind generator and the 615 MW synchronous generator (red and blue lines, respectively). The frequency of oscillations is less than at 7% wind, however they endure for a longer period. In both cases, the 60 MW synchronous compensator oscillates around 0 MW for a brief period.

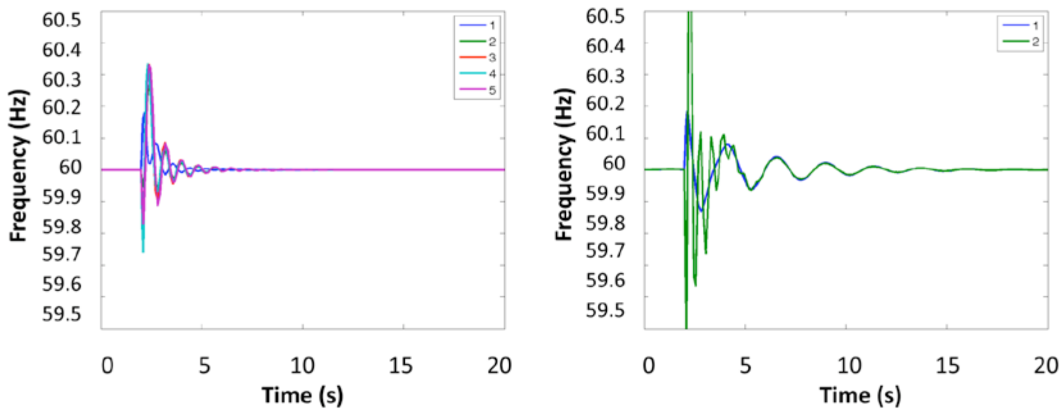


a ***b***

Figure 4. Synchronous Machine and Wind Farm Real Power Output at (a) 60 MW Wind Capacity (7% of Total Generation) and (b) 240 MW Wind Capacity (28% of Total Generation)[7]

Synchronous machine frequency, shown in Figure 5(a) and (b), agrees well with the real power output oscillations. The frequency oscillations for both synchronous machines increase in magnitude and duration, and decrease in frequency, which corresponds exactly with the oscillation characteristics of the real power output. It should also be noted that the frequency deviations are very large, especially at 18% wind penetration. The deviation observed at the synchronous machine bus in Figure 5(b) drops well below 59.6 Hz for just over six cycles.

[7] In Figure 4(a) and 5(a), the lines labeled 1, 2, 3, 4 and 5 correspond to the five synchronous machines connected to the power system. Machine 1 is the 615 MW generator, and machine 4 is the synchronous compensator. Machines 2, 3 and 5 are each 60 MW generators. In Figure 4(b) and 5(b), line 1 is the 615 MW generator, and line 2 is the synchronous compensator.



a *b*

Figure 5. Synchronous Generator Frequency at (a) 60 MW Wind Capacity (7% of Total Generation) and (b) 240 MW Wind Capacity (28% of Total Generation)

However, these figures do not reveal the full scope of the results of the experiments. While not originally hypothesized, the data reveal a "tipping point" in LOLP as wind penetration increases, which is not immediately apparent from simple plots of power output or frequency at different levels of wind penetration. Figure 6 plots the average LOLP of the different wind interconnection buses for a fault at bus 1.

