Final Report:

Advisory on Equipment Limits associated with High RoCoF

Prepared for: **Australian Energy Market Operator**

"Advising on RoCoF System Limits" project

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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 AEMO. Questions and any correspondence concerning this document should be referred to:

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AEMO Statement

"This report was commissioned by AEMO in August 2016 under its Future Power System Security Program. The report forms part of the broad analysis AEMO is undertaking to identify and specify potential technical solutions to current and future power system security challenges."

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List of Acronyms

AC	Alternating Current
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
BESS	Battery Energy Storage System
BOP	Balance of Plant
CCGT	Combined cycle gas turbine
CIGRE	International Council on Large Electric Systems
CO	Carbon Monoxide
CWFT	Continuous Wave Frequency Transducer
DC	Direct current
DCS	Digital (plant) control system
DFG	Double-fed generator
DOE	Department of Energy (U.S.)
DSM	Demand Side Management
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
GE	General Electric International, Inc.
GO	Generation Owner
HP	High pressure (turbine)
HVDC	High Voltage Direct Current
IEC	International Electrotechnical Commission
IP	Intermediate pressure (turbine)
IV	Intercept valve
LBO	Lean blow out
LCC	Line commutated converter
MCV	Main control valve

MW	Megawatt
MWH	Megawatt hour
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NOx	Oxides of Nitrogen (pollutant)
OCGT	Open cycle gas turbine (a.k.a. SCGT)
OEM	Original Equipment Manufacturer
OLL	Operating limit line
PCS	Power Conversion System
PFR	Primary Frequency Response
PLL	Phase-locked loop
PSS	Power System Stabilizers
PWM	Pulse Width Modulation
PV	Photovoltaics
RBO	Remote breaker operation
RoCoF	Rate of Change of Frequency
SA	South Australia
SCGT	Simple cycle gas turbine
SCR	Short Circuit Ratio
SOx	Oxides of Sulfur (pollutant)
SVC	Static VAR Compensator
TSO	Transmission system operator
UFLS	under-frequency load shedding
UHC	Unburned hydrocarbons
VSC	Voltage Source Converter
WTG	Wind Turbine Generator

1 EXECUTIVE SUMMARY

This document reports on the behavior and vulnerability of equipment to high rate of change of frequency (RoCoF). The focus of this document is behavior of a variety of equipment in the power system that has the potential to adversely affect the resilience or robustness of the system. Parts of the NEM, most notably South Australia, may be subject to high RoCoF following a variety of disturbances. Existing equipment on the NEM will, in general, have not been specified or designed to handle these high RoCoF conditions. Consequently, there is a risk that unexpected behavior of equipment, subject to conditions for which it was not designed, may exacerbate the systemic challenge of trying to tolerate and recover from frequency events.

High RoCoF is likely to follow other violent grid events which have their own consequences. Nevertheless, this is deliberately a narrow investigation - focused on this one part of a larger issue. Specifically:

- This discussion is specifically focused on RoCoF. Other variations on fault-ride-through, such as depth, duration and unbalance of voltage disturbances, are not in scope.
- Low short-circuit strength concerns are explicitly excluded, and yet this will have significant implications that must be considered.
- This is not a discussion of whether the existing under frequency load shedding scheme is adequate, will work as designed, or indeed whether that scheme is even appropriate for the present and future reality of South Australia.

This work has been conducted with an engineering focus of “what could go wrong?” Engineers are trained to ask such uncomfortable questions, and throughout the report, possible mechanisms for undesirable behaviors are presented. In the narrow context of potentially significant risks associated specifically with high RoCoF (rather than the much broader context of system disturbances), we see a limited number of significant risks, including:

- Gas-fired generation tripping due to lean blow out (LBO) on high positive RoCoF (rapidly rising frequency), such as might occur after substantial (and excessive) load-shedding or system break-up. There is also some risk associated with possible high positive RoCoF that accompanies the successful recovery of frequency from the nadir following a loss of generation or loss of infeed (e.g. trip of the Heywood Interconnector) event
- Gas-fired generation tripping due to compressor surge on high negative RoCoF (rapidly dropping frequency), such as might occur following an islanding (e.g. trip of the Heywood Interconnector) event. Risk is highest at high or maximum power

output, for extremes of ambient temperature, and for large industrial frame gas turbines.

- For all synchronous units, potential for misbehavior of power system stabilizers, especially those which calculate accelerating power.
- Protective schemes mis-operating because of poor settings; i.e. the relay behaves as instructed, but has settings incompatible with high RoCoF. This is associated with all generators, as well as transmission and distribution network elements. Any remaining electro-magnetic relays in critical applications should be tested for RoCoF performance.

The table below provides a synopsis of the risks discussed in the report, with a subjective grading and a note on the rationale for the grading. The rationale entry includes a note as to whether the concern is mainly of dropping frequency (- RoCoF), rising frequency (+ RoCoF) or both (+/- RoCoF).

Recommendations are summarized here under "inventory", "monitor" and "analysis", by which the intent is a segregation of activities aimed at (1) figuring out what is on the system now and needs more attention, (2) watching how it behaves, and then (3) digging into elements that are determined to be both critical and poorly understood or poorly represented.

Inventory

- **Thermal Generation Capability**

Initiate inquiries into known capability and limitations of synchronous generators that are critical to security following major frequency events. This will likely require engagement not only with plant owners but with equipment OEMs. Items listed (in the table below) need to be checked (e.g. does the plant have an island-mode? What type of PSS is on the plant?, etc.)

We do not, at this point, recommend a mandatory, detailed analytical evaluation of RoCoF tolerance for thermal generation. Such mandate will impose substantial costs on generation owners and may not be required.

- **Distributed Solar PV Inverters and Anti-Islanding Schemes**

Investigate potential for mis-operation of anti-islanding protection on distributed generation.

- **Relay Exposure**

Before meaningful testing of relays can be performed, an inventory of which transmission and distribution protection relays are critical to system security is needed. This is primarily a planning function, in that elements of the system – e.g. lines, transformers, sectionalizers, etc. – that will cause or exacerbate a system disturbance by incorrectly tripping are the highest priority for testing. This is a non-trivial investigation.

Table Synopsis of Risks

Technology group	Equipment	Risk Description	Risk Level	Rationale
Utility-scale Synchronous Generation	Gas-fired generation	LBO		Observed behavior; high consequence; not easy to anticipate or correct. Mainly a positive RoCoF (frequency rise)/backswing concern.
	Gas-fired	Surge		Mainly a concern at maximum/high power and on large turbines; a negative RoCoF (frequency drop) concern.
	Gas and Steam	Drive-train torques		No history of this being an actual problem (with +/- RoCoF)
	Gas and Steam	PSS		Significant concern for PSS that calculates acceleration. Both +/- RoCoF
	Gas and Steam	Island mode		Only on plants with this feature. Mainly a +RoCoF risk.
	Gas and Steam	Sensors		Part of overall evaluation of RoCoF performance.
	Gas	Encroachment		A general warning.
	Steam	Valves		Mainly a wear and maintenance issue. +/- RoCoF.
	All	V/Hz		Some increased risk with high voltage swings accompanying -RoCoF events
	All	Reverse Power Protection		Mainly a concern at low power and for +RoCoF
	All	Overcurrent		Mainly a concern at high loading and excitation for -RoCoF
Utility-scale Asynchronous generation	Wind Generation	Active and reactive injection errors		Older type 3 & 4 machines may track poorly; high RoCoF has been observed to result in departure from expected active and reactive power.
	Utility-scale Solar PV	Trip on "erroneous" instantaneous Frequency thresholds		Recent, unconfirmed widespread tripping attributed to this. This is not a RoCoF concern, but a FRT problem that looks like a frequency problem. +/- RoCoF
	Wind Generation	Tripping		Similar to preceding concern. "instantaneous" trip settings on frequency, with poor measurement of frequency is a problem that has occurred. +/- RoCoF
Transmission and Power Delivery Equipment	Electro-mechanical relays	Mis-operation; failure to operate		EM relays are known to have errors with frequency. Unlikely that there are EM relays in operation in the NEM, particularly in critical locations. Risk is high if there are any. +/- RoCoF
	Digital Relays	Setting Errors		Problems associated with relays acting properly as set, but with setting incompatable with substantial RoCoF conditions +/- RoCoF
	Digital Relays	Measurement Errors		Modern digital relays employ frequency tracking that should provide good performance. Minor measurement errors possible; a concern for some applications. +/- RoCoF
	FACTS devices	Mis-operation		Measurement errors and tracking errors are possible. No examples within interviewed community. +/- RoCoF
	HVDC	Active and reactive injection errors		Measurement errors and tracking errors are possible. No examples within interviewed community. +/- RoCoF
End User and Distribution Equipment	Loads	Modeling Fidelity		This a known and ongoing concern in the industry. It is well known that changing load modeling assumptions can result in wildly different simulation results. +/- RoCoF
	Distribution PV	Tripping on Frequency		Ongoing concerns about systems (particularly legacy systems) tripping. +/- RoCoF
	Distribution PV	Anti-islanding		Especially a concern if RoCoF based decisions are used. +/- RoCoF.
	Reciprocating Distributed Generation	Mis-operation or tripping		No significant risks were identified.

