White Paper:

Low Carbon Grid Study:

Discussion of Dynamic Performance Limitations in WECC

Prepared for: **California 2030 Low Carbon Grid Study**

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Imagination at Work

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Foreword

This paper was prepared by General Electric International, Inc. acting through its Energy Consulting group based in Schenectady, NY, and submitted to the California 2030 Low Carbon Grid Study. Questions and any correspondence concerning this document should be referred to:

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1 INTRODUCTION

The California 2030 Low Carbon Grid Study (LCGS): Phase I study explores the ability of California's electricity system to support deep emissions reductions by the year 2030. The study is based on PLEXOS production cost model simulations performed by the National Renewable Energy Laboratory (NREL), and shows that California's grid can reduce the state's greenhouse gas emissions from the electricity sector to 50% below 2012 levels by 2030. Large power grids must successfully negotiate all of the variations that occur, many of which are beyond the control of system operators. A wide range of simulation tools are used by system planners to determine how the system should behave. Properly designed production simulations capture the impacts associated with seasonal, weekly, daily, hourly and some subhourly variations and constraints on operation. Heat rates, hydrology, fuel consumption, ramps and a spectrum of other real-world limitations, such as the time, cost and emissions associated with starting and stopping, are all reflected in the production simulation model used for Phase I of the LCGS. This class of analysis is essential to good fidelity determination of emissions and variable cost impacts of changes in generation, load and grid portfolios [1].

But successful production simulations, while being a necessary part of system planning, alone are not sufficient to assure successful operation under all conditions. Acceptable dynamic performance of the grid in the fractions of a second to one minute following a large disturbance (e.g., loss of a large power plant or a major transmission line) is critical to system reliability. Thus, there is a need to analyze the dynamic behavior of systems under high variable renewable conditions. The Western Interconnection, in particular, has a long history of dynamic performance constraints on system operation—so any dynamic performance changes due to increased wind and solar generation could have substantial impact on all aspects of renewable integration. Phase I of the LCGS does not include such analysis. This paper complements the Phase I (and Phase II) analysis by providing discussion based on other recent work that provides quantitative insight to the potential dynamic implications and limitations for California and the Western Interconnection under this low carbon scenario. Of particular relevance is the recently completed Western Transient Stability and Frequency Response Study, Phase 3 of the Western Wind and Solar Integration Study (WWSIS-3) [2] which examined the large-scale transient stability and frequency response of the Western Interconnection with wind and solar penetration at levels similar to those of Phase I of the LCGS. That study included investigation of means to mitigate any adverse performance impacts via transmission reinforcements, storage, advanced control capabilities, or other alternatives. That study evaluated a variety of system conditions, disturbances, locations, and renewable penetration levels to help draw broader conclusions from an analysis of two specific types of power system dynamic performance: frequency stability and transient stability. A technical definition of these aspects of power system stability is provided in the WWSIS-3 executive summary [3]. Discussion of dynamic performance for the LCGS is provided in the following sections.

2 FREQUENCY RESPONSE

Frequency Response Obligation. To reliably operate a large, interconnected power grid such as the Western Interconnection requires a constant balancing of electricity generation with electricity demand. Electricity must be generated at the same instant it is used. In order to address this, operating procedures have developed to forecast electricity demand, schedule electric generators to meet that demand, and ensure sufficient generating reserves are available to respond to forecast errors and system disturbances. The measure of success in this balancing act is frequency.

However, disturbances do occur, including large ones that affect overall system frequency (e.g., abrupt outage of a large generator or a major transmission line). The downward frequency swings that immediately follow such disturbances must be limited by control so that the nadir (the lowest frequency reached after the disturbance) stays above the level that will result in customer interruptions. One key metric of frequency stability is based on the frequency change down to the settling frequency (the quasi-equilibrium reached about half a minute after the disturbance), and the change in power from controlled resources (mostly generators) up to that time. This is called frequency response (FR) and is formally defined by the North American Electric Reliability Corporation (NERC) [4]. There is a new NERC standard [5] that establishes a "Frequency Response Obligation" (FRO) that applies to each balancing authority (BA). Starting in 2016, CAISO will be obliged to assure that their BA has adequate FR, or face penalties. CAISO's obligation is currently on the order of 300 to 400 MW/0.1Hz.

Presently CAISO (and all BAs in North America) are examining their current performance for FR, and determining whether changes are needed to bring them into compliance. Phase I of the LCGS shows that introduction of large amounts of low-carbon resources will tend to displace higher carbon resources that currently supply FR to the grid. Broadly, the question addressed here is "will the need to maintain adequate frequency response in California mandate a minimum level of fossil generation commitment that causes curtailment of renewables, compromising the findings of the LCGS?"

