An Enterprise Control Assessment Method for Variable Energy Resource Induced Power System Imbalances. Part 2: Parametric Sensitivity Analysis

Aramazd Muzhikyan, *Student Member, IEEE,* Amro M. Farid, *Member, IEEE,* and Kamal Youcef-Toumi, *Member, IEEE*

***Abstract*—In recent years, renewable energy has developed to address energy security and climate change drivers. And yet, as energy resources, they possess a variable and uncertain nature that significantly complicates grid balancing operations. As a result, an extensive academic and industrial literature has developed to determine how much such variable energy resources may be integrated and how to best mitigate their impacts. While certainly insightful with the context of their application, many integration studies have methodological limitations because they are case specific, address a single control function of the power grid balancing operations, and are often not validated by simulation. The prequel to this paper presented a holistic method for the assessment of power grid imbalances induced by variable energy resources (VER) based upon the concept of enterprise control. This paper now systematically studies these power grid imbalances in terms of five independent variables: 1.) day-ahead market time step 2.) real-time market time step 3.) VER normalized variability 4.) normalized day-ahead VER forecast error and 5.) normalized short-term VER forecast error. The systematic study elucidates the impacts of these variables and provides significant insights as to how planners should address these independent variables in the future.**

***Index Terms*—Power system imbalances, reserve requirements, variable energy resource integration.**

I. Introduction

IN recent years, the trend towards renewable energy integration has developed to address energy security and global climate change drivers. And yet, as energy sources, they possess a variable and uncertain nature that significantly complicates power grid balancing operations. To address these challenges, an extensive academic and industrial literature [1]–[8] has developed to determine how much such variable energy resources may be integrated and how to best mitigate their impacts. As discussed in the methodological prequel [9] to this work, most integration studies use variations of the statistical methods found in [10]. The standard deviation of the potential imbalances, σ, is calculated using the probability distribution of the net load variability *or* forecast error. Then, the load following reserve requirement is taken equal to 2σ [10], [11] to comply with the North American Electric Reliability Corporation (NERC) balancing requirements [12]. Other integration studies use 3σ [13], [14] as found in industry standards [15]. The regulation reserve requirement is normally chosen between 4σ and 6σ [10], [11], [16]. However, variability and forecast error are two emphasized factors that distinguish VER from the ordinary load and both should be taken into consideration when assessing the reserve requirements. Also, load following and regulation reserves operate in two separate timescales, and their requirements should partly depend on different parameters.

This paper uses the methodology from the prequel [9] to provide a systematic study of VER induced power grid imbalances. This provides a detailed insight into the mechanisms by which the need for reserves emerges. The concept of enterprise control allows five independent variables to be studied holistically: 1.) the day-ahead market time step (T_h) 2.) the real-time market time step (T_m) 3.) the variability (α) 4.) the day-ahead forecast error (ε_{DA}) and 5.) the short-term forecast error (ε_{ST}). The application of an enterprise control assessment framework allows the empirical identification of the most influential parameters on balancing performance as well as the load following, ramping, and regulation reserve requirements. The inclusion of the day-ahead and real-time market steps are a particularly distinguishing feature of the work. Use of the case-independent methodology allows generalization of the results and prediction of how the system reserve requirements change when one of the parameters varies. Moreover, the results reveal the degree of importance of each lever for the balancing which is crucial for the strategic planning of the grid modernization.

The paper is organized as follows: Section II provides a brief summary of the methodology as background, Section III describes the case study and the simulation scenarios, Section IV discusses the simulation results and finally Section V presents the conclusions.

II. Methodological Background

For the sake of continuity with the prequel to this paper [9], the simulation methodology is briefly summarized. The power system enterprise control simulation consists of three consecutive control layers on top of the physical power grid, namely

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A. Muzhikyan is with the Department of Engineering Systems and Management, Masdar Institute of Science and Technology, PO Box 54224, Abu Dhabi, UAE. amuzhikyan@masdar.ac.ae

A. M. Farid is with Faculty of Engineering Systems and Management, Masdar Institute of Science and Technology, PO Box 54224, Abu Dhabi, UAE. afarid@masdar.ac.ae

K. Youcef-Toumi is with Faculty of Mechanical Engineering, Massachusetts Institute of Technology, 77 Massachusetts Avenue Cambridge, MA 02139, USA. youcef@mit.edu

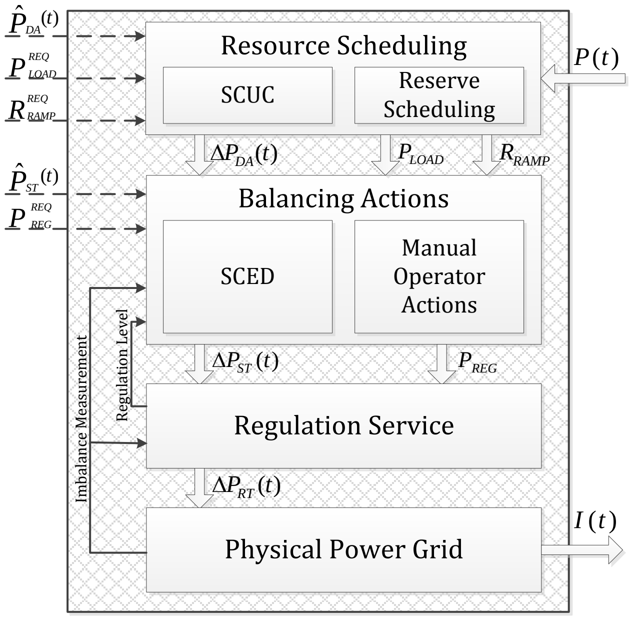

Fig. 1. Conceptual model of a power grid enterprise control simulator

resource scheduling in the form of a security-constrained unit commitment (SCUC), balancing actions in the form of a security-constrained economic dispatch (SCED) and manual actions, and regulation service in the form of automatic generation control (AGC). Fig. 1 presents the conceptual diagram of three-layer power system balancing control, where each lower layer operates at a smaller timescale resulting in subsequently smaller imbalances. The net load $P(t)$ can be considered as the starting imbalance. In the resource scheduling layer, the SCUC uses the day-ahead net load forecast $\hat{P}_{DA}$ to schedule the generation. However, due to the limitations of the scheduling resolution, the day-ahead forecast error, and the system losses, the scheduled resources and the actual demand do not match, and some portion of imbalances remains at the SCUC output:

