Influence of Renewable Integration on Frequency Dynamics

Mei Li, *Student Member, IEEE* James D. McCalley, *Fellow*, IEEE

Abstract—**Southern California Edison (SCE) is planning to integrate more than 7 GW renewable into their grid by year 2020. As transmission operator, they need to know whether their system can handle this big amount of renewable without compromising system frequency stability. Wind and solar generators connect to power grid via power electronics converters; they are not supplying system with inertia or governor response, which is different with traditional synchronous generators. The influence of renewable generations on system frequency control is investigated in this paper, including reduced inertia and primary control. Besides this, the interaction between frequency stability and voltage stability is analyzed including load modeling characteristics. The ramp down of renewable is studied together with loss of one big plant. Simulation results are demonstrated to validate the analysis. Suggestions for future research and studies will be identified.**

***Index terms*--Grid frequency response; reduced inertia; primary control;renewable generation; wind and solar power**

I. INTRODUCTION

The state of California has Renewable Portfolio Standards (RPS) requirements of 33% of renewable generation by year 2020 [1]. At the same time, another mandate is created by the California State to retire or re-power the generation in the coastal regions which are equipped with Once Through Cooling (OTC) technology by the year 2015 [2]. These resources' shortage will be compensated mostly by the wind, solar and other renewable generation in the California area to meet the state's RPS requirements. Being close to the load centers, these OTC units are providing big amount of active and reactive power support. Whereas, most of the bulk wind and solar generation are planned in the Mohave Desert and Tehachapi area, which are quite far away from the major load centers. These renewable units do not currently participate in system frequency control while the total ratio of units with this capability is decreasing relatively. When more thermal units retire or are replaced by renewable units, system inertia and governor response will decrease accordingly.

To get ready for this future trend, complete study is undergoing to identify potential problems which might come with integration of the big amount of renewable. This study assessed three significant changes to the Southern California Edison (SCE) bulk transmission and generation system including retirement of the once-through-cooling (OTC) units located along the Southern California coast, increase of wind energy resources in the Northeast region, and increase of solar resources in the Eastern region. This study was motivated by the concern that these changes would result in occurrence of one or more problems under normal or contingency conditions: circuit overload, voltage magnitude violation, voltage instability, transient instability, oscillatory instability, and frequency dip violation. This paper will focus on frequency stability study. In part II, power system frequency basics are introduced. Frequency dynamics under different system conditions is studied in part III with analysis of results. Interaction between frequency stability and voltage stability are analyzed in part IV. In part V, Ramp down of renewable are discussed. Conclusion is given in VI.

II. POWER SYSTEM FREQUENCY CONTROL

The maintenance of power balance occurs at five different levels with each one corresponding to a different time frame, as indicated in Table I, where we observe that the first three of those levels are concerned with power balance and frequency control[3], and the last two are concerned with power balance and economics. The first three control levels are sometimes referred to as MW-frequency interactions.

TABLE I
SUMMARY OF POWER BALANCE CONTROL LEVELS

No.	Control Name	Time frame	Control objectives	Function
1	Inertial response	0-5 secs	Power balance and transient frequency dip minimization	Transient frequency control
2	Primary control, governor	1-20 secs	Power balance and transient frequency recovery	Transient frequency control
3	Secondary control, AGC	4 secs to 3 mins	Power balance and steady-state frequency	Regulation
4	Real-time market	Every 5 mins	Power balance and economic-dispatch	Load following and reserve provision
5	Day-ahead market	Every day	Power balance and economic-unit commitment	Unit commitment and reserve provision

This work was supported by the Southern California Edison under Grant BS123.

The authors are with the Department of Electrical and Computer Engineering, Iowa State University, Ames, IA 50010 USA (e-mail: meili@iastate.edu; jdm@iastate.edu).

