

# Studying the Variability and Uncertainty Impacts of Variable Generation at Multiple Timescales

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**Abstract**--With increasing levels of variable renewable energy there is a growing need to study its impacts on power system operation. Variable generation (VG) is variable and uncertain at multiple timescales and it is important that system operators understand how each of these characteristics impact their systems since each may have different mitigation strategies. To date many of the studies of VG integration are limited to studying at one time resolution and therefore cannot analyze the variability and uncertainty impacts across multiple timescales. Here we study the variability and uncertainty impacts across multiple operational timescales. A model is used which integrates multiple scheduling sub-models with different update frequencies, time resolutions, and decision horizons. Using metrics that describe reliability and costs with a methodology that describes the sensitivities and tradeoffs of variability and uncertainty impacts separately with respect to the conditions that cause those impacts, case studies are performed which display greater information on expectations of these impacts on future systems with high penetrations of VG.

**Index Terms**-- automatic generation control, economic dispatch, power system operations, power system reliability, unit commitment, variable generation, wind integration.

## I. INTRODUCTION

RENEWABLE power generation has seen a tremendous growth as its environmental benefits and zero variable costs (i.e., zero fuel costs) have been viewed as an acceptable alternative to other more conventional sources of power generation. Unlike conventional energy sources, many renewable energy sources like wind and solar power have a maximum generation limit that changes with time (*variability*) and this limit is not known with perfect accuracy (*uncertainty*). The variability and uncertainty impacts of variable generation (VG) occur on multiple timescales. These characteristics can create challenges for system operators when ensuring a balance between generation and demand while obeying system constraints at lowest cost. Many entities have been studying these impacts using hourly production costing models and statistical analyses [1]-[6]. A summary of studies can be found in [7]-[8]. More information on production costing models can be found in [9]-[10].

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This work was supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy Wind and Hydropower Technologies Program as well as Science Foundation Ireland under Grant Number SFI/09/SRC/E1780.

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The impacts that occur on the power grid generally result from two conditions. When conditions occur that were not anticipated when scheduling the system, this *uncertainty* can cause issues. When conditions occur on the system at time resolutions the system is not prepared for, this *variability* can also cause issues. The issues include energy imbalance which can lead to high area control error and system frequency excursions, changes in power flows which can lead to overloaded lines, reactive power imbalance which can lead to voltage instability, and changes in various costs. For example, an hourly unit commitment model will face *uncertainty* in today's systems since it cannot anticipate forced outages or load forecast errors, and will face *variability* in the load that is not constant for the full hourly time resolution in which it has scheduled. To accommodate variability and uncertainty in today's scheduling programs, system operators carry operating reserve to cover energy imbalances [11]-[12], operate security-constrained scheduling programs to limit power flows before and after transmission contingencies [13]-[14], and use nomogram constraints [15] or AC power flow constraints [16] to cover reactive power imbalance and limit voltage levels. In recent research, improved forecasting has been suggested to limit the impact of the uncertainty of VG [17] and higher scheduling time resolution has been suggested to limit the impact of the variability of VG [18].

In the recent wind integration studies [1]-[8], the simulations are fixed to one time resolution. This makes it difficult to analyze the variability within the single time frame. The studies will also use either a one-stage or two-stage scheduling model when determining the commitment and dispatch. This means either a perfect forecast is assumed or there is one single chance of forecast error (typically the day-ahead forecast error). In reality forecasts are updated continuously as the system approaches real-time at different time intervals and all of these forecast errors will have different economic and reliability impacts on the system. The studies are typically run at hourly resolution with the real-time scheduling programs ignored. It is difficult to show any reliability impacts using the single hourly resolution and therefore production costs are usually the only metric used. Although the models carry operating reserve in their scheduling systems, the deployment of operating reserve is never realized nor is any operator action. The studies will measure the statistics of the VG data at high resolution, but this does not show how it impacts the system at that time resolution. Lastly, the studies will assume one scheduling strategy and therefore do not realize how different scheduling strategies may change the impacts of VG nor can they observe

the apparent tradeoffs of these strategies.

Recently, many research studies have been performed to better understand these variability and uncertainty impacts. For example, studies have been performed that attempt to model the uncertainty explicitly with stochastic input of wind power [19]-[21]. In [22], a model was developed to study wind integration impacts by explicitly modeling the uncertainty as contingencies. Meibom [20] advanced the studying of the uncertainty impacts using a model with rolling planning to better capture the continuous updates made to the wind and load forecasts. However, the study could not capture the impacts of forecast errors that can occur within a few hours of the real-time and therefore it is still difficult to see any reliability impacts from uncertainty. These studies are also all still structured at the hourly “unit commitment” time resolution and therefore impacts that occur within the hour or between scheduling sub-models are largely unknown. All of these issues will become increasingly important when studying higher amounts of VG. Therefore, there is a need for studies that simulate multiple time resolutions, integrate all the scheduling programs used in practice with multiple updates to forecasted conditions, with flexibility to test different scheduling strategies in order to study the variability and uncertainty impacts and tradeoffs at multiple timescales.

Here we develop a methodology that allows for studying the impacts of variability and uncertainty at multiple operational timescales. A model was developed, the Flexible Energy Scheduling Tool for Integration of VG (FESTIV), which integrates multiple scheduling sub-models across multiple time resolutions accounting for inter-temporal coupling between them, with the flexibility to study different scheduling strategies. The model consists of security-constrained unit commitment (SCUC), security-constrained economic dispatch (SCED), and automatic generation control (AGC) and is modeled after system operations at independent system operators (ISO), regional transmission organizations (RTO) and transmission system operators (TSO). Although these models are well known in today’s system operations, they have not been integrated together in a simulation environment with the flexibility to study the time varying affects of variability and uncertainty of VG. At the finest scheduling interval, the frequency at which AGC is run; production costs, MW imbalances, and branch flow violations are calculated. This allows for useful metrics that can show the variability and uncertainty impacts as a function of the characteristics that can influence them and can show important tradeoffs when metrics are conflicting. This integrated modeling approach at multiple time resolutions is crucial when getting a realistic perspective on the impact of variability and uncertainty of VG at multiple timescales.

In section II, we describe the individual sub-models of FESTIV and how they are integrated into one model. Section III will discuss the methodology and metrics for studying the variability and uncertainty impacts with respect to system characteristics and scheduling strategies. Section IV will perform four case studies on a high wind power penetration system. Section V concludes.

## II. MODEL DESCRIPTION

Fig. 1 shows the high-level flow diagram of FESTIV. Full lines represent process flow and dashed lines represent data flow. Each of the sub-models is run at specific intervals as defined by the user, and each of their outputs is used as inputs to other sub-models.