$$\Delta P_{DA}(t) = P(t) - \hat{P}_{DA}(t) \tag{1}$$

The SCUC also manages the procurement of load following and ramping reserves that are used in the balancing layer to mitigate imbalances.

In the balancing layer, the SCED uses the available load following and ramping reserves to re-dispatch the generation units in the real-time market. The short-term net load forecast $\hat{P}_{ST}(t)$ is used to calculate the re-dispatched levels of the generation units. However, due to the limitations of the real-time market resolution and the short-term forecast error, the dispatched generation and the actual demand do not match, and some portion of imbalances remains at the SCED output:

$$\Delta P_{ST}(t) = P(t) - \hat{P}_{ST}(t) \tag{2}$$

It should be noted that $\Delta P_{ST}(t)$ only depends on dispatching time step, the short-term forecast error, and the current level of imbalances since the system losses are taken into account in the SCED formulation.

In the regulation service layer, the available regulation reserves are used to fine-tune the system balance. It should be noted, that $\Delta P_{DA}(t)$ is in a slower timescale and occurs due to insufficient load following and/or ramping reserves, while $\Delta P_{ST}(t)$ is in a faster timescale and occurs due to insufficient regulation reserves. To distinguish between these two components, $\Delta P_{DA}(t)$ and $\Delta P_{ST}(t)$ are called slow and fast imbalances respectively. The effective imbalance $I(t)$ is the combination of slow and fast imbalances and occurs when at least one of the system reserves is insufficient.

III. Case Study

This section describes the case study used in this paper. It consists of five simulation scenarios that demonstrate the impact of VER penetration on power system imbalances. This section also describes the test case and the net load profile used in the simulations.

A. Simulation Scenarios

To achieve the objective of this paper, a set of steady-state simulations are performed that demonstrate the impact of VER penetration on power system imbalances and reserve requirements. The following scenarios are studied:

A. **Impact of day-ahead market time step on reserve requirements.** One of the contributors to the slow imbalance term is the limited resolution of the day-ahead market. While the scheduled generation remains constant during the given time step, the actual demand fluctuates. Thus, the resulting imbalance is expected to depend on the day-ahead market time step. The system contains no VER for this scenario.
B. **Impact of real-time market time step on reserve requirements.** One of the contributors to the fast imbalance term is the limited resolution of the real-time market. While the dispatched generation ramps at the constant rate to the dispatched value, the actual demand fluctuates. Thus, it is expected that the resulting imbalance depends on the real-time market time step. The system contains no VER for this scenario.
C. **Impact of VER variability on power system imbalances and reserve requirements.** As already stated, the limited resolutions contribute to both slow and fast imbalance terms, and the previous scenarios are designed to test the impact of time steps. However, since the variability is present across all time scales, it is expected to affect both types of imbalances. The forecast errors are taken to be zero for this scenario to emphasize the impact of the variability.
D. **Impact of VER day-ahead forecast error on power system imbalances and reserve requirements.** The second contributor to the slow imbalance term is the day-ahead forecast error. Thus, it is expected that the resulting imbalance also depends on the day-ahead forecast error. The short-term forecast error is taken to be zero for this scenario, to emphasize the impact of the day-ahead forecast error.
E. **Impact of VER short-term forecast error on power system imbalances and reserve requirements.** The second contributor to the fast imbalance term is the short-term forecast error. Thus, it is expected that the resulting

imbalance also depends on the short-term forecast error. The day-ahead forecast error is taken to be zero for this scenario, to emphasize the impact of the short-term forecast error.

For the sake of simplicity in the simulations, this study assumes that the load has no forecast error. This assumption does not decrease the value of the obtained results since both VER and load forecast errors are added together to a net load forecast error. A nonzero load forecast error would only increase the net load forecast error by a specific amount and, hence, decrease the sensitivity of the results to the VER forecast error. In the simulations to come, the quantity of reserves is said to reach the required level when its increase does not bring about any further improvement in the level of imbalances.

B. The Testcase and the Simulation Data

Wind and load profiles from the Bonneville Power Administration repositories [17] are used for this case study. However, the available data has only 5-minute resolution, while the simulator operates at a 1-minute time step. This issue is overcome by up-sampling the available data to the necessary resolution. The up-sampling process is performed with *sinc* functions to not introduce distortions into the power spectrum [18] which defines the distribution of the variability over different timescales. The IEEE RTS-96 reliability test system is used as the physical grid [19]. It is composed of three nearly identical control areas, with a total of 73 buses, 99 generators and 8550*MW* of peak load (Fig. 2).