978-1-4673-2729-9/12/$31.00 ©2012 IEEE

There are four attributes of the power system which dictate the frequency performance:

- Contingency: Size of the disturbance in terms of MW imbalance; Amount of reactive resources lost as a result of the disturbance, subsequent voltage decline, and resulting impact on load via the voltage sensitivity of the load.
- Total amount of inertia in the interconnection, in units of MW-seconds.
- Primary control: Total amount of generation in the interconnection having primary control capability, in MW; Response characteristics of speed governors.
- Load characteristics: Frequency sensitivity and voltage sensitivity of the load.

A. Power-frequency basics

In the case of the synchronous turbine-generator, synchronous speed for each machine is set by the network frequency of 60 Hz. We see that as long as the mechanical torque applied to the turbine equals the electromagnetic torque applied to the shaft by the synchronous generator, the machine will not change its speed and the network frequency will not increase or decrease, respectively. Because power is torque times radial frequency, the above mentioned torques are directly proportional to the corresponding powers, assuming frequency deviations from 60 Hz are not large. Thus, for a constant mechanical power input to the turbine, the shaft speed (and thus the frequency) will change as the electrical demand on the generator changes. There are three power-frequency basic ideas to discuss.

1) Inertial effect: For a given instantaneous change in electric demand seen by the generator, the amount of acceleration is inversely proportional to the inertia of the machine, i.e., the greater the inertia, the less acceleration will be observed and the less will be the frequency deviation. Inertia is proportional to the total rotating mass of the turbine, generator, and shaft.

2) Primary control: Most synchronous generators have primary control, which senses shaft speed, proportional to frequency, and modifies the mechanical power applied to the turbine to respond to the sensed frequency deviations. When a power imbalance occurs as a result of a generator outage somewhere in the network, the frequency decline is arrested and partly restored by the actions of the primary frequency control.

3) Aggregation: Because variation in frequency dynamics from one network location to another is extremely fast, the network frequency is practically the same throughout the interconnection during the time period of interest for transient frequency performance. This means that all machines see almost the same frequency variation. As a result, for purposes of frequency assessment, the inertial and primary governing dynamics may be aggregated into a single machine, as shown in Fig. 1.

It means that the 0 to 20 second frequency transients are interconnection wide, i.e., they are not constrained by balancing area boundaries (as is frequency regulation which is performed by AGC). The frequency transient that is seen in Los Angeles is also seen in Vancouver, Phoenix, and Denver. As a result, effects of inertial and primary control reductions in the SCE area are not dictated by their percentage of total SCE inertia but rather by their percentage of total WECC inertia and governing capability.

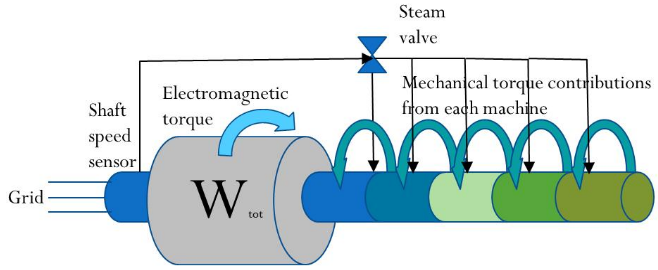

Fig. 1. Aggregated machine

B. Inertia and primary control from solar and wind

Solar photovoltaic (PV) and wind plants are unique resource types for bulk transmission systems because, unlike traditional synchronous generators, they are controlled on the mechanical and the electric side, i.e., the power into the machine and the power out of the machine is controlled[4,5]. This is in contrast to the traditional synchronous generator which controls only the mechanical power into the machine. (It should be recognized that solar thermal, which utilizes a conventional steam turbine, is excluded from this characterization, i.e., it can be thought of, for purposes of frequency dynamics, as a traditional synchronous generator.) This control paradigm is easy to conceptualize for solar PV since there is a full converter interface between the resource and the grid. This control paradigm for the most common type of wind turbine today, the double-fed induction generator (DFIG), is illustrated in Fig. 2 at the bottom and compared to the control paradigm of the traditional synchronous generator at the top [6].