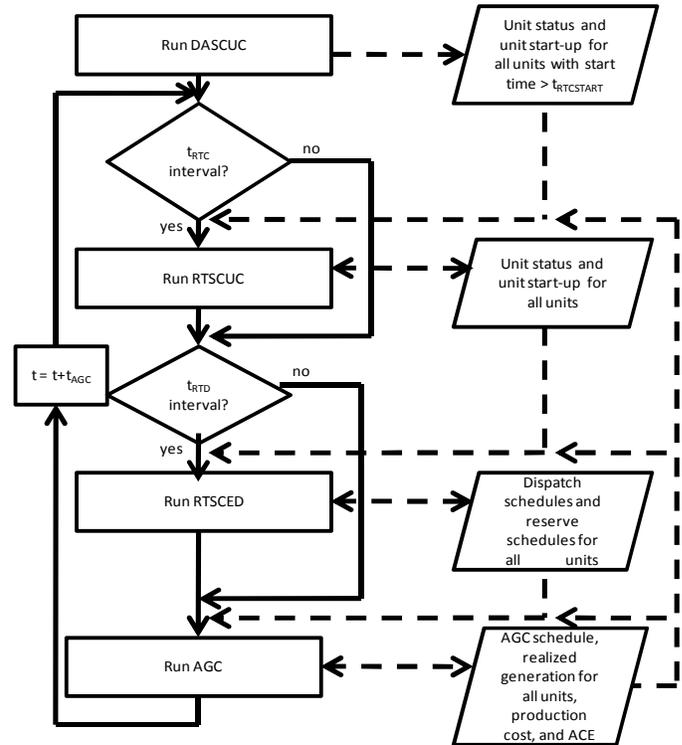


Fig. 1. Flow diagram for FESTIV.

The details of the FESTIV sub-models can be found in [23]. Two SCUC [24] sub-models are included: Day-Ahead SCUC (DASCUC) and Real-time SCUC (RTSCUC). DASCUC is run for the entire day and gives the initial commitment status for all units. After this, the daily operation begins and RTSCUC is repeated throughout the day to update unit commitment based on new real-time forecasts and system conditions. RTSCUC is very similar to DASCUC, but will usually have a shorter optimization horizon and can only start and stop units if the units have a start-up time less than  $t_{RTCSTART}$ . As seen in Fig. 1, the unit status and unit start-up of units with start-up times greater than  $t_{RTCSTART}$  are the output of DASCUC and used as input to RTSCUC. RTSCUC also uses unit start-up and unit status from past RTSCUC runs as input. RTSCUC provides the unit start-up and unit status as output. RTSCUC is run every  $t_{RTC}$  minutes throughout the day.

Real-time SCED (RTSCED) [13] is similar to RTSCUC except that it cannot change the commitment status of units. As seen in Fig. 1, RTSCED uses the unit start-up and unit status from past RTSCUC runs as input. It also uses dispatch schedules from past RTSCED runs as input. It provides the dispatch schedules and all reserve schedules as output. RTSCED is run every  $t_{RTD}$  minutes throughout the day.

The AGC [25] sub-model uses a rule-based algorithm. Unlike SCUC and SCED, it is not optimizing the scheduling of units nor is it considering the transmission network. Instead it uses all units that are given regulation schedules (we refer to

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the type of reserve used by AGC as regulation throughout the rest of the paper) by RTSCED to assist in correcting the Area Control Error (ACE), proportional to its regulation schedule. ACE is calculated by subtracting the total load from the total generation (which is similar to actual ACE assuming nominal frequency and a lossless transmission system). Units not given a regulation schedule are scheduled by AGC by interpolating to the next RTSCED dispatch schedule. The realized generation output is then determined by the prior AGC schedule and the resource's behavior rate (i.e., how well it follows schedule). As seen in Fig. 1, AGC uses the dispatch and reserve schedules from RTSCED as input. The RTSCED regulation schedules determine how each resource is utilized by AGC. AGC provides AGC schedules and realized generation as output. AGC is run each iteration at  $t_{AGC}$  second intervals. Also, the realized generation is used as input in all but the DASCUC sub-models.

The inter-temporal coupling of sub-models is important because of the configurable timing parameters and to ensure a realistic study with meaningful results. Fig. 2 shows how the different sub-models are integrated into the FESTIV model. The blocks represent the running of the sub-models. The points ahead represent the scheduling horizon.  $I$  represents interval length,  $t$  represents time between updates,  $P$  represents model process time, and  $H$  represents scheduling horizon. For DASCUC, the interval resolution is  $I_{DA}$ , which in today's systems would normally be one hour. DASCUC is performed just once per day and would usually have an optimization horizon ( $H_{DA}$ ) of one day. RTSCUC is repeated every  $t_{RTC}$  at an interval resolution of  $I_{RTC}$  and optimization horizon of  $H_{RTC}$ . RTSCED is repeated every  $t_{RTD}$  at an interval resolution of  $I_{RTD}$  and optimization horizon of  $H_{RTD}$ . RTSCUC takes  $P_{RTC}$  minutes to solve and RTSCED takes  $P_{RTD}$  minutes to solve. These  $P$  values are accounting for the fact that the system conditions can change between when sub-model inputs are received and the solution is found. For RTSCUC, start-ups are only binding if there is no more time to change the decision (i.e., the unit must start now to be at minimum capacity at some time in the scheduling horizon due to its start-up time). For RTSCED, the first interval provides the only binding dispatch schedules and reserve schedules with all others being advisory. AGC is run every  $t_{AGC}$ .  $H_{AGC}$  and  $I_{AGC}$  are equal to  $t_{AGC}$ . For comparison, Table I shows common values for these parameters in the production costing models used in the previous studies and in actual system operations. The flexibility of the FESTIV model allows for any combination of values for these parameters.

