Final Report:

Primary Frequency Response: Maintaining System Reliability

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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 Western Interconnection Regional Advisory Body/Western Interstate Energy Board. Questions and any correspondence concerning this document should be referred to:

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List of Acronyms

AESO	Alberta Electric System Operator
BA	Balancing Authority
DER	Distributed Energy Resources
EI	Eastern Interconnection
ENTSO-E	European Network of Transmission System Operators for Electricity
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FR	Frequency Response
FRM	Frequency Response Measure
FRO	Frequency Response Obligation
GE	General Electric International, Inc.
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IFRO	Interconnection Frequency Response Obligation
LGIA	Large Generator Interconnection Agreement
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOI	Notice of Inquiry
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PFR	Primary Frequency Response
PTC	Production Tax Credit
PV	Photovoltaics
REC	Renewable Energy Credit
ROCOF	Rate of Change of Frequency

RPS	Renewables Portfolio Standard
SGIA	Small Generator Interconnection Agreement
UFLS	Under-Frequency Load Shedding
VER	Variable Energy Resources
VOM	Variable Operations and Maintenance
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study

1 INTRODUCTION

Power systems are designed to maintain reliability of the system in the event of a contingency, such as the loss of a large generator. This loss is invisible to the end-users, who see no interruption in service or quality. In North America, each interconnection should have enough arresting power so that under-frequency load shedding (UFLS) does not occur in a design-basis event (in the Western Interconnection, this is the loss of the two largest resources – 2 Palo Verde units, which is 2,740 MW). UFLS, in which blocks of firm load are disconnected from the grid in order to keep the rest of the grid operational, starts at 59.5 Hz in the Western Interconnection.

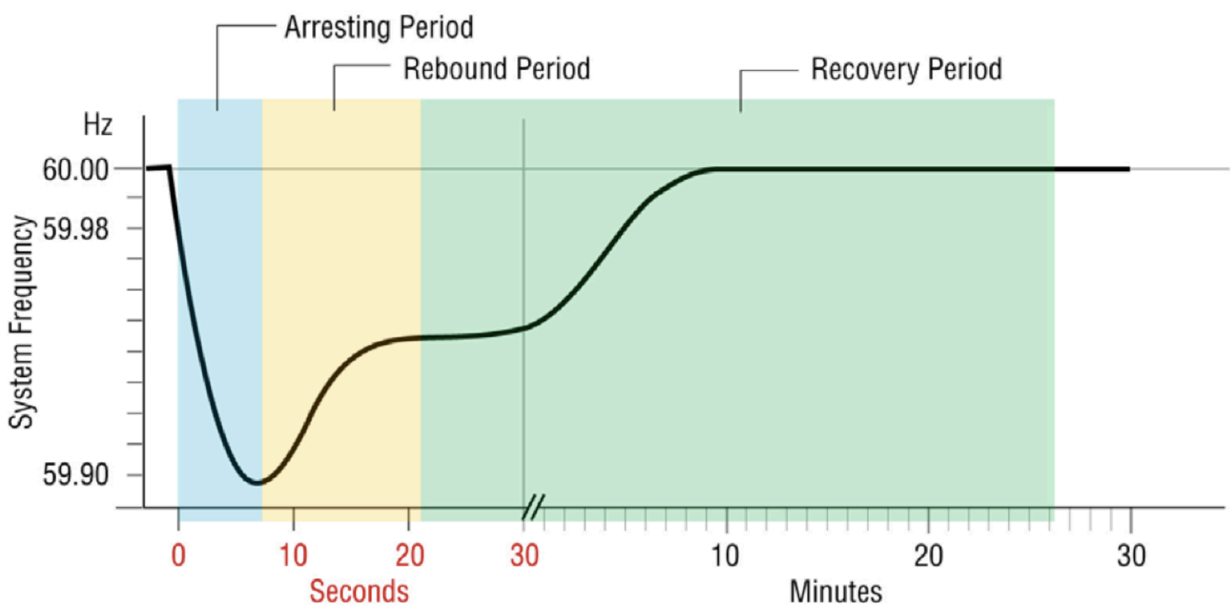

Figure 1 – Frequency response to a loss of generation[1].

When generation is lost (see Figure 1), frequency across the interconnection will decline. Inertia from the rotating mass of generators and induction motors that are online will define how fast frequency falls immediately following the event. This is called the initial Rate of Change of Frequency (ROCOF). The first few seconds, up to the time of a frequency minimum (the frequency 'nadir') is called the arresting period, and is shown in blue in Figure 1. The inertia of the system is not a control action, but rather a physical characteristic of the rotating mass of connected devices at the time of the disturbance. The deliberate control actions power system, Primary frequency response (PFR) and Fast Frequency Response (FFR), will stabilize frequency in the seconds to tens of seconds time-frame. FFR is similar to PFR but acts much faster, providing power in the 0.5 second time-frame, with the specific

[1] J. Eto, et al. "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation", LBNL-4142E, Dec. 2010. http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf

objective of providing arresting power before the frequency nadir. PFR and FFR both help to arrest frequency and interact with inertia to determine the frequency nadir.

Following the frequency nadir is the rebound period, shown in yellow in Figure 1. The PFR will allow the frequency will settle at a new point based on the load/generation balance. FFR will also contribute to establishing this new settling point, if the FFR is sustained past the time of the nadir into this rebound period. Both PFR and FFR are autonomous controls, that act based on local conditions, i.e. in response to quantities (i.e. local frequency or machine speed) that can be measured at, or very close to, the equipment providing the service.

Secondary frequency response, also called regulating reserve, will increase output during the recovery period, shown in green in Figure 1, to return frequency to nominal. Secondary frequency response occurs in a few minutes. Unlike PFR and FFR, secondary response is a centralized control action, with the central energy management system of the grid operator sending power instructions to individual resources (mostly participating generators) in response to deviation of system frequency and tie-line flows.

The Federal Energy Regulatory Commission (FERC) issued a Notice of Inquiry (NOI) to obtain information and perspectives on PFR and how to ensure reliability is maintained despite declining metrics in some regions, and as the generation portfolio changes. Specifically, the NOI asks about mandatory requirements for PFR for new and existing generators and how to compensate for PFR. Limiting the depth of the frequency nadir to avoid UFLS is the primary and critical focus of the FERC NOI and of the related NERC standards.

1.1 Declining frequency response

Frequency response started to become a concern a few decades ago as the industry realized that PFR had been declining over time[2]. This was occurring far before there was significant non-synchronous generation on the grid. The Eastern Interconnection is of particular concern due to its “lazy L” frequency response: instead of frequency declining to a nadir and then bouncing back up as shown in Figure 1, it would remain at the nadir for tens of seconds[3] as shown in Figure 2. Investigation revealed 1) large numbers of generators had wider dead bands than the target range, 2) large numbers of generators had their governors disabled for under-frequency response and 3) a large portion of the gas fleet operated under set point control that defeated proper PFR response[4].

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2 EPIC Engineering, “Impacts of Governor Response Changes on the Security of North American Interconnections,” EPRI, TR-101080, Oct. 1992. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=TR-101080

3 NERC, “Eastern Interconnection Frequency Initiative Whitepaper,” Oct. 28, 2013. http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/EI%20Frequency%20Initiative%20Whitepaper.pdf

4 NERC, “Frequency Response Initiative Report,” Oct. 30, 2012. http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

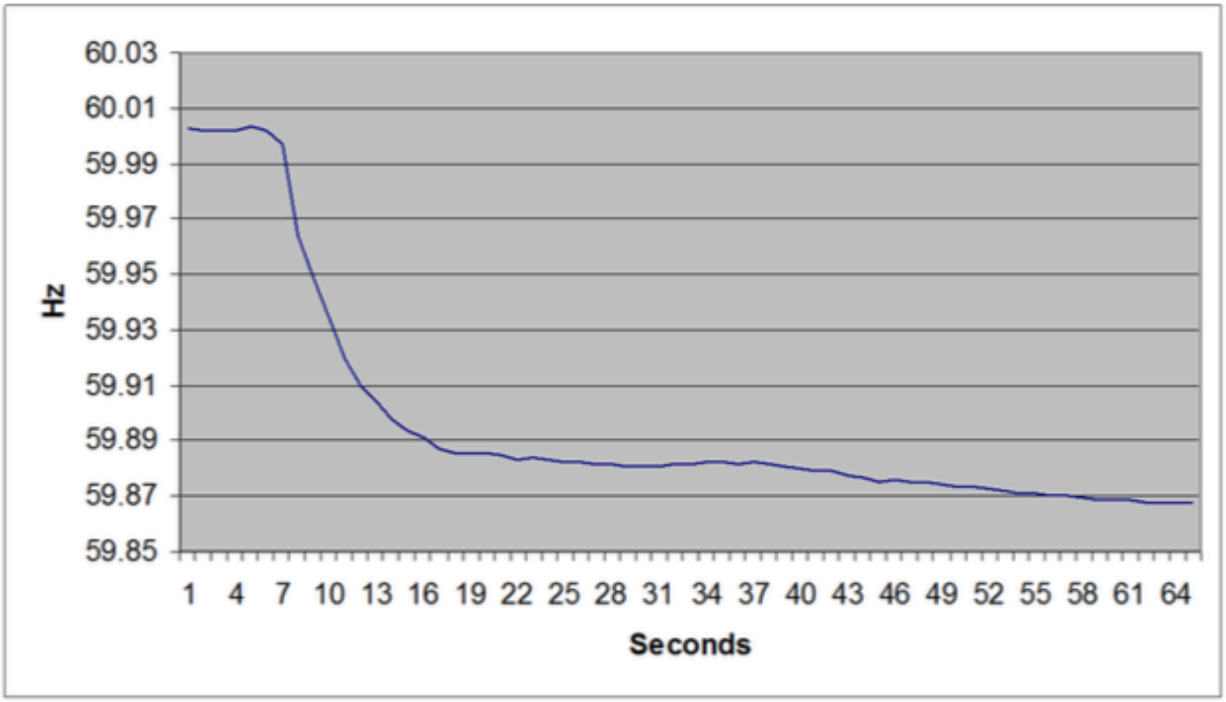

Figure 2 – Eastern Interconnection Frequency Response for loss of 4,500 MW of generation on Aug. 4, 2007[5].