The wind turbine can control the output mechanical power applied to the generator through pitching the blades. Therefore pitching the blades is analogous to steam flow control in a steam turbine. This control capability in each machine is connected via a dashed line in the middle portion of Fig. 2. Whereas the steam turbine has the additional power control capability at the fuel input (indicated by a dark snaked arrow at the top of Fig. 2), which the wind turbine does not have, the wind turbine has power control capability at the generator output (indicated by a dark snaked arrow at the bottom of Fig. 2), which the steam turbine does not have. Control of the generator power output is performed via control of the d-axis component of the rotor current.

The ability to control mechanical power into the generator using pitch control and generator power output using rotor current control enables avoidance of deviation between mechanical power in and electrical power out and, therefore, also avoidance of rotor deceleration under network frequency decline. This means DFIGs contribute no inertial energy during under-frequency conditions.

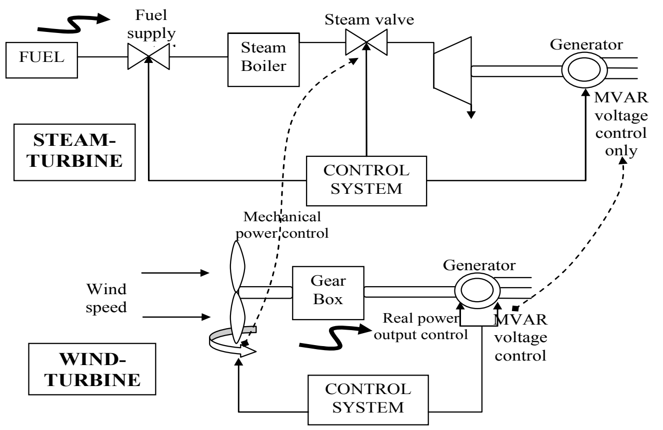

Fig. 2. Control Scheme of DFIG compared with synchronous generator

C. Relation between inertia and frequency dips

An expression for rate of change of frequency (ROCOF) following a MW load increase (or equivalently, a generation decrease) of ΔP_L is derived in the equation (1), given below:

$$\frac{d\,\overline{\Delta f}}{dt} = \frac{-\Delta P_L f_{\mathrm{Re}}}{2\sum_{i=1}^{n} H_i} \equiv m_f \qquad (1)$$

Where the summation in the denominator is the total inertia normalized by the system MVA base, in seconds. If DFIGs and solar PV displace conventional generators in the generation commitment schedules, the denominator of (1) will decrease, and as a consequence, the ROCOF will increase. This results in lower (greater) transient frequency dips under large-scale generation outages. This is of concern because the WECC imposes constraints [7] on maximum frequency dip, as indicated by Table II. At the same time, we also need to satisfy NERC stability criteria[8], which doesn't allow any load-shedding following category B events.

TABLE II
WECC REQUIREMENTS FOR TRANSIENT FREQUENCY PERFORMANCE

Performance Level	Disturbance	Transient Voltage Dip Criteria	Minimum Transient Frequency
B	Generator One Circuit One Transformer PDCI	Max voltage dip - 25% Max duration of voltage dip not exceeding 20% - 20 cycles. Not to exceed 30% at non-load buses.	59.6 Hz for 6 cycles or more at a load bus.
C	Two Generators Two Circuits IPP DC	Max voltage dip - 30% at any bus. Max duration of voltage dip exceeding 20% - 40 cycles at load buses.	59.0 Hz for 6 cycles or more at a load bus.

III. SIMULATION RESULTS AND ANALYSIS

Peak case with maximum amount of solar power and off-peak case with maximum amount of wind are studied. Coastal plants are retired. Contingencies which might cause big frequency dips are considered, like loss of biggest units. Tripping two or three large generating units at a power station causes a substantial frequency excursion on the WECC system. While this multi-unit event of 4,200 MW loss is beyond normal design basis events (e.g., NERC type B and C), it is possible to happen. This event was used for the examination of frequency response.