- **Monitor**

Initiate a program of high resolution monitoring of system events, including digital fault recorders (or equivalent), and all the necessary human and data infrastructure to collect, store and (most importantly) process event data. The focus should include a broader spectrum of events than just RoCoF, including faults and other disturbances. The behavior of load and all major power plants should be captured with sufficient resolution to evaluate performance and validate models. This a substantial research undertaking.

Analysis

- **Thermal Generation Performance**

In the event that both the inventory and monitoring aspect of checking on the RoCoF performance of thermal plants, especially gas-fired generation, does not adequately increase confidence that generation will behave satisfactorily, more detailed investigation can be pursued. There is limited industry experience with these investigations, and they can involve substantial costs.

- **PSS**

Performance of power system stabilizers for all synchronous machines under expected extremes of frequency and RoCoF needs to be analyzed. This is to assure that they do not create stability or voltage problems on synchronous generation. PSS that calculate acceleration are of particular concern. Traditional stability programs may be sufficient, and investigation can be a part of broader stability investigations. This can be accompanied by state-space analysis, although non-linear effects of signal saturation constitute the major risk, and so small signal analysis is mainly useful as a test that efficacy is not compromised by modified settings.

- **Critical Relays**

Settings of critical protective relays on generation, transmission and distribution must be checked for proper behavior during extreme frequency events. Again, traditional stability programs can be a part of this analysis. However, relay testing of actual devices is a more complete method of testing. Playback of simulated frequency events (from stability programs, EMT programs or real-time simulators) into bench tests with actual relays is best, and should be considered (for critical relays). All electro-mechanical relays that are critical to system security for major frequency events should be bench tested this way, as modeling of these devices is notoriously poor.

- **Inverter Behavior**

Bench (laboratory) tests of common PV inverters should be considered (if OEMs do not have useful responses to the recommended inquires above).

- **Load models**

Load models should be examined and improved (per discussion in Section 5), particularly if monitoring suggests substantially different performance from that observed.

RoCoF Ranges

One of AEMO's objectives for this work to identify ranges of RoCoF for which AEMO can be confident that there will or will not be security issues. There is no level of negative RoCoF for which there is *confidence* that equipment will behave poorly. This observation must be paired with two important points: First, levels of RoCoF in excess of -2 Hz/sec are extreme for industry experience in interconnected systems of any size, so experience is limited. Second, the physics is complex and each OEM has their own specifics. There is no substitute for experience. Imposing tight systemic RoCoF targets based generically estimated vulnerabilities is likely to be uneconomic. Operating strategies for gas fired generation that are biased towards keeping units off of maximum dispatch during periods of highest exposure to high RoCoF, and that consider more conservative operation during extremes of ambient temperature, may be desirable.

Positive RoCoF is a known issue for gas fired generation. The consensus opinion is that levels below +0.5 Hz/sec represent a confident lower bound (below which no RoCoF problems are well assured).

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2 INTRODUCTION TO ROCOF TOLERANCE

The Australian grid is faced with operational challenges related to the rapid evolution of the mix of generation on the system. One aspect of concern is management of fast variations in system frequency following system disturbances. This is a growing challenge in many systems around the world and is driving the development of new practice and technologies to address reduction in the amount of synchronous generation on the grid.

The intent is to help manage severe frequency excursions, with particular emphasis on managing RoCoF and the avoidance of frequency-induced adverse impacts on customer loads (especially load shedding) and system equipment. The findings presented in this report are intended to provide a portion of the quantitative information necessary for AEMO to plot a course forward that respects the requirements of security, economy and neutrality of the Australian grid.

This work has two major constituents:

Part 1: RoCoF Tolerance and Vulnerability

This technical document describes the various key components of the grid (with particular attention to the South Australian grid) which could be affected by high levels of RoCoF.

Specifically, this is aimed at identifying key equipment that may trip off line (i.e. have a frequency or RoCoF ride-through failure), or which may mis-operate or behave in unexpected ways.

We provide discussion of the mechanical and electrical response of the various technologies to RoCoF – with the intent of illuminating what behaviors might pose a risk of tripping or mis-operation. To the extent possible, we have provided a quantitative description of the limitations. There are many nuances, many of which are specific to different OEMs. The discussion provided delves into the phenomena in general, and attempts to provide a degree of guidance on sensitivities.

For each technology, we have tried to provide insight into what vulnerabilities controls introduce. To a considerable extent, this is integral with the mechanics discussion. But some types of vulnerabilities will be primarily related to the control settings or structure. Without exception, the final word on how specific pieces of equipment perform for high levels of RoCoF lies with tests and the equipment manufacturer[1]. This applies to every piece and type of equipment discussed in this report. Even in places where the caveat "the performance depends on specific equipment design and control" is not made explicitly, the reader is admonished to remember that it still applies.

The reader is also cautioned again that the scope of this work is specific to RoCoF. This investigation is emphatically not a review of vulnerabilities of equipment to the full spectrum

[1] Discussion provided throughout this document is primarily based on experience of GE specialists. Comments are based on both GE and a broader range of OEM equipment. Public sources, especially industry group (e.g. IEEE), have also been used.

of challenges that might accompany a RoCoF event. As noted above, fault ride-through, voltage disturbances or collapse, unbalance, and weak grid all might accompany a RoCoF event, but we are not assessing equipment performance for these challenges.

Part 2: Recommended AEMO actions regarding RoCoF Tolerance

This portion of the document summarizes risks, and describes actions that AEMO might take (i.e. "next steps") to develop better quantitative information on the various key components of the grid, with particular attention to those elements in the South Australian grid that the previous investigation shows to be of most concern (with respect to high levels of RoCoF).

Recommendations on options for either testing or further analysis that can be performed on individual elements (e.g. individual power plants) have been provided, where we can. Further, in so far as the investigation suggests it is possible and useful, we have recommended systemic measurements, monitoring and data collection, which will help inform AEMO and guide practice.

2.1 Overview of Impacted Power System Technology

Elements of the power system each have the ability to impact the robustness of response to high RoCoF events. In the report, system resources have been divided into broad classes of system elements, as follows:

- Utility-scale generation. Generating resources, at the least, ought not to disconnect from the grid prematurely and unexpectedly. In a sense this a variation or subset of the broader concern for "ride-through". Basically, we are addressing "RoCoF ride-through", although that language is not used in the industry. But further, connected generation should not just remain connected, it ought to perform in a fashion that (a) is expected, and (b) benefits the overall performance of the grid during events. In this work, we focus primarily on the first aspect – performance as expected. The second topic is a broader set of system planning and operation issues outside the scope of this work.
- Transmission and power delivery. The (remaining) transmission system ought not to experience unexpected degradation during RoCoF events. For most system transmission elements, this is a question of protection: do protective relays or other protective functions respond in an undesirable fashion to high RoCoF events? In short, do elements trip that ought not to? In the case of controlled elements, like SVCs or HVDC, there is a second aspect of unexpected behavior, due to controls that do not expect or understand high RoCoF.
- End Users. Loads and embedded distributed generation (DG). In some regards, behavior of loads and DG are the least well understood elements. Unlike generation and transmission assets, there are circumstances under which disconnection of loads is beneficial during high (negative) RoCoF events. The aggregate behavior of distributed generation, most notably distributed solar PV, during high RoCoF events is

not well understood. The issues noted above for utility-scale generation apply here, with the added complexity of diversity and generally poor observability (i.e. the utility can't "see" the DG.)

2.2 General Discussion of RoCoF Vulnerability

In the chapters below, we will consider basic characteristics and physics of the various critical elements described above. But the art of hardening power systems against misbehavior under extreme stress requires a broader view of the system, of equipment, and of failure modes, than is the normal purview of power system planning.

Specifically, an over-dependence on traditional planning models can lead to unfortunate outcomes. A few broad observations are offered here for context:

It's the old stuff that will kill you

- You don't know what's in there anymore
- The people that understand the equipment have moved on
- The manufacturers don't support the equipment (maybe with parts…) anymore
- The equipment probably wasn't designed to handle such stimulus anyway.