TABLE I  
TYPICAL TIMING PARAMETERS

Sub-Model	Parameter	Production Cost Models	Actual System Operations
DASCUC	$I_{DA}$ (hours)	1	1
	$H_{DA}$ (hours)	24 (once per day)	24 (once per day)
	$H_{DA}$ (days)	1-7	1-2
RTSCUC	$I_{RTC}$ (minutes)	N/A	15 - 60
	$t_{RTC}$ (minutes)	N/A	15 - 60
	$H_{RTC}$ (minutes)	N/A	60 - 300
RTSCED	$I_{RTD}$ (minutes)	60	5 - 60
	$t_{RTD}$ (minutes)	60	5 - 60
	$H_{RTD}$ (minutes)	60	5 - 60
AGC	$t_{AGC}$ (seconds)	N/A	4-6

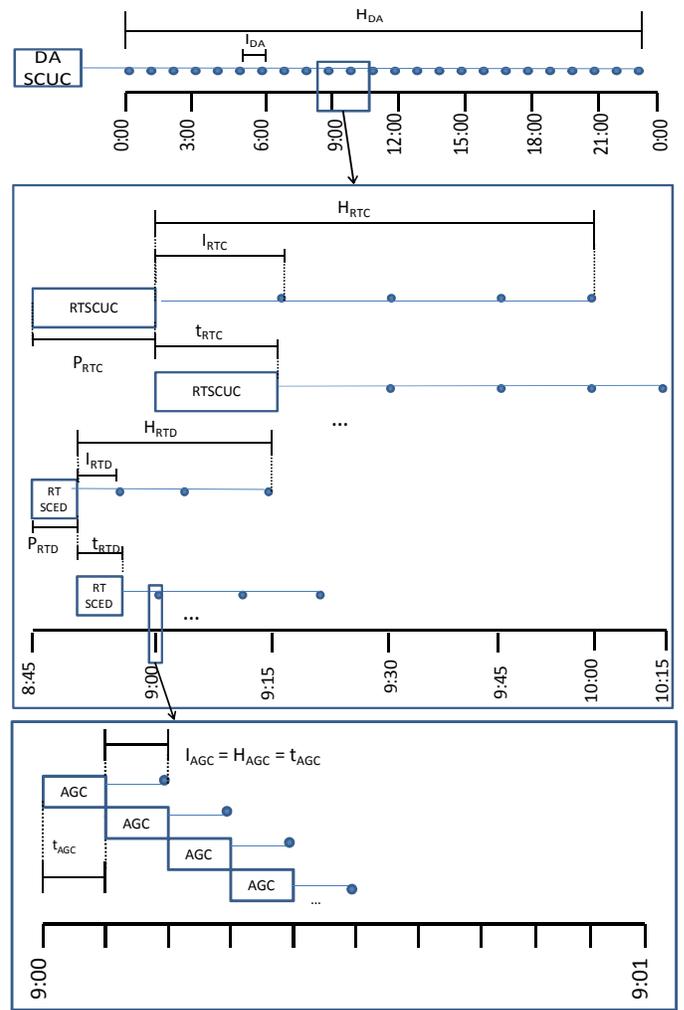


Fig. 2. Timeline for DASCUC, RTSCUC, RTSCED, and AGC in FESTIV.

The sub-models differ in what they are attempting to accomplish (e.g., commitment vs. dispatch vs. control) and are at different time resolutions and horizons. However, all efforts should ensure that constraints affecting the ultimate outcomes must be reflected consistently in all the sub-models. For example, the different time resolutions for each sub-model is exemplified in the production of one unit in Fig. 3 where a perfect forecast was assumed. This simulation used in minutes:  $I_{DA} = 60$ ,  $I_{RTC} = 15$ , and  $I_{RTD} = 5$ ; and  $I_{AGC} = 6$  seconds. Each sub-model must ensure the resources are in the correct mode (e.g., start-up, shut-down, emergency, and normal) by linking decisions of other sub-models with the correct interval resolutions and optimization horizons.

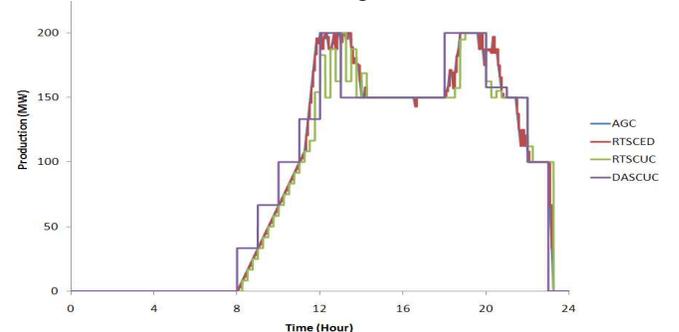


Fig. 3. Example generation production for all sub-models.

The results of sub-models are continuously communicated to other sub-models throughout the simulation. The model ensures that the results of one sub-model are incorporated into the inputs and constraints of others. The realized generation of units should be known for the RTSCUC, RTSCED, and AGC sub-models so that they do not give infeasible schedules. For example, RTSCED must know both the realized generation of the units it is scheduling as well as their prior RTSCED dispatch schedule. In practice, the RTSCED and RTSCUC sub-models would require time to solve ( $P$ ) and they are solving for points ahead ( $I$ ). With this information, schedules will be feasible based on where the unit is operating at the time the sub-model starts and based on the predicted direction that it is moving toward while the sub-model is solving (i.e., based on its last update,  $t$ ) considering its ramp rate. For example, Fig. 4 shows the operating range (shaded region) that the next RTSCED can schedule a unit based on its realized output at the start of the RTSCED initialization and the prior RTSCED dispatch schedule. With this implementation, units that are given AGC schedules that oppose the direction of RTSCED dispatch schedules (due to unforeseen ACE) are given feasible dispatch schedules. This procedure is very important for realistic integration of scheduling sub-models. Without this communication between sub-models, infeasible outputs (outside of the shaded region) would result.

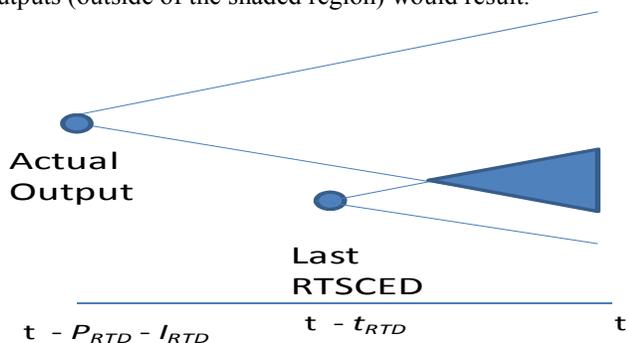


Fig. 4. RTSCED dispatch range considering communication of actual output and last schedule from prior RTSCED.

The model disregards frequency response, voltage magnitudes, and reactive power flows. The FESTIV model and AGC sub-model are implemented in Matlab [26]. The SCUC and SCED sub-models are implemented in GAMS using CPLEX MILP and LP solvers, respectively [27]. Matlab calls GAMS and retrieves data based on [28].