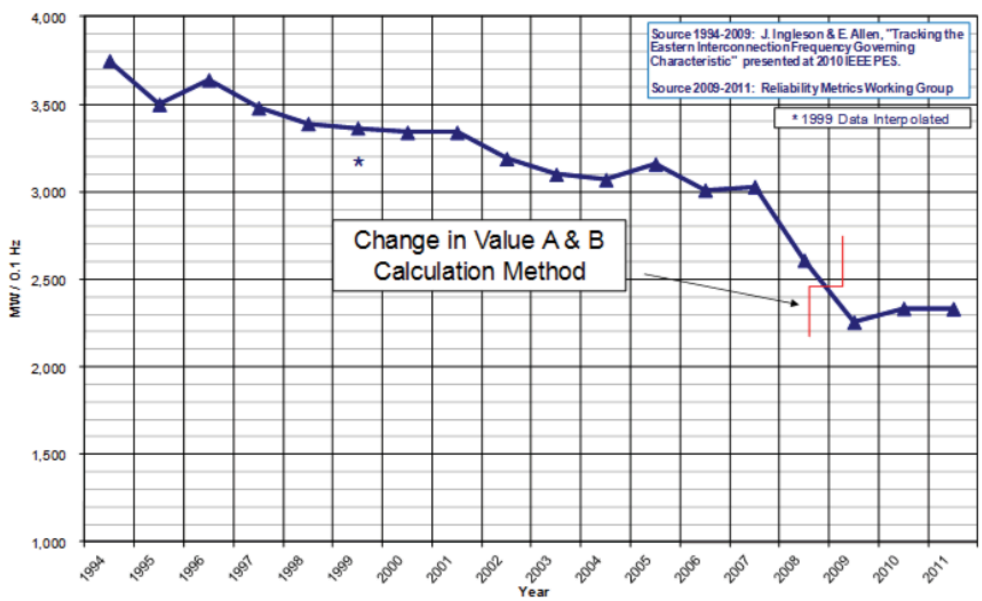

Figure 3 – Eastern Interconnection Mean Primary Frequency Response[6,7].

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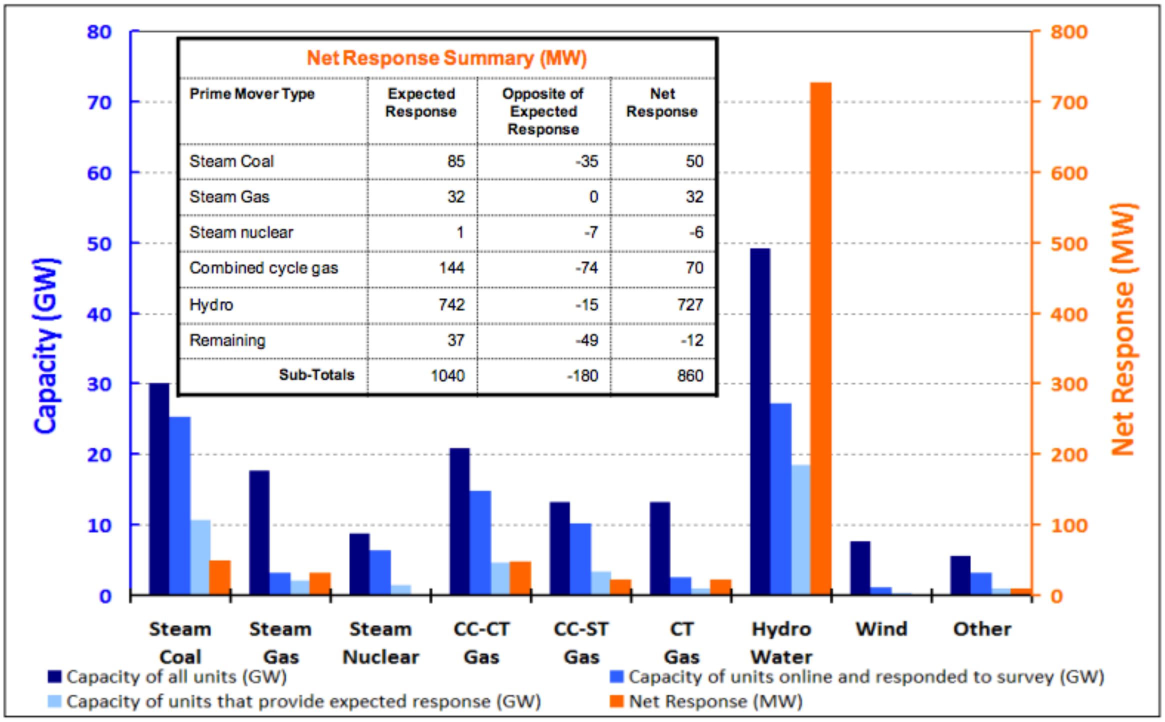
5 NERC, "Frequency Response Initiative Report," Oct. 30, 2012. http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

FERC is being proactive by issuing an NOI. But it is worth noting that, so far, there hasn't been a deficit of FR. Rather, PFR is not sustained, leading to the response in Figure 2 and the amount available is showing a downward trend, as shown in Figure 3.

While the Eastern Interconnection has more issues, frequency response has also been declining in the Western Interconnection. NERC conducted a survey of generator governor response to a significant event in the Western Interconnection and found that of the total generating capacity online, 44% responded in the expected direction of response, 35% did not respond, and 17% responded in the wrong direction (see Figure 4).



Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	85	-35	50
Steam Gas	32	0	32
Steam nuclear	1	-7	-6
Combined cycle gas	144	-74	70
Hydro	742	-15	727
Remaining	37	-49	-12
Sub-Totals	1040	-180	860

Figure 4 – Western Interconnection Generator Governor Performance[8].

1.2 Implications for non-synchronous generators

Inverter-based generators such as modern utility-scale wind turbines and PV, are non-synchronous generators as compared to synchronous generators such as nuclear, gas, coal, oil and hydro generators. In the Eastern and Western Interconnections, wind and PV are not

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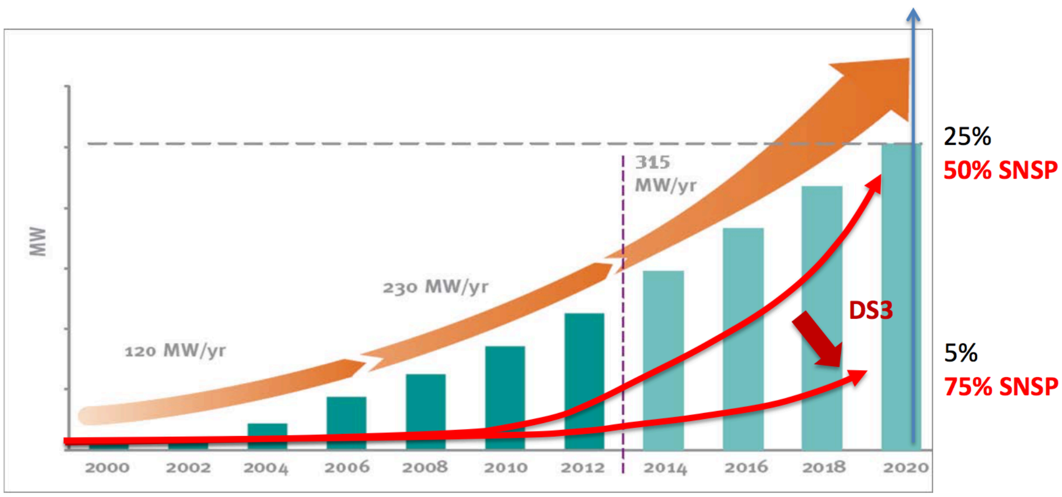
[6] NERC "Eastern Interconnection Frequency Initiative Whitepaper," Oct. 28, 2013. http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/EI%20Frequency%20Initiative%20Whitepaper.pdf

[7] PFR is measured as the change in output of resources (mostly generators) in response to change in frequency (dP/dF). Units of MW/0.1Hz are used, for consistency with other control practice and NERC standards.

[8] NERC, "Frequency Response Initiative Report," Oct. 30, 2012. http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

required to provide inertia, PFR or FFR, and so they do not. There is a concern that at high penetrations of non-synchronous generation, there will be insufficient arresting power (inertia, PFR, FFR) to avoid UFLS and to recover the system in a contingency. In Ireland, the grid operator EirGrid, has limited instantaneous penetration levels of non-synchronous resources such as wind (and HVDC) to 50% in order to maintain transient stability and sufficient arresting power for system reliability[9]. Increasing levels of wind capacity in Ireland are projected to lead to increasing levels of wind curtailment until grid codes can be modified to ensure reliability with higher instantaneous penetrations of non-synchronous resources (see Figure 5).



Illustrative SNSP curves

Figure 5 – Impact of system non-synchronous penetration on curtailment[10].

While wind and PV do not provide arresting power in most of North America today, wind does provide some of these services in regions such as ERCOT, Hydro-Quebec and IESO.

1.3 NERC Frequency Response and Frequency Bias Setting Standard

The NERC BAL-003-1 standard requires each Balancing Authority (BA) to meet a Frequency Response Obligation (FRO) and to achieve an annual Frequency Response Measure (FRM)[11]. The FRO is the BA's contribution to the overall interconnection's obligation, which is determined annually and set to avoid UFLS in a design-basis event. The standard establishes how the BA determines whether it meets its FRO often enough (i.e. 95% of the measured incidents in a year) to satisfy its overall obligation. But the standard does not discuss how to

[9] EirGrid worries about ROCOF > 0.5 Hz/sec which will initiate protective actions, presently mandated in the Irish interconnection, that will exacerbate frequency deviations, and could lead to cascading failures.