It is useful to examine this question in the context of an ancillary service. While CAISO presently procures regulation and spinning reserve ancillary services, these are not exactly equivalent to FR. California will need mechanisms to make sure that adequate FR services are available. The delivery of services necessary to maintain reliable and compliant performance depends on two separate, but interconnected, requirements: a) resources must be technically able to deliver the service, and b) resources must be willing to deliver the service. This simple observation has profound implications for California: if the traditional sources of FR services are pushed out by low carbon resources, there must be others ways to get the service, and the service needs to be paid for.

Today, California depends solely on synchronous generation to provide all of its FR. The ability of generation resources to provide frequency response requires that (1) they are running and synchronized with the grid, (2) they must have active governors, and (3) they must be dispatched so that they have the ability to increase power output. In order to meet these three constraints, additional thermal generation may need to be committed. When thermal generation is committed, it must run at a minimum power level that is dictated by the turbine capability as well as economic and emissions constraints. Consequently, this minimum power output can lead to an over-generation condition, which is presently managed by curtailment of wind and solar power.

The risk of curtailment in order to provide FR is generally expected to be greatest at low net-load conditions, i.e. either low load, high renewable production or both. These are conditions when imports will be down (or exports up), load shifting technologies (e.g. storage of all types) will be consuming power, and committed generation will tend to have the ability to increase power output. These factors tend to improve opportunities to obtain FR services. However, system inertia will tend to be lower, and committed generation may lack capability to very rapidly increase output. These factors tend amplify the need to have fast acting resources available. By the 2030 date of the LCGS, evolution of California ancillary services and, more broadly, essential reliability services across WECC, will move away from traditional sole reliance on synchronous generation to provide frequency response. The following discussion examines potential resources and strategies to assure adequate frequency response in California and WECC:

New Renewable Generation Resources. Wind and solar generation can contribute to improved frequency response, if required and incentivized to do so. The WWSIS-3 includes a number of simulation cases in which wind, solar photovoltaic generation (PV) or concentrating solar thermal plants (CSP) are equipped with commercially available frequency responsive controls. Those cases, which included inertial and governor-like controls, demonstrated that these controls on renewable plants are very effective at providing frequency response, if instructed and dispatched to do so. These controls were also demonstrated to be highly effective in the California Frequency Response Study [6].

All generation resources incur costs to provide frequency response. Those costs vary widely by resource and system operating condition. Fossil plant owners incur operating costs, in the form of decreased efficiency and wear-and-tear, and opportunity cost for power kept in reserve. For wind and solar PV plants to provide frequency response through governor-like controls, some curtailment is required. The energy lost to curtailment represents a potentially significant opportunity cost to the plant owners. Adequate market mechanisms are needed to assure that frequency response services are offered by generation resources, and that the least cost option is procured.

New Non-generation Resources. New and rapidly growing resources within California, most notably energy storage and demand response (with particular attention to electric vehicles), will be capable of contributing substantially to improved frequency response. Phase I of the LCGS concluded that storage was the primary source of cost-effective ancillary services, and that fossil resources (mainly gas) should either be block-loaded near maximum output for minimum heat rate or not committed at all.

As noted above, the function of frequency response is to arrest the drop in system frequency following a disturbance and to restore it to enough equilibrium that secondary frequency control (aka “frequency regulation” or “automatic generation control – AGC”) can bring the grid back to 60 Hz. The need to arrest the frequency drop places value on the speed of response. In simple terms, a faster acting resource does a better job of “catching” the grid on the way down. This is leading the industry to differentiate response based on speed. ERCOT and others are introducing variations on an ancillary service called “fast frequency response” (FFR). Generally, these are resources that act before the frequency nadir, contributing to the arrest of the frequency drop. Resources like inverter-based energy storage, e.g. battery energy storage systems (BESS), and inverter-based loads, e.g. electric vehicles and aluminum potlines, are especially well suited to providing FFR services.

As wind and solar displace synchronous generation, the WECC grid inertia drops. This increases the initial rate of frequency decline, and increases the value of fast acting frequency responsive resources. The highest level of instantaneous penetration of wind and solar generation in the LCGS for all of WECC is about 45%. For a rough comparison, the WWSIS-3 gave a close examination of one condition that had 53% instantaneous penetration. In that case, fast acting frequency responsive (FFR) resources where added to FR provided by economically dispatched generation. A total of about 400 MW of inverter-based energy storage (e.g. BESS) were added across all of WECC, of which about 120MW where added in California. It was found that the added FFR resources were sufficient to bring all the monitored subsystems of WECC to the level of FR targets by the NERC standard. Other conditions, including those studied in the LCGS, might require more FFR resources than the 400MW in the WWSIS-3 case. However, the LCGS includes an additional 2200MW of synchronous energy storage (pumped hydro and CAES) in California above the baseline case. This suggests that there is enough energy storage in the plan to largely mitigate any frequency response issues that might arise, assuming that the energy storage is enabled and operated in such a fashion to provide FFR services.