A. lower inertia in SCE area

First, we consider the situation that there are 33% renewable added into the SCE power system in the 2020 year's case. At the same time, OTC units in the coastal area are retired. The overall changes cause about 17% inertia reduction in SCE area. When system looses two biggest generating units (about 2800MW generation in total), frequency response is shown in Fig. 3.

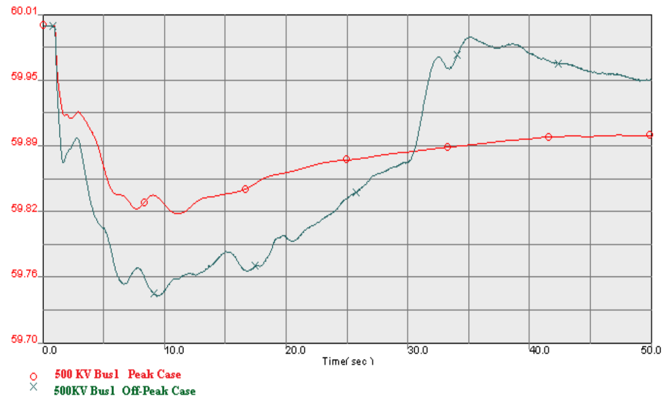

Fig. 3. Loss of two biggest generation units for peak and off-peak case

From Fig. 3, we can see that system frequency nadir reaches about 59.82 Hz for peak case and about 59.74Hz for off-peak case. This is because off-peak case has much less inertia than peak case. The criterion of frequency under loss of 2 units is 59.0 Hz for 6 cycles. For loss of one biggest unit, the frequency response is much better than the response of loss of 2 biggest units. There is no load-shedding happen for loss of one biggest unit. It indicates that system is very safe when there is 33% renewable added into only SCE area. A sudden frequency jump happens at about 30s for off-peak case and it is caused by low frequency load shedding.

B. Lower Inertia in WECC area

As shown above, system frequency is safe when loosing 2 biggest units. Now instead of only reducing inertia in SCE area, WECC system's inertia is reduced by 17% and the contingency is loss of 3 biggest generating units (about 4200MW generation).

The results are shown as Fig. 4 and Fig. 5. For both peak and off-peak cases, the lower inertia causes steeper drop of system frequency and reaches lower nadir. Without load-shedding, frequency is able to return to 59.82Hz for peak case. Because of shedding of loads, frequency is able to return to around 59.90 for off-peak case.