Do an inventory

- Figure out what elements are critical, and concentrate on them.
- In most power plants, it isn't going to be the generator, it will be:
    - Pumps
    - Fuel systems
    - Contactors
    - Combustion controls
- Once you've determined what's critical to continued operation
    - Go look at it.
    - If it's important, maybe it can be tested.
    - Don't kid yourself that asking the manufacturer necessarily is going to give you good answers.

One test is worth a 1000 expert opinions

2.3 Discussion of Field Testing and Monitoring

The distinction between control tests in which error signals are injected to control summing junctions, and actual events, in which the power equipment is subjected to actual variation in terminal conditions is important. Control tests are highly valuable for determining if gains, limits and other settings critical to system performance are correct. For example, consider the (simple) turbine governor model shown in Figure 1. In this model, a steadily increasing power reference (Pref), is proportionally similar to the speed error that would accompany a negative RoCoF event. Response of the turbine would manifest itself with increasing mechanical power to the high pressure and low pressure turbines. When run in a simulation, the test (ramping Pref) will provide a great deal of information about the performance of the turbine, including control. A field test of this variety is relatively easy to stage, and can show how well the model replicates the observed behavior. It may possibly illuminate vulnerabilities to high RoCoF, as the equipment responds. (e.g. unexpected internal protections might activate, or equipment like pumps or contactors could malfunction).

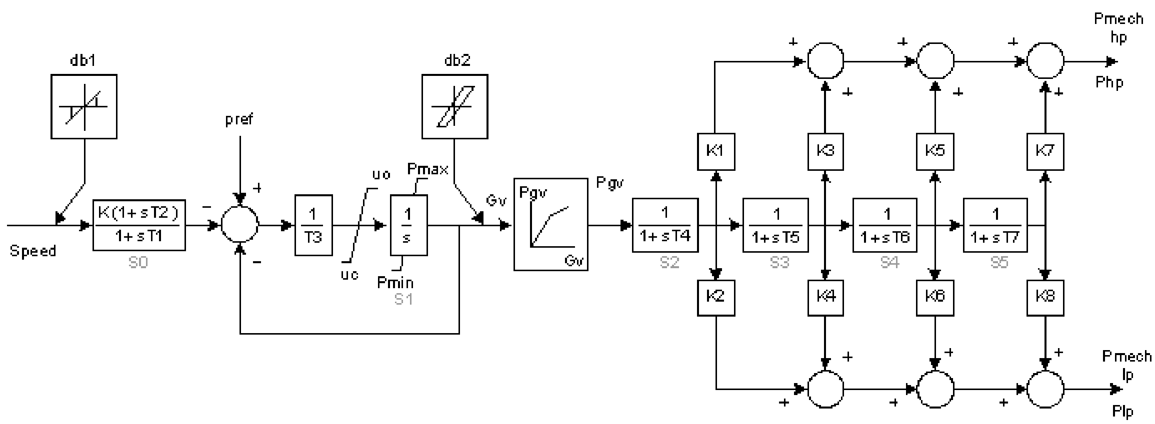

Figure 1 IEEE G1 Model

But, useful as such tests can be, they will not tell the entire story of how equipment performs in the field. Consider the simulation traces in Figure 2, which shows the aggregate behavior of multiple units with active governors to an event that causes a rapid drop in frequency (loss of 2 large nuclear units). The green trace is the aggregate turbine governor response. The blue trace, in the lower figure, is the electric power. A field test could capture (and verify) the green part of the behavior. A test like this would be performed by feeding in a speed signal (or scaled power reference signal) like the upper trace. The turbine mechanical power (and *electrical power*) would respond to the input. In a successful model validation test, the actual tubine output would look like the green trace. This would be indication that the model is good, and that turbine controls and protections can tolerate this input stimulus. But there is no practical field test that would drive the stimulus from the grid through the generator the way a real grid disturbance will. That means the electrical behavior that accompanies an actual grid event, like that shown in the lower blue trace, can't be practically reproduced with a staged field test. The practical implication of this limitation is that some elements will not "see" the same conditions during a test that they will during an actual event. This leaves a degree of uncertainty about performance and robustness.

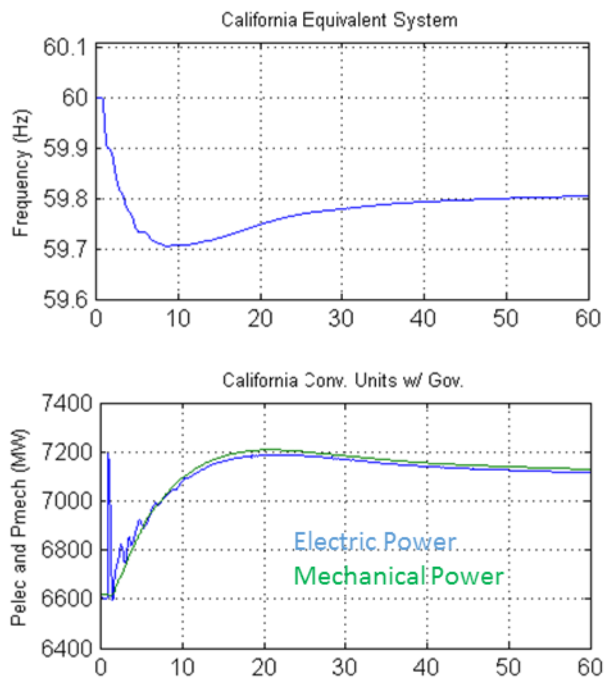

Figure 2 Response to High RoCoF Event

2.3.1 Monitoring, Recording and Post-processing

One practical option for systemic testing of generating equipment response to high RoCoF is *monitoring*. Broadly, that means providing instrumentation that will capture information about equipment performance when actual events occur on the system.

As noted above, the focus of this document is behavior during conditions of high RoCoF. But, given that there is a high likelihood that system disturbances that result in high RoCoF will involve other departures from nominal (i.e. grid faults, unbalances, distortion, etc.), high resolution monitoring of individual phase voltage and current waveforms is required. Instrumentation of this type can also normally provide processed voltages (i.e. phase and sequence amplitudes), current magnitudes, active and reactive power, and frequency. Given the extremes that South Australia is facing, the necessity is to have high resolution measurements. This presents a data handling challenge, as storing data from continuous monitoring can produce unmanageable quantities. Recording devices need to be triggered on events, and must capture enough pre-disturbance information to make a good assessment of the equipment's pre-disturbance operating condition.

A typical failure mode for monitoring systems is to have inadequate processes in place to collect, store and post-process disturbance data. Recording buffers fill up, making new measurements impossible or overwriting previous events. Piles of unprocessed data collect in the receiving "office" with no time or resources (budget, humans) dedicated to post-event analysis. Another institutional failure mode is to identify vulnerabilities or deficiencies in performance, but to lack the jurisdiction or mechanisms to effect (or even communicate) improvements.

2.3.2 Laboratory Testing

There is good precedent for laboratory testing. For example, fault ride-through testing of wind turbines is performed regularly, both by OEMs and by independent labs[2] .

However, testing of large scale equipment (i.e. wind turbines or thermal generators), for RoCoF is difficult. Normally, test facilities can manipulate voltage magnitudes in a broad variety of ways. This allows for emulation of various grid faults, voltage unbalances and overvoltage. But, most facilities with sufficient scale to handle (for example) a multi-MW wind turbine, are fed from a host grid. That means that manipulating the *frequency* is not possible. Testing for RoCoF requires the ability to manipulate the frequency of the source. For small pieces of equipment, like individual PV inverters and relays, this is common equipment[3]. But for multi-MW tests, there are only a few labs in the world with this capability. Testing of large thermal plants by this method is not done.

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[2] CEPRI China; DNV GL;

[3] The Controllable Grid Interface at the US National Renewable Energy Lab is one such facility.

3 UTILITY-SCALE GENERATION

This section describes:

- Gas turbines
- Combined cycle, gas-fired power plants
- Steam fossil plants
- Fossil reciprocating engine generators
- Wind turbines
- Inverter based resources: Solar photovoltaics (PV) and battery energy storage systems (BESS)

Elements common to multiple generation technologies have been noted, but not repeated in each section. (Therefore the reader is cautioned if they skip down to later sections without reading the intervening discussions).

3.1 Open-Cycle and Combined-Cycle Gas Turbines

While most grid codes around the world have frequency response requirements, generally tested and confirmed through frequency injections, some grid codes now call for power plants to meet RoCoF requirements in the range of 1 Hz/sec to 4 Hz/sec. These RoCoF requirements are on the order of five to ten times faster than many gas turbine OEM's previous design experiences, and consequently may not have been fully envisioned during design and commissioning phases. Furthermore, as discussed above, in Section 2.3, testing for RoCoF compliance is difficult, since standard testing through frequency injections into the controller is not the same as the actual grid frequency when experiencing a disturbance. Therefore, many of the issues related to RoCoF discussed in this report have been identified by detailed modeling and simulations as well as lessons learned from actual frequency events on grids throughout the world.