### III. METHODOLOGY AND METRICS

In order to quantify the variability and uncertainty impacts of increasing penetrations of VG across multiple time scales, we first need to define a set of suitable metrics. As mentioned earlier, the energy imbalance (ACE) is calculated at every  $t_{AGC}$ . The absolute value of the imbalance is also calculated at every  $t_{AGC}$  and summed up for the entire day. We refer to this metric as AACEE, for Absolute ACE in Energy, which has units of MWh. The performance of different systems can also be measured with CPS2 violations [29] with the violations based on exceeding the ACE limit (L10) for the compliance interval (e.g., 10 minutes). A standard deviation of the ACE ( $\sigma_{ACE}$  in MW) is also calculated. These metrics can show how the overall imbalance performance is, how often extreme

imbalances occur, and the variation of the imbalance throughout the study period. Note that we are always evaluating the imbalance of the entire study area and not imbalances of separate control areas within an interconnection. This alleviates some of the concerns that have been raised against ACE and CPS2 in which systems can be harming system frequency when improving their own ACE [30]. ACE can be thought of as a proxy to frequency for the system studied if it were its own interconnection and is a very valuable metric for understanding how a system performs on its own individual balancing of active power. Similar metrics can be used for line flow violations, like the Absolute Line Flow Exceedance in Energy (ALFEE), and metrics on how the generators are being operated (e.g., number of cycles). Lastly, the production costs of the resources meeting the demand at every  $t_{AGC}$  can be calculated and summed up to compare production costs for the operating period being evaluated. Note that for more direct comparisons, the total inadvertent interchange (e.g., sum of ACE) of the day is sold (positive) or bought (negative) at the highest average bus price and added to the production costs.

Variability can have impacts if the resources managing the variability are constrained or if the time resolution ( $I$ ) of the scheduling strategy is not prepared for the time resolution of the variability. A system with less flexible resources due to small ramp rates, long start-up times, and high minimum or low maximum capacity limits will be more impacted by variability than systems with more flexibility. Systems that have low time resolutions (longer intervals) for its scheduling programs will also be more impacted by variability because more variability will occur within the time frame that the resources are being scheduled. Time horizon ( $H$ ) also will affect the impact of variability. If more of the future is considered (longer  $H$ ) when operating the present, more flexibility can be manipulated to prepare for future variability. Sources of variability are active and reactive load and generation output (conventional and VG). Impacts of variability are active power imbalance, line flow exceedance, production costs, and voltage violations.<sup>1</sup>

Using an integrated model, the variability impacts can be shown as a function of the factors that influence it. This can allow for systems to understand what characteristics contribute to variability impacts in different ways. Equation (1) shows the AACEE as a function of the time resolution of the RTSCED, the time horizon of the RTSCED, the amount of VG on the system ( $P_{VG}$ ), the load ( $P_{LOAD}$ ), and the amount of total ramp available of the resources managing the variability ( $P_{GRAMP}$ ). Adjusting the characteristics (denominators) while keeping other contributions to variability constant will change the metrics (numerators) thereby giving the sensitivities (2). Most of these will be nonlinear functions and it is important to understand their impacts at different levels. Note that while the sensitivity to the amount of VG or load on the system is good information, the characteristics of the variability source may give more information. For example, the sensitivity of

<sup>1</sup> For simplicity and without loss of generality we will ignore reactive power variability and uncertainty and voltage violations in our studies and throughout the rest of the paper. Although not simple nor often performed in current systems, AC power flow can be modeled in the SCUC and SCED and these metrics can be quantified similarly to line flow exceedance and ACE.

1 AACEE from VG can be calculated from the standard  
2 deviation of the output changes at different timescales.

$$3 \text{ } AACEE = f(\mathbf{x}) = \alpha_1 * I_{RTD} + \alpha_2 * H_{RTD} + \alpha_3 * P_{VG} +$$

$$4 \alpha_4 * P_{LOAD} + \alpha_5 * P_{GRAMP} + \dots \quad (1)$$

$$5 \alpha_1 = \frac{\partial AACEE(\mathbf{x} | x_2 = \hat{x}_2 \dots x_n = \hat{x}_n)}{\partial I_{RTD}} \quad (2)$$

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10 Uncertainty can have impacts in addition to variability  
11 because the resources managing it have time-dependent  
12 characteristics and will be managing the system in a different  
13 way than how it actually results. The system with more  
14 uncertain variables will obviously have higher uncertainty  
15 impacts. A system with less flexible resources or a system  
16 with less updates ( $t$ ) or lower time resolution ( $I$ ) can also have  
17 higher uncertainty impacts. For example, even if a system has  
18 significant uncertainty, if its resolution ( $I$ ) and update  
19 frequency ( $t$ ) parameters approach 0, and its resources start-up  
20 times and minimum capacities approach 0 and ramp rates  
21 approach  $\infty$ , it can essentially avoid all uncertainty impacts of  
22 ACE. A system with more flexible resources will be able to  
23 correct the error more easily as the uncertainty improves  
24 closer to real-time. A faster update ( $t$ ) or shorter time  
25 resolution ( $I$ ) improves uncertainty since forecast errors  
26 improve closer to real-time. Sources of uncertainty are load  
27 and VG forecast errors, and conventional generation and  
28 branch forecast errors (outages). Impacts of uncertainty are  
29 active power imbalance, line flow exceedance, and costs.

30 Using an integrated scheduling model, the uncertainty  
31 impacts can be shown as a function of the characteristics that  
32 contribute to it. Equation (3) shows how the uncertainty  
33 impacts of AACEE can be affected by various changes on the  
34 system that influence these impacts. These can be assessed  
35 similarly to variability sensitivities and also will likely be  
36 nonlinear. Again, the amount of VG or load on the system can  
37 give information as to what uncertainty impacts to expect, but  
38 the specific characteristics of what makes these variables  
39 uncertain can give more information on the uncertainty  
40 impacts, like for example the root mean squared error (RMSE)  
41 of forecasts at different forecast horizons (4).

$$42 \text{ } AACEE = f(\mathbf{x}) = \beta_1 * t_{RTD} + \beta_2 * I_{RTD} + \beta_3 * P_{VG} +$$

$$43 \beta_4 * P_{LOAD} + \beta_5 * P_{GRAMP} + \dots \quad (3)$$

$$44 \text{ } AACEE = f(\mathbf{x}) = \dots + \beta_6 * RMSE_{VG, RTD}$$

$$45 + \beta_7 * RMSE_{VG, RTC} + \dots \quad (4)$$

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49 Different forecasts of individual VG and load are needed  
50 for every RTSCUC and RTSCED. So for instance, if  $t_{RTC}$  is 15  
51 minutes and  $t_{RTD}$  is 5 minutes, this would mean one day would  
52 require 384 real-time forecast sets per day (96 RTSCUC + 288  
53 RTSCED). Each RTSCUC and RTSCED are also optimizing  
54 over a horizon ( $H$ ) rather than a single point, so there are  
55 forecasts for multiple points for each sub-model run.  
56 Therefore, the RTSCUC and RTSCED will have multiple  
57 chances to correct forecast errors depending on their  $I$ ,  $t$ ,  $P$ ,  
58 and  $H$  parameters. The forecast errors apparent for all of these  
59 times will have varying uncertainty impacts. For instance, a  
60 day-ahead forecast error will have a very long time for the

system to correct the imbalance, however, has more options do  
so in a costly way. A short-term forecast error will have less  
time for the system to correct the imbalance, and will have  
fewer options to correct it with. This infers that the long-term  
forecast errors may have larger uncertainty impacts on  
production costs, whereas short-term forecast errors may have  
larger uncertainty impacts on reliability.