Along with the variability and the forecast error, the impact of VER integration on power system operations also widely depends on the distribution of VER units on the system buses and the correlation of their outputs [20]. A random distribution may lead to heavy congestions on some transmission lines. Also, depending on their geographic distribution, the VER unit outputs may have different levels of correlation, which may either aggravate or diminish the overall variability. These effects are considered outside the scope of this paper. Instead, this paper assumes that the distribution of VER capacity on the system buses is proportional to the peak loads on corresponding buses. Furthermore, the VER outputs are assumed to be perfectly correlated to eliminate the effect of geographical smoothing on the reserve requirement [21]. It is worth noting, however, that these assumptions do not significantly diminish the results of this paper since the SCUC and SCED models are linear and have very little sensitivity to the distribution of the sources on the buses.

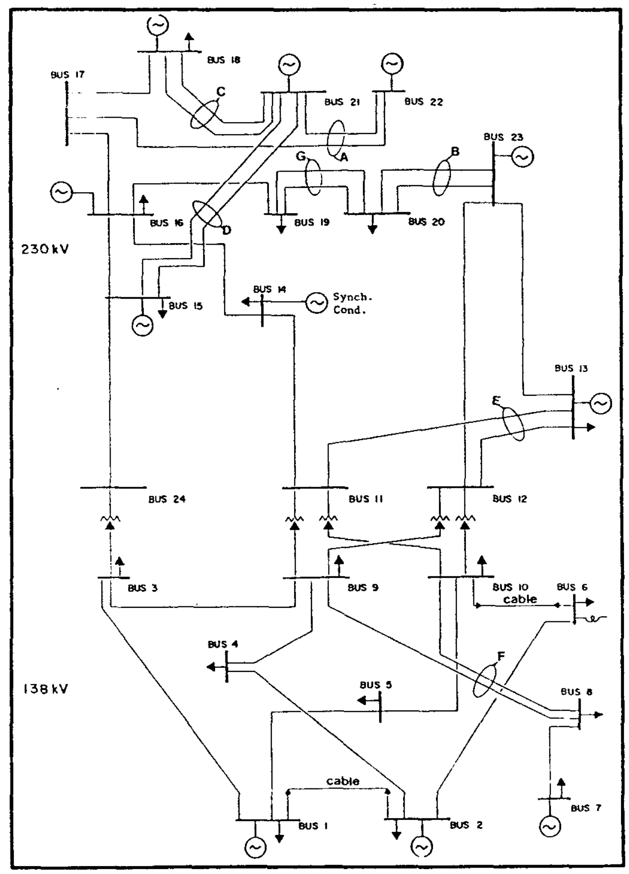

Fig. 2. One area of the IEEE reliability test system-1996 [19]

IV. Results and Discussion

This section presents the simulation results for each scenario.

A. Impact of Day-Ahead Market Time Step on Reserve Requirements

The limited resolution of the day-ahead scheduling process creates a mismatch between the scheduled resources and the real-time demand fluctuations. As described above, the load following and ramping reserves depend on the day-ahead market time step while the regulation reserves operate on a smaller real-time market timescale and should be able to avoid the impact. To this end, three simulations are performed to test the impact of the day-ahead market time step on each type of reserve requirements. Fig. 3 and 4 show the load following and ramping reserve requirements for three different scheduling time steps: 60min, 30min and 15min. These figures show similar patterns for load following and ramping reserves and reveal some important aspects of the impact of day-ahead

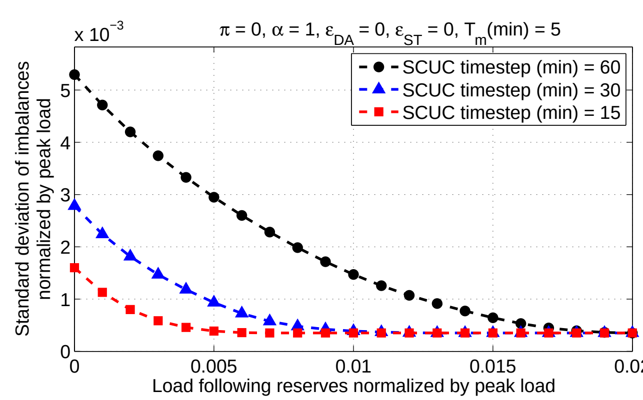

Fig. 3. Impact of day-ahead market time step on the load following reserve requirements

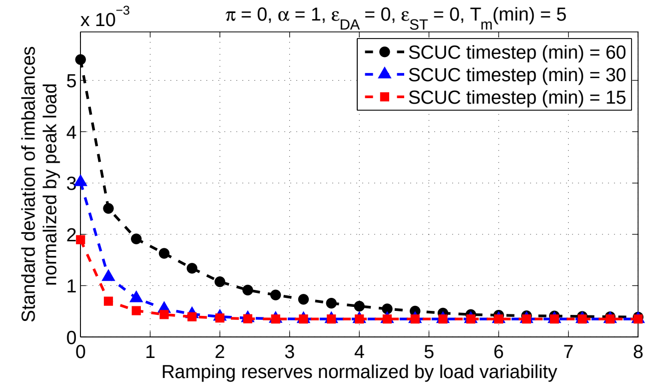

Fig. 4. Impact of day-ahead market time step on the ramping reserve requirements

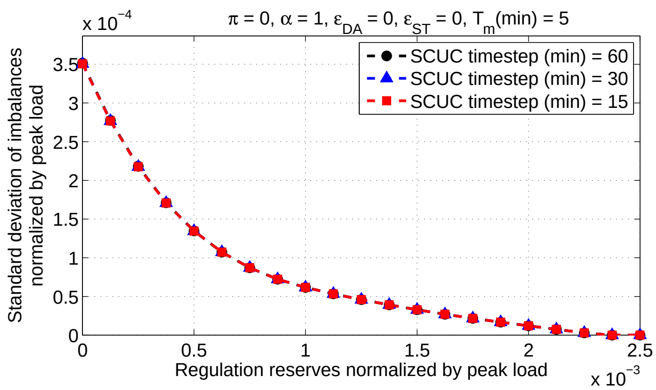

Fig. 5. Impact of day-ahead market time step on the regulation reserve requirements