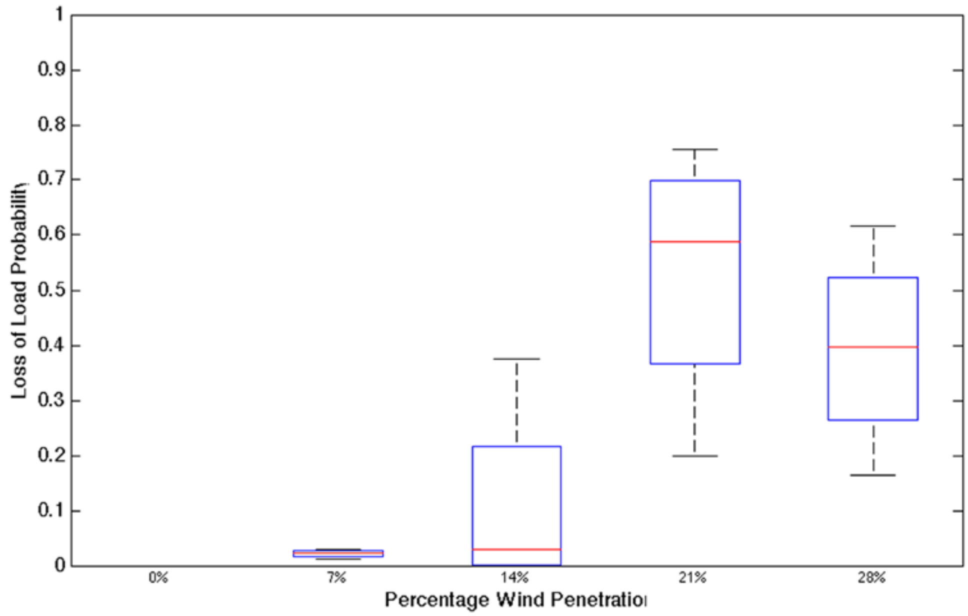


Figure 6. Power System LOLP for Faults Located at Bus 1. The lower and upper sides of the boxes are the 25% and 75% LOLP values; the horizontal line inside the box is the median value; the lower and upper "whiskers" are the lowest and highest LOLP values.

The box and whisker plots represent the values for LOLP when the wind farm is interconnected to each of the four high voltage buses where the fault is not located. In Figure 6, the fault is always located at bus 1. Thus, the data points consist of the range of LOLP values when the wind farm is interconnected at buses 2, 3, 4 and 5.

The values for the mean power system LOLP for each of the other bus locations of the fault are essentially identical: 0% LOLP at 0% wind penetration; near-zero LOLP at 7% wind penetration; 10% at 14% wind penetration; 50% at 21% wind penetration; and 40% at 28% wind penetration. The results reveal a clear trend of a step change in LOLP that is independent of the fault location. The shape of the trend suggests a nonlinear response in the system LOLP as wind penetration increases, pointing to a possible "tipping point" of wind penetration, above which the relationship between LOLP and wind penetration is fundamentally altered in the 14 bus system. For this particular system, the tipping point is somewhere between 14% and 21% wind penetration.

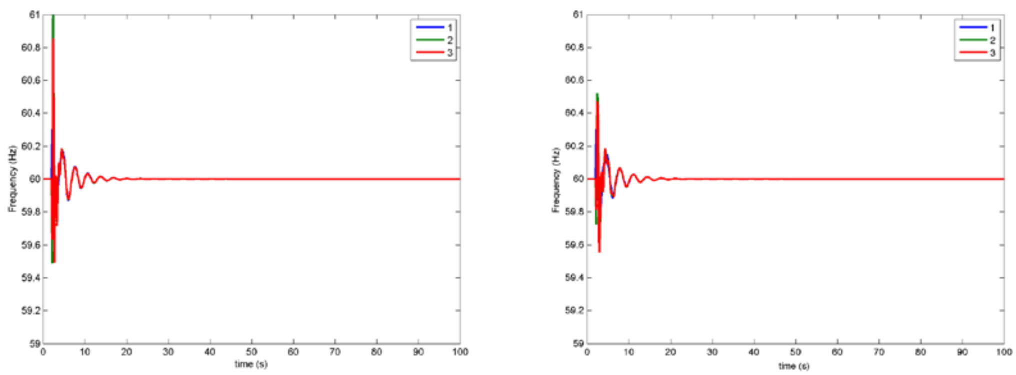
5.2 Hypothesis Two

There is not very strong evidence to support hypothesis two – that the location of the wind farm interconnection would significantly affect power system transient stability. There is certainly variance across the LOLP values for the different wind farm interconnection locations (visible in the breadth of the whiskers in Figure 6.) However, the underlying shape of the response between LOLP and wind penetration remains unchanged for a particular wind farm interconnection location.