The WWSIS-3 case was based on using inverter-based energy storage (e.g. BESS) to provide FFR, but fast acting demand side controls or renewable generation controls would be equally effective. In addition to new and existing energy storage in California for the LCGS, it should be noted that California has many very large water pumping loads, which have historically been controlled resources of last resort for the grid. These could be used as a regular source of FR for California. New storage resources, such as the thermal (ice-making) storage systems that were just procured by SCE [7] should be adaptable to fast response (i.e. triggered shut down).

The Phase I LCGS includes 4.25M EVs in the scenarios tested. Of that EV load, 6.2TWh is “utility controlled”. That represents an average charging load of about 700MW, but during charging periods (when curtailment is a higher risk), the MW load level would be much higher than this. Properly controlled EVs are able to stop charging rapidly. Various researchers have also proposed more sophisticated controls for EVs that could inject power back into the grid under emergency conditions, but so-called V2G capability is not assumed in the LCGS. In order for EVs to provide FFR, very rapid response is required (i.e. on the order of 1 second). Participation of EVs in managing system frequency should be part of California’s overall EV integration strategy.

Discussion of CA Energy Storage Mandate. The CPUC Energy Storage procurement decision [8] includes 3 stated objectives:

1. *The optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investment;*
2. *The integration of renewable energy; and*
3. *The reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California goals*

This mandate clearly provides grounds for use of the energy storage assumed in the study to be applied towards the provision of *any* ancillary service (or more broadly essential reliability service), including FR and FFR. As always with energy storage applications, care must be exercised so that multiple, simultaneous and mutually exclusive benefits are not claimed [9].

Mitigation of Causes of Over-generation. Over-generation is caused by a combination of inability to adequately reduce the power output of synchronized generation combined with requirements to keep units in operation (e.g. in order to meet frequency response, near-term ramping or load serving requirements). Investment in existing (or new) thermal generation to either reduce minimum power (i.e. allow deeper turn-down) or allow units to be decommited at low net load conditions would help relieve over-generation conditions that can lead to curtailment of renewables. The economics of such investment are challenging: plant owners may need to make capital investment in their plants that effectively reduces their sales of energy to the market.

Operational anecdotes from California suggest that not all minimum and/or must-run generation constraints are physical limitations on plants. Many generators within California are self-scheduled. This appears to decouple those generators from the economic and environmental consequences of curtailing wind and solar renewables. Market mechanisms will likely be needed to mitigate this problem, as the constraint is contractual and economic, not just physical. The issue is complex. From the perspective of a low carbon grid, reducing generation from some self-scheduled generation makes little sense. For example, some of these self-scheduled generators are themselves low carbon resources, like geothermal and biomass. Some others are qualifying co-generators, which in many cases encounter emissions limitations when they reduce electricity production or incur high costs for reduced electricity production on the process side of their facilities.

Another apparent major contributor to over-generation in California is imports, and in particular imports that are inflexibly scheduled long before real-time (e.g. day ahead). California has a substantial amount of scheduled imports, many of which come from renewable generation, that contribute to over-generation. The present reality is that California is hard pressed to reduce imports to zero, and does not have practice that allows for significant exports. The anecdotal evidence is that contractual and institutional barriers tend to make resources outside of California quite inflexible and poorly responsive to real-time pricing signals.

As the economic consequences of these historic practices become transparent and are phased out, the transition to new forms of ancillary services and noncombustion sources of frequency response can be phased in.

Bilateral Exchange of Frequency Response. NERC Frequency Response Obligation rules explicitly allow for balancing authorities to obtain frequency response (services) from other BAs. At present both the technical and business practices to facilitate this exchange of FR are in their infancy. Care will need to be taken to avoid unintended consequences of bilateral exchange (e.g. line overloads or violating stability limits), but the fact that CA imports decline in the LCGS as the scenarios move from the baseline case to the target case is directionally consistent with CA importing FR services when the service is in short supply in the state. That is, there is more room on the lines to import FR services. In the LCGS target case, CA has net export during about 500 hours per year, and for all but about 1000 hours, the import is reduced from the business as usual baseline case by at least an extra 1000MW.

California's two major HVDC tie lines also present possible resources for import or exchange of FR ancillary services. The sending ends (rectifiers) of the HVDC lines are in neighboring systems. There is precedence for the DC lines to host controls that improve the performance of the WECC system and of California in particular (e.g. Power Swing Damping Controls to improve damping of interarea power swings). Design and implementation of such controls is clearly possible. It takes cooperation with neighboring systems and significant specialized engineering design. However, no new technology is required and costs are potentially modest.

