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A Flexible Power System Operations Simulation Model for Assessing Wind Integration

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***Abstract*--With the advent of wind power generation on worldwide power systems, many operators and researchers are analyzing the impacts that higher future amounts may have on system operations. Many of the tools are analyzing longer term impacts on the steady-state operations of power systems and are primarily using cost as a metric. They are also using tools that are often inflexible to accommodating different market designs or operational structures. In this paper a model was developed to mimic operator behavior using a combination of security-constrained unit commitment, security-constrained economic dispatch, and automatic generation control programs. New metrics are used to compare reliability in terms of energy imbalance for different systems or different market and operational structures at very high time resolution. Finally an example application of the tool and results for a test system are shown.**

***Index Terms*— automatic generation control, economic dispatch, power system operations, unit commitment, wind integration**

I. Introduction

WIND power generation has seen a tremendous growth in past years as its environmental benefits and zero variable costs have been viewed as an acceptable alternative to other more conventional sources of power generation. Wind power is considered variable generation (VG) however, and can be both variable and uncertain. Unlike non-VG generation sources, it has a maximum generation limit that changes through time (variability) and this limit is also not known with perfect accuracy at times in the future (uncertainty). These impacts can create challenges for system operators when ensuring enough units will be online to meet reliability requirements, and to schedule the system to maintain a stable system frequency and minimize the imbalance between generation and load. Many entities therefore have been studying these impacts using production cost simulation models and statistical analyses [1]. The state of the art in the modeling techniques to analyze wind integration methods has been described in [2], [3].

Many production costing programs have been developed and used for a variety of applications, see for example [4]-[6]. Although the production cost models used in these analyses are very sophisticated and are efficient tools for use in many applications, there are a few drawbacks to using them for steady-state power system integration impacts. Many are fixed to certain operating and market structures (e.g., scheduling intervals, optimization horizons, reserve requirement rules, etc.). This makes it difficult to analyze the impacts that different operating and market structures have on the integration of wind. Recently, many research models have been built to give more flexibility toward solving different types of issues involved with wind integration. For example, models have been built that incorporate the stochastic input of wind power and other stochastic variables to better estimate its integration impacts [7]-[10]. In [11], a model was built that ensured possible scenarios of wind production could be met with a given unit commitment set, but based on minimizing the cost of one scenario. In [12], a model was developed similar to commercial unit commitment programs, but with sophisticated modeling to represent real-time pricing showing the influence of demand response on wind integration impacts. However, these are all built at the hourly "unit commitment" time resolution and therefore impacts that occur inside the hour may be hidden. Since it is difficult to see any reliability impact result at average hourly resolutions, the only meaningful metric is total costs. These models also do not capture the detailed costs from units dispatch inside the hour to follow the intra-hour variability through automatic generation control (AGC) or from being deployed as reserve.

Many of the models used for wind integration studies are very capable of showing the costs of requiring and holding operating reserves due to sophisticated solvers that co-optimize energy and operating reserves. However, they do not typically show the utilization of these operating reserve or mimic operator actions when deploying operating reserves. Therefore, the required operating reserves are usually determined off-line using statistical analysis as can be seen in [13] and these reserve values are rarely validated using simulation.

We introduce the Flexible Energy Scheduling Tool for Integration of Variable generation (FESTIV), which is a high resolution steady-state power systems simulation model that has parameters that can be flexibly configured by the user. The model uses various combinations of security-constrained unit commitment (SCUC), security-constrained economic dispatch (SCED), and AGC to schedule the system at different operating time frames. At the finest scheduling interval, the frequency at which AGC is run (which in North America is normally 4-6 seconds), the imbalance between generation and load is calculated, as are the production costs. The costs and imbalances at this resolution give realistic metrics that can

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show how well the system is balanced, how well it avoids extreme imbalances and how much it costs to run that system. These metrics can be used to compare different operating strategies (e.g., dispatch intervals) as well as different inputs (e.g., wind penetrations).

This paper introduces the tool and describes some of the applications it has for evaluating the impacts of wind power on power system operations. In section II, we describe the overall structure of FESTIV and the individual models that make up FESTIV, including its SCUC, SCED, and AGC. In section III, we then show an application of the tool where we evaluate the performance of different economic dispatch scheduling intervals, forecast errors, and mode of AGC operation on a test system with a high penetration of wind power. Section IV concludes the paper.

II. Description of Model

FESTIV includes three models that are each run at time intervals configured by the user: SCUC, SCED, and AGC. In general, the model was tailored towards evaluating the short-term operational impacts that occur, while the hourly resolution production cost models that are currently being used for evaluating the impacts of wind integration are a better choice for evaluating the long-term impacts (i.e., annual or longer). The model attempts to replicate actual system operations at a high resolution and allows for flexibility to accommodate the many different market and operational structures that are in existence throughout the world. Fig. 1 shows the high-level process and data flow of FESTIV. Full lines represent the flow of process and dashed lines represent the flow of data.