The previous methodologies focused on continuous  
sensitivities that can give system operators information on  
how various changes on the system contribute to variability  
and uncertainty impacts. Different scheduling strategies can  
also have changing results on the variability and uncertainty  
impacts on the system, either positively or adversely. These  
are discrete sensitivities, but can be used in a similar manner  
to (1)-(4). System studies should attempt different scheduling  
strategies to see how the uncertainty and variability impacts  
vary. Although this type of study is useful on any system, the  
variability and uncertainty impacts are likely to increase with  
greater VG penetrations and therefore understanding the  
impacts of different scheduling strategies becomes more  
important. Equation (5) shows a simple example of measuring  
the ALFEE changes when using a dispatch with (RTSCED)  
and without (RTED) considering contingencies. Since new  
scheduling strategies may have conflicting improvements, it is  
important to understand the tradeoffs as well. Computation  
time, generator cycling, or production costs may increase with  
scheduling strategies that improve reliability. This is shown  
for example in (6).

$$\Delta ALFEE = ALFEE_{RTED} - ALFEE_{RTSCED} \quad (5)$$

$$\frac{\Delta ALFEE}{\Delta COSTS} = \frac{ALFEE_{RTED} - ALFEE_{RTSCED}}{COSTS_{RTSCED} - COSTS_{RTED}} \quad (6)$$

#### IV. WIND INTEGRATION CASE STUDIES

We will now use the model described in Section II and  
methodologies and metrics of Section III on a basic test  
system with a high penetration of VG to understand the  
variability and uncertainty impacts of VG added to the system  
as well as the other factors that contribute to these impacts.  
For these studies we will use a modified IEEE 118-bus system  
with wind power injected at 4 buses (bus 42, 43, 69 and 77).  
The test system and wind, load, and net load time series are  
shown in the Appendix (Fig. 9 and Fig. 10). Further  
information on the test system can be found at  
[motor.ece.iit.edu/data/SCUC\\_118test.xls](http://motor.ece.iit.edu/data/SCUC_118test.xls). Total wind energy  
for the day is 15,172 MWh with a total load of 70,539 MWh  
(~21.5% wind penetration). The realized wind and load data  
come from the National Renewable Energy Lab's data  
collection set and are at 6-second time resolution, which is  
 $t_{AGC}$ . Wind is dispatchable up to the maximum available wind  
at a cost of \$0/MWh. We consider 10 critical branches as  
contingencies in the security-constrained sub-models. For the  
DASCUC, hourly resolution is used for the full day (i.e.,  $I_{DA} =$   
1 hr,  $H_{DA} = 24$  hr). The reserve requirements for this system  
are based on the largest unit (420 MW) for 10-minute spin (50%  
or 210 MW), 10-minute non-spin (100% or 420 MW), and 30-  
minute reserve (150% or 630 MW) for all hours and is based  
on 1% of hourly load for regulation reserve. These  
requirements are inclusive, meaning that some reserves can be

used as part of other reserve requirements (excepting regulation, the slower reserves will include the faster reserves). The ACE limit (L10) is 65 MW in 10-minutes, representative of a system of similar size. The parameter  $t_{RTCSTART}$  is kept at 60 minutes, with the combustion turbines of the system having start-up times of either 10 or 30 minutes.

### A. Variability Impacts

We first will look at the impacts of variability on the system by assuming all forecasts are perfect. For perfect forecasting cases, the only possibility of imbalance is variability occurring within the time resolution the scheduling structure is prepared for or beyond the time resolution that the flexible resources are prepared for (e.g., units not having enough ramping capability even if it is known the ramp that is needed). A perfect forecast here refers to one that is exactly the average of the predicted variable for the length of the associated interval ( $I$ ). To understand the impacts of variability within the dispatch interval we vary RTSCUC and RTSCED timing parameters as shown in Table II. Note that as described in Table I, the 5-minute case may be similar to parameters of system operations at most U.S. ISOs, while the 60-minute case is similar to parameters of some European TSOs and balancing areas of the Western and Southeastern U.S. All VG cases use the very same *realized* data for VG and all cases use the same *realized* load.

TABLE II  
REAL-TIME INTERVAL CASE DESCRIPTION (ALL IN MINUTES)

$I_{RTD}$ (case)	$t_{RTD}$	$H_{RTD}$	$I_{RTC}$	$t_{RTC}$	$H_{RTC}$
5	5	60	15	15	180
10	10	60	30	30	180
15	15	60	30	30	180
30	30	60	60	60	180
60	60	60	60	60	180

Each case progressively has longer time between updates ( $t_{RTD}$ ,  $t_{RTC}$ ) and longer interval resolution ( $I_{RTD}$ ,  $I_{RTC}$ ). Each of these cases was run on FESTIV for a full day with and without the wind power. Imbalance results are shown in Fig. 5 and in Table III as a function of  $I_{RTD}$ . These are comparisons of the same scheduling structures and strategies for the system with and without wind. The sensitivity to the imbalance metrics with respect to the wind on the system is shown as a function of GWh of wind power in the right-most columns of Table III.

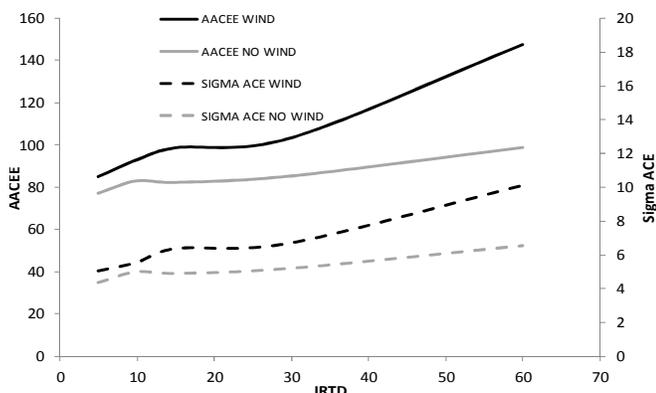


Fig. 5. Variability impacts of wind at as a function of scheduling resolution.