5.3 Hypothesis Three

We sought to confirm a conclusion of the recent Lawrence Berkeley National Laboratory study [16] that "The effect of increased wind generation in lowering system inertia is not significant compared to the effects of primary frequency control actions." In other words, frequency response is not made significantly worse by increased wind penetration because of the displacement of inertia provided by conventional generators, but rather because of the displacement of the primary frequency control offered by conventional generators. To test this, the inertia parameter of the synchronous machines in the 14%, 21% and 28% wind penetration cases was doubled compared to the original parameters. We also sought to expand on the approach of Eto et al. [16] by including higher levels of wind penetration. That study capped the wind penetration to levels that are expected to be reached in each of the three major US interconnections by 2012. The highest level for WECC was 5%, while the highest level for ERCOT was 17%. In contrast, our approach includes levels of up to 28% penetration.

Point solution results for a 200ms fault at Bus 1 with 180 MW of wind power (21% penetration) suggest that inertia has a significant effect on transient stability. As is visible in Figure 7, the envelope of frequency oscillations in (a), where there is less inertia, is much larger than that of (b), though the decay rate is essentially the same. The effects of the increased inertia in 7 (b) suggest that more system inertia significantly dampens the frequency oscillations caused by a fault. A logical conclusion would be that this also enhances transient stability to the same degree.



a ***b***

Figure 7. Synchronous Generator Frequency Response at (a) Original Inertia Parameters and (b) Doubled Inertia Parameters

However, the probabilistic results tell a different story. These are shown in Figure 8. When examined over 501, 1 millisecond step increases in fault length, system LOLP with more inertia is not significantly different when compared to the original results shown in Figure 6. This similarity between the results of the normal and high-inertia simulations agrees with the conclusion reached in Eto et al. [16] at lower wind penetration levels than examined here.

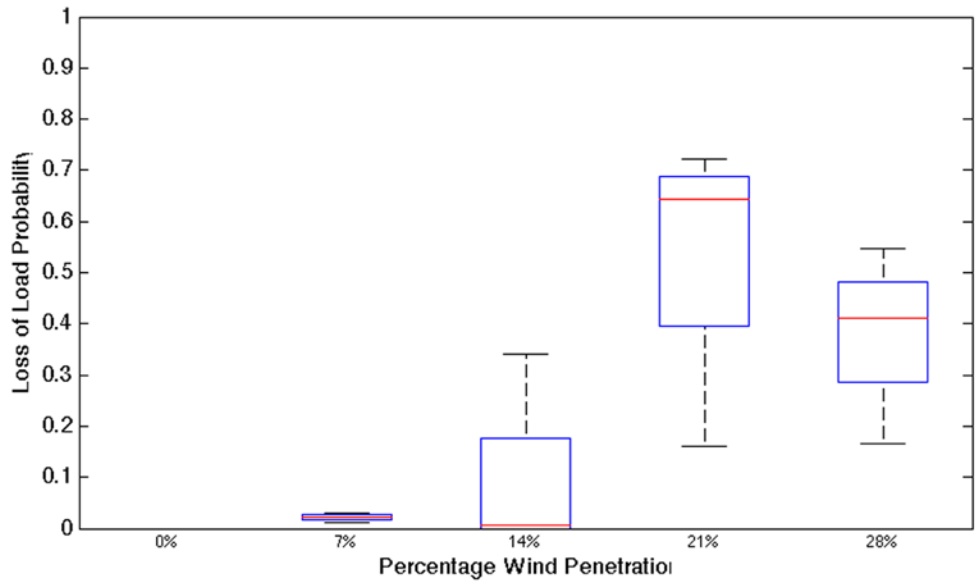


Figure 8. Power System LOLP for Faults Located at Bus 1 with Increased System Inertia

The experiments performed were done on a very small system, which, while designed to mimic real power system behavior, is never-the-less orders of magnitude smaller and less complex than any interconnection in the United States. Therefore, there is a possibility that the observed relationships between LOLP and wind farm location, fault location and wind penetration are purely an artifact of the IEEE 14 bus system's topology and dynamics. The clear next step is to run the experiments with a dynamic model of a real power system to see whether the observed trends are general.