[10] Peter Campbell, EirGrid Group, "Operating the Power System with High Levels of Wind Generation – Ireland," Utility Variable Generation Integration Group Forecasting Workshop, Denver, CO, Feb 18-19, 2015.

[11] NERC Standard BAL-003-1 – Frequency Response and Frequency Bias Setting.

get FR, how to measure individual resources, the speed of the FR, or how to incentivize or punish BA's for compliance.

There are provisions within BAL-003-1 that *should* result in most of the concerns raised in the NOI (e.g. lower inertia, squelch, reduced PFR participation) being reflected in the metrics of the standard. The accompanying issue, a *portion of which* FERC is trying to address with this NOI, is to assure that there are sufficient *options* available to meet the requirements of BAL-003-1.

Also BAL-003-1 lacks provisions to address some of the issues in the NOI, such as reward for resources to provide greater speed – i.e. arresting power, or how to measure individual resources.

1.4 PFR is not needed from all generators all the time

It's important to note that the overall goal of frequency response is to provide enough arresting power to avoid UFLS in a design-basis event. The point is not to maintain some level of inertia or to minimize ROCOF (which can be important in places like Ireland). NERC BAL-003-1 standard's FRO and FRM are one framework to try to meet that goal. The arresting power is really a combination of inertia, PFR and FFR and these all interact.

No analysis shows operating conditions in a typical US/North American interconnection for which *every* committed generator *must* provide frequency response. Rather the reliability need is that an *adequate* amount be provided. Rules should be structured so as to assure that this outcome is achieved economically.

Then how much do we need? At the system level, the single most important metric for primary frequency control is K_t, which is the fraction of online units that provide primary frequency control, and a rule of thumb is that a K_t of at least 30% is necessary to maintain system reliability[12,13,14,15]. As K_t increases, the frequency nadir increases. But, K_t is not a perfect metric, as it does not distinguish between faster and slower response.

Thus, at *any given instant* we need to ensure the system has enough FR (including PFR) to meet its obligations. This is the basic premise of BAL-003-1. In the case of requiring PFR *capability* on new generation, barring exceptional circumstances, this ought not to represent an undue burden. But to require the *retrofit* of controls and equipment on existing facilities, when it may not be needed for a BA to meet its FRO, could be unnecessary and uneconomic.

[12] J. Eto, et al. "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation", LBNL-4142E, Dec. 2010. http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf

[13] N. Miller, et al, "California ISO (CAISO) Frequency Response Study," Nov. 9, 2011. https://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf

[14] N. Miller, et al, "Eastern Frequency Response Study," NREL//SR-5500-58077, May 2013. http://www.nrel.gov/docs/fy13osti/58077.pdf

[15] N. Miller, et al, "Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability", NREL/SR-5D00-62906, December, 2014. http://www.nrel.gov/docs/fy15osti/62906.pdf

Retrofit requirements should demonstrate that there is risk that a BA or interconnection will have a shortage under credible anticipated operating conditions

If PFR capability is voluntary, there will be natural incentives and disincentives to install the capability. For example, units that lack PFR capability may not be committed for preference of a unit that can provide this reliability service. This would be an incentive for a resource to install PFR capability. On the other hand, units that have PFR capability may be dispatched down to provide headroom, so that these units earn less energy revenue. This would be a perverse incentive, that rewards inflexibility and punishes resources that provide the service.

Important considerations in establishing new requirements are determining whether there is a current lack of PFR, and under what operating conditions, and whether future scenarios predict a lack of PFR, and under what operating conditions. With the changing generation mix, it is important to be proactive, but at the same time, we don't want to impose unnecessary or uneconomic requirements.

2 IMPORTANT DISTINCTIONS

2.1 Over- versus Under-frequency response

The ability of a generator to provide over-frequency response is different from under-frequency response. Over- and under-frequency response entail different costs, can have different speeds, and can provide different levels of aggressiveness. As such, these two responses should be disaggregated and considered two different products or services, similar to up-regulation and down-regulation in some ISOs.

Figure 6 shows the droop characteristic for a plant. Consider a plant operating at the intersection of the dashed blue (nominal frequency) and dashed green (dispatched set point) lines. As frequency increases above the dead band, the slope of the droop characteristic tells the plant how to decrease output. It's noted that if the plant is operating at a minimum generation level, then the plant may not be able to decrease output unless it is decommitted. As frequency decreases below the dead band, the slope of the under-frequency droop characteristic tells the plant how to increase output. It is noted that the plant needs to be operating below its maximum output in order to have headroom to increase output.

Over-frequency response has no opportunity cost and little or no variable cost. It is beneficial to the system in the event of a loss of load event, during some system separation events, or in response to overly aggressive UFLS on a loss-of-generation event. This last consideration is not insignificant, as historically many large grid disturbances have had major problems associated with this "backswing" of frequency. To the extent that the cost to enable over-frequency response is very small, enabling this response at all times should be considered.

The aggressiveness of the response (droop) may vary for over-frequencies versus under-frequencies. In the past, this response was symmetric. This was largely a historical artifact of mechanical (e.g. flyball) governors that were symmetrical (the weight was fixed). But modern controls, and particularly those available on wind or PV plants need not be symmetrical.

Droop characteristics may be different for over versus under-frequency for wind, and especially PV. The system should take advantage of these responses.

While the primary focus of PFR tends to be on under-frequency events, it should be noted that historically, over-frequencies can lead to, or be part of, severe system disturbances (e.g. FRCC Turkey Point blackout, Malaysia blackout). Unlike combustion-based resources (especially gas turbines), wind and, especially solar PV, can reduce power output fast and to very low levels without much risk of tripping offline. Such aggressive response requires higher gains (again less droop) for over-frequency. The response here should be to explicitly *allow* (*not require*) that generating resources can have asymmetric droops and that they can be less than 5%, based on mutual agreement of the BA and the plant owner.

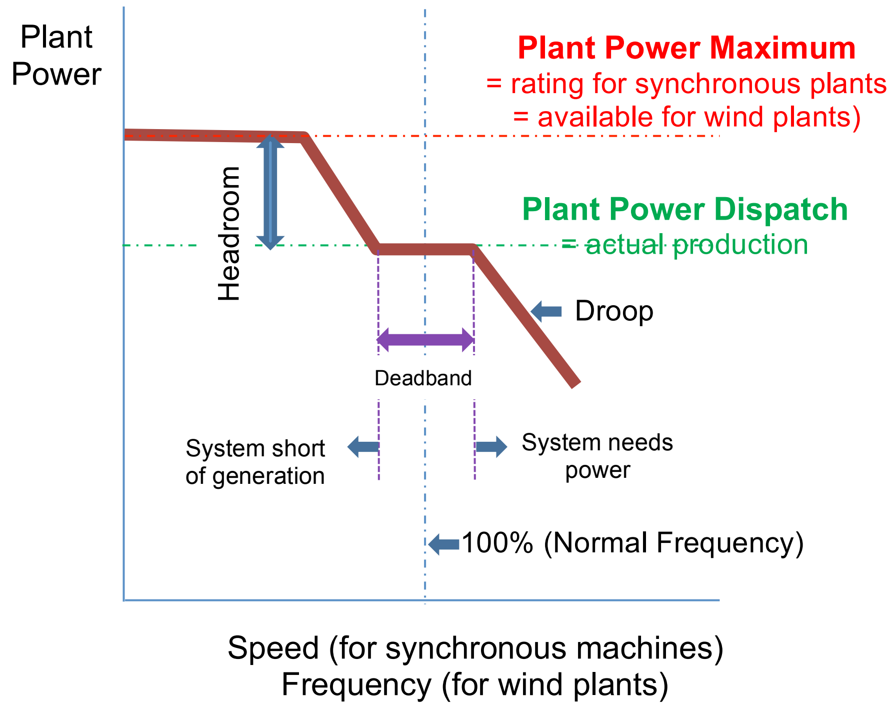


Figure 6 – PFR Droop characteristic.

2.2 Capacity/Enablement/Headroom/Actuation for Under-frequency Events

For a power plant to increase output based on frequency, four things are needed:

1) Capital equipment: the power plant needs install new or retrofit PFR ***capability***. For wind or PV plant, this capability is part of the control software and may be an additional cost compared to current standard offerings.
2) Provision: In operation, the plant needs to ***enable*** PFR controls. The generator then will respond to frequency deviations if it can. If the generator is a wind plant

operating at maximum power output based on wind speed, then it may not be able to respond to an under-frequency deviation but it will be able to respond to an over-frequency deviation.

3) Headroom: The plant needs to operate at an operating condition that ***allows*** it to increase MW quickly. For a wind or PV plant, this requires pre-curtailment to provide the headroom. The pre-curtailment may be intentional (so that the plant can provide PFR) or for other reasons (transmission congestion or system level constraints). For a gas turbine to have headroom, it would need to be dispatched down to less than maximum output so that it had adequate room to move up. A steam turbine operating at a sweet spot in its efficiency curve may be operating at less than maximum output and have headroom available due to the economics of its natural operation. It's important to note that headroom is *not* defined as maximum output minus operating output. The steam turbine of a combined cycle plant typically operates at sliding pressure (valves wide open). Even if the unit is operating at a fraction of its nominal rating, there is no headroom for this unit.
4) Actuation: Frequency deviations beyond the dead band settings ***cause*** the plant to respond. Thermal generators may have increased fuel and VOM costs as well as wear-and-tear costs for actuation of the response. Wider dead band settings may be preferable for some generators to decrease actuation and wear-and-tear costs. The speed of the response varies with generator type and faster speed has greater arresting power for frequency stabilization.