Discussion of Ancillary Services for Frequency Response. As noted, there is a need for ancillary service definitions and markets to become better aligned with the reality of present and future US grids. This is true across all of the US, not just California, and is part of the motivation for the NERC Essential Reliability Services Task Force (ERSTF) activities. A spectrum of industry experts (including representatives from California) are crafting new metrics to better monitor the performance and needs of systems. Of particular note for this discussion is the leading work of ERCOT. That work recognizes the relationship between increasing inverter-based renewables, dropping system inertia, scarcity of primary frequency response from synchronous generation and the duality between FFR and conventional spinning reserve. Today ERCOT allows load to provide up to 50% of their Responsive Reserve Service (RRS). They have about 3000MW qualified to do so. ERCOT is targeting 2018 for introduction of a new FFR ancillary service market [10], for which energy storage will be a significant participant. On February 19, 2015, FERC made a notice of proposed rulemaking for "Third-Party Provision of Primary Frequency Response Service" [11]. By the 2030 time horizon of the LCGS, industry practice for procurement of FR should evolve substantially.

Displacement of Responsive Resources and Current Practice. Some resources being displaced in the LCGS *tend* to *not* be contributing much to frequency response now. In particular, Diablo Canyon and some fossil plants are not responsive today. The inability or unwillingness of some thermal generation to provide frequency response today indicates that their displacement by low carbon resources has minimal incremental consequences for maintaining adequate frequency response. Further, WWSIS-3 showed that California hydro is important to provision of FR in the state. Including FR performance as part of hydro management is one of the likely outcomes of market improvements.

Until such time as rules and markets to assure both provision and exchange of FR services, California will likely continue to depend largely or solely on traditional synchronous generation (mainly hydro and gas-fired). The California Frequency Response Study [6] showed that, California should maintain about 3000 MW of conventional frequency responsive headroom and that each monitored entity in the west, including the major IOUs in California, ought to maintain frequency response on about 30% of their synchronized generation. This study result is one of the factors that led to present CAISO guidelines for each entity to maintain approximately a minimum commitment of 25% synchronous generation. Part of the motivation for that guideline is to maintain adequate frequency response. Other motivations include maintaining adequate maneuverability to handle variation in net load. In addition to distorting the economics of commitment and dispatch, this guideline results in forced commitment of synchronous generation in California that will increase renewable curtailment and variable costs. The need for the guideline is further evidence of the need for market signals to procure the necessary type and amounts of ancillary services at the lowest cost. New policy and new ancillary services are needed, and they must be defined so that the California system can benefit from all the frequency response options discussed above.

Discussion of Inertia. Considerable attention has been given to the decline in system inertia as inverter-based variable renewables displace synchronous generators. The WWSIS-3 work showed that initial rate-of-change-of-frequency (ROCOF) could increase by as much as 18% when instantaneous wind and solar penetration rises from 21% to 44% in WECC. The faster drop in frequency increases the relative efficacy of FFR resources in arresting the initial frequency drop, but otherwise has little impact on system stability. The new ERCOT ancillary services work recognizes this effect, and has provision for procurement of the proper mix of FFR and conventional primary response services to manage frequency excursions.

3 TRANSIENT STABILITY AND WEAK GRID/MAXIMUM SNSP CONCERNS

Transient Stability Background. In addition to maintaining the balance between electricity generation and electricity demand, power system operators must ensure that the grid can successfully transition to a new, satisfactory state of equilibrium in the 10–20 seconds immediately following a disturbance. The ability to make this successful transition is called transient stability. While this phenomenon is related to frequency stability, it is even faster, and comprises the necessity that further components (e.g., all transmission lines and generating units) other than the line or unit causing the disturbance remain in service, and that customers continue to be served. Transient stability requires that all portions of the system remain tied together in synchronism, and that swings across the system (aka "interarea oscillations") be well damped. Transient stability concerns generally have much higher dependence on the location both of the disturbance and of all elements of the grid (i.e. generation, transmission, reactive compensation, loads, and protection) than frequency stability. The dynamic reactive power characteristics of all these elements are often more important than the active power behavior that tends to dominate frequency stability concerns.

Discussion of Wind and Solar Stability Characteristics. The fact that all photovoltaic solar and all modern utility-scale wind generation interface with the electric power system by power electronics (inverters) causes them to have fundamentally different dynamic characteristics in the time-frame of transient stability. The inverters isolate the power source, either PV panels or wind turbine-generators, from the grid so that power production is essentially decoupled from grid frequency. This has the effect of making these generators appear to have no inertia to the grid. As noted above, this has an impact on frequency performance. This decoupling also changes the synchronizing behavior of the generators, and therefore affects transient stability as well. In the case of wind turbines, the decoupling reduces the urgency to immediately balance electrical and mechanical power that is needed for synchronous machines to stay connected. In short, inverter-based generation tends to not swing. The net result is that up to high levels of penetration, the addition of inverter-based generation tends to have a *beneficial* impact on transient stability and on the damping of interarea oscillations [12].