A. *SCUC*

Two SCUC models are included: Day-Ahead SCUC (DASCUC) and Real-time SCUC (RTSCUC) with the key difference being what generating units the program can turn on or off. The DASCUC is run for the entire day and gives the initial commitment status for all units. This would be similar to the day-ahead unit commitment currently performed in many regions. After this, the daily operation begins and the RTSCUC is repeated throughout the day to update unit commitment based on new forecasts and system conditions. This SCUC is very similar to DASCUC, but can only start and stop units differently than the status given from the initial SCUC, if the units have a start time less than $t_{RTCSTART}$, which is configurable by the user.

The DASCUC and RTSCUC model designs are very similar. They minimize costs including variable, no load, start up, and reserve costs and include load shedding and insufficient reserve penalty costs. They ensure typical generator constraints including min./max. capacity, ramp rate, minimum on/off time, maximum starts per day, etc. DASCUC also allows for variable startup costs that depend on the offline time of the unit starting up. Start-up trajectories are also modeled in both programs similarly to [14] where the start-up ramp rate is always Pmin/SUtime. SCUC also models the transmission network including contingencies via a dc load flow method using power transfer distribution factor (PTDF) and line outage distribution factor (LODF) matrices. The algorithms also allow for HVDC lines and phase shifting transformers to be part of the network.

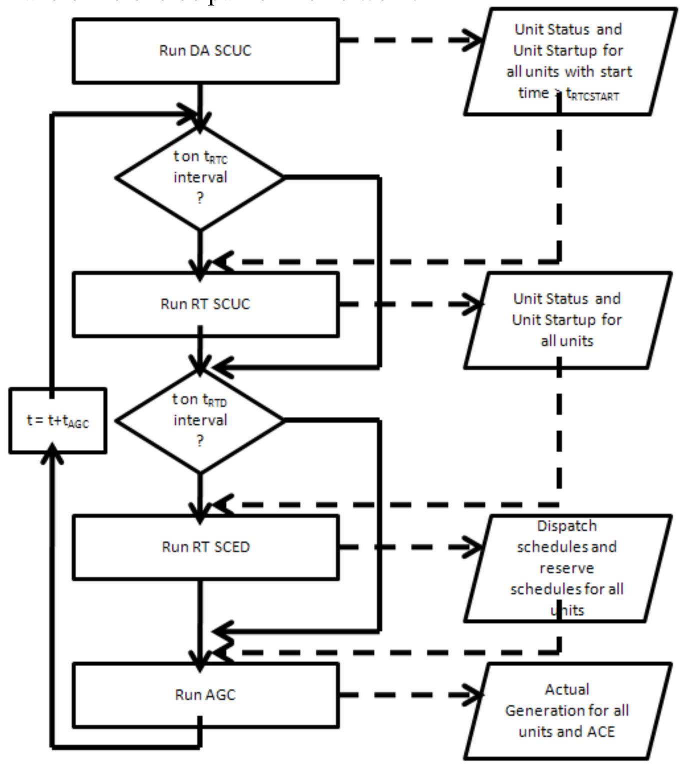

Fig. 1. Process flow diagram for FESTIV.

B. *SCED*

RTSCED is very similar to RTSCUC except that it cannot change commitment status that was provided by RTSCUC. SCED minimizes variable costs including reserve costs and load shedding and insufficient reserve penalty costs. It also contains all of the generator constraints except for commitment-based constraints, and network constraints including contingencies using PTDF and LODF. It includes modeling of HVDC lines and phase-shifting transformers as well.

C. *AGC*

Lastly, the AGC model is a rule-based algorithm. Unlike SCUC and SCED, it is not optimizing the scheduling of units. Instead it uses all units that are providing regulating reserve as scheduled by SCED to assist in correcting the Area Control Error (ACE). ACE is calculated by subtracting the total load from the total generation (which is similar to actual ACE assuming nominal frequency). In most cases, AGC will schedule the ACE correction needed, proportional to the units regulating schedules and ramp rates provided by the last SCED. AGC is run at the finest of all time resolutions, t_{AGC}, which is also configurable by the user. Units not providing ACE regulation are given a schedule by AGC that interpolates one SCED schedule to the next.

The AGC built in FESTIV currently has four different modes it can be run at. The first mode, which we designate as "blind mode," basically does not provide any ACE regulation. All units, whether they were given a regulating schedule by SCED or not, are interpolated from one SCED schedule to the next regardless of the ACE (i.e., AGC is "blind" to the ACE).