When discussing mandatory requirements or market products for PFR, it's important to distinguish between these four steps. Not all generators need to provide PFR all the time. But then it is necessary to determine which generators have the capability, which generators are enabled, and which generators operate so that they have headroom (and how much headroom). Clearly, adequate headroom to meet the BA's FRO is required. A market mechanism would be one way to enable PFR and provide headroom to exactly meet the FRO. But anecdotal evidence from many BA's is that there is no shortage of PFR. In the event that PFR is 'free', e.g., thermal units are dispatched below maximum generation levels and/or wind is curtailed, then it may be reasonable to enable more than the FRO. More PFR can provide reliability benefits in an event that is worse than the design-basis event, or if the event results in loss of other generators or lines.

It is worth noting that the TRE (ERCOT) requirement has two important aspects: First, generators are required to have the capability and to enable it (steps 1 & 2 above) but not required to carry headroom (step 3) in order to be able to actuate frequency response (step 4), rather they are expected to provide FR when there is headroom in the dispatch. In the case of wind and PV, they always provide over-frequency response but they provide under-frequency response only when they are curtailed by the system operator for other reasons (i.e. *not* specifically for the purpose of providing FR). ERCOT seems to recognize that pre-curtailing wind/PV specifically for the purpose of providing headroom for PFR requires financial compensation due to the opportunity cost incurred.

If we allow economics to dictate which generators provide PFR, one option is to enable PFR by default, if (and only if) doing so does not incur an opportunity or variable cost for the resource. But, whenever a resource incurs a cost to have PFR enabled, the default should be for the PFR to be off. This cost distinction should differentiate between over-frequency and under-frequency response, since for many resources, including wind and solar power, the variable cost of providing over-frequency response is very small, and the variable cost of providing under-frequency response is high. In this framework, operating conditions could help define the default PFR setting. For example, curtailed wind/PV (e.g., because of transmission congestion or thermal generators hitting their minimum limits) could have under-frequency PFR enabled by default because there is not opportunity cost to provide PFR when the wind/PV is already curtailed for other reasons. This framework would require a dynamic PFR setting on generators and monitoring of dynamic PFR headroom for each generator based on a changing operating condition in the system operator's energy management system. When there is a shortage of PFR, this framework could be used to determine which resources can most cost-effectively bridge the gap, i.e. to allow the interconnection to meet its Interconnection Frequency Response Obligation (IFRO).

The distinction in variable cost causality has some potentially confusing nuance, as evidenced by the ERCOT practice noted above: a wind plant that is curtailed *for other reasons* incurs a significant variable cost penalty for that curtailment, but will incur no variable cost penalty for enabling PFR under that condition.

2.3 Inertia/FFR/PFR

It is important to make a distinction between the essential reliability services that provide the arresting power to stabilize frequency. As noted above, PFR is only one piece of the frequency control puzzle. BAL-003-1 addresses all of the dynamic issues associated with avoiding UFLS. The impact of inertia on frequency response, on under-frequency load shedding, and on how the system might change in the future, are all in the existing standard.

Inertia, FFR and PFR all interact in system recovery. Figure 7 shows the frequency response in ERCOT to a similar sized generation loss at a time when the system has high inertia (red trace) and a time when the system has low inertia (blue trace). The low inertia case shows a steep decline in frequency. NERC points out that displacement of conventional resources with non-synchronous resources during light loads can lead to this type of low inertial response. Non-synchronous resources may, however, be enabled to provide a more grid-friendly response.

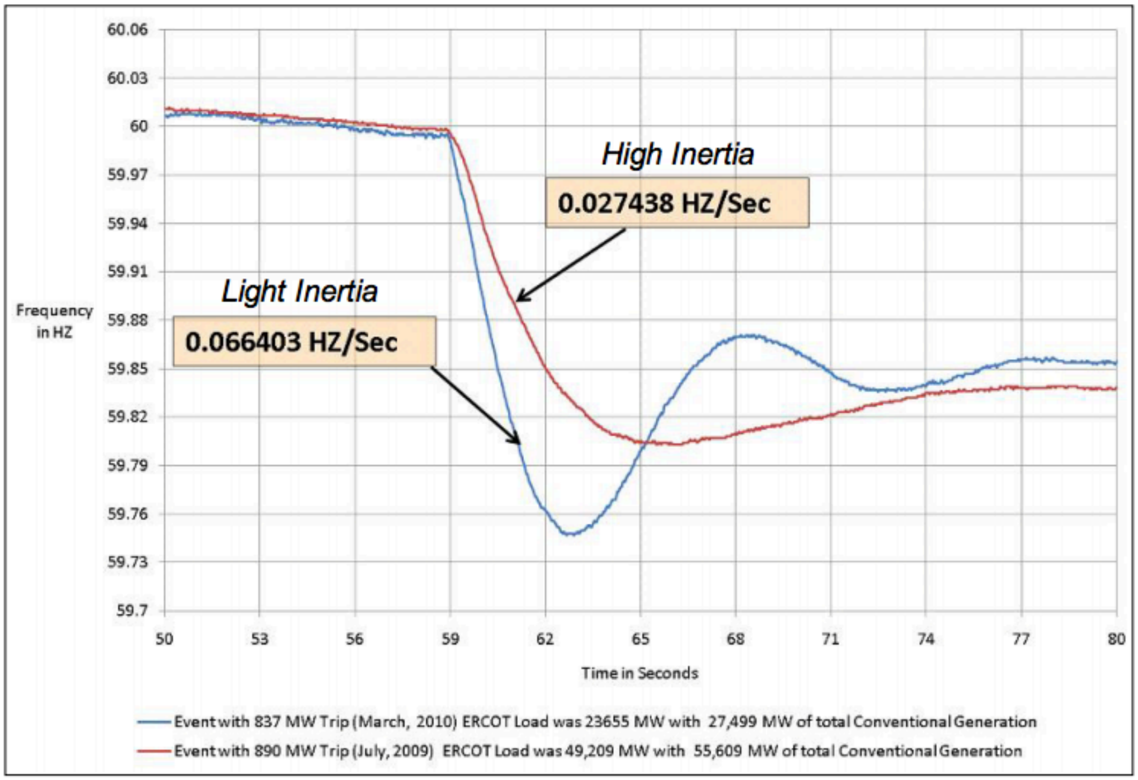


Figure 7 – Sensitivity of frequency response to inertia[16].

Figure 8 shows the frequency response in the Western Interconnection with high levels of wind and solar. The blue trace is the 'out-of-the-box' response (i.e. no frequency response contribution from wind and solar), which is marginally acceptable. The green trace shows the impact of having the wind turbines provide PFR[17] – the settling frequency improves and system recovery is faster. The red trace shows the impact of having the wind turbines provide FFR, in the form of a synthetic inertia control[18] – the frequency nadir improves, although the system does not recover as fast. The pink trace shows the impact of wind providing both inertia control and PFR – the nadir improves and the event recovery is relatively quick.

[16] NERC, "Frequency Response Initiative Report," Oct. 30, 2012. http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[17] In this particular case, the PFR of the wind plants was tuned to give similar speed of response to "representative" thermal generation.

[18] This particular inertial control is based on the present GE Wind offering. Other OEMs may have somewhat different control schemes.

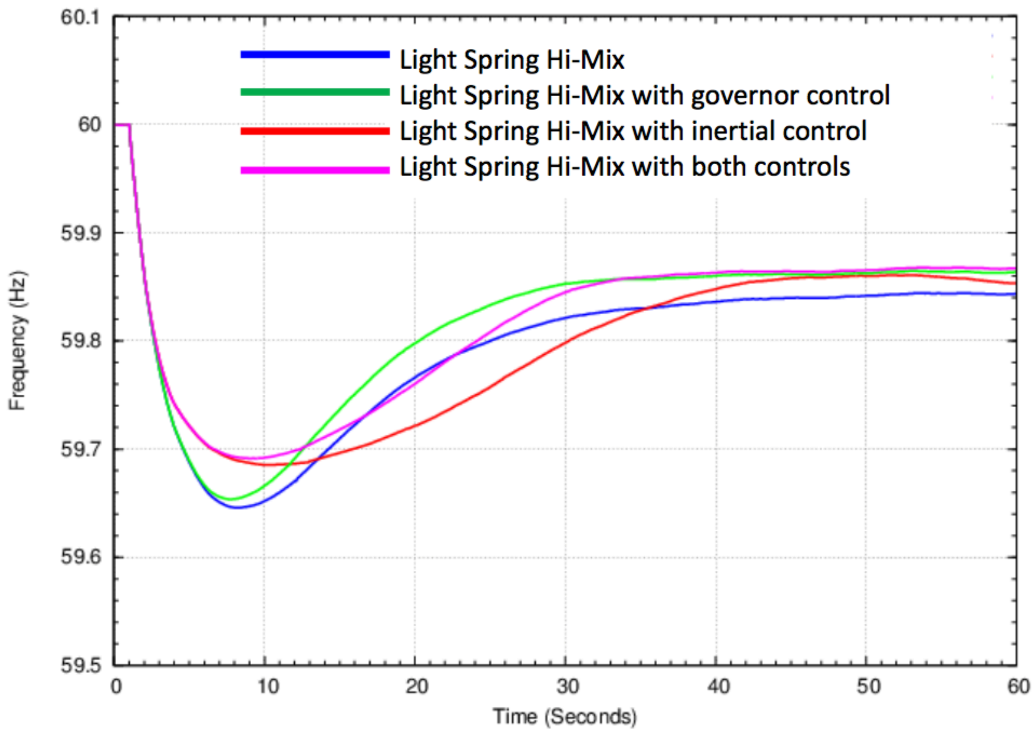


Figure 8 – Frequency Response to two Palo Verde units trip with three combinations of frequency controls on wind plants[19].

Metric	Year	Eastern	Western	ERCOT	Quebec
IFRO (MW/0.1Hz)	2012	1002	840	286	179
	2015	1014	907	471	183
CBr	2012	1.0* (.989)	1.625	1.377	1.550
	2015	1.0* (.979)	1.672	1.700	1.550**

Table 1. Frequency response obligations and CBr (frequency nadir divided by settling frequency) over time for North American interconnections[20].