If they are found to be general, simulations could lead to an estimate of the amount of frequency response reserves required at different levels of wind penetration. These simulations should incorporate energy storage as sources of frequency response. Including energy storage devices would help verify whether they have the physical capability of contributing to primary frequency control. It would also be interesting to define optimal allocations of the capacity of a given energy storage device to primary and secondary frequency control, as well as the optimal allocation of a balancing authority's overall frequency response obligation to different types of sources.

6. Conclusions and Recommendations

Across the US, the contribution of energy storage to regulation is still small. There appear to be just two commercial-scale projects greater than 1 MW in operation in the US, both of which are in NYISO and contribute to regulation: an 8 MW Li-Ion battery project operated by AES Energy Storage, and a 20 MW Flywheel project operated by Beacon Power. The AES project came online on December 20th, 2010 [20], and the Beacon project was inaugurated on July 21st, 2011 [21]. The two projects account for about 10% of the total peak NYISO regulation requirement.[8]

Broadly, the results of our experiments underscore the importance of primary frequency control in mitigating instability. Power system operators do not face much risk from the fact that renewable resources will displace inertia, but rather that they will displace resources capable of primary frequency control. Crucially, it appears that the relationship between the megawatts of resources capable of primary frequency control displaced by renewable resources and the probability of lost load is non-linear. At low levels of displacement, loss of load probability remains fairly constant, while at high levels (>20% penetration), there is a step change increase in loss of load probability. This observation verifies hypotheses one and three, and supports the conclusion of Eto et al. [16] at even higher levels of wind penetration than included in that study.

[8] NYISO peak regulation requirement is about 275 MW [8,22].

Hypothesis two, that the location of the wind farm will significantly affect transient stability, is not supported by the results. While levels of LOLP vary depending on wind farm location, the overall trend of the relationship between wind penetration and LOLP tends to be relatively independent of both wind farm and fault location.

At the heart of the problem highlighted by these results is the declining adequacy of primary frequency control with increasing wind penetration, especially above a certain "tipping point" of wind penetration. Since April 1, 2005, NERC Standard BAL-003-0 has been used by Balancing Authorities to calculate their frequency bias settings [6].

In 2007, the Federal Energy Regulatory Commission (FERC) issued Order 693, which directed NERC to update its BAL-003 Standard [4]. FERC's concerns with the extant standard are that effective primary frequency control is not being guaranteed and that compliance with the standard is not being measured frequently enough or with sufficient rigor. The solution proposed by FERC is that NERC, rather than the Balancing Authorities, should be responsible for explicitly determining and assigning a frequency bias setting for each Balancing Authority [4]. The assigned bias setting is known as the Balancing Authority Frequency Response Obligation (FRO_{BA}), and is calculated as the total interconnection FRO multiplied by the percent of total peak generation and peak load within the given Balancing Authority [5,7]. In this way, the full Interconnection FRO is accounted for, proportionally, by each of its constituent Balancing Authorities. While NERC expects that "most, if not all BAs should have no trouble meeting [their] FRO[s]," under current conditions [5], increased wind penetration could create difficulty.

Energy storage may be an attractive option to Balancing Authorities for meeting their FRO_{BA}. Unlike generation capacity, the addition of energy storage will not increase the Balancing Authority's proportion of total peak generation and peak load in the Interconnection. As such, the BA can keep its individual FRO_{BA} at a minimum. If control systems and algorithms are developed so that batteries can act as primary frequency control, utility scale batteries can play a larger future role in contingency reserves than if they were limited to secondary frequency control. However, the regulatory landscape for such a role is still uncertain; FERC issued a Notice of Inquiry on June 16th, 2011 to solicit comments on, *inter alia*, energy storage device participation in ancillary services markets [23]. Much as FERC order 719 directed RTOs and ISOs to treat demand response comparably to supply-side resources and eliminate barriers to demand response through market rule changes, we may expect that FERC will soon issue a similar order to reduce barriers for energy storage, particularly in ancillary service markets [24].