The second mode, designated as "fast mode," will use its units providing ACE regulation to follow each instantaneous ACE. This would create incredible wear and tear, and most units would be incapable of following. The third mode is designated as "smooth mode," where regulating units from SCED follow a proportional integral ACE signal, also called smoothed ACE (SACE) [15]. This would follow most closely what is done in actual operation [16] [5]. This is shown in (1) and both the proportional and integral terms are configurable by the user. The last mode is designated as "lazy mode." It is based on [17] and is essentially a combination of "blind mode" and "smooth mode." The units given AGC regulation schedules by SCED do not correct ACE unless it appears that the CPS2 interval will violate the CPS2 compliance. The anticipated violation is based on the ACE that has occurred since the beginning of the CPS2 interval and the assumption that the ACE will stay constant at the current instantaneous ACE for the remainder of the CPS2 interval. Therefore, when this violation is anticipated, the units providing AGC regulation will follow a SACE signal such that the integral and proportional terms are calculated based on (2), (3), and (4).

$$SACE(t) = K1 * ACE(t) + \frac{K2}{Tn} \int_{t-Tn}^{t} ACE(\tau)d\tau \qquad (1)$$

$$K1 = \frac{CPS2interval - mod(time, CPS2interval)}{CPS2interval} \qquad (2)$$

$$K2 = 1 - K1 \qquad (3)$$

$$Tn = mod(time, CPS2interval) \qquad (4)$$

Each of the four AGC modes acts as a different benchmark for analysis. Note that if, for example, AGC is run at 6-second intervals, the AGC will be run 14,400 times for a single-day simulation. The rule-based algorithm without optimization allows for this operation to occur and is most closely related to AGC programs used in ISO/RTO operations.

D. *Model Interface and Communications*

Fig. 2 shows how the different programs are run in the FESTIV model based on the configurable time parameters. The blocks represent the running of the models with each point following this block representing a future time interval that is part of the scheduling horizon of that model run. 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 have an optimization horizon of one day. RTSCUC is repeated every t_{RTC} and run at an interval resolution of I_{RTC}, which normally would be the same as t_{RTC}, but can be different. RTSCUC would have a horizon of H_{RTC}. RTSCED is run every t_{RTD} minutes with interval resolution of I_{RTD} and optimization horizon of H_{RTD}. An additional parameter $I_{RTD\text{-}ADV}$ is also used to represent the fact that the time resolution for dispatch is very important in the immediate future, and less so further out ahead in the optimization. Therefore, $I_{RTD\text{-}ADV}$ is always larger than I_{RTD} and represents all but the first interval length. The AGC model is repeated every t_{AGC}, and for only one time point, which is t_{AGC} ahead.

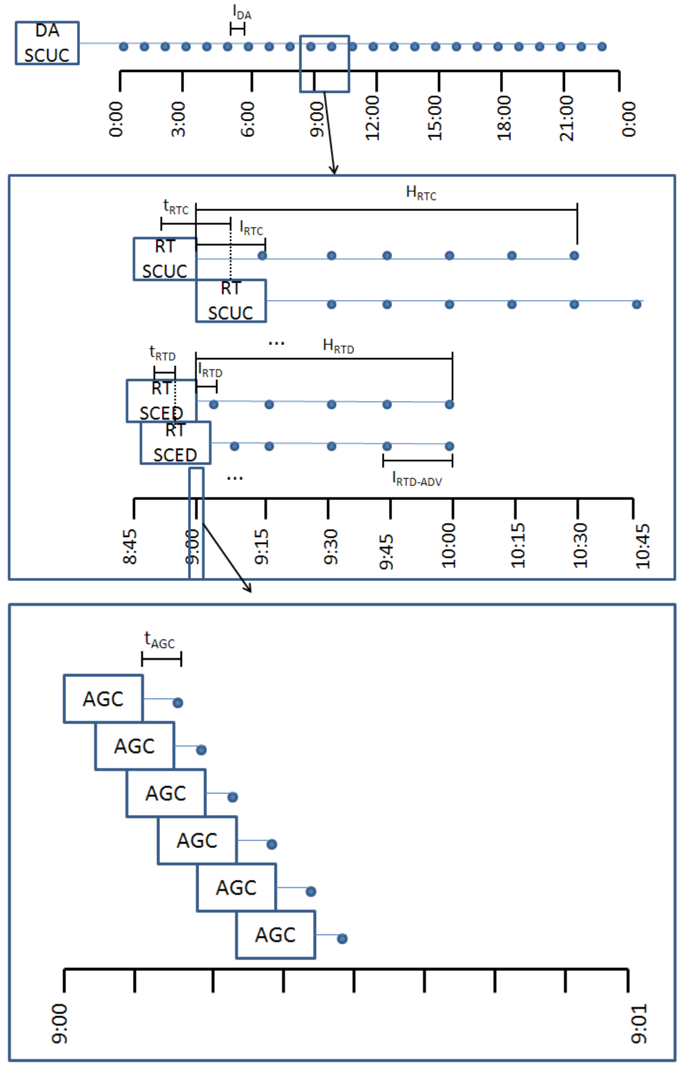

Fig. 2. Timeline for DASCUC, RTSCUC, RTSCED, and AGC in FESTIV model.

The three models have significant communication between each other (see Fig. 1). The unit status and startup for all units with start times greater than $t_{RTCSTART}$ are an output of the - DASCUC and cannot be changed by any of the other models (unless contingencies are simulated). It should be noted that by making $t_{RTCSTART}$ very high, this would effectively eliminate this constraint. RTSCUC takes the fixed status from the DASCUC and as output sets the unit status and startup for all units. RTSCED would then take the unit status of all units as set by RTSCUC and as output set the economic dispatch signals and reserve schedules for all units. Lastly, AGC would then take the unit status and unit startup from SCUC and dispatch and reserve schedules from SCED to compute the actual generation of all units and the ACE. An additional model called a reserve pick up (RPU), which is similar to the RTSCUC, is also part of FESTIV. The RPU reflects an operator action if a contingency occurs or the ACE is over some threshold, and an immediate correction is more desirable than waiting for the next t_{RTD} or t_{RTC}.