A critical consideration in the setting of IFRO is the ratio between the frequency nadir and the settling frequency. This ratio, CBr, is monitored and used as input to provide an annual update of IFROs. As both system inertia and the speed of response of frequency sensitive

[19] N. Miller, et al, "Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability", NREL/SR-5D00-62906, December, 2014. http://www.nrel.gov/docs/fy15osti/62906.pdf

[20] NERC, "2014 Frequency Response Annual analysis", December 2014 (version dated 1-12-15 on www.ercot.com/../Fr_2014...)

resources change, this metric moves. NERC annually updates this metric, and the process appears to be working well. The most recent update[21] shows the latest updates to both the IFRO and CBr. Some of the metrics are summarized here in Table 1. The IFROs and CBr are inching up, possibly because of declining inertia (although there is not necessarily causality implied). The BAs are obliged, under the existing standard, to consider this trend, regardless of the cause, and assure that they meet their obligations. It is not at all clear what added reliability benefit related to frequency would be met by layering another standard on top of this one.

The only piece of the puzzle that is arguably not explicitly in BAL-003-1 is the relative contribution of individual BAs within an interconnection towards improving (or degrading) the metric CBr. Clarification of this element, which would probably take the form of monitoring (and rewarding) the provision of arresting power, might prove to be an appropriate and valuable improvement to the standard. Some monitoring of trends and behaviors across BAs in this regard is probably prudent now. Innovative definitions and provision of new services, such as ERCOT's FFR, will result in improved CBr.

Inertia is part of overall system dynamics, and is largely covered by existing planning practice. A recent NERC document included the statement: "…important that any potential decrease in system inertia be considered when determining resource planning…" . This is certainly prudent advice, with "considered" being the operative word. The inertia of the system, and the inertia of individual resources, is an important piece of system stability in all its forms – transient stability, frequency response, damping, and even voltage stability. All changes to the network and to the dynamic characteristics of specific generating resources need to be covered in system planning studies. For example, there are existing NERC standards that dictate that large generators have excitation systems, governors, etc. It is understood that having voltage regulators and excitation systems on generation is good for system stability, and therefore reliability. But, it is also understood that more is not necessarily better: unduly aggressive excitation degrades some aspects of system performance. The benefits are situational and locational, and so the industry and NERC have (wisely) avoided being too prescriptive in this regard. The same can be said of inertia: there are situations where inertia is detrimental to the stability of the system. More is not necessarily better. That is why the industry has developed practice to evaluate the specifics of system dynamic performance. Considering changes in system inertia is just another facet of existing and accepted practice. There is little evidence that this needs to be changed or augmented by requirements, standards or markets for inertia. Rather, the reliability urgency is that planners have good tools, good models, and good understanding of the changes in system dynamics brought by different technologies, including inverter-based resources.

2.4 Supply-side versus demand-side

Load resources can provide high quality FFR. In ERCOT, loads provide half of the interconnection's Frequency Responsive Reserves that support the system in a sudden loss

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[21] NERC, "2014 Frequency Response Annual analysis", December 2014 (version dated 1-12-15 on www.ercot.com/../Fr_2014...)

of load event. Because loads, storage and switchable devices (e.g. dynamic brakes) can provide FR, it's important to ensure that all resources are allowed to participate in potential markets for these services. PFR from these resources may prove to be more effective and economic than PFR provided by generation resources in meeting the frequency reliability needs of systems.

3 ALL PFR IS NOT CREATED EQUAL

There are a number of details and practical issues associated with frequency response that enter in the practical consideration of meeting reliability objectives and compliance with BAL-003-1.

3.1 Squelch/Governor withdrawal

The NOI mentions governor withdrawal or squelch and this has been surveyed and investigated in some depth in the Eastern Interconnection. Squelch is a serious problem that NERC actively addressing. There are significant activities in ISO-NE, and other ISO's, to address the problem. To the authors' knowledge, this has been less studied in the Western Interconnection. While the Western Interconnection does not suffer the same level of frequency response degradation as the Eastern Interconnection, it is likely that similar squelch issues are occurring at generators in the Western Interconnection and this should be a high priority for investigation.

At least some synchronous generator (e.g. thermal generator) OEMs have been supporting NERC, with the introduction/development of frequency-supervised load controllers, intended to mitigate the squelch problem – from a performance perspective. There may still be mitigation needed in some markets to address potential penalties on plants for being off-schedule during times when their PFR is actuated.

3.2 Speed

Different technologies can provide different speed of response. Most notably, inverter-based controls (from wind, PV, batteries, frequency-responsive load) can provide faster response than thermal generators. FFR in ERCOT is enabled within 0.5 seconds of an event. Figure 9 compares the frequency response of ERCOT to the design-basis event with three combinations of PFR and FFR. The frequency nadir is approximately the same for the three combinations, illustrating that under these high wind, low load conditions, 1,400 MW of FFR provides the same response as 3,300 MW of PFR (i.e., 1 MW of FFR provides the same reliability impact as 2.35 MW of PFR).

To the authors' knowledge, there is no additional wear-and-tear, or variable, cost on the wind/PV for providing FFR versus PFR. If there is no additional cost, the system may want to take advantage of the faster response which is more effective. In order to incentivize the faster response, it will be important to reward the faster response.

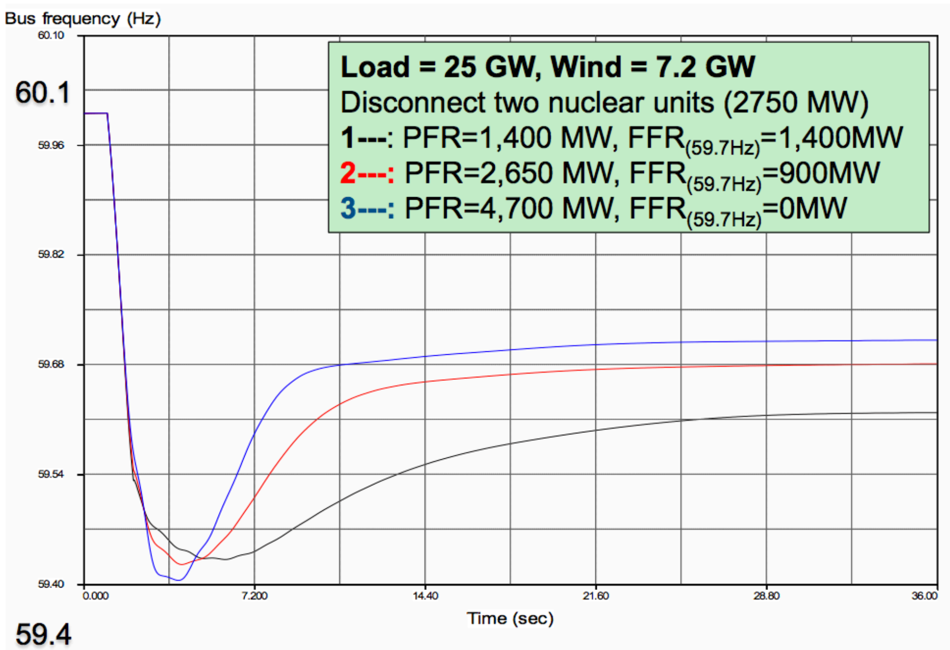

Figure 9 – ERCOT frequency response, showing 1 MW FFR is equivalent to 2.35 MW of PFR, during high wind, low load operating conditions[22].

3.3 Measuring Frequency

The reality is that *all* synchronous generation uses the *speed* of the machine as a proxy for system frequency. That is the origin of the word "governor" – it governs the speed of the machine. There is a close relationship between the speed of a synchronous machine and the system frequency, but the two quantities are *not* interchangeable when it comes to controls. Non-synchronous generation must measure frequency by some other means. This opens the potential for superior FR, but it also presents an additional (and new) technical detail than can lead to unintended consequences for overly prescriptive rules.

The measurement of frequency from observable quantities, i.e. voltage or current, is more of a deduction than a direct measurement. Assuming that measured voltages are sinusoidal[23] (at 60 Hz ± Δf), frequency deviation from 60 Hz is effectively the rate of change of the angle of the measured phasor. This means that frequency is effectively the derivative of an observed signal: it is noisy. That means that the measurement can not be made instantaneously, since some filtration is needed. There are a variety of algorithms that have different trade-offs in accuracy and speed. In short, measuring frequency isn't as simple as it might seem. Further, controls are occasionally proposed that are responsive to ROCOF. This

[22] J. Matevosyan, "Future Ancillary Services Developments in ERCOT," *NERC Essential Reliability Services Task Force* presentation, Aug. 7, 2014.

[23] This assumption good enough for most purposes here, but the sinusoids are distorted and imperfect during severe events, such as before a fault is cleared.

is the time derivative of a signal that is itself a derivative – a difficult and noisy signal that requires a significant sample interval to achieve good fidelity. Extremely fast measurement of ROCOF for control purposes is difficult.

3.4 Locational Aspects of Frequency

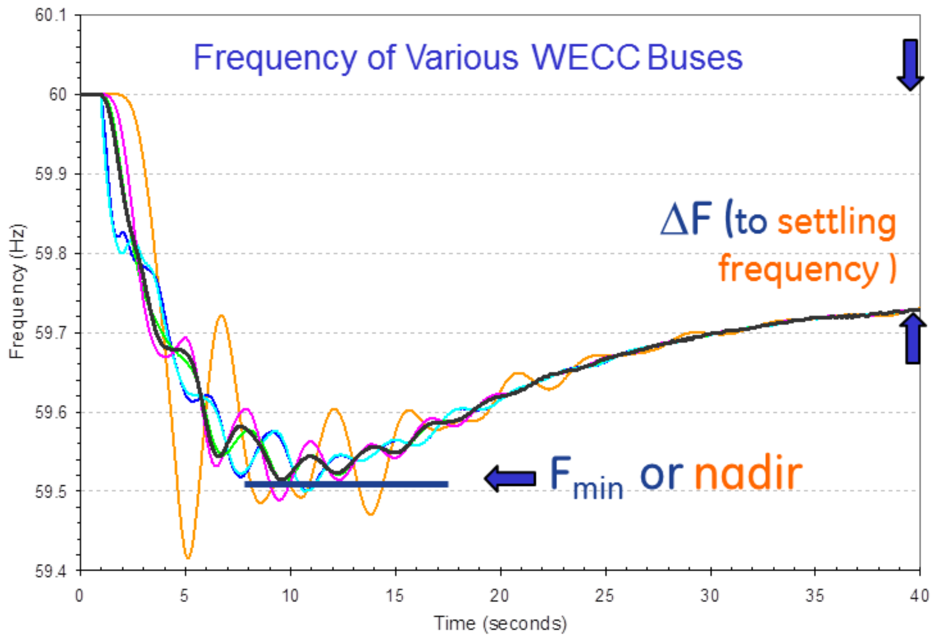

Figure 10 – Bus Frequencies for a large disturbance.