scheduling time step on reserve requirements. First, all three graphs start at different levels of imbalances in the absence of reserves, which shows that the imbalances are inherently smaller for systems with shorter day-ahead market time step. Second, the graphs with shorter scheduling time step reach the saturation level sooner, which indicates that they require less load following and ramping reserves. Third, both graphs have the same saturation level, which means that the fast imbalance is the same for all cases and does not depend on the day-ahead market time step. This fact is clearly demonstrated in Fig. 5. The graphs for three different values of the day-ahead market time step replicate each other identically and go to saturation for the same value of regulation reserves. As expected, this shows that the regulation reserve requirement does not depend on the day-ahead market time step. Note here that the zero value for the standard deviation of imbalances means that all steady-state imbalances with one minute resolution have been mitigated. In all, Fig. 3-5 show that SCUC time step reduction potentially reduces the load following and ramping reserve requirements. Such a reduction, however, would have to be assessed in the context of the additional computational burden and require market lead time.

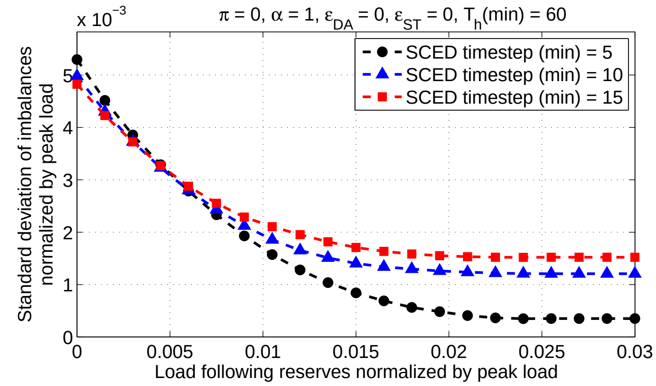

Fig. 6. Impact of real-time market time step on the load following reserve requirements

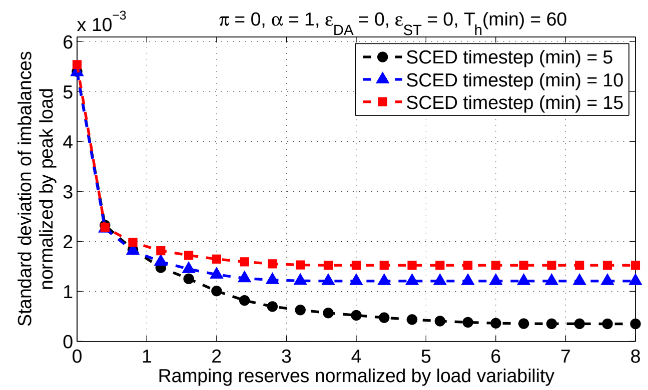

Fig. 7. Impact of real-time market time step on the ramping reserve requirements

B. Impact of Real-Time Market Time Step on Reserve Requirements

The limited resolution of the real-time market creates a mismatch between the dispatched resources and the real-time demand fluctuations. As described above, the dispatching of the system generation is affected by the real-time market time step, while the load following and ramping reserves operate on a larger timescale and should be able to avoid the impact. To this end, three simulations are performed to test the impact of the real-time market time step on each type of reserve requirements. Fig. 6 and 7 show the load following and ramping reserve requirements for three different real-time market time steps: 5min, 10min and 15min. Similar to the previous scenario, the figures for load following and ramping reserve requirements show some common characteristics. First, the graphs start from approximately the same point, which shows that the imbalances stand at the same level in the absence of reserves. This is explained by the fact that the real-time market time step only defines the splitting threshold between slow and fast imbalances but does not affect the magnitude of total imbalances. Second, the graphs reach their respective saturation levels for the same value of reserves, regardless of SCED time step, which indicates that the load following and ramping reserve requirements do not depend on the real-time market time step. Third, the saturation level is always lower for the system with smaller real-time market time step, which

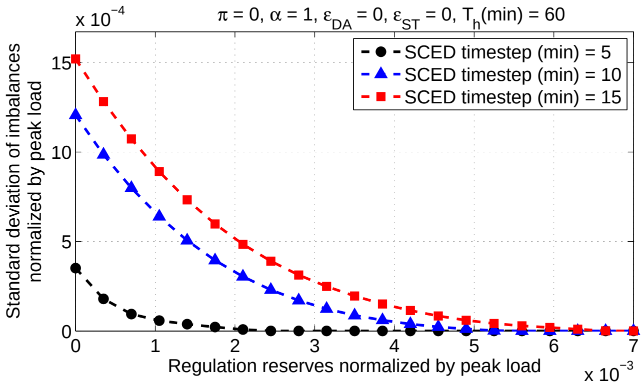

Fig. 8. Impact of real-time market time step on the regulation reserve requirements