The communication of data does not only flow from the lower resolution models to the higher resolution models (e.g., SCUC to SCED) as shown in Fig. 1, but also from lower resolution to higher resolution models. The unit status of prior points in time are needed for each real-time SCUC to ensure that any decisions it makes in future SCUC solutions do not violate any minimum on time or other commitment constraints. The actual generation of units should also be known for the RTSCUC, RTSCED, and AGC processes so that the program does not give infeasible scheduling solutions. This is important when modeling the actual detailed operation of the system and the interaction between regulating units and economic dispatch schedules. For example, SCED needs to know both the actual generation of the units it is scheduling as well as the dispatch schedule that the prior SCED gave these units. This is due to the time delays involved with both the running of the model as well as the fact that the dispatch is for some time in the future. With these two pieces of information known, SCED can now give a dispatch schedule that is both feasible based on where the unit is actually operating at the time the program starts and is feasible based on the predicted direction the unit will be moving toward while solving the program using the individual unit's ramp rate. This practice is based on actual operations at the New York Independent System Operator (NYISO) [18]. For example, Fig. 3 shows the operating range that the current SCED can schedule a unit based on its actual output at the start of the program initialization and the prior SCED schedule considering its ramp rate. This assumes a 5-minute process time and a 5-minute dispatch interval. The shaded region is the range where the current SCED is allowed to give it a schedule. With this implementation, units that were directed by the AGC to correct ACE differently than RTSCED directed it are not given infeasible schedules by the next RTSCED.

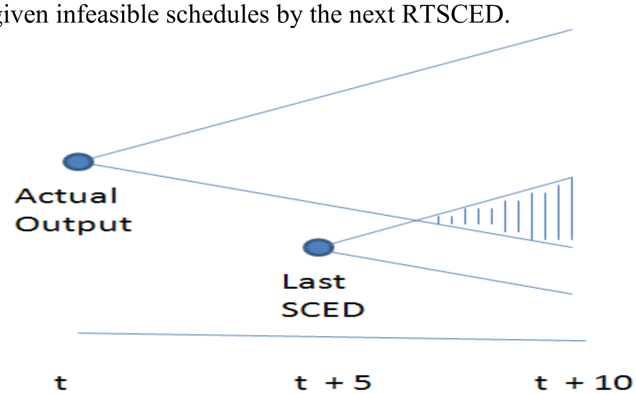

Fig. 3. Use of ramp constraints based on actual output and last schedule.

It should be noted that different forecasts of wind and load are needed for every RTSCUC and RTSCED run. So for instance, if t_{RTC} is 15 minutes and t_{RTD} is 5 minutes, this would mean one day would require 384 real-time forecast sets (96 RTSCUC + 288 RTSCED) for every wind plant and load as well as one more for the DASCUC program. Since each SCUC and SCED may be optimizing over periods of time and not single instances, there is actually a forecast for each time point of each of the aforementioned sets. For instance, if H_{RTC} is 3 hours (meaning 12 points at 15-minute intervals), there would be 12 forecasts for every wind plant and load for every single RTSCUC. This is important for analyzing the impacts of wind integration and makes the simulation as close to reality as possible.

Other options are included in the model including behavior rates and contingency simulations. Behavior rates model how well the conventional generating units follow their dispatch schedules based on random numbers. A behavior rate of 1 would follow AGC perfectly, whereas a behavior rate of 0 would give completely random output. Contingencies can be simulated using random numbers for either generator or network outages. The model disregards frequency response, voltage magnitudes, and reactive power flows. It also currently models all conventional units alike without detailed multi-mode constraints for combined cycle gas turbines or hydrological constraints for hydropower units. The flow of processing between the models and the flow of data is mainly implemented with Matlab. AGC is built in Matlab and SCUC and SCED models are built in GAMS using CPLEX MILP and LP solvers, respectively [19]. Matlab calls GAMS for each optimization and retrieves its output data based on the process implemented in [20].

III. Application of the Tool to Wind Integration Impacts

The major impacts that wind and other VG can cause on power system imbalance are caused by its variability and uncertainty. Variability and uncertainty are certainly interrelated. However, we attempt to distinguish how each may affect the operations of the power system. For example, both may have to be managed in different ways. The way that they are managed may be through the SCUC, SCED, and AGC programs and operating reserves that may be held in one model to be used in another. Although the main factor to the degree to which variability and uncertainty impact the power balance are due to the variable and uncertain variables themselves (e.g., wind output), the way in which the system prepares for that variability and uncertainty can also have a significant impact on these impacts as well as the costs to manage the impacts. The following case studies therefore all use the very same stochastic variable time series, the actual load and wind power, with simple adjustments in how the model prepares for and manages the system through the SCUC, SCED, and AGC processes.