In the examples of simulated frequency shown above, system frequency appears to be a uniform quantity. However, in the initial period following a large disturbance, system dynamics result in multi-modal swings. Consequently, until these inter-area swings damp out, frequency varies with location, as shown in Figure 10. The significance for mandating and paying for frequency response – especially *fast* frequency response can be significant. In Figure 10, the disturbance occurs at 1.0 seconds. The buses near the lost generation (teal blue) drop very rapidly (i.e. high initial ROCOF), but the bus farthest from the disturbance, the orange trace here (which is more than 1000 miles away from the disturbance), doesn't "see" the event for nearly 3 seconds. Compliance based on when the event *occurred*, rather than when the bus could *observe* the event, would have very different conclusions.

3.5 Droop

Modern generation, particularly inverter-based resources like wind and solar have the potential to respond very aggressively (and effectively) to frequency deviations[24]. Historic practices of enforcing uniform droops (typically 5%) have some benefits in terms of

[24] This has been shown in several studies. A sequence of illustrative cases in the Western Wind and Solar Integration Study Phase 3 show this result quite clearly.

coordination and simplicity, but also carry a penalty in terms of flexibility and efficacy. Consider, per BAL-003-1, that the frequency nadir should be no deeper than about 59.6 Hz (1st stage of UFLS in the US is usually at 59.5Hz). Thus, the maximum increase in output realizable for the design-basis events targeted by BAL-003-1 are limited to about 15% of machine rating, *regardless* of whether more headroom is available. Thus, there will be *no* systemic benefit for design-basis events of holding more than about 15% headroom on an individual unit.

Under conditions of scarcity, this could represent a reliability concern as well as an economic one. This can be easily addressed by an acknowledgement that more aggressive response (i.e. lower droop) may be appropriate. That is, under some operating conditions, the system may need more than 15% response and wind/PV may be able to provide that, provided they are compensated accordingly. Additionally, more aggressive response (lower droop) should be rewarded.

3.6 Dead band

With the very small dead band being advocated by NERC, all of the major US interconnections will *often* have frequency deviations that exceed the dead band. Consider, a simple case (that might occur multiple times per hour in ERCOT) of a frequency excursion to 60.02 Hz. With a 16.7 mHz deadband, this is a 0.0033 Hz error, which, with 5% droop, means that the generator or plant should reduce its output by 0.11%. That would be 23 kW for a 20 MW plant (about 1 hairdryer worth of power, per wind turbine). This implies a degree of precision in control of any resource that may be quite difficult to realize. The point is that, as with all performance requirements, a degree of flexibility is required in determining compliance.

3.7 Sustain

The NOI's discussion of "sustained" response is clearly aimed at eliminating squelch, but introduces a concern for wind and PV. If, for example, the period imposed to define sustained is several minutes, then it is possible that the wind speed or solar insolation could decrease so as to use up whatever headroom has been accessed by the frequency responsive control. If no provision for such an eventuality is made in the language of the ruling, the impact could be a severe, and presumably unintended, consequence: that the resources would need, at all times, to retain not only the curtailment necessary to meet the procured headroom, but additional headroom to cover the statistical expectation of how much deviation in the energy source might occur over the period defined by "sustained". That result could be economically severe and should be carefully considered in any ruling.

In the case of over-frequency, there is a minor, but non-trivial concern about operation at very low power. Wind turbines are technically challenged to continue operation (i.e. keep spinning) at zero power. Unlike thermal, hydro or any other synchronous generation in normal use, it is possible for wind turbines to operate at very low power levels – even a few percent of nameplate rating is possible. And thus, it is possible that an over-frequency event could drive the turbine to zero power. Some language in the ruling that provides relief from performance requirements at very low power levels (for this and other functions, such as reactive power requirements) is appropriate. Another aspect of very low power rating, is that on a plant level (especially for wind), at low power levels (statistically in the neighborhood of 10 to 20 percent production), the variation in wind speed across a plant will often result in some turbines stopping while others continue to run. The net result is an apparent, temporary derating of the plant. This should be considered and allowed in any ruling.

3.8 Delay

The NOI's discussion of providing response without "undue delay" presumably means that the controls shall not *deliberately* be delayed or act more slowly than is "practical". This is unfortunately a grey area for most resources: extra speed may be possible but have a cost – in equipment risk, wear-and-tear, or stability. Ultimately, economic signals should be provided to reward speed of response. Plant owners can then weigh the increased VOM or capital costs against the increased value of fast response and make appropriate decisions.

4 PFR CAPABILITY

4.1 LGIA vs SGIA

If PFR capability is mandated, it will be important to allow exemptions or modifications of the rules for certain technologies that have physical machine limitations. For example, nuclear plants may not be able to provide under-frequency response or comply with tight dead bands. Consideration should be given to allow for partial or full exemptions in the Large Generator Interconnection Agreement (LGIA) given strong justification as to how full PFR response is not compatible without extreme plant modifications.

If PFR capability is mandated, it may be useful to set up categories of generators under the Small Generator Interconnection Agreement (SGIA) to allow for some exemptions. Small generators are of special consideration because 1) some small generators may be incapable of providing PFR and 2) it may be cost-prohibitive for some small generators to provide PFR. For example, it is essentially impossible for non-variable speed wind turbine generators (i.e. type 1 and 2 wind turbine generators) to provide PFR. While this technology is not typically used in utility-scale wind plants, it is still common in small wind systems (e.g. <100kW or so). Very small hydro or Brayton cycle solar plants may also fit into this category. The absence of an exemption for some technologies could result in effectively prohibiting their use.

While we note that mandates of PFR capability would require potential exemption clauses, we also note that if plausible operating conditions include high penetrations of these exempted systems, it may not be possible to maintain system reliability. The system operator needs to be able to commit adequate generation that has PFR capability. Therefore, if a generator requests an exception to PFR requirements, it should instead be required to have capability to curtail by system operator action.

This includes Distributed Energy Resources (DERs), which, for the most part, are not currently curtailable by system operator actions. This is not meant to put an undue burden on DER but rather to acknowledge the fast growth of DER and the possibility of instantaneous high penetrations of DER that may displace other generation that is providing essential reliability services. A binary curtailment control on the DER is sufficient; set point control on the DER is not necessary for this purpose.

4.2 European rooftop solar experience

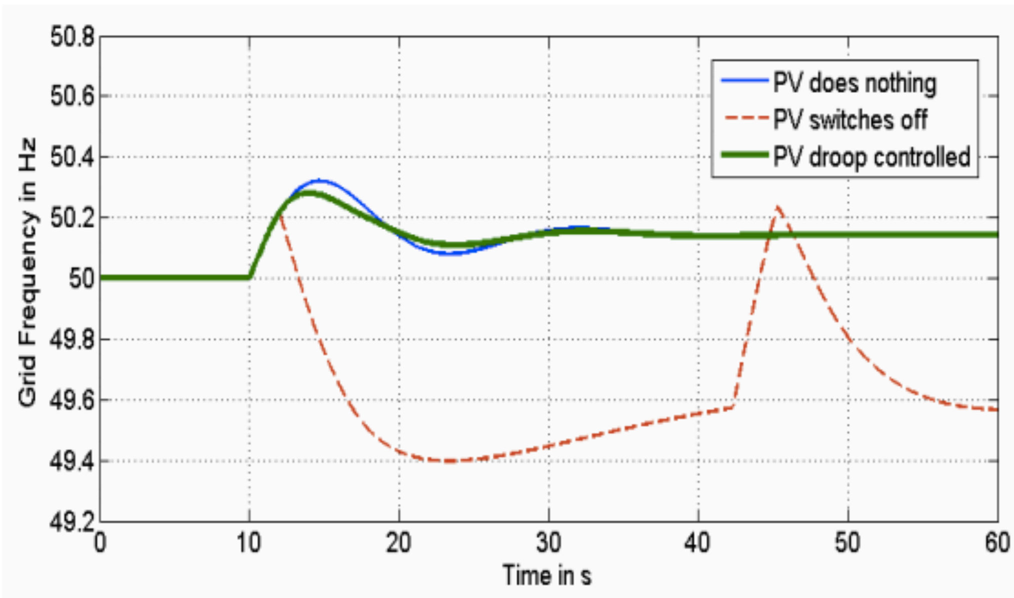

Figure 11 Overspeed event due to loss of load of 5 GW in Europe resulting in disconnection of 10 GW of DER at 50.2 Hz[25]

Germany has extensive experience with retrofitting DER to comply with updated interconnection requirements. During 2005-2006, Germany did not anticipate high penetrations of DER, so the interconnection requirement was established such that rooftop solar inverters had to trip offline for over-frequency events at 50.2 Hz[26]. In subsequent years, about 12,700 MW of rooftop solar was interconnected to Germany's low-voltage distribution system. The European grid is designed to survive a sudden loss of load of 3,000 MW. This is much smaller than the amount that could be lost upon common-mode tripping of 12,700 MW of rooftop solar. Common-mode tripping of the 12,700 MW of rooftop solar could plausibly occur due to a loss-of-load event (e.g., loss of an intertie during export conditions) that increased frequency to 50.2 Hz. This identified reliability problem led to studies: the

[25] Kastle, G. et al, "Improved Requirements for the Connection to the Low Voltage Grid," CIRED 21st International Conference on Electricity Distribution, Frankfurt, Germany, 6-9 June 2011. http://www.cired.net/publications/cired2011/part1/papers/CIRED2011_1275_final.pdf

[26] J. Boemer, et al, "Overview of German Grid Issues and Retrofit of Photovoltaic Power Plants in Germany for the Prevention of Frequency Stability Problems in Abnormal System Conditions of the ENTSO-E Region Continental Europe," *1st International Workshop on Integration of Solar Power into Power Systems*, Aarhus, Denmark, Oct. 24, 2011

dashed red trace in Figure 11 shows a simulation of such an event in the European grid, with the rooftop solar systems tripping offline at 50.2 Hz and then trying to reconnect after 30 seconds. The green trace simulates the same event, but with the PV providing over-frequency droop response.