The following sections describe various aspects of open-cycle and combined-cycle gas turbines where RoCoF events may cause serious issues.

3.1.1 Phenomena: Lean Blowout (LBO) or Loss of Flame

3.1.1.1 Physics Behind Gas Turbine Lean Blowout (LBO) or Loss of Flame

Strict emission regulations by federal and state agencies limit the amount of smoke (particulates), oxides of sulfur (SOx), carbon monoxide (CO), unburned hydrocarbons (UHC) and nitric oxide/nitrogen dioxide (NOx) that a gas turbine can exhaust into the atmosphere. Gas turbine designers are continually challenged to improve cycle efficiency, while maintaining or reducing these emissions. This challenge is made more difficult by the fact that these can be conflicting goals. The path to improving efficiency is through higher working fluid temperatures, but these higher temperatures promote NOx formation. At 2,800 °F the threshold for thermal NOx formation is reached. Furthermore, reducing available oxygen to reduce NOx can result in higher CO and UHC emissions due to incomplete combustion. Moreover, increasing firing temperatures above 2,350 °F represents a significant materials science challenge.

To achieve lower pollutant emission rates, a variety of pre-formation and post-formation control technologies have been utilized, either individually or in combination. The most commonly used techniques include dry combustion controls, water or steam injection into the combustor, and/or selective catalytic reduction.

Of the numerous techniques used by various manufacturers, an ultra-lean combustion is one of the most commonly used approaches. However, ultra-lean combustion can be susceptible to thermoacoustic instabilities and lean blowout (LBO). LBO is a known characteristic of gas turbines due to the lean fuel and air mixture design needed to reduce emissions and meet the emissions regulations.

Note that LBO is a function of the combustion system and OEM designs vary, with some being much better than others at dealing with this issue.

3.1.1.2 Gas Turbine Lean Blowout (LBO) During RoCoF Events

If we imagine a severe event on the power grid which causes an imbalance in generation and load causing frequency to increase, gas turbine-generators in the area would accelerate with the frequency excursion. The directly-coupled turbine compressors would force more air into their associated combustion chambers while at the same time the governor speed controls reduce fuel input in response to the increase in speed. Depending on the controls, the operating conditions of the unit and the severity of the frequency event, the turbine could be susceptible to LBO, or loss of flame, causing the units to trip offline. The highest probability for risk of disconnection is during a frequency rise where air flow will increase with an increase in compressor speed while fuel decreases due to governor action. After frequency decline events, the gas turbine is also vulnerable to a LBO during the frequency recovery phase depending on how fast it occurs in the power system due to fast-acting governor controls on other units, unit trips or the under-frequency load shedding (UFLS) scheme being utilized. That is, positive rate of change of frequency occurs from the frequency nadir until recovery, not just from events that *start* at nominal frequency and go up.

3.1.1.3 Testing for Gas Turbine Lean Blowout (LBO) During RoCoF Events

Understanding of the LBO phenomenon throughout the industry has been, and to some extent continues to be, incomplete. It is dependent on equipment, the control philosophy implemented, operating conditions and various frequency parameters that include frequency magnitude, rates of change, and the source of the frequency excursion.

In the past, such gas turbine-generator trips may have been reported as "sympathetic trips" as this phenomenon may not have been initially identified. This issue can be difficult to identify since the trip does not usually result from a direct machine protective action, but from the various impacts external system frequency excursions have on the internal machine combustion tuning and control systems. Even when the trip is determined to be a LBO, the cause is not always fully understood.

Generator owners and operators can work with the gas turbine OEMs to understand and identify the unit's susceptibility to LBO because of system frequency transients in order to develop mitigations to the LBO issue and, at a minimum, inform the system operator of the unit's vulnerability to LBO for planning, modeling and operating purposes. Complete, detailed evaluation is complex, expensive and time consuming. Complete model based evaluation of plant RoCoF performance can cost more than A$1M. Costs for evaluation, and improvement if necessary, need to be balanced against the responsibility of system planners and system operators to plan, operate and manage the grid to respect constraints imposed by equipment capabilities.

Gas turbine OEMs can work to determine the unit's LBO margin for various operating conditions (loading levels, ambient conditions, fuel type, etc.) against predicted frequency events. Various methods to calculate the LBO margins may include testing in the lab, the use of historical data on LBO events, or high fidelity modeling of the gas turbine, generator and electrical systems. These models need high levels of detail of the turbine, compressor and control systems and input from the OEM design teams. It is also beneficial for the models to incorporate the "as running" control software to ensure the latest controls are being tested. Testing methods, data or models should be available from most OEMs to derive a classification of the LBO characteristics of the combustion systems. However, this is not guaranteed, and different OEMs will have different levels of practice for managing tests and different models or methods available. (System planners accustomed to grid models of generation, GGOV1 for example, should recognize that these detailed models have immensely higher levels of complexity, often with hundreds of state variables.) These types of proprietary models should be available to evaluation personel within most OEMs.

Some gas turbine OEMs may not necessarily be able to make a determination of the unit's LBO margin because it is dynamically altered in the presence of thermoacoustic instabilities that are not included in even the detailed models. In future, strategies for early detection of imminent blowout and adoption of appropriate measures to mitigate it may become available.

3.1.1.4 Avoiding Gas Turbine Lean Blowout (LBO) During RoCoF Events

It is possible that specific LBO issues (by OEM and model) can be mitigated through proper tuning of the fuel proportioning control settings or through adaptations of the implemented control philosophy. This further depends on the combustion system and the severity of the frequency events to which the unit will be subjected.

Other techniques may be available where the limitations of the hardware or controls are reached without a resolution to the LBO risk. This may include the addition of new, more dynamically capable combustion systems that may use pilot fuel or advanced fuel management to maintain operation. These additions may allow the turbine to maintain operation during transient events that would normally cause a LBO. The downside to these additions (pilot flame or diffusion flame), is that it will have undesirable characteristics from an emissions point of view. These modifications are conditional, and so will only affect emissions during the events. Consequently, the total impact on emissions would likely be small. For emissions limits that are based on rolling averages, compliance issues are unlikely. However, it may be necessary to relax instantaneous emissions compliance requirements in order to allow generation owners to implement this corrective action. There may be ways or methods to reduce the emissions somewhat, such as selective catalytic reduction or higher NOx combustors. These are expensive options and will still not completely mitigate the emissions penalty of LBO mitigation. Broadly stated, the understanding of the industry in general, and the OEMs in particular, is growing but still incomplete.

3.1.2 Phenomena: Compressor Surge-Protection / Operating Limit Line

3.1.2.1 Physics Behind Gas Turbine Compressor Surge

Gas turbines include either an air compressor driven by a gas generator turbine with a separate power turbine (two-shaft engine), or an air compressor and a turbine on one shaft, where the turbine provides both power for the air compressor and the load (single-shaft engine). These air compressors provide the high pressure, high volume air which, when heated by combustion and expanded through the turbine section, provides the power output required by the process.

Two types of compressors are in common use today—they are the axial compressor and the centrifugal compressor. The axial compressor is used primarily in medium and high horsepower applications, while the centrifugal compressor is utilized in low horsepower applications.

Axial compressors are dynamic rotating compressors that use arrays of airfoils to progressively compress gas which principally flows parallel to the axis of rotation. Axial compressors consist of rotating and stationary components. A shaft drives a central drum, retained by bearings, which has several annular airfoil rows attached usually in pairs, one rotating and one stationary attached to a stationary tubular casing. A pair of rotating and stationary airfoils is called a stage. The rotating airfoils, also known as blades or rotors, accelerate the air. The stationary airfoils, also known as stators or vanes, convert the increased rotational kinetic energy into static pressure through diffusion and redirect the flow direction of the air, preparing it for the rotor blades of the next stage. The cross-sectional area between rotor drum and casing is reduced in the flow direction to maintain an optimum Mach number using variable geometry as the air is compressed.

Centrifugal compressors raise the pressure of the air by accelerating it in an impeller, then, by Bernoulli's principle, slowing the air down in the diffuser section to convert the velocity energy into pressure energy. The velocity energy that is imparted to the air is a function of its density and tangential velocity (tip speed) of the impeller. Therefore, with a given gas and impeller speed, there is a finite pressure ratio (discharge pressure vs. suction pressure) that can be supported by a centrifugal compressor.