In order to test the impacts, we first define our metrics. As mentioned earlier, both imbalance and costs are calculated at every t_{AGC}. The absolute value of the imbalance (ACE) is also taken at every t_{AGC} and summed up for the entire study period. We refer to this measure as AACEE, for Absolute ACE in Energy, which has the units of MWh. The performance of different systems can also be measured with CPS2 violations, which is based on the North American Electric Reliability Corporation (NERC) standard [21]. The user can configure the L10 value (ACE limit) as well as the CPS2 interval (nominally 10 minutes according to NERC) to what is deemed as a violation for the particular system. This can show how often the system being evaluated has extreme instances of imbalance, whereas the AACEE shows overall imbalance performance. A standard deviation of the ACE can also be calculated. Lastly, the detailed costs of the resources meeting the demand at every t_{AGC} can be calculated and summed up to compare costs for the operating period being evaluated. We will use the AACEE, CPS2 violations, σ_{ACE}, and costs as the metrics in the following case studies.

We test the variability and uncertainty impacts on the PJM 5-bus system with wind power added at bus E as shown in Fig. 4. Generator data is shown in Table I. Wind, load, and net load for the day are shown in Fig. 5. The wind and load data are actual data and are at 6 second time resolution, which is t_{AGC}.

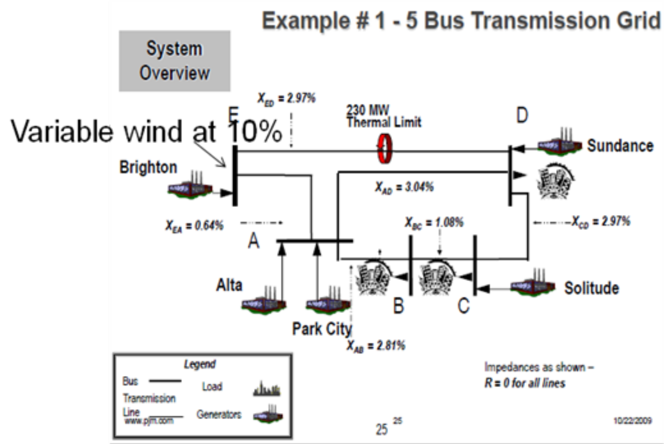

Fig. 4. PJM 5-bus system with variable wind added to bus E.

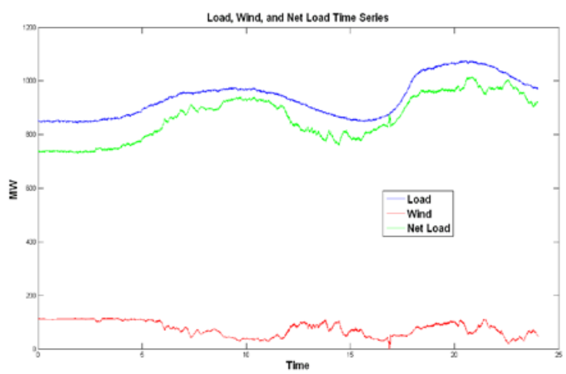

Fig. 5. Wind, load, and net load used in test system.

TABLE I
TEST SYSTEM UNIT DATA

	Minimum Capacity	Maximum Capacity	Incremental Cost	No Load Cost	Startup Cost	Regulation Cost	Min Run/Down Time	Ramp Rate	Startup Time
Alta	40 MW	110 MW	$14/MWh	$100/h	$450	$5/MWh	4 h	2 MW/min	3 h
Brighton	200 MW	600 MW	$10/MWh	$100/h	$1200	$8/MWh	8 h	0.5 MW/min	6 h
Park City	40 MW	100 MW	$15/MWh	$100/h	$900	$10/MWh	4 h	2 MW/min	3 h
Solitude	100 MW	520 MW	$28[1]/MWh	$100/h	$300	$4/MWh	6 h	5 MW/min	3 h
Sundance	50 MW	200 MW	$40 /MWh	$50/h	$150	$1/MWh	1 h	5 MW/min	0.5 h

A. *Variability Impacts and Scheduling Resolution*

All of the scenarios mentioned in these first two analyses will use the 'blind mode' of AGC, meaning that there will be no units regulating the ACE but only moving from one dispatch schedule to the next. For the DASCUC, all use hourly resolution (i.e., I_{DA} = 1 hr) and the DASCUC forecast is perfect for both wind and load. There are no simulated contingencies of transmission or conventional generator outages, all behavior rates are set to 1, and RPU is not used. $t_{RTCSTART}$ is set at 0.5 hours, meaning that only "Sundance" can be started by the RTSCUC. Also, even though the units are operating on 'blind mode,' there is regulating reserve that is scheduled by RTSCED along with spinning and non-spinning contingency reserve. The regulating reserve would simply leave upward and downward room to regulate but never do so. The L10 value for determining CPS2 violations is 25 MW in a 10-minute interval, which is similar to L10 values of North American systems of similar size.