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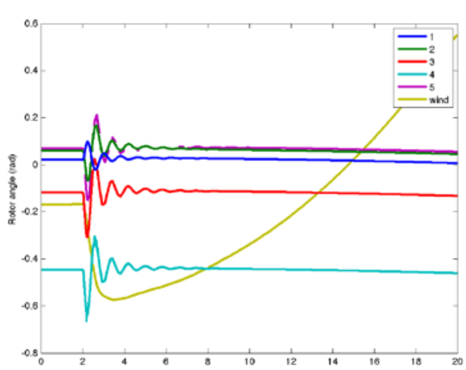
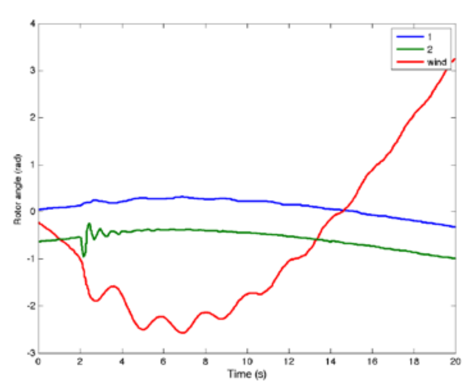
Appendix A: Disqualifying the use of rotor angle as a metric of power system stability in the presence of high wind penetration

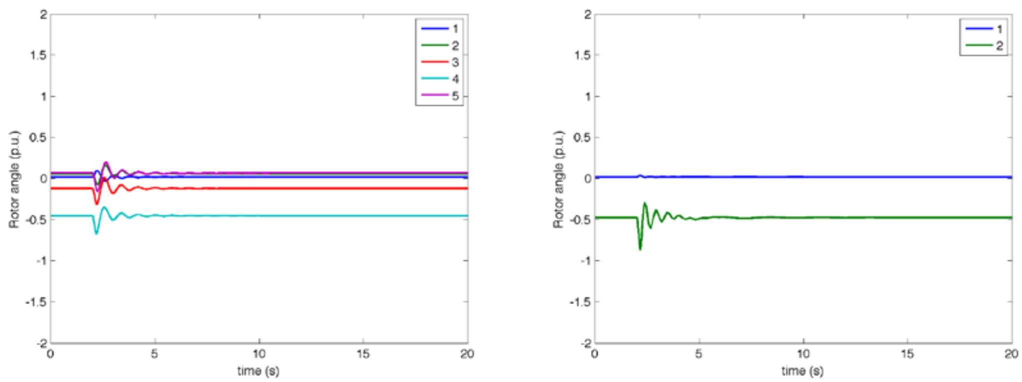
As measured by frequency deviation and generator power swing, the power system behavior deteriorated as more wind power capacity replaced synchronous generator capacity. While rotor angle deviation would ordinarily be used as a measure of transient stability, its use is questionable for the purposes of this paper. Rotor angle can typically be observed in one of two ways: absolute rotor angle, and rotor angle center of inertia [3]. Absolute rotor angle is a direct measurement of the rotor angle of a synchronous generator, while center-of-inertia rotor angle is defined as the absolute rotor angle weighted by that synchronous generator's fraction of inertia provided to the system as a whole. In addition to the two representations of rotor angle, there is the option of whether or not to introduce an artificially constructed version of rotor angle for wind generators. As discussed previously, Anaya-Lara et al. [19] proposes a method for constructing an artificial rotor angle for wind generators, but when applied to this research the results conflicted with the real power output of the generators. Figure 4(a) and 4(b) chart the real power outputs of the synchronous and wind generators where wind represents 7% and 28% of total capacity, respectively. The real power oscillations of the synchronous generators at 7% wind energy are large and short lived. The oscillations are greatest for the large 615 MW generator. The oscillations for the wind generators are comparable to the smaller 60 MW synchronous generators. At 28% wind capacity (Figure 4(b)), the initial real power excursion is equally large for the wind generator and the 615 MW synchronous machine (red and blue lines, respectively). The frequency of oscillations is greater than at 7% wind, however they endure for a longer period. In both cases, the 60 MW synchronous compensator oscillates around 0 MW for a brief period.