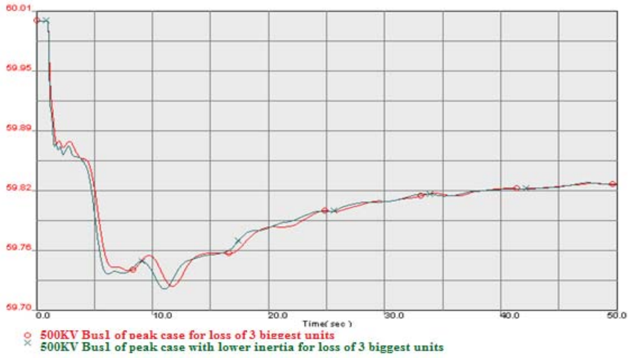

Fig. 4. Circle is Peak Case, Star is peak case with lower inertia

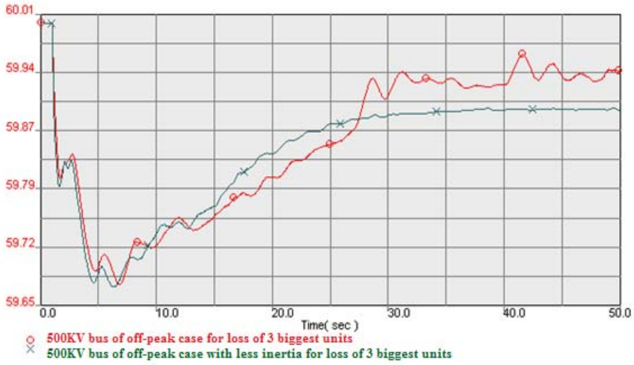

Fig. 5. Circle is off- Peak Case, Star is off-peak case with lower inertia

C. Less Governor system's response to loss of 3 biggest units

As we discussed in section II, inertia response and primary control (governor response) are the two key factors influencing frequency dynamics. To see primary control's contribution to frequency dynamics, we reduced the available reserve in the system, which is the headroom generators can spin up to support generation loss in contingency. The difference between the two curves in Fig. 6 and Fig. 7 shows that when system has less primary control, it has lower nadir and returns to a lower post-contingency frequency.

Fig. 6. Circle is peak case; Star is peak case with less governor control

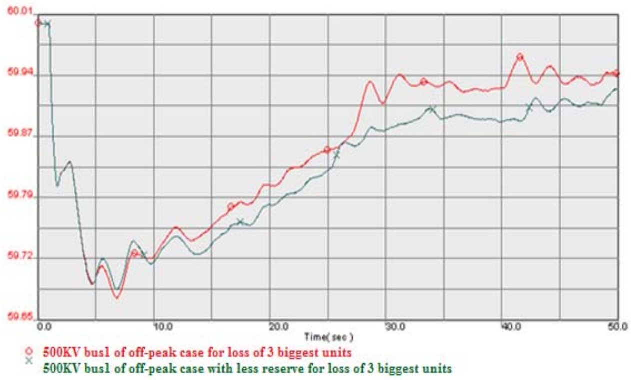

Fig. 7. Circle is off-peak case, Star is off-peak case with less governor control

D. Lower-Inertia and Lower-Governor Control

Now both the system inertia and governor control are reduced at the same time. The simulation results are given in Fig.8. It is telling that when system's inertia and governor control both decrease, frequency will be influenced to have lower nadir and lower steady state value. Inertia plays the main role at first 1-4 seconds and then governor starts to dominate the effect in the following 10-20 seconds.

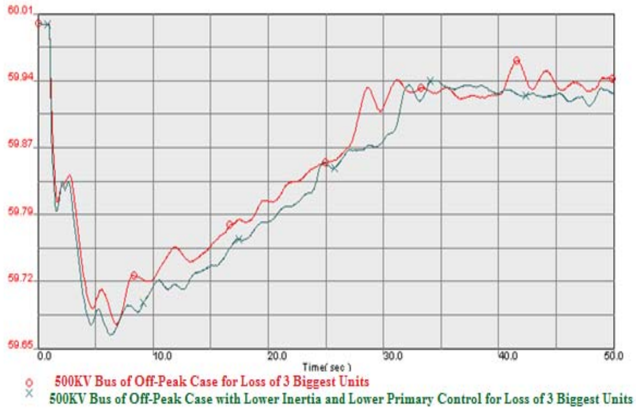

Fig. 8. Frequency following loss of 3 biggest units for off-peak cases: Circle is off-peak case; Star is off-peak case with less inertia and less governor control.

IV. INTERACTION BETWEEN VOLTAGE STABILITY AND FREQUENCY STABILITY

Frequency performance for loss of two large units (about 2000MW in total) near load center draws our attention and its result is shown in Fig. 9. The lower inertia case performs better (has higher frequency nadir) than the normal case.

This counter-intuitive result occurs because of interaction between the loss of the reactive resources of these two big units and the voltage-sensitive loads. Because these two units are such a large (550 MVARs per unit) reactive resource, dropping them results in significant voltage decline throughout the SCE area which in turn causes lower real power consumption for the loads having constant impedance or constant current representation. The lower real power consumption of the load partially counteracts the real power imbalance caused by the loss of these two units, thus causing less severe frequency decline. On the other hand, the normal peak case response is more severe (lower in frequency nadir) because the coastal plant reactive resources, which are not available in lower inertia case, tend to arrest the voltage decline, and the real power consumption of the load does not change much, resulting in an “effective” generation drop that exceeds the one of lower inertia case for the same loss of two big units contingency.