Considerable practical work on this topic has originated at EirGrid [13], the grid operator for all of Ireland. Ambitious renewable targets, and the fact that their system is electrically asynchronous with other grids, make it essential for Ireland to address stability concerns. At present, EirGrid limits their total "simultaneous non-synchronous penetration" (SNSP) to no more than 50%, and is working towards raising that limit to 75%. Note that these concerns apply to each instant of operating time: SNSP is a measure of "instantaneous penetration", i.e. what is the relative amount of inverter-based wind, solar, BESS and HVDC running *now* compared to all the synchronous machines running *now*. It should not be confused with "annual energy penetration". EirGrid's 50% SNSP limit exists mainly because the beneficial stability impacts of inverter based generation reach a maximum around 50% instantaneous penetration, and stability starts to degrade at higher penetrations. At around 75% system-wide instantaneous penetration, the stability impacts become acute without further mitigation. These results tend to be supported by the WWSIS-3 work, which shows some stability problems emerging at around 60-70% instantaneous penetration in the eastern part of the Western Interconnection. The Irish experience is system-wide. Industry experience and understanding of regional stability limits within an interconnection based on SNSP are not extensive. However, this research is ongoing around the world (see, e.g. [14]) and will be well developed by the 2030 time frame.

For the LCGS, we define a variation on the EirGrid SNSP. The SNSP is intended to give a metric of the amount of inverter-based resources running at any instant compared to the sum of everything that is running. In simple terms, a higher SNSP means there is proportionally more inverter-based equipment running. The concept is simple, but the exact definition of what counts is not standardized. Here, we introduce a definition that is based primarily on committed rating, rather than dispatch. This is a better proxy for the stability limit than dispatch because most of the relevant dynamics are dominated by the rating of the various equipment, rather than by the amount of power they are producing (or consuming) at a particular moment. For the inverter-based term, i.e. the "simultaneous non-synchronous" component, the wind, PV, HVDC and non-synchronous storage (e.g. battery energy storage) are all contributors. Note that each terminal of HVDC counts as a non-synchronous contributor to this component, regardless of whether it is functioning as an inverter or rectifier. Similarly, battery storage is a contributor to the non-synchronous component, regardless of whether it is charging or discharging. For the synchronous component, conventional synchronous generation is the major contributor. Unlike battery systems, pumped hydro storage is a synchronous resource. The synchronous loads, notably the large water transfer pumps discussed above, are not counted here, but would be a positive contributor to the synchronous component. Concentrating solar thermal plants as well as geothermal resources contribute to the synchronous component.

Because of some degree of uncertainty about the exact commitment status of wind, solar and hydro, the metric is actually a mix of MW rating (for thermal and pumped storage hydro, Wind, Solar and HVDC) and MW dispatch for Hydro, rather than just dispatch. This mix definition is deliberately somewhat conservative, in that it tends to overstate the connected inverter based wind and solar (makes the metric worse) and understate the quantity of hydro synchronized (also makes the metric worse).

The SNSP reported here is given at the WECC, California and southern California (south of Path 26) levels. In Figure 1, a snapshot of two very high penetration days for Phase I of the LCGS are shown. On the left are MVA levels by WECC (top), California (middle) and southern California (bottom). The SNSP for the same data is shown on the right. The yellow and red lines are added to highlight the EirGrid limits. At the WECC level, the SNSP just touches 50% for an hour or two on the morning of May 10. This suggests that on a systemic basis, the non-synchronous penetration should be manageable without extensive mitigation. However, the concerns for transient stability are more localized. In California, the system is in the 50-75% SNSP range as soon as the PV starts up with sunrise. In southern California, most of the day is at or above the 75% EirGrid future upper limit.