Gas turbine and compressor performance varies significantly from one design to the other. Compressor maps are used by the manufacturers to determine the performance of the engine at a specified operating point. Manufacturer's compressor performance maps are generally shown as pressure ratio [P_{EXIT} / P_{INLET}] plotted versus some function of compressor entry mass airflow against a series of constant corrected speed lines. There are many variations, and OEMs generally regard these as proprietary. A simple generic version is shown in Figure 3. Complete maps are based on compressor rig test results or predicted by computer programs. Compressor maps are an integral part of predicting the performance of a gas turbine engine, both at design and off-design conditions.

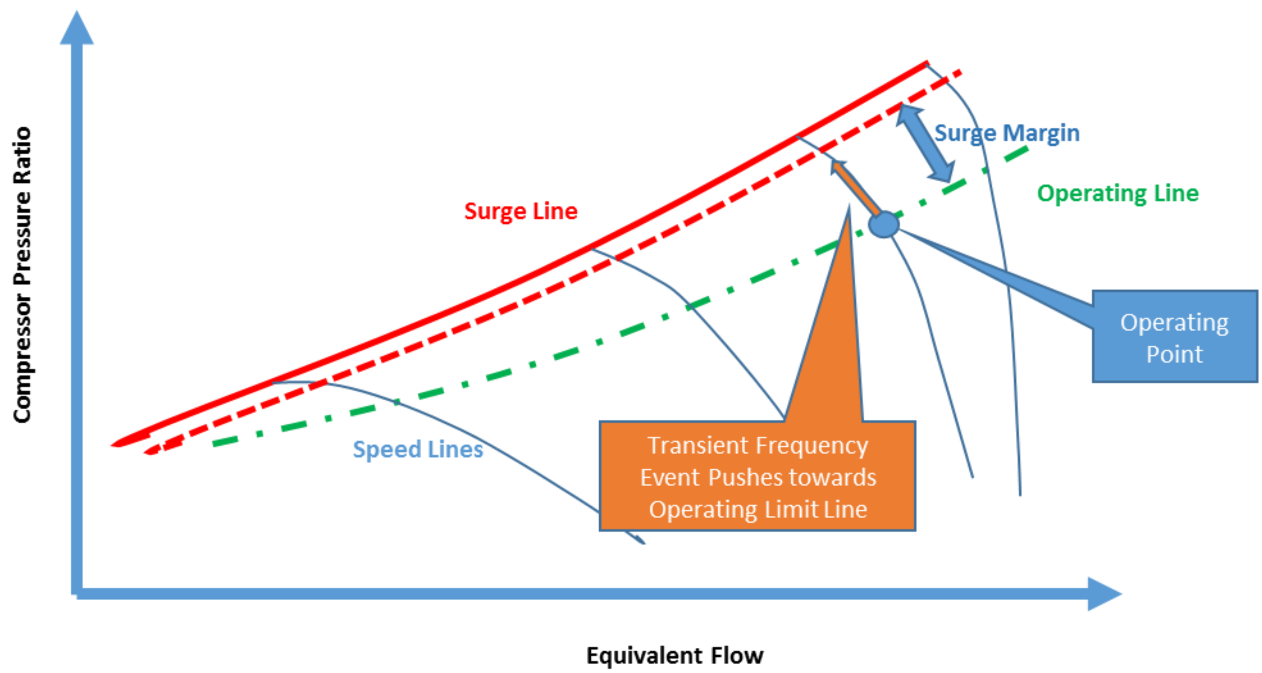

Figure 3 Generic Compressor Performance Map of an Axial Compressor

A stall or surge from a turbine engine is the result of instability of the engine's operating cycle, with the compressor being the most susceptible. Both the axial and centrifugal compressor are limited in their range of operation by compressor surge. This phenomenon occurs at certain conditions of airflow, pressure ratio, and speed (rpm), which result in the individual compressor airfoils going into stall like that experienced by an airplane wing at a high angle of attack. When this airfoil stall occurs, the passage of air through the compressor becomes unstable and the compressor can no longer compress the incoming air. The high-pressure air behind the stall further back in the engine escapes forward through the compressor and out the inlet. This escape is sudden, rapid and often quite audible as a loud bang. A compressor surge may or may not result in severe damage, but sustained surging will eventually overheat the turbine, as too much fuel is being provided for the volume of air that is reaching the combustor. Compressor blades may also be damaged and fail because of repeated violent surges. (RoFoF related causes of surge are discussed in the next section).

OEMs typically use or characterize the compressor maps to determine an appropriate operating surge margin. Typically, the surge margin is the area between the steady state operating line and a margined compressor surge line or an operating limit line (OLL). These maybe inside of the actual surge limit, as suggested by the dashed line in the figure, since the control objective is to avoid crossing the surge line.

Compressor stall or surge is not peculiar to any one brand or type of engine although in general, there are fewer surge problems on centrifugal compressors compared to axial. While there are various reasons for this, the primary reason is that centrifugal compressors operate at somewhat lower pressure ratios than axial compressors. It still should be noted that it may occur on any gas turbine if the conditions are right. As gas turbines are designed to meet demands for higher power or lower specific fuel consumption, the turbines must accommodate for:

- Increased mass airflow.
- Increased pressure (compression) ratio.
- Increased maximum allowable turbine inlet and outlet temperatures.
- Improved efficiency of the compressor and turbine sections.
- Requirements for quick starts and rapid accelerations

To provide higher power with low specific fuel consumption and acceptable starting and acceleration characteristics, it is necessary to operate as close to the surge region as possible, reducing the surge margin.

3.1.2.2 Gas Turbine Compressor Surge Issues During RoCoF Events

A gas turbine compressor is susceptible to a reduction in surge margin or possibly even experiencing a compressor surge during a fast frequency drop event. During a frequency drop, the volumetric mass flow of air through the compressor is reduced as the rotor slows down leading to an increase in turbine inlet temperature and changes in the air fuel ratio. This drives the turbine towards the surge line, as suggested by the orange arrow in Figure 3. If the event is sufficiently violent, the surge margin will be crossed. The surge protection (operating limit line protection) may act during these events causing the turbine-generator to trip. In the most extreme events, the actual surge line will be crossed, resulting in surge and a likely trip. Crossing these limits can be due to the tuned rate of response of the control system. In rare occurrences, a compressor could be subjected to surge during control instabilities experienced during the recovery (frequency drop) following an extreme frequency rise event.

In systems experiencing violent frequency instabilities, with repeated extreme swings of frequency, multiple surges can occur.

3.1.2.3 Testing for Gas Turbine Compressor Surge During RoCoF Events

Generator owners and operators can work with the gas turbine OEMs to understand and identify the unit's current surge margin at various operating conditions, and its susceptibility to compressor surge because of system frequency.

Gas turbine OEMs can determine the unit's surge margin for various operating conditions (loading levels, ambient conditions, fuel type, etc.) against predicted frequency events or mandated grid code requirements. OEMs should be able to calculate the compressor surge margin from the detailed operability models discussed above and compressor maps for the specific turbine and compressor designs at the plant.

Lastly, the capability of the compressor protection methodology can be evaluated where a dynamic event in the system exceeds a known or anticipated event. Without evaluation, this could lead to either a false protective action or possibly a surge before protective action causing damage to the equipment.

3.1.2.4 Operation to Avoid Gas Turbine Compressor Surge During RoCoF Events

In instances where compressor surge is possible, it may be determined that the unit will need to be operated with a larger surge margin. This may require that the unit be operated at a lower power output or lower efficiency than where it is currently operated. This type of operating change can greatly impact the performance of the unit.

It may also be possible to mitigate the compressor surge issue through controls changes but this will depend upon the compressor and the severity of the frequency events to which the unit will be subjected. These mitigation strategies must be evaluated with regard to other required operability criteria such as maintaining power levels, connection criteria or response characteristics of the equipment.

3.1.3 Phenomena: Drivetrain Torque Limit Analysis

3.1.3.1 Physics Behind Drivetrain Experienced Torques

Localized, rapidly changing disturbances occurring on the transmission system such as a trip of a generator or disconnection of a large consumer can result in fast changes to frequency and voltage in the transmission system. These electrical disturbances and the ensuing transient responses affect the electromagnetic torque in the air gap of synchronous generators, inducing, among other things, a rotor angle oscillation resulting in mechanical torsional oscillations in the shaft line of the turbine-generator, accompanied by electrical power output oscillations.

There has been considerable focus on the drivetrain torques caused by the transmission operation interacting with the turbine-generator. The shafting system of modern large turbine-generator units is a high speed coaxial solid of revolution. It is connected by elastic-coupling parts, and composed of the turbine rotors, generator and exciter. An electromechanical transient process caused by power system failure or changes of operating conditions may lead to shaft stresses.

An understanding of the torques applied to the gas turbine drivetrain, compared to the design torque limits, is highly recommended. Discussion is provided here in the context of RoCoF events, but there is a broad spectrum of grid induced torques for which this statement applies[4].