Fig. 9. Frequency at 500kV bus, blue circle curve for peak case, purple star curve for peak case with less inertia.

The above analysis is verified by comparing loss of both units at lower inertia case with and without an SVC installed near the generator bus which causes reactive power shortage. The results of frequency and voltage at a 500KV bus are shown in Fig.10 and Fig.11. It is clear that the reactive resource makes the voltage level higher than that in the case without SVC, which causes frequency nadir much lower than the case without SVC. This is showing that load modeling has significant affect on dynamic analysis. The load combination of SCE area has about 40% of load being modeled as constant impedance or constant current load. This is consistent with what we have observed from simulation results.

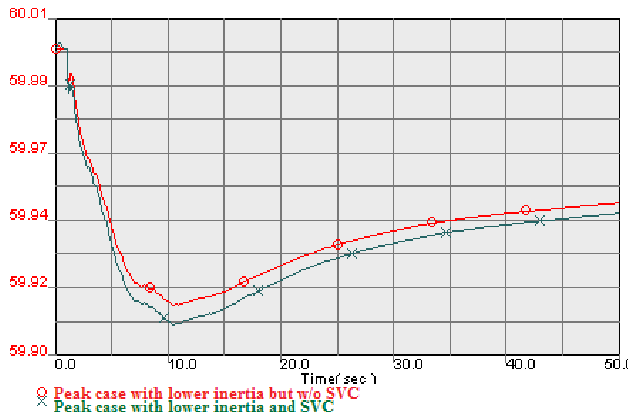

Fig. 10. Frequency at 500kV bus, green Star is peak case with SVC and red circle is peak case without SVC

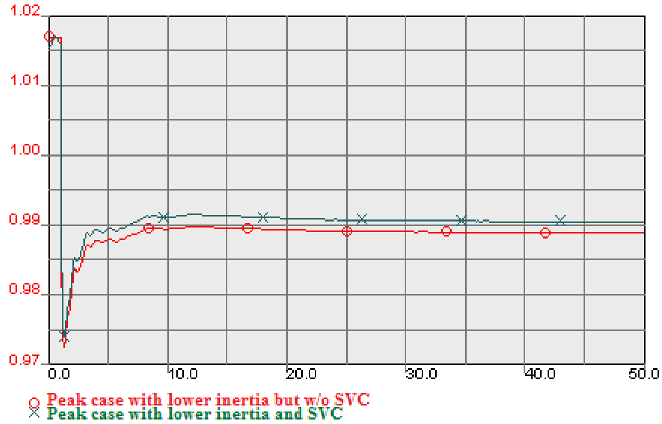

Fig. 11. Voltage at 500kV bus, green Star is peak case with SVC and red circle is peak case without SVC

V. RENEWABLE RAMP DOWN TOGETHER WITH LOSS OF ONE LARGE GENERATOR

When system has big amount of renewable, it is necessary to consider the situation when there is a big amount of fast ramp down of renewable generation [9]. The variability of wind and solar power can be very high and fast at special circumstances [10]. Depending on the aggregation level and geographic diversity, solar plants output can decrease/increase within a range of 20%-80% of its capacity while wind plants can vary within a range of 5%-30% of its capacity at 1 min time interval [11,12]. In this section, we will see the effect of this ramp down together with loss of one biggest unit. Load shedding is disabled to see frequency response without support from load decrease. Simulation is run on peak case. There is a fast ramp down of about 3300 MW renewable (about 40% of total capacity) and loss of one biggest generating unit (about 1400 MW). This ramp down of renewable is a very extreme case which might happens in real world, so it worth to see its possible impact on frequency stability.

The results are shown in Fig.12 and Fig.13. For 500KV bus, the frequency is close to but still above 59.60Hz for the case with lower inertia and lower governor under losing 1 biggest unit. But for some load buses, the frequency is below 59.6 Hz for more than 6 cycles (0.1s) as shown in Fig.13.