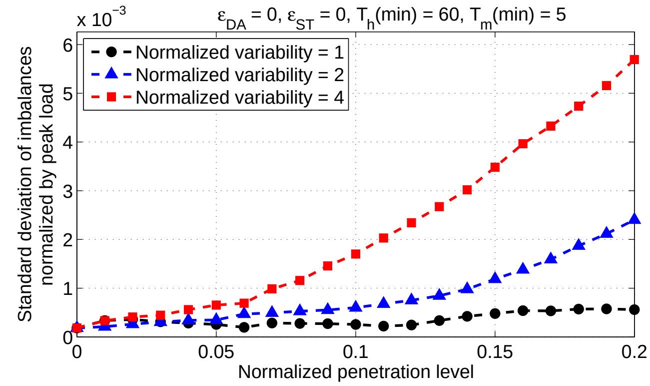

Fig. 9. Impact of VER variability on the power system imbalances

means that the real-time market affects the fast imbalance and the regulation reserve requirement. This fact is clearly demonstrated in Fig. 8. As expected, the system with smaller real-time market time step goes to saturation sooner, which means that it requires less regulation reserve. In all, Fig. 6-8 show that SCED time step reduction potentially reduces the regulation reserve requirement. Such a reduction, however, would have to be assessed in the context of the additional computational burden and generators' ability to adhere to the newly distributed dispatches.

C. Impact of VER Variability on Power System Imbalances and Reserve Requirements

As discussed above, the limited resolutions of the day-ahead and real-time markets create a mismatch between the dispatched resources and the real-time demand fluctuations. While the simulation results from the previous two scenarios show that the system imbalances and the reserve requirements depend on the day-ahead and real-time market time steps, the actual variability of the net load also needs to be considered. Generally speaking, since the variability indicates the rate of the net load profile fluctuations, changing the scheduling/balancing time step and changing the profile variability should have equivalent effects on the system. Moreover, the variability is the only VER parameter that spans over all timescales and is expected to have impact on all three types of reserves.

To this end, four simulations are performed, where the first one studies the impact of VER variability on the power system imbalances, while the other three study the impact of VER variability on each type of reserve requirements. Fig. 9 shows the change of the power system imbalances as the VER penetration level increases for three values of normalized variability: 1, 2 and 4. According to the definition of normalized variability, in the absence of forecast errors, increasing VER penetration level also increases the introduced total VER variability. As a result, increasing VER penetration level has a similar impact on power system imbalances as increasing VER normalized variability. The graphs in Fig. 9 start from the same imbalance level and start to diverge as the VER penetration level increases. This shows that higher levels of imbalances correspond to higher variability, which indicates that in the presence of high variability the adequacy of the existing reserve requirements is challenged.

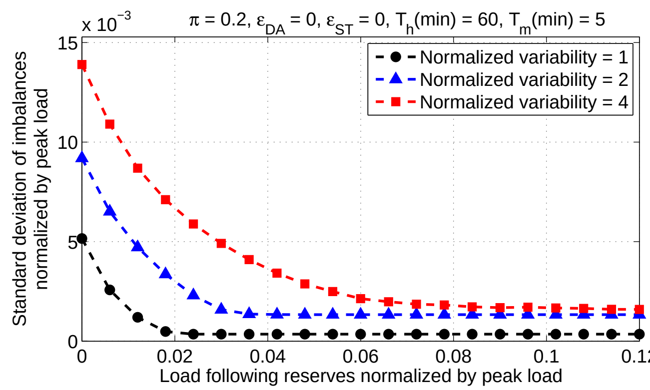

Fig. 10. Impact of VER variability on the load following reserve requirements

Next, the impact of VER variability on reserve requirements is studied. Fig. 10 and 11 show the load following and ramping reserve requirements for different variabilities. These graphs reveal important aspects of VER variability impact on the reserve requirements. First, the graphs have different imbalance levels in the absence of reserves, which shows that the imbalances are smaller for the system with smaller variability. Second, the graph with smaller variability reaches the saturation level sooner, which indicates that the systems