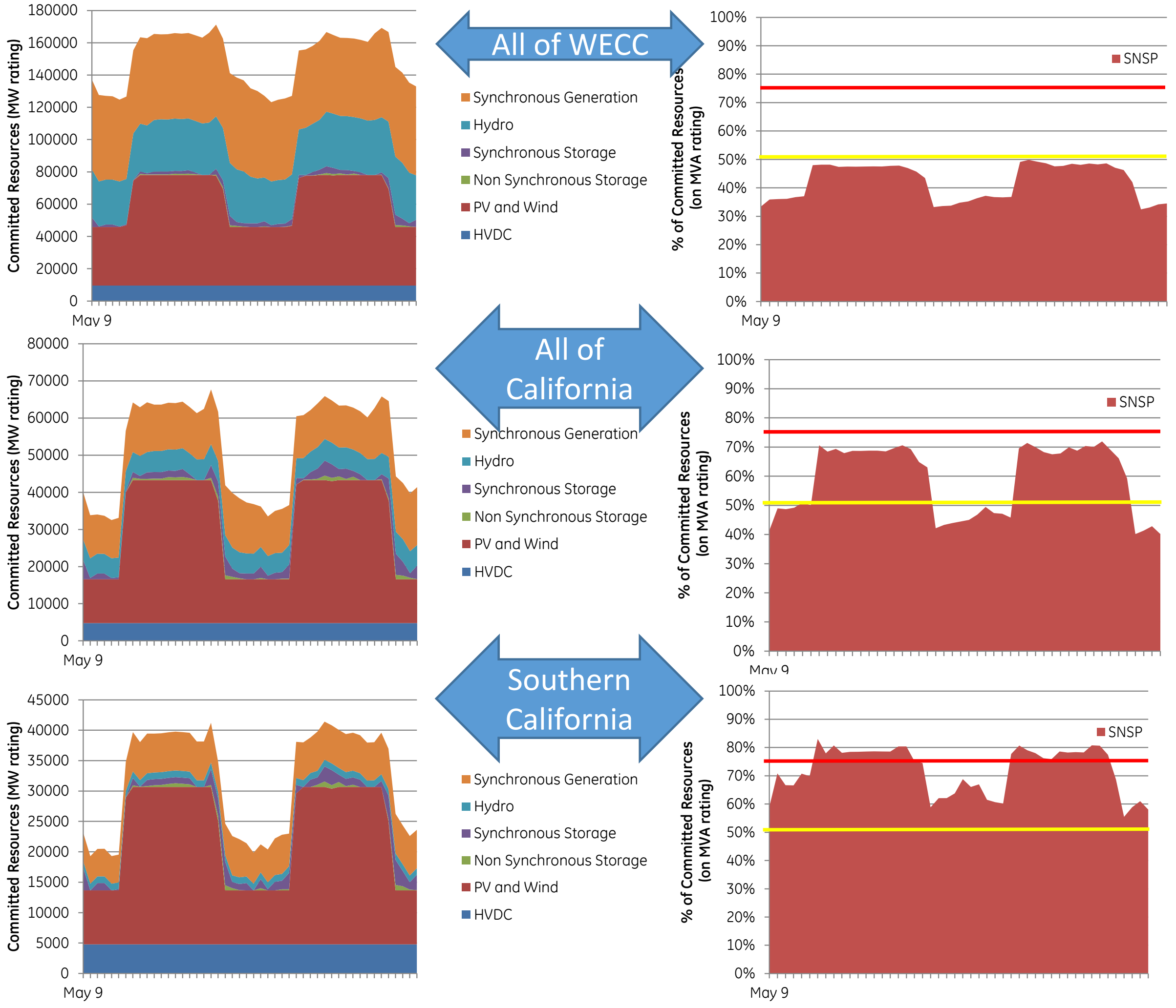

Figure 1 Simultaneous Non-Synchronous Penetration - May 9-11 Target Case

That these two days are representative of the most challenging days can be seen in the duration curves of Figure 2. These curves show the GW rating of the total non-synchronous resources on the left and the SNSP (according to the same definition used above) on the right. The color coding on the SNSP curves again marks the present EirGrid limit of 50% in yellow, and the future target limit of 75% in red. The worst hours of the May days of Figure 1 reside on the far left of the duration curves. The present upper threshold of 75% SNSP bears similarity to the CAISO minimum 25% synchronous generation guideline discussed above. They are both objectives that tend to force commitment of conventional (synchronous) generation in certain conditions (i.e. too much non-synchronous generation) in certain geographic regions to maintain grid stability. But they have different emphasis. In simple terms, the SNSP is more focused on transient stability and other very fast phenomena, and the CAISO minimum guideline is more focused on frequency stability and other slower balancing needs.