3.1.3.2 Electrical and Mechanical Torques During RoCoF Events

If we imagine a severe event on the power grid which causes an imbalance in generation and load causing frequency to drop, gas turbine-generators in the area would decelerate with the frequency excursion. Based on the power-speed relationship, the electrical power and therefore electrical torque would increase while the mechanical power (mechanical torque) would slowly change based on the governing system. During this fast frequency event, there can be a large imbalance between the electrical and mechanical torques.

The figure below shows a simulation model's electrical and mechanical torques to a 1 Hz/sec frequency event. While the simulations show about a 1.4 per unit electrical torque, depending on the severity of the frequency event, the electrical torque could be as high as 2 times the full rated torque of the machine.

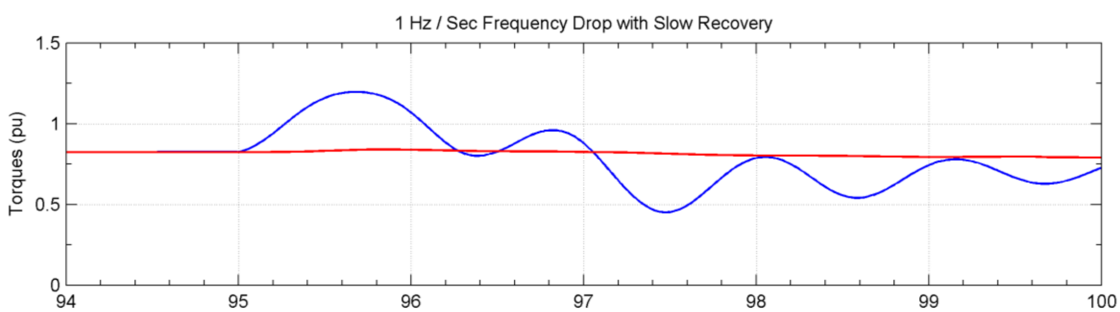

Figure 4 Electrical (Blue) and Mechanical (Red) Torques to a Simulated RoCoF Event

3.1.3.3 Drivetrain Torque Limit Assessment During RoCoF Events

The gas turbine OEMs should understand the RoCoF requirements and identify the electrical and mechanical torques that the unit will be subjected to. The magnitude and transient behavior should be compared to current design limits. A determination could be made if there could be a mechanical torque "event" on the drivertrain associated with the expected levels

4 Recent events in which connected generation in the NEM was subjected to multiple grid faults in rapid succession fall into this category. These can be highly stressful, and result in loss of life for synchronous generation.

of RoCoF. In this context, an event could cause loss of life, or alter inspections, service interval or other maintenance activities. The guidance would be largely dependent on the magnitude and frequency of occurance of the RoCoF occurances.

Grid simulations (i.e. transient stability simulations) or actual measurements can be used to determine the electrical torques (or generator terminal conditions) for RoCoF events. But, again, high fidelity modeling of the gas turbine, compressor, generator and electrical systems can be used to determine impact of these torques on the machines. These models require high levels of detail of the turbine, compressor and control systems and input from the OEM design teams.

3.1.3.4 Issues Associated with Excessive Torques Due to RoCoF Events

The electrical torque seen by the drivetrain for a RoCoF event should be well within the OEM design limits of the drivetrain. Most gas turbine-generator sets should be able to handle short-circuit faults which can provide torques well beyond the normal operating torque. The question is more as to whether the number of expected RoCoF events are enough that the torques experienced will cause drivetrain loss-of-life from component material fatigue. The rather high level of concern about torque impacts in the industry notwithstanding, the magnitude of RoCoF induced torques is generally far lower than that associated with grid faults (and especially with repeated grid faults occurring in rapid succession, as has happened recently in Australia).

3.1.4 Phenomena: Off-Frequency Impact Assessment

3.1.4.1 Physics Behind Gas Turbine Off-Frequency Response

Gas turbines are engineered to operate at 100% speed and typically with the capability to operate over a 95% to 105% speed range, or a range of frequency defined in the grid code. Operation other than at rated speed can affect maintenance requirements. Depending upon the industry code requirements, the specifics of the turbine design, and the turbine control philosophy employed, operating conditions can result that will accelerate life consumption of gas turbine components, particularly rotating flow path hardware. Where this is true, the maintenance factors associated with this operation must be understood. These off-frequency events must be analyzed and recorded, to include them in the maintenance plan for the gas turbine.

For all synchronous generation, a drop in frequency corresponds to dropping turbine speed. For under-frequency operation, gas turbine turbine output will normally decrease with a speed decrease. Most grid codes require turbines to remain online in the event of a specified range of frequency disturbances. If there is no further obligation on the turbine, then no control action is taken to counter the power drop, and the net effect on the turbine is minimal.

Some turbines are required to meet operational or power requirements that are aimed at maintaining grid stability under sudden load or capacity changes. Since a drop in speed results in a drop in power output for gas turbines, some control action may be required to meet a defined minimum. For example, the UK grid code requires that power drop no more than linearly with frequency (after moving below the frequency deadband. Most gas turbines can not meet this requirement without some compensating control action. Note that, at this point, we are not discussing frequency response in the sense of FCAS or primary frequency (governor) response. We are primarily discussing the behavior of the gas turbine when it is dispatched at 100%, and would normally *not* be expected to provide up response.

Turbine over-firing is the most obvious compensation option, but other means, such as water-wash, inlet fogging, or evaporative cooling also provide potential means for compensation. A maintenance factor may need to be applied for some of these methods. In addition, off-frequency operation, including rapid grid transients, may expose the blading to excitations that could result in blade resonant response and reduced fatigue life.

For units to provide *increased* electrical power in response under-frequency operation, turbine output must be increased to meet the performance specification, e.g. 5% droop-defined output requirement. In the NEM, increased output is required if the unit is providing frequency control ancillary services (FCAS). More generally, this the response expected by generation providing primary frequency response. Some of these same techniques are used to meet performance objectives.

It is important to understand that operation at over-frequency conditions will not trade one-for-one for periods at under-frequency conditions. Operation at peak firing conditions has a nonlinear, logarithmic relationship with maintenance factor.

Over-frequency or high speed operation can also introduce conditions that affect turbine maintenance and part replacement intervals. If speed is increased above the nominal rated speed, the rotating components see an increase in mechanical stress proportional to the square of the speed increase. If firing temperature is held constant at the overspeed condition, the life consumption rate of hot gas path rotating components will increase.

3.1.5 Phenomena: Islanding Detection / Protection

3.1.5.1 Physics Behind Islanding Detection

Certain gas turbines may have islanding detection, protection and control enabled as part of their distributed control system (plant control). Island control typically refers to the transition from parallel grid operation to isolated operation, otherwise known as island mode, and subsequent steady state island mode operation. Typically, island mode operation is used to support local processing plant load or relatively small local "house" loads. Parallel grid operation is typical of supplying power to an external electrical load. The transition to island mode occurs because of severing of the tie line circuit breakers (52TL or 52L as shown in the figure below), coupling the generator to the external electrical load, during which the turbine remains in operation to support the local plant electrical loads. During the transition to island mode, the control system responds to the tie line breaker opening, and enables the island speed control governor to automatically maintain the system frequency as per the island speed set point.

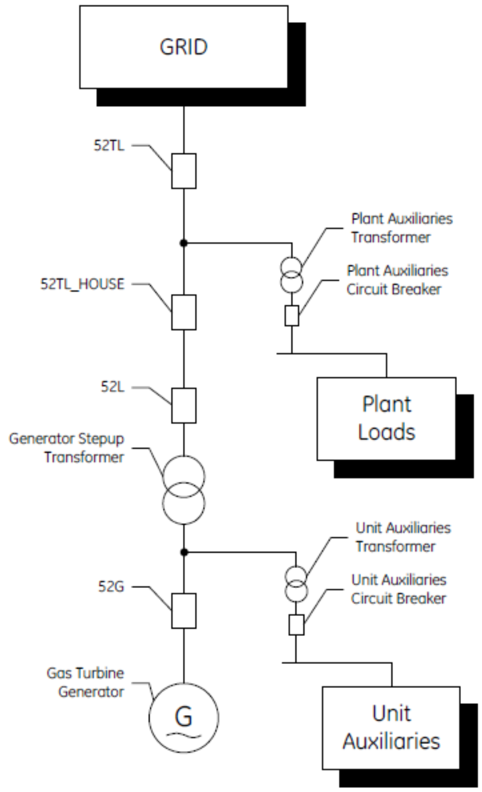

Figure 5 Synchronous Generation Relay Schematic

Gas turbine island mode operability typically involves two stages: grid separation stage and island governor control stage. During the grid separation stage, the gas turbine undergoes load rejection. The sudden loss of load on the generator can cause the gas turbine to dramatically accelerate to over speed conditions. To counter the shaft acceleration and overspeed, the speed governor, e.g. droop governor, responds by rapidly reducing fuel to limit the acceleration and avoid over speeding the gas turbine generator. The rapid reduction in fuel from the speed governor response imposes turbine operability restrictions during the grid separation stage. During the next stage, the island governor assumes control and regulates frequency to the island speed setpoint.