TABLE III  
VARIABILITY IMPACTS AT DIFFERENT TIME RESOLUTIONS

case	AACEE wind (MWh)	$\sigma_{ACE}$ wind (MW)	AACEE no wind (MWh)	$\sigma_{ACE}$ no wind (MW)	$\frac{\partial AACEE}{\partial PVG}$	$\frac{\partial \sigma_{ACE}}{\partial PVG}$
5	84.9	5.0	77.0	4.4	0.52	0.04
10	92.9	5.5	83.0	5.0	0.65	0.03
15	98.6	6.36	83.2	5.0	1.01	0.09
30	103.3	6.7	85.3	5.2	1.19	0.10
60	147.4	10.1	99.0	6.53	3.19	0.24

In general, the imbalance impacts increase with longer dispatch resolution as well as with the addition of variable wind on the system. Interestingly though, the variability impacts of *integrating* wind do not necessarily increase as  $I_{RTD}$  increases as can be seen in the right-most column for the  $I_{RTD}=10$  minutes case.

Fig. 5 shows a very nonlinear dependency. The wind case has an average AACEE rate of 1.08 MWh per ( $I_{RTD}$ ) minute and a  $\sigma_{ACE}$  rate of 0.088 MW per minute. The case without wind has an AACEE rate of 0.36 MWh per minute and a  $\sigma_{ACE}$  rate of 0.035 MW per minute. Since all forecasts are perfect, these results can be thought of as the impacts of the load and wind variability. As the dispatch minute changes, the impacts of variability at different timescales are realized since the resolution of the different scheduling sub-models that are preparing for the variability has changed.

### B. Uncertainty Impacts

In order to understand the uncertainty impacts of VG, cases of varying degrees of forecast error must be compared to the system with perfect wind forecasts. Different forecasts will be used for different purposes and will have different characteristics. The impacts can therefore be quite dependent not only on the characteristics of the error but what type of forecast the error came from as well. We will study the uncertainty impacts of wind power with day-ahead and real-time wind forecast errors.

Four forecast representations are studied in order to understand the day-ahead uncertainty impacts of wind. (F1) The perfect DA wind forecast, (F2) a wind forecast with a typical DA forecast error (F3) a case where the wind forecast is zero, and (F4) a case where the wind forecast is the maximum capacities of all wind plants. F3 and F4 seem improbable from an operator perspective but these cases may represent an extreme reality where wind forecasts are not used in energy markets and wind plant owners have strong incentives to offer energy into markets that is not their expected production [31]. For example, wind plants may offer zero energy in the day-ahead markets to avoid penalties or imbalance payments or they may offer more than anticipated if higher prices were expected in the day-ahead market. Each forecast is run with the  $I_{RTD} = 5$  and  $I_{RTD} = 60$  minutes. These cases kept the real-time forecast perfect so that comparisons of only the day-ahead forecasts were made. Simulations were run with real-time forecast error and the comparisons were very similar. Table IV shows results along with the forecast's mean absolute error (MAE) and standard deviation of error ( $\sigma_{err}$ ).

TABLE IV  
UNCERTAINTY IMPACTS OF DAY-AHEAD WIND POWER FORECAST ERRORS

forecast - $I_{RTD}$	MAE / $\sigma_{err}$ (MW)	AACEE (MWh)	$\sigma_{ACE}$ (MW)	ALFEE (MWh)	Prod. Costs (\$)
F1 - 5	0/0	84.9	5.0	4689	733356
F2 - 5	62/77	84	4.9	4681	733592
F3 - 5	632/426	105	10.2	4750	750648
F4 - 5	734/433	87.1	5.3	4592	740888
F1 - 60	0/0	147.4	10.1	4693	733265
F2 - 60	62/77	141.3	10.11	4657	733435
F3 - 60	632/426	132.9	9.1	4760	747914
F4 - 60	734/433	148	10.5	4577	736208

To understand the impacts of uncertainty with respect to the real-time forecast errors two bookends will be used: a perfect forecast case (variability only) and a case where persistence forecasts are used. Other cases will be simulated in between these bookends with varying error. In our definition, the persistence forecast assumes the future will be the same as the last realized reading that occurred and therefore the simplest implementation for a system operator. Persistence wind forecasts are one of the most common methods of wind forecasting in the very short-term [32].

Fig. 6 shows the AACEE for  $I_{RTD}=5$  and  $I_{RTD}=60$  minutes where varying real-time forecast errors are realized. Note that the longer the time interval for both the RTSCUC and RTSCED, the larger the persistence forecast errors. This is because the end of the interval is further ahead from when the persistence forecast was created. The errors represent the root mean squared errors of the very first binding interval of the RTSCED.

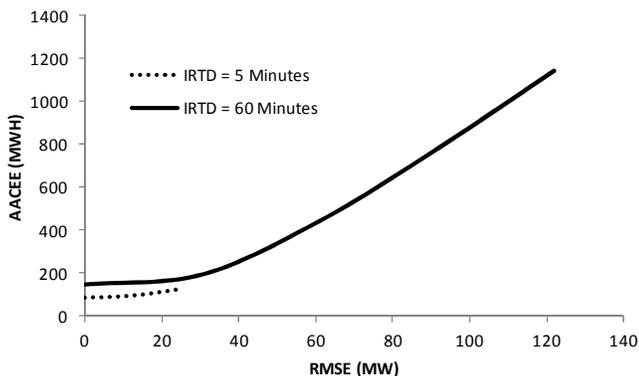


Fig. 6. AACEE impact of wind at various levels of real-time uncertainty.

The value that crosses the y-intercept (0 error) is the variability impact of VG. The change as the forecast error increases is the uncertainty impact of VG. The uncertainty impact is not significant until the error reaches a threshold. This is likely the error where the regulation reserve was no longer able to handle the error. The production costs and line flow exceedance had insignificant changes when the real-time forecast error increased. However, line flow exceedance and production costs can be significantly impacted by large errors in the day-ahead wind forecast (Table IV). By understanding what types of uncertainty impacts are affected by what

characteristics, systems can devise mitigation strategies toward which impact is most important to them.

### C. Scheduling Strategies Impacts

So far the variability and uncertainty impacts have been shown with the same scheduling strategies. The next two case studies will compare the uncertainty and variability impacts when different scheduling strategies are practiced. This type of study can now show not only what the variability and uncertainty impacts are, but how they can be reduced.