The studies led to a retrofit action. Nine hundred distribution system operators had to come together to reach agreement to retrofit some 350,000 existing systems at an estimated $520 million cost to correct this reliability problem[27]. Being proactive and undertaking careful planning is one of the lessons learned from the German experience.

There are two issues at play here. One is that the existing interconnection requirements should be revised so that DER supports grid reliability – so that DER does not common-mode trip at a tight voltage or frequency deviation. The second is whether DER should be required to provide PFR capability. It seems reasonable to have DER (of a specified minimum rating – ENTSO-E has a cut-off below 800 W) provide over-frequency response, in order to support system reliability without incurring an opportunity cost. But whether DER should be capable of under-frequency response needs careful consideration. On the one hand, DER is growing quickly, and as Germany has seen, retrofits can be expensive, time-consuming, and resource-consuming. On the other hand, providing PFR from the resources that are most cost-effective may be most economical to society and it's unlikely that rooftop PV owners will be interested in pre-curtailing their systems to try to make money in a potential PFR market. However, if one believes that very high DER penetrations or micro-grids are realistic future scenarios, then proactive planning would suggest that requiring PFR capability for these systems would be prudent.

Whether the exemption bar is set high enough to require new rooftop solar to provide PFR capability or not, we recognize that there will likely be DER exempt from the PFR requirement and it is important to note that as explained in Section 4.1, PFR needs to be binary curtailable by the system operator in the event that the system must be curtailed in preference of a system that can provide PFR.

4.3 DER interconnection standards

The IEEE-1547 standard, that specifies the technical requirements for interconnection of DER (whether inverter-based, synchronous machine, or induction machine), is currently under revision. The original IEEE-1547-2003 standard did not allow for some advanced inverter functionality (specifically prohibited active voltage regulation, low-voltage and low-frequency ride-through). The amendment IEEE-1547a-2014 allows for expanded functionality[28]. A full revision to the standard is underway and is anticipated to be balloted this year. Categories of DER are being considered to allow for current DER technology, DER that stays online for a wider range of faults, and DER in high penetration regions. Functions

[27] B. Ernst, SMA, "Evolution of LV PV Interconnection Requirements in Germany," Utility Variable Generation Integration Group Spring Technical Workshop, Anchorage, AK, May 2014.

[28] E. Reiter, et al, "Industry Perspectives on Advanced Inverters for U.S. Solar Photovoltaic Systems: Grid Benefits, Deployment Challenges, and Emerging Solutions," NREL/TP-7A40-65063, Sep. 2015. http://www.nrel.gov/docs/fy15osti/65063.pdf

to support PFR, which is also called 'frequency/power' operation, are also being considered in the revised standard and this functionality could vary depending on the DER category[29].

4.4 Capital Costs

The capital cost to wind plant owners for inclusion of PFR capability in a new plant is on the order of less than 1% of the capital cost of the overall project. While this is a small incremental cost, it is important to note that margins and returns on investment in the US electric power market are measured in quite small fractions of the overall initial capital cost of a project. A less than 1% increase in the capital cost of project might reasonably be regarded as a substantial sum by the investors.

Retrofits of PFR to existing plants are more expensive than inclusion of PFR in new plants. While capital costs for retrofitting the PFR capability in wind plants vary depending on the vintage and type of technology, a rule of thumb is that the capital cost for retrofits is on the order of less than 2%. Again, this is a small incremental cost, but in the case of mandatory retrofits, this incremental cost has not been built into the economic evaluation, justification, and financing for a project, and so the economic consequence to the plant owner is more significant. It is noted that the mandatory retroactive requirement for PFR capability was not well-received by wind plant owners in ERCOT.

There is not yet sufficient commercial experience to determine capital costs for PFR (or FFR, as the response can potentially be very fast) in PV plants. Because PFR is largely a control software modification more so than physical hardware (or inverter rating, which would impact copper content) modification, the incremental cost is thought to be modest. Inverter costs are a small fraction of the overall PV plant cost. NREL's Q1 2015 benchmarks for breakdowns of PV plant costs find that inverters cost $0.29/W out of a total installed cost of $3.09/W for residential, rooftop PV, or about 9% of the total cost[30]. If, hypothetically, PFR were to increase inverter costs by 25%, the total rooftop PV system cost would increase by 2%. For utility-scale PV systems, inverters cost $0.11/W out of a total installed cost of $1.77/W, or about 6% of the total cost[31]. A hypothetical, 25% increase in inverter costs would increase the total utility-scale PV system cost by less than 2%.

5 PFR ENABLEMENT AND HEADROOM

Once the PFR technology is installed on some number of plants, how should the system operator decide which plants should enable PFR at any time? Once PFR is enabled, how should the operator decide how to dispatch plants to provide headroom for the response? Different technologies have different costs for providing PFR and Table 2 below illustrates

29 J. Boemer, "Interconnection Requirements for DER: Regulatory landscape – issues and trends," Utility Variable Generation Integration Group PV Workshop, San Diego, CA, Oct. 13, 2015.

30 Chung, D., Davidson, C., Fu, R., Ardani, K., and Margolis, R. "U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems," NREL/TP-6A20-64746, Sept. 2015. http://www.nrel.gov/docs/fy15osti/64746.pdf

31 Ibid.

why it is better to determine PFR provision via economics/markets rather than mandatory regulation.

	Dispatch down for headroom	**Cost to provide PFR**	**Cost to actuate PFR**	**Priority for PFR**
Wind/PV/run-of-river hydro (*normal* operations)	Y	High – fuel is free (also lost REC/PTC revenue)	Zero	Low
Wind/PV/run-of-river hydro (*curtailed* operations)	N	Low	Zero	High
Gas turbine (open cycle)	Y	Moderate	Moderate	Medium
Gas turbine (combined cycle)	Y	Moderate	Moderate	Medium
Steam turbine	N	Can be zero or low	Moderate and depends on efficiency penalty	High
Steam turbine (combined cycle)	Y	High because causes overall efficiency penalty	Low	Low
Hydro with pondage	Y	Low	Low	High

Table 2. Opportunity and variable costs of PFR provision for various technologies.

Once PFR capability is installed, "enabled" represents a relatively unambiguous, and relatively straightforward, low variable cost requirement for most modern utility scale wind turbines and wind farms. This is a commercially available function on at least some (and probably most or all) utility scale wind generators. As noted in the previous section, this is not a widely available feature today on solar PV inverters. However, in the case of other synchronous generation, particularly some types/configurations of steam turbine systems, having the governor enabled may have an efficiency penalty for the plant. In this case, the plant incurs an operating cost just to have the function enabled – this is economically akin to curtailing a wind or solar plant in order to provide headroom. Judging from the accompanying language, it is not FERC's intent that generators incur a significant *variable operating cost* penalty without some economic/financial compensation. In some cases, simply enabling the governor may result in a variable cost.

For example, for a combined cycle plant, the steam turbine part typically operates with valves wide open (sliding pressure). Headroom is not simply the difference between maximum output and current output of the steam turbine. There is no headroom there even if unit is operating at less than full output. It can't produce more power in the seconds time-frame by adjusting controls or fuel input. The plant operator could throttle the steam turbine back but then the plant would take efficiency hit most of the time (when PFR is not actuated).

Steam turbines that are not in a combined cycle plant typically operate at a sweet spot in the heat rate curve. Increasing the output may operate the plant at a less efficient point in the curve. Efficiency in this case is optimal most of the time and could be suboptimal when PFR is actuated.

It is possible that some resources will incur significant costs, in terms of O&M. The authors' experience is that the PFR of wind plants were actuated more frequently than expected in ERCOT, where these controls are required. While wind turbines do not experience significant wear-and-tear costs, this could be an issue for other resources. The dead band settings may require review to ensure a balance of adequate frequency response while not incurring high wear-and-tear O&M.

6 METRICS AND MONITORING

At the system level, the single most important metric for primary frequency control is K_t [32,33,34]. It is incumbent on BAs (via BAL-003-1) to monitor their FR relative to their FRO. Some mechanisms must be made available to BAs that are faced with a credible risk of being short of FR to compel compliance (presumably that is the point of the section, rather than blanket compulsion when not shortage is credibly anticipated. These mechanisms should apply across the board (i.e. to new and existing resources). Clearly, monitoring is part of the solution: a BA must have good information about how/whether resources are providing PFR – thus the monitoring aspect, even as a retroactive requirement, may well be justified.

BAL-003-1 explains measurement of a BA's FRO compliance. How do we measure an individual power plant's PFR performance? The methods outlined in NERC BAL-003-1 for BA level measurements can be readily extended to monitoring individual plants, and indeed it would make a great deal of sense to "harmonize" the individual plant performance monitoring with the BA requirements. First, it is important to measure the plant response at a sufficiently high sampling rate to capture both the active power response and the system frequency as observable at the plant. Events need to be collected, time stamped, reported and archived. Responses need to be checked against obligations, including testing the

[32] J. Eto, et al. "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation", LBNL-4142E, Dec. 2010. http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf

[33] N. Miller, et al, "California ISO (CAISO) Frequency Response Study," Nov. 9, 2011. https://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf

[34] J. Undrill, "Power and Frequency Control as it Relates to Wind-Powered Generation," LBNL-4143E, Dec. 2010. http://www.ferc.gov/CalendarFiles/20110120114503-Power-and-Frequency-Control.pdf

performance of the dynamic model used for planning studies (as is already mandated by NERC).