Fig. 12. Frequency on 500kV bus1for peak case

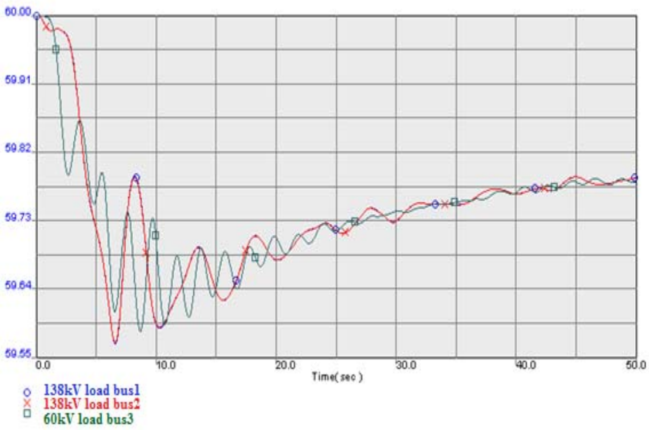

Fig. 13. Frequency on different load buses (Ramp down renewable and loss of 1 biggest unit with lower inertia and lower governor)

If we treat ramp down of renewable and loss of 1 large generating unit as a Category B disturbance, then this case violates the WECC standard as shown in Table I. If we keep automatic load shedding in dynamic data, the frequency will be within limits but load shedding will happen, which also violates the NERC criteria [8]. But we need to nice that this event rarely happens in real world, which might not be certified as Category B event.

VI. Conclusion

This above exploration of frequency performance tries to see the influence of the integration of 33% renewable at SCE area. In the first few seconds following a loss of large generating plants, the frequency excursion is affected by the inertial response of the on-line generation. The longer-term frequency response and recovery is dominated by the governor response of the committed synchronous machines. From this study, we see that reduced inertia and less primary control together degrade frequency response with lower nadir and lower restoration level. Simulation results shows that frequency dynamics are still within WECC transient stability criteria for loss of 3 biggest units for case with lower inertia and lower governor control, which is the possible worst condition. This is telling that renewable integration has adverse effect on frequency stability margin, but the influenced margin is still within safe range. When considering fast ramp down of renewable together with loss of one biggest unit, some load bus's frequencies violate category B standard, but this situation is not as frequent as normal category B contingency. So new definition for stability criteria of power system is necessary to include this situation. As the variability of renewable generation is causing frequency deviation, there is more work need to be done to access system frequency performance at longer time frame, like NERC control performance standards (CPS)-CPS1 and CPS2 [13]. The system operation methodology, including unit dispatch and commitment, are also critical to understanding the ramping impact of renewable generation. In our study, renewable generation like wind and solar generations is not supporting system frequency as thermal units. But they do have the capabilities like inertia emulation and primary frequency control if special control schemes are applied [14, 15]. So the contribution from renewable, like wind turbine and solar plant, can also be explored to improve system's frequency dynamics with proper additional control.

VII. Acknowledgment

Authors are grateful to Mr. Shimo Wang, Mr. Farrokh Habibiashrafi, Mr. Phillip Leung, and Mr. C. J. Jing at Southern California Edison (SCE) for their expert guidance on the study.

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IX. Biographies

Mei Li (S'09) received the B.E. degree in Electrical Engineering from Tsinghua University, China, in 2005, M.S. in EE from Graduate University of Chinese Academy of Sciences in 2008, and is pursuing her PhD in Electrical engineering with major concentration in Power System from Iowa State University. Her research interests include operational impacts of intermittent renewable generation, power system transmission reconfiguration and power system economics and optimization.

James D. McCalley (F'03) received the B.S., M.S., and Ph.D. degrees from Georgia Tech, Atlanta, in 1982, 1986, 1992, respectively.

He is a Professor of electrical and computer engineering at Iowa State University, Ames, where he has been since 1992. He was with Pacific Gas & Electric Company, San Francisco, from 1985 to 1990. Dr. McCalley is a registered Professional Engineer in California.