#### 1) AGC Mode of Operation

The impacts of variability and uncertainty are affected by the scheduling operation mode of the AGC sub-model. The study will compare four AGC scheduling strategies described below. All four AGC modes were tested with the 5-minute dispatch and 60-minute dispatch cases for perfect forecasts, persistence wind forecasts, and without wind power to understand both the variability and uncertainty impacts of VG. Fig. 7 shows AACEE for each AGC mode.

1. *Blind Mode*: Regulation units do not correct ACE but simply move from one RTSCED schedule to the next.
2. *Fast Mode*: Every  $t_{AGC}$ , regulation units correct the instantaneously calculated ACE. This is the mode that has been done in the previous sections (IV-A and IV-B).
3. *Smooth Mode*: The ACE signal is modified (smoothed) with an integral term of 3 minutes. Therefore, the regulation units are correcting the average ACE that has occurred over the past 3 minutes.
4. *Lazy Mode*: Regulating units only will correct the ACE if it appears that the ACE is such that it will violate the CPS2 for the 10 minute interval [33].

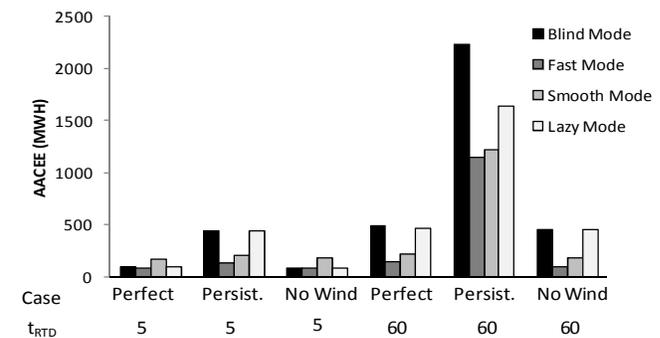


Fig. 7. AACEE for each AGC Mode.

Generally, the more active AGC is (with the order: *blind*, *lazy*, *smooth*, to *fast mode* being more active) the lower the imbalance. However, in the modes with 5-minute dispatch and perfect forecasts (with and without wind), the *smooth mode* actually performs worse at balancing than the *blind mode*. This is because the AGC is correcting the errors that have occurred within the *past* three minutes in the *smooth mode* while the RTSCED is already correcting the errors of the *next* five minutes, since it has perfect foresight. All of these cases actually had production costs that are within 0.1% of each other. However, hidden costs might be apparent in how the generating units are being used to follow ACE [34]. With higher penetrations of VG, this cycling impact may be increased [35]. Equation (7) shows the tradeoff comparison we

use to understand the improvements of each AGC mode to the *blind mode* in balancing against the increased requests to cycle generators. The denominator is created in such a way so that undefined values are not possible and so that more positive values are better. Any  $t_{AGC}$  interval where a generator (besides VG) changes from increase to decrease power, or vice versa, constitutes one cycle. A higher number means you are getting better balancing results with less required movement of your generators. Table V shows the results.

$$\frac{\Delta AACEE}{\Delta Gencycles} = \frac{AACEE_{blind} - AACEE_{modex}}{\max\{1, Gencycles_{modex} - Gencycles_{blind}\}} \quad (7)$$

TABLE V  
TRADEOFF OF BALANCING PERFORMANCE VS. ADDITIONAL CYCLING  
(MWH/CYCLES)

	Fast	Smooth	Lazy
5-minute no wind	<0.001	-0.093	0
5 minute perfect wind	0.001	-0.1	0
5-minute persistence wind	0.040	0.412	0.027
60-minute no wind	0.032	0.357	0.052
60-minute perfect wind	0.051	0.499	0.266
60-minute persistence wind	0.370	5.441	1.573

While *fast* and *smooth* modes have similar imbalance results with persistence wind forecasts, *fast* mode requires significantly more cycling from generators. However, *smooth* mode does not appear as a good choice with 5-minute dispatch when forecasts are very good. This type of results can help system operators choose the right scheduling strategies with higher penetrations of VG, which may or may not be the same strategies used with low penetrations of VG.

It is interesting to note the similarity in imbalances between the 5-minute persistence case and the 60-minute perfect case (Fig. 7). In this system for this day, the combined variability and uncertainty impacts when using 5-minute dispatch are about the same as the variability impacts alone when using 60-minute dispatch for all AGC scheduling strategies. All of these metrics can be used to adjust other strategies as well. For example, the metrics and tradeoffs can be used to adjust the operating reserve requirements to achieve the same level of reliability or by using a risk/cost tradeoff approach [36]-[37]. For this system, increasing the regulation reserve by a multiple of 5 gave similar imbalance results in the 60-minute persistence case as the 5-minute persistence case, but at a higher production cost.

### 2) Reserve Deployment and Operator Risk/Attitude

The final case study evaluated how the operator attitude toward risk and deployment of reserves could change the impacts. Three simulation cases were compared: 1: no operator action – *NO\_OP* 2: operator action only if a contingency occurs – *CTGC\_ONLY* and 3: operator action if absolute ACE is higher than 65 MW for 3 consecutive AGC intervals – *RPU\_65*. A simulated generator trip (300-MW generator) occurs at 18:30 for all simulations. This is added with the persistence wind forecasts to understand how different uncertainty sources interact. A new scheduling sub-model, the security-constrained reserve pick up, SCRPU, is

introduced. The SCRPU is essentially identical to the RTSCUC with a few significant changes. The SCRPU has no  $t$  value, since it is triggered by an event and not by a time interval. It adjusts the positive (if balancing under-generation) and negative (if balancing over-generation) reserve requirements in order to release the reserves for scheduling. Also, it can allow for usage of different limits (e.g., emergency ramp rates, short-term emergency transmission limits, etc.) Lastly, it has binding dispatch and commitment (whereas RTSCUC has only binding commitment). Essentially, operator action means that the operator runs an SCRPU deploying the held operating reserves. All cases use 60-minute RTSCED and RTSCUC, and *smooth* AGC mode. For the SCRPU,  $I_{RPU} = 10$  and  $H_{RPU} = 20$  minutes.

Fig. 8 shows the ACE during the contingency event for the three cases. When SCRPU is not used (*NO\_RPU*), the system takes well over an hour to return ACE to normal following the contingency at 18:30. The other two methods recover within 15 minutes, as spinning and non-spinning reserve were used in the SCRPU. Note that once the *CTGC\_ONLY* case returned the ACE to zero, schedules were reverted back to the original RTSCED because of the large persistence forecast error of the wind and therefore ACE began to decay again until hour 19, when a new RTSCED schedule was delivered to all units. Although this seems like unrealistic operation of the power system, it shows how important correct modeling is when simulating the details at these timescales.