If perfect foresight is known of all possible uncertain variables, the only possibility of imbalance is variability occurring within a dispatch interval or because of a physical constraint (e.g., units not having enough ramping capability even if it is known the ramp that is needed). A perfect forecast in this case refers to one that is exactly the average of the predicted variable for the length of the particular interval. To understand the impacts strictly based on the variability occurring within the dispatch interval we vary the RTSCUC and RTSCED timing parameters as shown in Table II. Note that in this table, H refers to the number of interval points in the optimization rather than the optimization horizon time.

[1] Solitude also uses a piecewise linear cost curve ranging from $28 to $40/MWh at different parts of its capacity.

TABLE II
REAL-TIME INTERVAL TEST CASE DESCRIPTION

Interval description	t_{RTD}, I_{RTD}	$I_{RTD\text{-}ADV}$	H_{RTD}	t_{RTC}, I_{RTC}	H_{RTC}
5	5	15	5	15	12
10	10	30	3	30	6
15	15	30	3	30	6
30	30	30	3	60	3
60	60	60	2	60	3

Each case progressively has longer time between updates and longer interval resolution. Each of these cases was run on FESTIV for a full day. Results are shown in Table III. This can be thought of as the impacts of the net load variability.

TABLE III
RESULTS FOR PERFECT FORECAST AT DIFFERENT RESOLUTIONS

Interval	AACEE	CPS2 Violations	σ_{ACE}	Cost
5	40.9 MWh	0	2.39 MW	$355,705.62
10	58.14 MWh	0	3.34 MW	$356,522.71
15	77.59 MWh	0	4.45 MW	$357,102.62
30	120.29 MWh	0	6.96 MW	$356,768.03
60	175.51 MWh	3	9.86 MW	$356,233.64

The first notable result is that the 60-minute SCED is the only case where any intervals violate the CPS2. This case had 3 10-minute intervals with ACE over 25 MW (or below -25 MW). In general, the ACE metrics increase with increasing dispatch resolution. The costs do not have a trend of any sort. Since there is no cost to having ACE or CPS2 violations built in the model, and units are not regulating the ACE between intervals, the costs are simply based on what the dispatch is telling the units to do to meet the average of the dispatch interval net load. Fig. 6 shows the AACEE and σ_{ACE} as a function of t_{RTD}. With a linear trend line, the plot shows that the variability of the net load increases the AACEE about 2.4 MWh for every minute longer the SCED dispatch interval is. Similarly, the standard deviation of ACE increases about 0.13 MW for every minute longer the SCED dispatch interval is. These rates decrease as the dispatch interval increases for both standard deviation and AACEE.

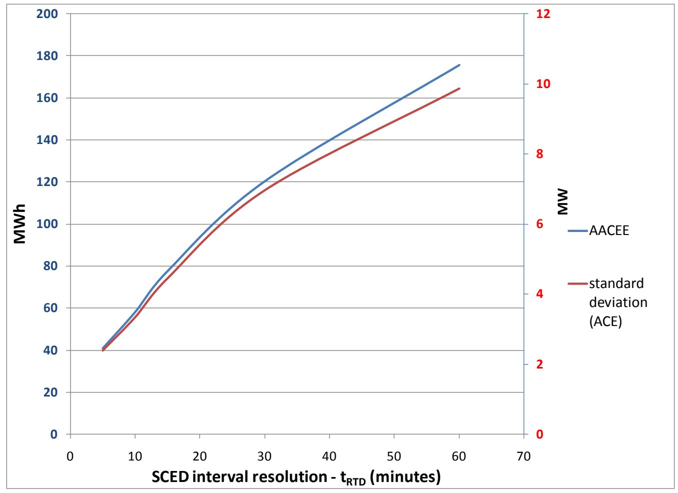

Fig. 6. AACEE and σ_{ACE} as a function of dispatch interval resolution.

B. *Uncertainty Impacts and Scheduling Resolution*

In order to test both the variability impacts of the wind generation as well as the uncertainty impacts we will compare the prior perfect forecast case with two imperfect forecast cases. One will have a perfect load forecast with a persistence wind forecast, and the other a persistence load and persistence wind forecast. In our definition, the persistence forecast assumes the future will be the same as the last actual reading that occurred. Note that due to the maturity of load forecasting a persistence load forecast is not likely to occur in today's system operations, but we use for comparison purposes. Persistence wind forecasts on the other hand are the most common method of forecasting in the very short-term.

Many of the integration studies in [1] determine that the forecast errors have larger impacts on costs and operations than does the variability. While most of these studies focus on the day-ahead forecasts, we will focus on the short-term forecast errors. While day-ahead forecasts have large impacts on costs, they usually will have fewer impacts on ACE and reliability as long as there are sufficient quick-start resources that can be started up in time. Short-term forecast errors, however, can impact ACE and costs. To show these impacts, we will run each of the prior cases of Table II with persistence wind forecasts, and then with persistence wind and load forecasts. Note that the longer the time interval for both the RT SCUC and RT SCED, the larger the forecast errors. This is because the end of the interval is further ahead from when the persistence forecast was created. For example, the end of a 5-minute SCED is basing its forecast on the actual from 10 minutes ago, while the end of a 60-minute SCED is basing its forecast on the actual 65 minutes ago.[2] Fig. 7 shows the AACEE and Fig. 8 the CPS2 violations for all cases. Again, all of these cases are using the exact same actual wind (since there was no curtailment) and load data at the t_{AGC} interval.