These controls are in place so that a power plant can detect if there is a problem on the power grid that will most likely lead to an unrecoverable situation, and disconnect from the grid to serve local load and be available for reconnection when needed. This type of control can be a double-edged sword, in that timing of the disconnection is critical. The plant does not want to disconnect too early and leave the grid in a worse condition, but disconnecting too late may do damage to the machine or cause a shutdown of the plant.

This type of control is used by many OEMs on OCGT and CCGT plants with islanding capabilities, and can use various methods to detect the grid condition and determine when to disconnect. These methods can include monitoring of acceleration, real power output and/or speed.

3.1.5.2 Islanding Detection During RoCoF Events

There are multiple methods utilized by OEMs in detecting an islanding event. The most prevalent detection method is via a breaker status. There is also the possibility of grid separations that will not include a specific indication of the separation. In these instances, other parameters may be involved in a control methodology to detect a grid separation event.

If we imagine a severe event on the power grid which causes an imbalance in generation and load causing frequency to increase, gas turbine-generators in the area would accelerate with the frequency excursion. The generator electrical response to this fast frequency rise would be the real power output rapidly decreasing. The gas turbine controls may determine that a full load rejection is taking place because the controls are unable to differentiate between a fast positive RoCoF event and a full load rejection due to the acceleration being very similar. Depending on the controls, it may be determined that island mode is needed or that an unintended trip has occurred and the generator breaker failed to open. In either case, the gas turbine protection may take over and trip the line breakers and setup the unit for island control mode by rapidly reducing the output demand to zero or "house" load.

3.1.5.3 Testing for Islanding Detection During RoCoF Events

Generator owners and operators can work with the gas turbine OEMs to identify if the units have islanding mode control or unintended trip protection. These controls and protections should be evaluated for susceptibility to operating because of system frequency transients. For units with islanding mode, gas turbine OEMs can determine the unit's probability of tripping for predicted frequency events or mandated grid code requirements. If there appears to be high risk, the detailed models discussed above, can be used to determine how the onsite turbine controls will behave against these requirements and the margin against this disconnection occurring.

For an example: on a particular unit investigated, the GE turbine controls for remote breaker operation (RBO) are acceleration based. The RBO detection is in place in the gas turbine to detect the loss of connection with the grid in instances where the breaker signal is not received. Based on several simulations, a risk was identified due to the combined effect of high turbine speed and acceleration levels experienced in a RoCoF event. These speed and acceleration levels were in the range of control settings used as criteria for the RBO detection. An example of the GT shaft acceleration vs speed was used to determine if the controls would activate, as shown in Figure 6 below for a 1 Hz/sec RoCoF event. The unit passed (it did not enter the red zone), but it was observed that GT disconnection risk increases with frequency rise rate and at base (maximum) load.

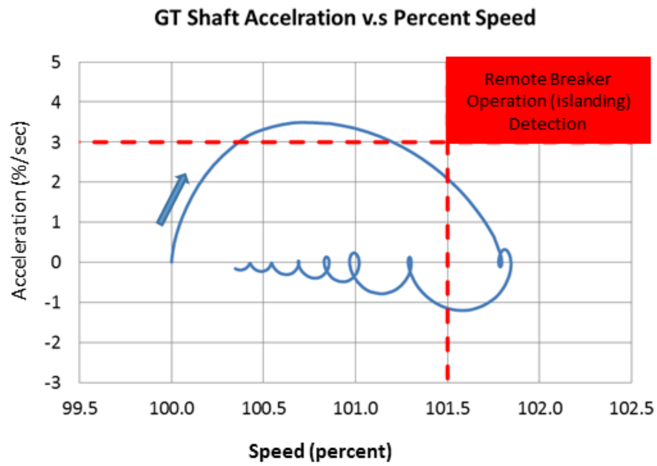

Figure 6 GT Acceleration Trajectory for Positive RoCoF Event

3.1.5.4 Improvements Needed to Avoid Unintended Trips During RoCoF Events

These issues can possibly be mitigated through proper tuning and configuration of the turbine controls by better differentiating between expected RoCoF events and what constitutes a legitimate reason for island mode disconnection or an unintended trip of the gas turbine. Depending on the severity of the frequency events to which the unit will be subjected or required to remain connected, this may be a significant undertaking and may require a complete redesign of the turbine controls.

3.1.6 Phenomena: Sensor & Measurement Issues

3.1.6.1 Sensors and Measurements During RoCoF Events

During RoCoF events, sensor measurements may experience unexpected and abnormally large swings that are well beyond what they typically sense. MW sensors, flow sensors, temperature sensors and pressure sensors can all be affected. Often when these sensors experience these abnormally large swings, they may not read measurements correctly or may go out of the expected range, which can have serious consequences on any controls that use these measurements. One of the measurements that is most critical to turbine control during a RoCoF event is the MW measurement. Depending on its uses within the controls, it can have serious implications for the response or protection of the machine.

3.1.6.2 Testing of Sensors for RoCoF Events

To test for these issues, gas turbine OEMs could determine which sensors are used at the power plant site and what the capabilities of those sensors are during abnormally large swings caused by predicted frequency events or mandated grid code requirements. An initial inventory check may be sufficient. But, this may require simulation or possibly lab tests. If the sensors are faulted for periods of time during the event, the OEM needs to determine what affects that can have on the turbine controls and their risk of disconnection.

3.1.6.3 Improvements Needed if Sensor Limits are Exceeded During RoCoF Events

If it is determined that any of the sensors are incapable of handling the large swings, they may need to be replaced with sensors capable of measuring values correctly for the predicted frequency events or mandated grid code requirements. This is especially important for any sensors that are in critical paths of turbine protection and control. The wrong measurement can lead to the inappropriate reaction of the protection and/or control.

3.1.7 Phenomena: Encroachment on Any Boundary Limitation

The limitations of LBO and Compressor Surge have been mentioned in detail in the sections above. OEMs need to be aware that other boundary limits may be susceptible to encroachment on their available margins during RoCoF events. Each OEM will need to make their own assessment on how the RoCoF event will affect their turbine design, controls and protection.

3.2 Steam Powered Generation Plants

Much like a gas turbine, the steam turbine control philosophy may be impacted by a RoCoF event. Steam turbines are operated in a variety of different ways and utilize many different control philosophies. Some, by the nature of the equipment, may be more tolerant than others.

In general, many of the issues discussed in the gas turbine section, can be applicable to steam turbines. The issues of relevance include torsional assessments, off-frequency assessments, governing, sensor measurement issues and encroachment on boundary limits.

3.2.1 Phenomena: Valve Actions / Throttling Issues

3.2.1.1 Steam Turbine Valve Action During RoCoF Events

During a RoCoF rise event, the steam turbine (regardless of load level) can experience a fast throttling action to help prevent over speeds. The steam turbine main controls valves (MCV) and Intercept valves (IV) transiently close down in rapid high frequency events as part of the steam turbine control philosophy. This valve action is typically based on speed or acceleration measurements. This action can be seen in the figure below.

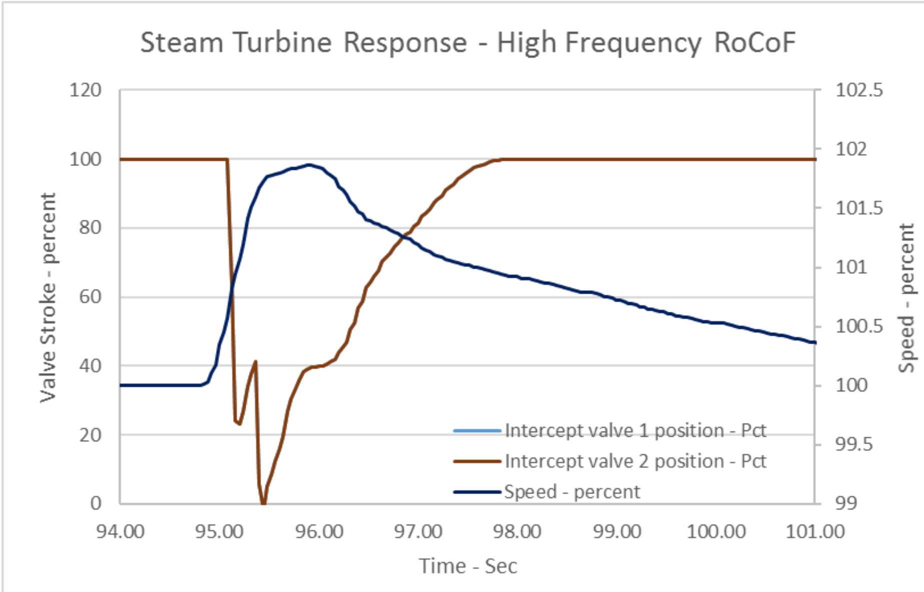

Figure 7 Measured Response of Steam turbine for RoCoF event

The valve closing results in a period where the steam flows in the High Pressure (HP) and intermediate pressure turbines (IP) are reduced. As the speed recovers, the valves return to their normal operating positions. A period of steam turbine bypass operation will accompany these events to manage steam pressure.