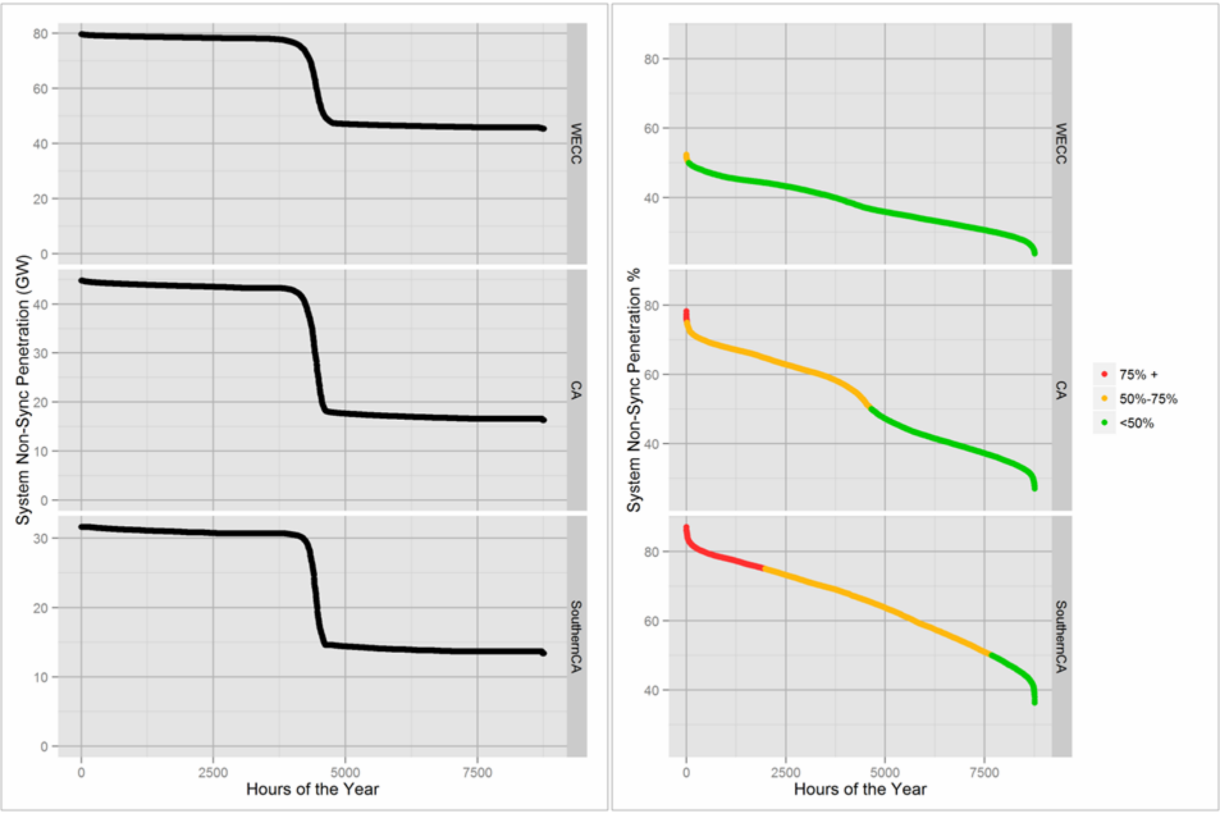

Figure 2 Simultaneous Non-Synchronous Penetration Duration Curves - Target Case

These results are indication of some degree of risk in California, and particularly in southern California. The results neither guarantee that there will be problems, nor do they give specifics of how problems might manifest themselves. But, at the least, mitigation of localized problems with voltage, transient stability and thermal overloading will be needed. However, numerous viable options are available that do not require must run fossil commitment, as will be discussed below.

Discussion of Weak Grid Concerns. Another aspect of displacement of synchronous generation with inverter-based resources is so-called "weak grid" considerations. Systems at high levels of wind penetration, such as those in west Texas, Australia, and Brazil, are challenged to provide fast, confident control during faults as wind and solar generation becomes the dominant generation resource in a particular portion of the grid. In systems with insufficient strength, rapid voltage collapse and system separation during or immediately following grid faults can occur. Modern wind turbines and all PV systems depend on power electronics that must behave well during grid disturbances. Until recently, this concern has primarily focused on fault ride-through capability. The wind industry has largely addressed the ride-through questions, and the solar industry is following suit. However, no commercially available wind or utility-scale solar PV generation is capable of operation in a system without the stabilizing benefit of synchronous machines. Although the specifics of "insufficient strength" are complex and nuanced, the overall concept is conceptually simple: the inverter-based generation controls expect to be able to "lean" on the grid to achieve their objectives. With no synchronous machines, there's nothing to lean on. For present technology wind and solar generation, there is a point at which the amount of short circuit strength provided by synchronous machines becomes insufficient, and some mitigation is needed. "Weak grid" is a generic term that describes operating near that point. Metrics such as the SNSP discussed above and minimum composite short circuit ratio (CSRC) give an indication of risk. It is possible that some locations or operating points in the LCGS will be subject to this risk.

Discussion of Distributed Generation Impact on Stability Concerns. The accelerating development of distributed generation (DG), especially residential and behind-the-meter PV, has the potential to have substantial impacts on system frequency and transient stability. Of particular concern is wide-spread common-mode tripping of distributed PV in response to grid disturbances. IEEE Standard 1547 addresses the obligation of DG to trip in order to avoid inadvertent islanding. That standard provides ranges of voltage and frequency depression depth and duration for which DG must trip. The standard has been recently modified, with the intent to provide a mechanism by which the must-trip behavior can be modified. The issues between the desire to avoid inadvertent islanding and the desire to maintain bulk power system reliability are complex. They need resolution if California is to successfully integrate levels of distributed PV contemplated in the LCGS. A German standard somewhat similar to IEEE 1547, in that it required aggressive tripping of PV for frequency excursions, was recently modified. In Germany, widespread retrofit of PV inverters has been required. There are a variety of technology options that can be beneficial in resolving this problem; they include coordination of must-trip and must-ride-through thresholds, introduction of randomization in trip characteristics, and better differentiation between local and bulk grid disturbances.