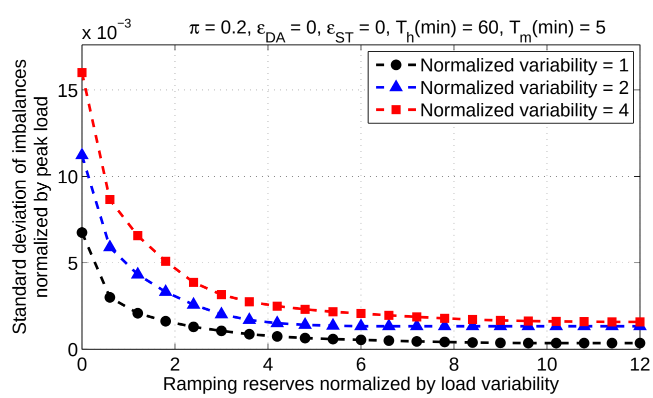

Fig. 11. Impact of VER variability on the ramping reserve requirements

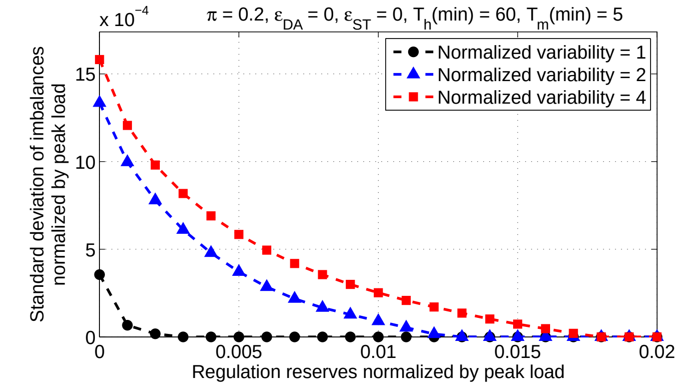

Fig. 12. Impact of VER variability on the regulation reserve requirements

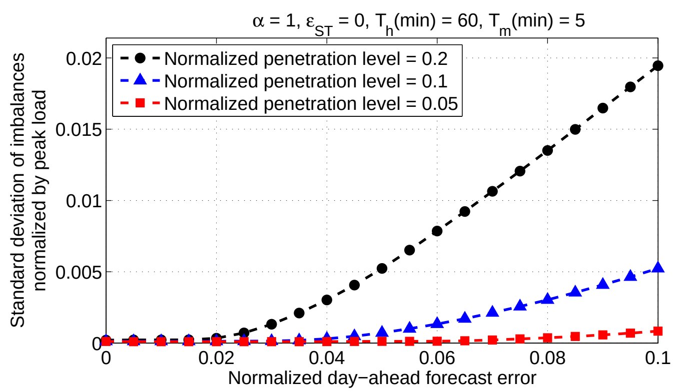

Fig. 13. Impact of VER day-ahead forecast error on the power system imbalances

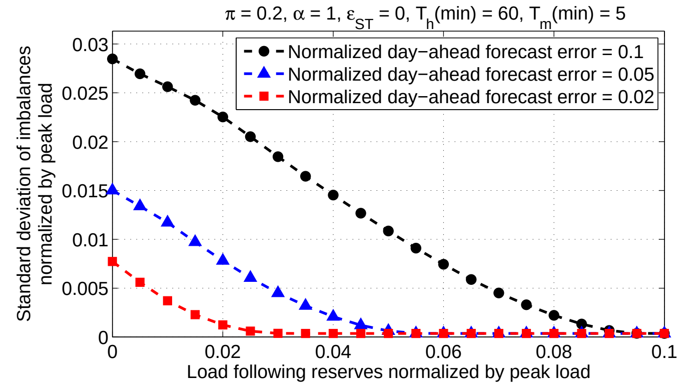

Fig. 14. Impact of VER day-ahead forecast error on the load following reserve requirements

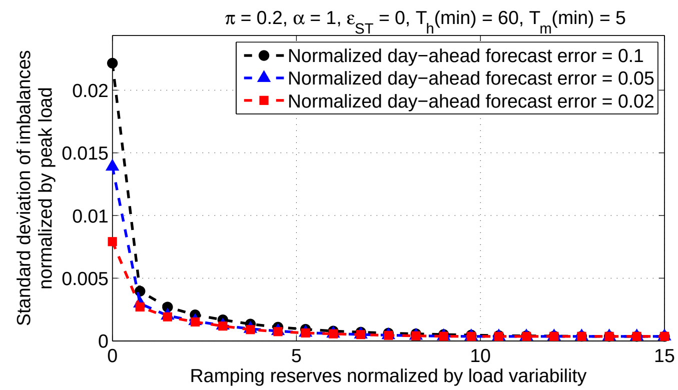

Fig. 15. Impact of VER day-ahead forecast error on the ramping reserve requirements

with less variability require less load following and ramping reserves. Third, the saturation level for the system with less variability is lower, which means that high variability increases the fast imbalance and the regulation reserve requirement, which is demonstrated in Fig. 12. As expected, the system with less variability goes to saturation sooner, which means that it has smaller regulation reserve requirement.

D. Impact of VER Day-Ahead Forecast Error on Power System Imbalances and Reserve Requirements

The day-ahead forecast error impedes the match of scheduled resources to real-time demand fluctuations and, hence, contributes to the slow imbalance term. As described above, both load following and ramping reserve requirements depend on the day-ahead forecast error, while the regulation reserve operate at a smaller timescale.

To this end, four simulations are performed, where the first one studies the impact of the VER day-ahead forecast error on the power system imbalances, while the other three study the impact of the VER day-ahead forecast error on each type of reserve requirements. Fig. 13 shows the change of the power system imbalances as the VER day-ahead forecast error increases for three values of the normalized penetration level: 0.05, 0.1 and 0.2. According to the definition of the VER day-ahead forecast error, increasing the VER penetration level also increases the introduced total day-ahead forecast error. As a result, increasing the VER penetration level and increasing the VER day-ahead forecast error have equivalent impacts on power system imbalances. The curves in Fig. 13 start from the same level and start to diverge as the VER day-ahead forecast error increases. The graphs show that higher levels of imbalances corresponds to higher day-ahead forecast error, which indicates that in the presence of day-ahead forecast error the adequacy of the existing reserve requirements is challenged.

Next, the impact of VER day-ahead forecast error on each type of reserve requirements is studied. Fig. 14 and 15 show the load following and ramping reserve requirements for three values of normalized VER day-ahead forecast error: 0.02, 0.05 and 0.1. The curves in Fig. 14 reach saturation for different values of load following reserves, which shows that the system with higher VER day-ahead forecast error have higher load following reserve requirement. In contrast, Fig. 15 shows that the ramping reserve requirements are affected by the day-ahead forecast error only slightly. This is because the day-ahead forecast error appears in the ramping reserve scheduling process in a differential form. Also, for both figures, the graphs have different imbalance levels in the absence of reserves, which shows that the imbalances are inherently smaller for the system with smaller day-ahead forecast error. Moreover, all three graphs have the same saturation level, which means that the fast imbalance is not affected by the day-ahead forecast error. This phenomenon is clearly demonstrated in Fig. 16,

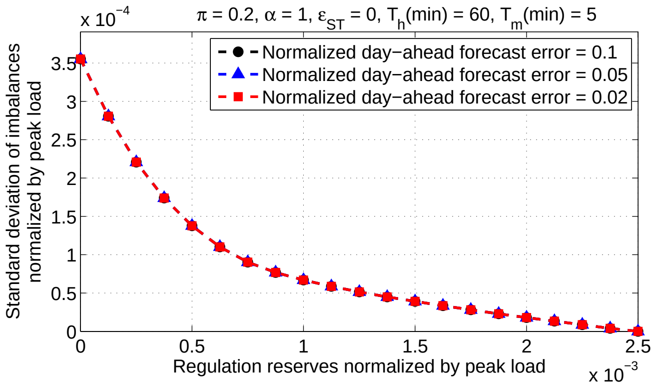

Fig. 16. Impact of VER day-ahead forecast error on the regulation reserve requirements