[2] All SCED runs are assumed to take 5 minutes regardless of the interval parameters and all SCUC runs are assumed to take 15 minutes regardless of the interval parameters. This is where the additional 5 minutes is from.

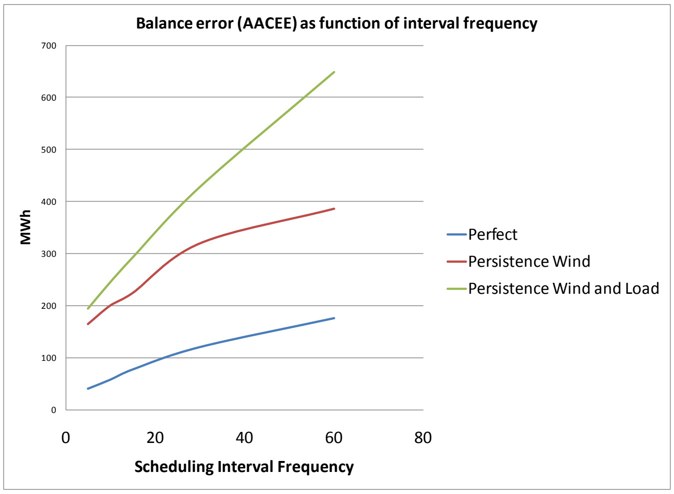

Fig. 7. AACE for different forecast errors.

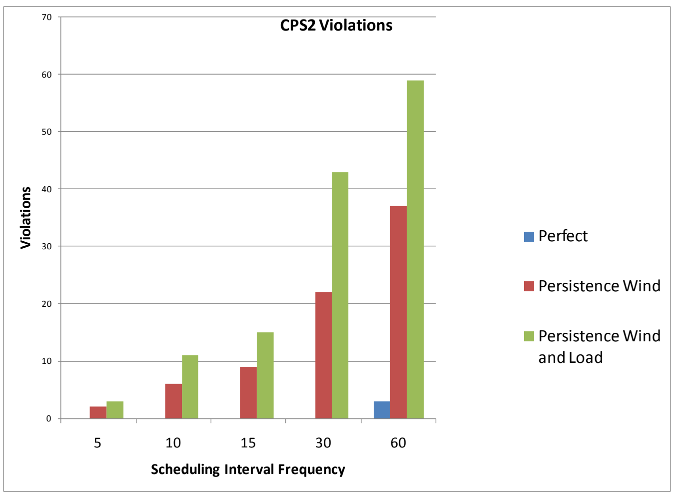

Fig. 8. CPS2 violations for different forecast errors.

It can first be observed that introducing the forecast error has a significant effect on the imbalances. Since increasing the dispatch interval increases both the variability impacts by having resources set at a longer time at one optimal level, and the uncertainty impacts by increasing the error the further out in time, both CPS2 violations and AACEE have a much higher rate of increase per dispatch resolution minute when forecast error is introduced. According to NERC BAL001, a balancing area's CPS2 score must be above 90% to be acceptable. This means that of the 144 10-min intervals in a day, 14 or fewer CPS2 violations are acceptable. Therefore, with no AGC and no operator action whatsoever, both 30-minute forecast error cases, both 60-minute forecast error cases and the 15-minute persistence wind and load forecasts case would have violated CPS2.

C. *Uncertainty and Variability Impacts and AGC Operation Mode*

To correct the system ACE that is occurring due to variability and uncertainty on the system, power system operators rely on units with AGC to automatically adjust output in order to reduce the ACE and bring it close to zero. All four AGC modes were tested with the 5-minute dispatch and 60-minute dispatch cases for both perfect forecasts and persistence forecasts. It is very important to note that all cases required the same amount of regulating reserve capacity of between 10 and 25 MW up and down depending on the time of day. Therefore, when all regulating range was used up in the particular time interval, there was no more the AGC could do. Fig. 9-11 show CPS2 violations, AACEE, and total costs for each AGC mode.

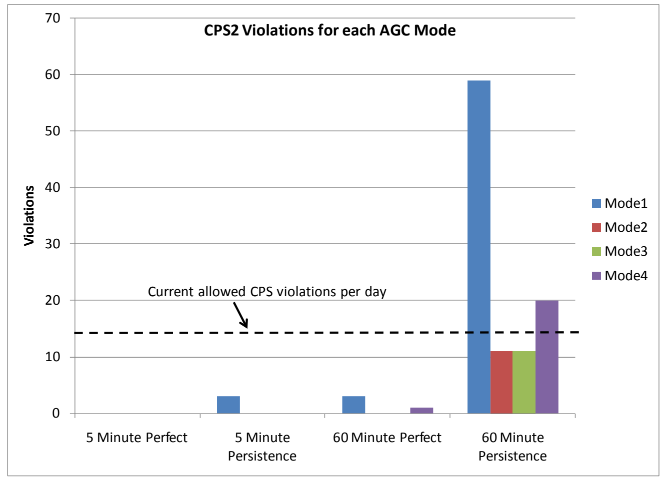

Fig. 9. CPS2 violations for different forecast errors.