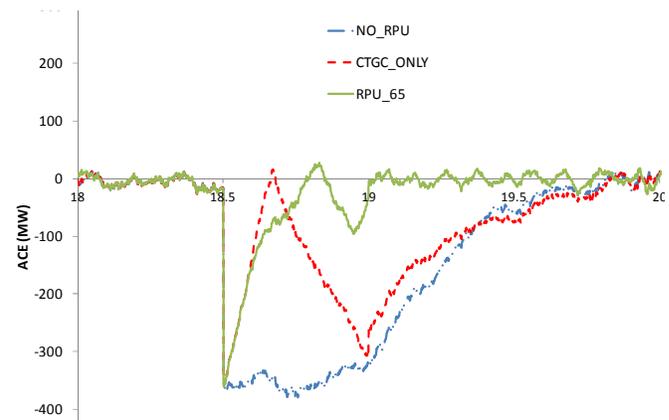


Fig. 8. AACEE for each AGC Mode.

Table VI shows the tradeoff of reducing the number of CPS2 violations with the increased costs based on equation (8). The quantities show that tremendous value is received in reducing CPS2 violations when running the SCRPU during contingencies and if ACE exceeds 65 MW for this system using a 60 minute dispatch. However, depending on what objectives the system operator is after and what tradeoffs are more important, results may show different strategies as being better options.

$$\frac{\Delta \text{ProdCost}}{\Delta \text{CPS2Viol}} = \frac{\text{ProdCost}_{\text{RPU}} - \text{ProdCost}_{\text{noRPU}}}{\text{CPS2Viol}_{\text{noRPU}} - \text{CPS2Viol}_{\text{RPU}}} \quad (8)$$

TABLE VI  
TRADEOFF OF CPS2 VIOLATIONS WITH INCREASED PRODUCTION COSTS

	CPS2 Violations	Proc Cost (\$)	$\Delta$ (\$/Viol)
NO_OP	46	739348.4	-
CTGC_ONLY	41	742437.8	617
RPU_65MW	3	742872.6	82

#### D. Practical Considerations

It is important to briefly mention some issues so as to understand the practicality of performing these studies on large realistic systems, as has been done in the previously mentioned studies of [1]-[6]. For the 118-bus system with 10 contingencies at 5-minute RTSCED, 15-minute RTSCUC, 6 second AGC, the one day simulation took about 11 minutes to solve. All simulations were run on a laptop with Intel Core 2.7 GHz Processor with 8 GB of RAM and MILP used a 0.1% duality gap. The most computational intensive factor is how often the RTSCUC is run, and how many units can be started by RTSCUC (i.e., number of integer variables), as the MILP is the most difficult problem to solve. For studies evaluating a few days, the studies can be done for large existing systems (e.g., 1,000s of buses). However, high resolution data needs to be obtained for multiple VG in order to perform the study. Since it is becoming more and more important to study future systems with higher VG penetrations, this data is not available. Not all the VG is in existence and therefore accurate data modeling techniques must be performed to create it.

#### V. CONCLUSION

This paper introduces a new way to study the detailed impacts of integrating large penetrations of variable generation onto the power system at multiple timescales. The variability and uncertainty of VG at multiple timescales that adds to that of the existing system needs to be analyzed correctly in order to know which mitigation techniques are worth pursuing. An integrated model is needed to capture the impacts at multiple timescales, modeling the interaction between different scheduling programs used in practice with updated forecast conditions, and offering the flexibility to test various scheduling strategies to understand benefits and tradeoffs. It is clear from these studies that analyzing the VG data alone does not give much information on what variability and uncertainty impacts to expect.

Variability and uncertainty can each have different mitigation techniques. For example, improving forecast accuracy can assist in uncertainty impacts, and geographic diversity and shorter time resolution can assist in variability impacts. This type of study captures the detailed ways in which the scheduling models would be used in system operations, capturing the issues that operators can use to justify what type of mitigation techniques are needed. It is extremely important to simulate the system at multiple time resolutions when studying the variability and uncertainty of VG since the impacts occur on different timescales and the different scheduling programs used at different time resolutions are coupled together. By modeling each separately, and simply adding the impacts together, it is likely that the impacts are not representative. Furthermore, if operators can value reliability metrics based on their particular risk attitudes

(e.g., value of AACEE, value of ALFEE, cost of CPS2 violations, etc.) as is done with value of lost load (VOLL) in hourly models, these studies can give better comparisons of the tradeoff between reliability and costs of different scheduling strategies ensuring the impacts of multiple timescales are captured. Understanding the tradeoffs of benefits of some characteristics with the shortcomings of other characteristics can give the information on which strategies and systems will allow for superior integration of VG.

#### VI. APPENDIX

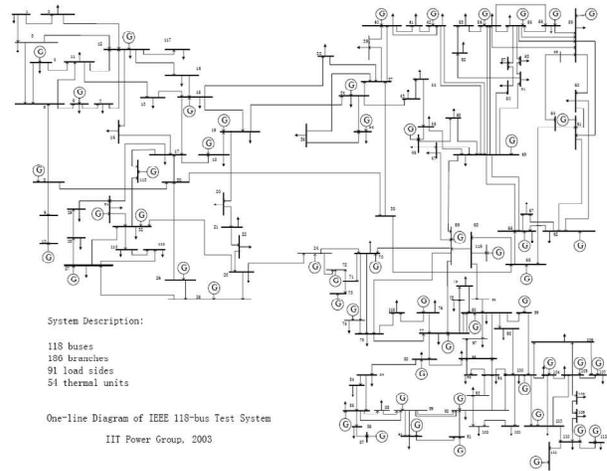


Fig. 9. 118-bus system with wind located at 4 buses throughout network.

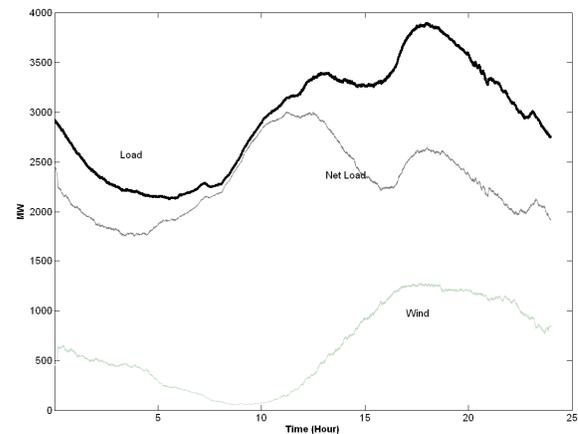


Fig. 10. Wind, load, and net load used in 118-bus test system.

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#### VIII. BIOGRAPHIES

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