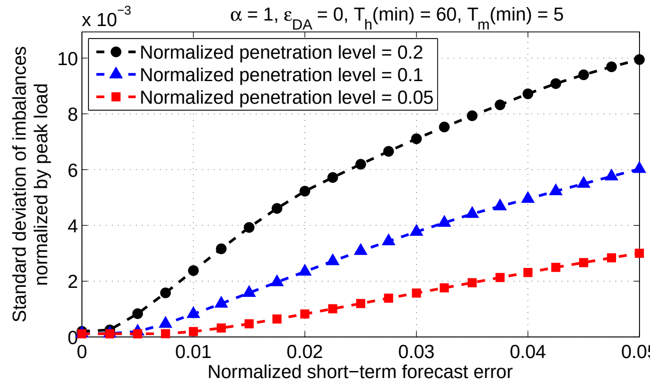

Fig. 17. The impact of VER short-term forecast error on the power system imbalances

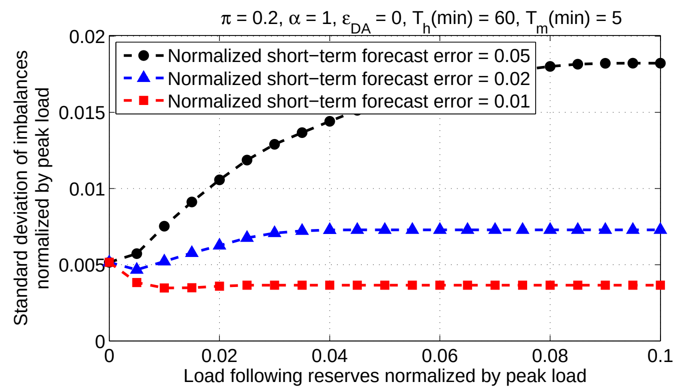

Fig. 18. The impact of VER short-term forecast error on the load following reserve requirements

where all three graphs replicate each other identically. As expected, the regulation reserve requirement is the same for all three values of the day-ahead forecast error. In all, Fig. 14-16 show that mitigation of the day-ahead forecast error potentially reduces the load following and ramping reserve requirements. This suggests that investments to improve forecasting technology can be directly weighed against the value of the required reserves.

E. Impact of VER Short-Term Forecast Error on Power System Imbalances and Reserve Requirements

The short-term forecast error creates a mismatch between the dispatched resources and the real-time demand fluctuations and, hence, contributes to the fast imbalance term. As described above, dispatching of the generation is affected be the short-term forecast error, while the load following and ramping reserves operate at a slower timescale and should be able to avoid the impact.

To this end, four simulations are performed, where the first one studies the impact of the VER short-term forecast error on the power system imbalances, while the other three study the impact of the VER short-term forecast error on each type of the reserve requirements. Fig. 17 shows the change of the power system imbalances as the VER short-term forecast error increases for three values of the normalized penetration level: 0.05, 0.1 and 0.2. According to the definition of the normalized short-term forecast error, increasing the VER penetration level increases the introduced total short-term forecast error. As a result, increasing the VER penetration level and increasing VER normalized short-term forecast error have equivalent impacts on power system imbalances. The curves in Fig. 17 start at the same level and start to diverge as the short-term forecast error increases. The curves show that higher imbalance level corresponds to higher short-term forecast error, which indicates that increasing short-term forecast error challenges the adequacy of the existing reserve requirements.

Next, the impact of VER short-term forecast error on each type of reserve requirements is studied. Fig. 18 and 19 show the load following and ramping reserve requirements for three normalized short-term forecast errors: 0.01, 0.02 and 0.05. The resulting curves are potentially counter-intuitive but entirely explainable. The conventional wisdom is that adding load following and ramping reserves *always* improves power system imbalances regardless of the short-term forecast error. However, this is not always true. In the absence of load following or ramping reserves, the system has no flexibility and the generation units follow the schedule defined in the day-ahead market. In this case, only the slow imbalance term exists, which is relatively small in the absence of the day-ahead forecast error. However, as the load following and ramping reserves are added to the system, the generation units'

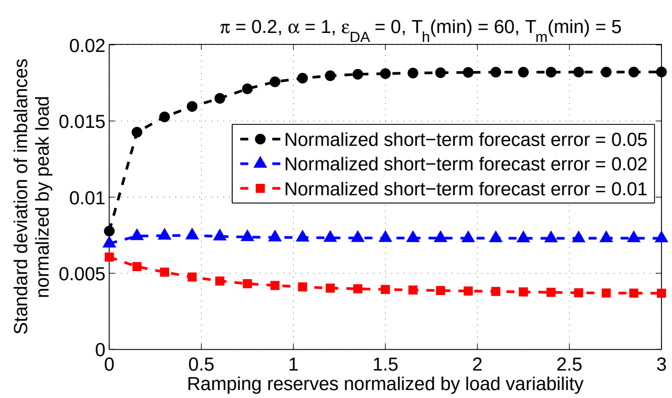

Fig. 19. The impact of VER short-term forecast error on the ramping reserve requirements