BAL-003-1 has introduced a variety of tools and application rules – including a spreadsheet-based analysis tool – that is intended to allow BAs (and other entities) to determine whether they are in compliance with the standard. It would be appropriate for a similar set of tools to be developed that are intended to establish how individual resources (at least generators, but other resources as well) respond to frequency events.

BAL-003-1 correctly recognizes that perfect adherence to the performance target is neither possible nor necessary. Consequently, there are metrics included in the standard (e.g. 95% confidence level in performance). Similar rules should be applied to individual resources, although it is not clear that the same confidence levels are necessarily appropriate. This is yet another aspect of FR and individual resources that needs more quantitative analysis before being required.

7 WESTERN INTERCONNECTION ANALYSIS NEEDS

In the Western Interconnection, WECC, as the regional entity, and Peak Reliability and AESO, as the reliability coordinators, work to ensure reliability and security of the grid. This discussion highlights current needs to ensure that existing system reliability as well as proactive measures to maintain reliability in future scenarios with new technologies.

When new rules, that may incur costs, are contemplated, it is incumbent upon the decision-makers to demonstrate that these rules are needed. FERC is being proactive in examining existing downward trends in PFR and positing future scenarios that may hold less PFR. Analysis is needed to model future scenarios and operating conditions to understand potential future PFR needs and potential pitfalls. The discussion in this report raises the need for examination of futures with high penetrations of inverter-based generation, high penetrations of generator without inertia, high penetrations of gas, and high penetrations of DER under different interconnection requirements.

This FERC NOI is symptomatic of a wave of change already impinging on the Western Interconnection. The lead time for significant infrastructure changes, particularly additions of renewable resources and retirements of fossil resources, is shorter than ever. Further the lead time for implementation of some types of mitigation, especially new transmission, is longer than ever. This creates an environment were there is an acute need to examine a wider range of questions and issues for a wider range of possible futures than ever before. Maintaining adequate *frequency response* becomes a critical subset of these challenges.

With this in mind, we recommend specific analyses that could provide value in navigating this uncertain future while maintaining system reliability:

Round-trip: Tight linkage between production simulations and dynamic simulations

Production simulations can illustrate the various operating conditions (commitment and dispatch) that can be mined for those hours in which the system is most vulnerable (defined by, for example, non-synchronous penetration, headroom, inertia). We then need to understand where and when these scenarios fail. With emerging significant changes in both generation mix and power flow patterns, today's selection of operating conditions and disturbances for evaluation is likely to be inadequate. Identification of vulnerabilities under credible new operating conditions should be pursued on a broad and systemic fashion. Round-trip analyses could be set up to pull vulnerable hours from production simulations and examine their system responses to various contingencies or faults. Failing responses could be examined with increasing headroom to determine new rules of thumb for FR. Correlations between new operating conditions and new limits (including, but not limited to path limits) may be needed to augment or even replace existing limits, nomograms and other related criteria. This type of analysis will also advise on the locational needs of frequency response, for example providing guidance on the amount of FR that can be traded between BAs in order to satisfy their FRO.

Expanded DER Penetration Analysis

The rapid expansion of DER has already shown the potential for disruption, as seen by the rooftop solar contribution to the California duck curve. How DER is included in both production simulations and in dynamic analyses needs to expand in scope and sophistication. Impacts of high levels of DER on stability, reserves, path ratings, load dynamic behavior all have the potential to impact system reliability, including frequency response.

High non-synchronous penetration/Low short circuit ratio analysis

The Western Interconnection is evolving towards higher levels of power electronics-enabled resources – generation, transmission, energy storage and load. This can lead to dynamic performance concerns that we tend to think of as "weak grid" issues. Resources like wind and PV, battery energy storage, HVDC transmission, static VAR compensators and STATCOMs, do not contribute to the short circuit strength of the system. Other systems, most notably EirGRid (Ireland) have found that there are limits to the instantaneous penetration of such devices. The understanding and art for this type of analysis is not well established, and the Western Interconnection has very different characteristics from the smaller, isolated and more homogeneous Irish system. Investigations to determine if there are significant weak grid problems, and how they might be mitigated, are needed.

Extreme Future Analysis

Preparation for the future tends to be limited to incremental changes to infrastructure, including generation, transmission and loads. But recent history has demonstrated rapid, disruptive changes in the utility sector with more extreme changes likely. We would be well-advised to conduct careful planning today and undertake some degree of preparedness rather than repeat mistakes such as occurred in Germany. Challenging questions like "what happens if all the nuclear stations must shut down?", "what happens if capital cost of dPV drops significantly?", "what happens in an extremely high hydro year?", etc. are examples of potential extreme futures to examine.

8 CONCLUSIONS

Adequate arresting power is essential for a reliable power system. However, PFR is not needed from every generator at all times. The current situation for PFR is summarized as follows:

1. Currently, there is not a shortage of PFR in the Eastern or Western Interconnections or ERCOT.
2. NERC BAL-003-1 should help to address issues around governor enablement, settings and performance.
3. Frequency response studies have been undertaken to examine impacts of increased wind and PV penetrations and have not found problems but have found that PFR/FFR/inertia from wind and PV can be very helpful to maintain system reliability.
4. Frequency response studies have been undertaken that illustrate problems with the dynamic planning models.

It is important to be proactive because 1) frequency response has been declining, 2) there have been problems with governor settings and performance, 3) the grid has increasing amounts of inverter-based generation which do not provide PFR "out-of-the-box", 4) the grid is likely to change in other ways that cannot be easily forecast.

PFR Capability

FERC's NOI asks about whether new and existing generators should be capable of PFR. Reliability and economics must be assessed to determine the balance of maintaining reliability while not creating an undue burden to generators which ultimately is borne by the ratepayer. Additionally, imposing a retroactive requirement on existing generators requires sufficient justification because it may be viewed as unfair.

Because PFR is not needed from every generator at all times and because frequency response studies with moderate wind and PV penetrations do not show a problem, it is unlikely that a retroactive requirement on existing generators is necessary. Studies with plausible scenarios would have to demonstrate a need for a retroactive requirement, showing where and when shortages occur. Even with a retroactive requirement, there would need to be an exemption clause because it is not possible to retrofit PFR on some types of generators.

For new generators, the need is for *adequate* PFR. Adequate levels of PFR can be sourced through *either* mandates or voluntary markets. The authors lean towards mandates for PFR *capability*, with appropriate exemptions, for the following reasons:

1. The future grid is likely to have a very different generation mix from today. Commitment and dispatch are likely to be very different from today. Therefore it is difficult to forecast which generators need to have PFR capability and under what operating conditions.

2. Wind, PV and other resources, that do not currently tend to provide PFR, may have to be curtailed in favor of generators that do provide PFR. This could undermine policies and incentives that have been established to encourage low carbon energy sources.
3. It is likely that the costs do not place an undue burden for wind or PV in the LGIA, although this report has not undertaken a cost analysis. For the LGIA, the cost of PFR capability for new wind is anticipated to be small (for example, <1% of a wind project cost), and the cost for retrofitted PFR is more expensive (<2% of project cost). Because the cost is less for new PFR than for retrofits, it is not clear that a market-based approach is the most cost-efficient way to ensure adequate PFR capability as the generation mix evolves.

Whether mandates or markets are used to determine PFR capability, it is important that generators which do *not* provide PFR are controllable because they may need to be curtailed in favor of a generator that does provide PFR.

PFR Provision

It is important to determine PFR *provision* based on economics or through markets because different resources have different opportunity and variable costs. Over-frequency response should be distinct from under-frequency response because they have different costs.

PFR provision includes enabling PFR and operating so that the unit has headroom or footroom to move. Generators need to be compensated for PFR because they may incur opportunity and variable costs in enabling and operating to provide PFR, as well as wear-and-tear costs in the actuation of PFR. These costs vary depending on the operating condition of the resource, so the determination of which resources provide PFR should be made as close to real-time as possible. This allows a BA to take advantage of the fact that while PV in normal operating conditions incurs a significant cost to provide PFR, under *curtailed* conditions for system reasons, this same PV can provide PFR easily, quickly, and at no cost. Determination of real-time PFR provision may require enhancements to existing energy management system tools.

All PFR is not equal. Some resources (wind, PV, some storage, load) can provide faster and more aggressive (lower droop) responses. Faster and more aggressive responses can be more effective than conventional PFR and should be rewarded. Speed and droop characteristics need not be the same for over- and under-frequency response.

Western Interconnection Actions

There are a range of actions that can be undertaken as 1) proactive measures to maintain reliability in future scenarios with changing generation portfolios and 2) opportunities to capitalize on the faster and more aggressive responses that new technologies can bring to the system.

Actions to address the current state of frequency responsive measures:

- Current state of governor settings – determine which governors are enabled; determine their dead band and droop settings; address potential governor withdrawal issues.
- Allow load to provide FFR.

Good planning for future scenarios and capitalizing on new technologies:

- Examine potential revision of ancillary services that capitalizes on fast responses from capable load, generators and storage and addresses a changing generation mix. Gain a better understanding of the PFR/FFR/inertia interaction and how faster or more aggressive responses may be more effective and under what conditions. Also examine the system dynamics of faster, more aggressive responses to ensure that stability is not undermined.

Improve models:

- Continue and expand benchmarking of dynamic planning models against real events; improve these models and use for planning studies.
- Improve load and validate models.
- Expand and refine processes for creating correct initial conditions (i.e. loadflows) from observed operating conditions (i.e. from operating records and state estimators).