These results, however, appear to conflict with the rotor angle center-of-inertia oscillations both in the cases where an artificial wind generator rotor angle is constructed, and when one is not. Figure A.1(a) and (b) depict the center-of-inertia rotor angles when the wind generator inertia is included in the weighted average. Figure A.1(c) and (d) omit the wind turbine generator inertia. Figure A.1(c) appears to correspond with the observed real power output oscillations show in figure 4(a), where the oscillations are frequent, diminish quickly, and are observed in all generators. However, figure A.1(d) conflicts with the real power output observed in figure 4(b), as the rotor angle oscillations of synchronous generator 1 (blue line) are essentially non-existent. This is strange not only due to the fact that less inertia on the system would result in larger oscillations than compared to figure A.1(c), but also that the real power oscillations observed in figure 4(b) would require large rotor angle oscillations. To resolve these conflicting observations between real power oscillations and rotor angle oscillations, one could attempt to include an "artificial" wind generator rotor angle. It was suspected that, if such a rotor angle could be produced, it would capture the rotor angle oscillations that appear to be "missing" from synchronous generator 1 in Figure A.1(d).





a ***b***



c ***d***

Figure A.1. Synchronous Machine and Wind Farm Rotor Angle Center of Inertia at (a) 60 MW Wind Capacity (7% of Total Generation) and (b) 240 MW Wind Capacity (28% of Total Generation); and Only Synchronous Machine Rotor Angle Center of Inertia at (c) 60 MW Wind Capacity (7% of Total Generation) and (b) 240 MW Wind Capacity (28% of Total Generation)

Unfortunately, this was not the case. The resulting “artificial” wind rotor angle appears to reveal an increasingly unstable system, as shown in figures A.1(a) and (b). This conflicts directly with the real power outputs shown in figure 4(b) which indicates that the system returns to equilibrium in approximately 10 seconds after the fault.

Due to the conflicting observations of rotor angle and real power output, it is suggested that rotor angle is not a sufficient indicator of power system stability when large amounts of wind power are connected. However, synchronous machine frequency, shown in Figure 5(a) and (b), agrees well with the real power output oscillations. The frequency oscillations for both synchronous machines increase in magnitude and duration, and decrease in frequency, which corresponds exactly with the oscillation characteristics of the real power output.

Appendix B: Disqualifying the use of Critical Fault Clearing Time as a metric of power system stability in the presence of high wind penetration

Initially, an attempt was made to use the Critical Fault Clearing Time (CCT) of the system as a point solution metric. CCT is the duration of a fault beyond which the system is unable to converge to a stable equilibrium [3,13,25]. For power systems consisting of more than two or three buses, there is no closed-form solution for CCT. As such, it can be found only by repeatedly increasing the fault duration for subsequent time-domain simulations until the system is no longer able to recover to a stable equilibrium. However, problems were found with this metric, discussed below.

For CCT to be a valid quantitative metric for frequency response, simulations would have to respond to a fault of duration T ms, such that at $T < t_1$, the system falls into category 1; at $t_1 < T < t_2$, the system falls into category 2; and at $T > t_2$, the frequency response is category 3, where t_2 is equivalent to the CCT. However, what is observed is that as fault duration is increased, the system does not stay consistently in any particular category. Figure 3 shows the response of the system to faults from 100 ms to 600 ms in length with 180 MW of wind interconnected at Bus 1, and the fault at Bus 5. As can be observed in Figure 3, the system does not remain in the non-convergence state (category 3) after transitioning from stable frequency response (category 1). Rather, the system oscillates between categories 2 and 3, with occasional instances of category 1, as the fault length increases. Because of this behavior, CCT was abandoned as a metric. In other words, there is no true “CCT” because the simulation produces stable results for fault durations that were longer than those that produced instability. Thus, as explained in the main text, a probabilistic metric was devised which can loosely be defined as loss-of-load probability (LOLP) over a range of fault durations.

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