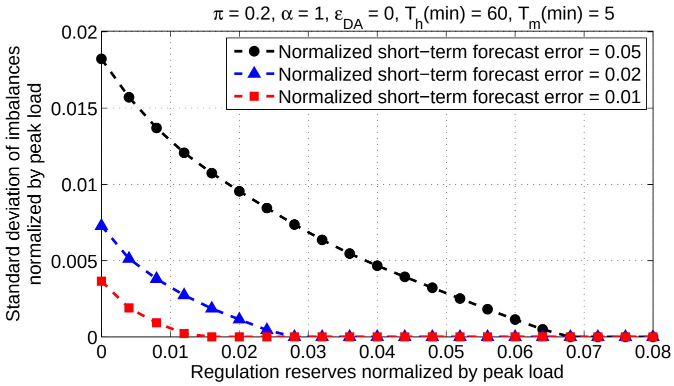

Fig. 20. The impact of VER short-term forecast error on the regulation reserve requirements

added flexibility wrongly track the erroneously forecasted net load. The fast imbalance term accordingly increases in value, which eliminates all the benefits from mitigation of the slow imbalance term. Such a scenario, however, is purely academic. In these simulations, the day-ahead forecast error has been neglected so as to reveal how and why imbalances occur. In practice, presence of the short-term forecast errors also guarantee day-ahead forecast error. And in such a scenario, the load following and ramping reserves would only improve the system balance.

Since neither load following nor ramping reserves are able to mitigate the imbalances in the case of short-term forecast error, the regulation reserves are the only solution. Since the short-term forecast error creates imbalances when the generators ramp from the current level to the new dispatched value, it is expected that increasing amount of regulation reserves should mitigate the imbalances in this scenario. Fig. 20 shows the impact of increasing the regulation reserves on the imbalances of the power system for three different values of short-term forecast error. The curves show that higher short-term forecast error leads to higher regulation reserve requirement. In all, Fig. 18-20 show that mitigation of the short-term forecast error potentially reduces the regulation reserve requirement. This suggests that investments to improve the forecasting technology can be directly weighed against the value of the required reserves.

To conclude, this study showed how the impacts of the power system variables, namely day-ahead market time step, real-time market time step, VER variability, day-ahead forecast error, and short-term forecast error, could be objectively measured and compared in regards to power system imbalances and reserve requirements. The simulation results show that decreasing day-ahead market time step decreases the load following and ramping reserve requirements with no corresponding impact on the regulating reserves. In contrast, decreasing real-time market time step decreases the regulation reserve requirements with no corresponding impact on the load following and ramping reserves. These reductions suggest that an enterprise control methodology could be used to make trade-off decisions of required reserves and market duration time step. The third parameter under consideration, VER variability, spans over all timescales and consequently required more reserves of all types. Finally, the day-ahead forecast error affects a slower timescale leading to increased load following and ramping reserve requirements. In contrast, the short-term forecast error operates in a faster timescale and increases the regulation reserve requirement. These results suggest that investments to improve the forecasting technology can be directly weighed against the value of the required reserves.

V. Conclusion

This paper has used a novel methodology based upon the concept of enterprise control to assess variable energy resource induced power system imbalances and their associated reserve requirements. The methodology's distinguishing feature is its holistic simulation-based approach; which in some cases provides highly intuitive results while in others much less so. To that effect, this study showed how the impacts of the power system variables could be objectively measured and compared in regards to power system imbalances and required reserves. While other integration studies make similar conclusions, this study is unique in that it shows by simulation the proper breakup of reserves and the points at which greater reserves do not further mitigate system imbalances. The study also showed the impact of forecast errors on system imbalances. In all, the study showed that a holistic enterprise control methodology is an effective approach to understanding the perpetuation and mitigation of imbalances at successively faster timescales. In terms of industrial adoption, the alternative to this approach is to return to analytical methods that simulate each control layer independently or as in renewable energy integration studies statistical approaches based upon questionable assumptions [22].

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Aramazd Muzhikyan received his Sc.B and Sc.M degrees from Yerevan State University, Yerevan, Armenia, in 2008. He completed his second Sc.M degree at Masdar Institute of Science and Technology, Abu Dhabi, U.A.E, in 2013. He is currently a research assistant in the department of Engineering Systems and Management at Masdar Institute of Science and Technology. His research interests include signal processing, power system optimization, power system operations and renewable energy integration.

Amro M. Farid received his Sc.B and Sc.M degrees from MIT and went on to complete his Ph.D. degree at the Institute for Manufacturing within the University of Cambridge Engineering Department in 2007. He is currently an assistant professor of Engineering Systems and Management and leads the Laboratory for Intelligent Integrated Networks of Engineering Systems (LI^{2}NES) at Masdar Institute of Science and Technology, Abu Dhabi, U.A.E. He is also a research affiliate at the Massachusetts Institute of Technology – Technology and Development Program. He maintains active contributions in the MIT Future of the Electricity Grid study, the IEEE Control Systems Society, and the MIT-MI initiative on the large-scale penetration of renewable energy and electric vehicles. His research interests generally include the system architecture, dynamics and control of power, water, transportation and manufacturing systems.

Kamal Youcef-Toumi joined the MIT Mechanical Engineering Department faculty in 1986. He earned his advanced degrees (M.S. 1981 and Sc.D. 1985) in Mechanical Engineering from MIT. Professor Youcef-Toumi's research has focused primarily on design, modeling, simulation, instrumentation, and control theory. The applications have included manufacturing, robotics, automation, metrology and nano/biotechnology. He teaches courses in the fields of dynamic systems and controls; robotics; and precision machine design and automatic control systems. He is the Co-Director of the Center for Clean Water and Clean Energy at MIT and KFUPM.