At high levels of penetration, DG has the potential to provide significant bulk system ancillary services that could benefit both frequency response and transient stability. The California Rule 21 Smart Inverter Working Group [15] is addressing both the common-mode tripping and ancillary services issues. In December, the CPUC adopted modifications to Rule 21 in D.14-12-035, "to capture the technological advantages offered by smart inverters" that can offer system support functions to distribution system operators. The new requirements are an outgrowth of recommendations made by the Smart Inverter Working Group (SIWG). The adopted Phase 1 recommendations address the following autonomous inverter functionalities:

- Anti-Islanding Protection
- Low and High Voltage and Frequency Ride-Through
- Dynamic Volt-Var Operation
- Ramp Rates
- Fixed Power Factor
- Soft Start Reconnection

The effective mandatory date of the new requirements will be the later of December 31, 2015, or 12 months after UL approves the applicable standards as applied to California, but smart inverters can be deployed sooner voluntarily. Phase 2 of the smart inverter proceeding will focus on inverter communication protocols, while Phase 3 will define and propose advanced functionalities utilizing the communications capabilities. The CPUC will also be examining the appropriate level of compensation for inverter owners that provide grid support functions. Although existing inverters requiring replacement are exempt from the smart inverter requirement, over time, these will represent a smaller share of systems installed. Recent experience in Hawaii indicates some of these needed changes can be made remotely and quickly [16].

Options for Mitigation of Transient Stability and Weak Grid Concerns. Mitigation of weak grid problems, should they manifest themselves in the LCGS scenario, can take many forms. That southern California reaches high levels of SNSP is evidence of risk. Transmission reinforcements, (e.g. new lines or transformers) are effective conventional methods to strengthen regional interconnections and reduce the risks associated with locationally high levels of SNSP. Increasing the tie strength from southern California to the north (e.g. Path 26) or to the east will be a way to reduce the risks of high SNSP.

One method to reduce SNSP and assure adequate system strength is by commitment of synchronous generators. This exacerbates over-generation. An alternative that avoids the costs and curtailment risks of over-committing synchronous generators is the provision of synchronous condensers. These can be either new purpose-built machines, or unit conversions. Unit conversions, which have been shown to be economic and have been performed in other systems as well as California, may continue to be an attractive option for California. This practice takes a retiring thermal turbine-generator, removes the turbine, and makes provision for the generator to start and run as a condenser. This has the advantage of reusing existing equipment and sites. It may be attractive for California given the impending retirement of several plants in electrically key locations. In at least one US application, a thermal plant has been temporarily disconnected from the turbine (rather than it being completely removed), and retains the ability to be reconnected.

Another option for addressing weak grid concerns is to include clutches on some new gas-fired power plants that have been authorized for procurement but have not been constructed, allowing operation as either generators or condensers. This is well established practice on smaller gas turbine-generators that are based on aircraft engines. Clutches on larger turbine-generators, both steam and gas, are possible in general, but need to be engineered specifically for the application. Retrofit of clutches is only possible on small machines.

As understanding of high SNSP and weak grid issues improves, other economic mitigation options are likely to emerge. Presently, control stability improvements for inverters also hold promise for reducing or removing the adverse consequences of weak grids.

As noted above, at the least, it is nearly inevitable that some mitigation will be required for localized problems. Consequently, it is essential that good utility practice for stability concerns be followed. Existing technologies should be sufficient to meet these needs, although new technologies may prove to be more cost-effective. Mechanisms that allow for investment for mitigation (e.g. grid improvements) are needed.

4 SUMMARY OF DYNAMIC PERFORMANCE CONCERNS

Frequency Summary. By 2030, California should have a wide range of available options to meet its frequency response obligations. Enforcement of the 25% synchronous generation guideline for each California participant will be obsolete. Curtailment of new renewables in order to obtain frequency response from fossil resources is unlikely to be necessary in the future. These conclusions assume that California adopts ancillary service markets and other rules that properly incentivize and enable provision of frequency response services from all available resources and technologies. Specific resources addressed should include:

- Frequency response capability from renewables, including wind, utility scale solar, hydro, and steam (biomass and geothermal),
- Frequency response from demand side; including loads (especially California's abundant pumping loads), electric vehicles , and other controllable resources,
- Frequency response from energy storage,
- Relief from contractual constraints that exacerbate over-generation problems.

Transient Stability Summary. In summary, transient stability presents a risk to implementation of the LCGS scenario. Careful, quantitative evaluation of system stability is warranted, especially in southern California under conditions of high SNSP. Multiple options exist today for mitigation of any transient stability problems that will arise, and by 2030, additional options should be available. Transient stability must be considered as part of the future changes to the system, but stability issues can be identified and handled with existing engineering best practices. Mechanisms to allow and pay for localized grid improvements are required.

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