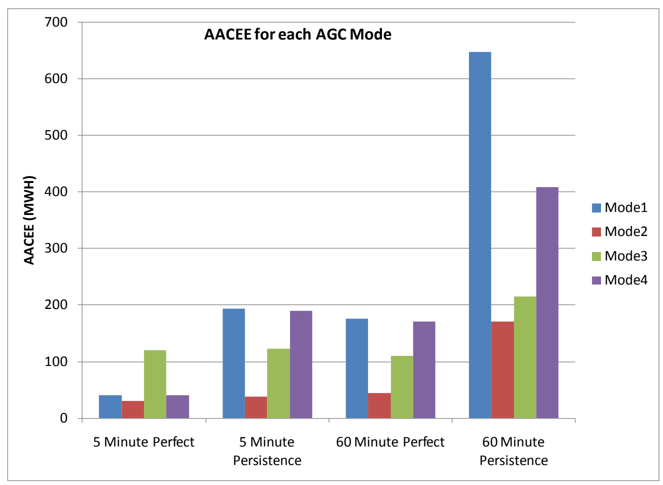

Fig. 10. CPS2 violations for different forecast errors.

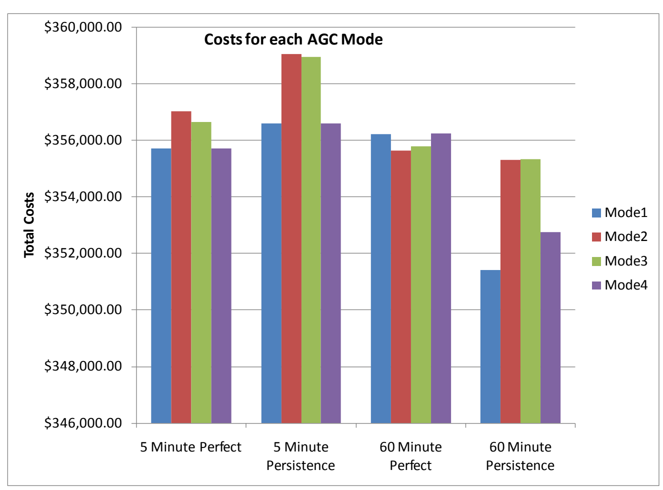

Fig. 11. CPS2 violations for different forecast errors.

Generally, the more heavily AGC is used will lead to lower imbalance and higher costs. This generally follows the order from light AGC to heavy AGC of mode 1, mode 4, mode 3, and mode 2. A few outliers are noticed, however. For the 5-minute perfect case, the "smooth mode" actually increases the AACEE. This is because the integral term of the SACE algorithm is three minutes and therefore the regulating units are correcting the mistakes of the last three minutes, whereas the SCED, with its perfect foresight, is already correcting what it knows will occur in the future. Also, the 60-minute perfect case has a reduction in costs when using active AGC modes (2 and 3) compared to "blind mode."[3] Through the analysis, it was seen that due to the ramping constraints (see Fig. 3) in this scenario, using AGC used 25 MWh less of Solitude generation (at \$28-30/MWh) and 34 MWh more of Brighton (at \$10/MWh) among some other differences, and overall used 13 MWh less of total generation throughout the day. AGC also does not model the transmission network as does SCED, which could lead to the reason why Brighton was used more.

AGC mode 4 can be seen to have significant differences in AACEE only when there are significant CPS2 violations. Lastly, it is interesting to note the similarity in reliability between the 5-minute persistence case and the 60-minute perfect case. It seems that in this system for this day, the combined uncertainty and variability impacts when using a 5-minute dispatch resolution are the same as the variability impacts alone when using a 60-minute dispatch resolution.

IV. Conclusions

This paper introduces a flexible model FESTIV to analyze the detailed impacts of integrating large penetrations of wind power onto the power system. The model interfaces between SCUC, SCED, and AGC programs and imitates actual system operations at a high time resolution. The model also creates some very flexible options so that users can not only compare different inputs, but different operational and market structures. With this flexibility, system operators can not only observe the impacts of high penetrations of wind power, but also what operating and market structures work best for integrating wind power in terms of both reliability and costs. A case study was performed using FESTIV to compare the impacts of wind power on a small test system. The impacts that wind and other sources may have on the imbalance of a power system are variability, uncertainty, and the physical inability of resources to meet both impacts. By adjusting the dispatch and commitment intervals, amount of forecast error, and mode of AGC, the way these impacts change can be observed. Further analysis can give insight into how other combinations of operating strategies using SCUC, SCED, and AGC programs can improve the operations of systems with high wind penetrations.

[3] Note that there is no cost for "cycling" or ramping accounted for in this analysis and all costs are from energy, no load, start up, and ancillary services.

V. References

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