3.2.1.2 Testing for Issues Related to Valve Action During RoCoF Events

Thrust balance checks could be conducted, due to this valve action, to assess thrust bearing wear, possible damage and/or reduction in equipment life. The thrust of the rotor is dependent on both the IP & HP section steam flows. Differences in the flows (IP vs HP) could be evaluated to ensure that the resulting thrust on the steam turbine rotor is within design limits through the transients. The steam turbine engineering design teams could review the data for the HP & IP flows and compare them to allowable thrust balances for the steam turbine design.

3.2.1.3 Improvements Needed due to Valve Action During RoCoF Events

It is believed that modification to throttling and/or governing actions will mitigate this concern, and result in behavior within equipment capabilities during a RoCoF event. Thrust balances should be within the steam turbine design limits since most bypass systems are capable and designed for handling full load rejections. However, OEMs could check expected scenarios and ensure that there are no issues.

The question here may be: is the rate of recurrence of a RoCoF event significant enough that the valve action experienced by the unit will cause a degradation of the life of the thrust bearings, causing material fatigue and possible failure? If the OEM determines this to be the case, the unit may be subjected to outages more frequently and require longer durations for maintenance and inspections. This is a significant concern for systems with frequent, substantial frequency excursions. For the NEM, violent frequency events are expected to be relatively infrequent. Consequently, this is not a major concern.

3.3 Power System Stabilizers

3.3.1 Theory: Integral of Accelerating Power Type PSS

The power system stabilizer (PSS) is a supplementary control system, which is often applied as part of the excitation control system. The function of the PSS is to apply a signal to the excitation system, creating electrical torques that damp out power oscillations. Since the primary function of the PSS is to add damping to the power oscillations, basic control theory would indicate that any signal in which power oscillations are observable is a good candidate for input signal. Some readily available signals are generator rotor speed, calculated bus frequency, and electrical power. These measurements have historically been used either singly, or in combination to derive accelerating power. There are several considerations in selecting the appropriate input signals. Some of these factors include the required gain and phase compensation, the susceptibility to other interactions such as torsional oscillations, and the noise level in transducers.

Historically, PSS designs have used either speed or frequency inputs. In the late 1980's, a PSS design based on the integral of accelerating power was more frequently used because it provided robust damping, reduced torsional interaction, and could be easily integrated into the excitation controls. The integral of accelerating power type PSS is a multi-input design, based on the generator electro-mechanical equations. The two inputs used in an integral of accelerating power PSS are most frequently electrical power and generator rotor speed.

For most events on the grid, this type of PSS works well in responding to an event and damping out the electrical MW oscillations quickly. This type of PSS can have an undesirable effect on unit response to a RoCoF event as the two inputs are greatly affected.

3.3.2 Integral of Accelerating Power PSS Response During RoCoF Events

During a RoCoF event, the PSS action is greatly affected by the fast frequency (acceleration) changes experienced. The PSS acts as a large gain on the automatic voltage regulator causing the field voltage to over respond, in turn causing large voltage and reactive power swings to occur while the event is taking place. While this response is normal during a short-circuit event, the duration is much smaller and therefore these swings are damped out quickly. During a RoCoF event, the duration of the acceleration happens over a much longer period (both during the initial RoCoF event and the recovery phase) which tends to cause the voltage and reactive power swings to occur over a longer period, becoming noticeable to the unit and the grid.

For example, the figure below shows the *simulated* unit response of a 1 Hz/sec RoCoF event with the tuned as-running integral of accelerating power PSS in service on a test unit. This unit uses electrical power and rotor speed inputs. It was observed that the terminal voltage experienced a 20% swing and the reactive power experienced a 250 MVAr swing (~50% of rated MVA) over an 8 second time frame. Notice that the PSS output (last signal in the lower right) gets pegged against its limit, driving the generator field voltage during the RoCoF rise, and completely reverses its action during the recovery phase, driving the field in the opposite direction, causing the voltage and reactive power swings.

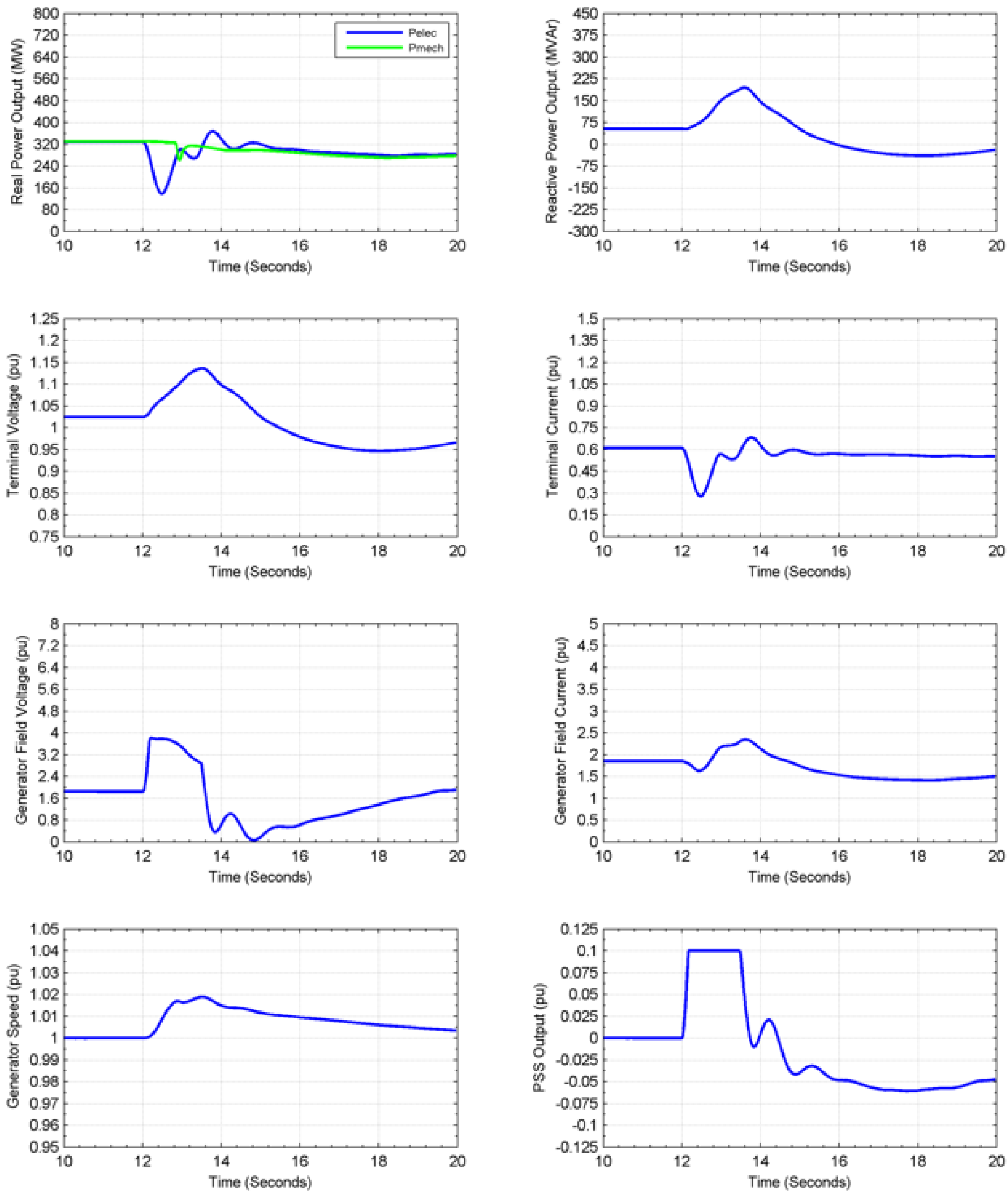

Figure 8 Simulation of 1Hz/sec RoCoF event

While the action itself is not necessarily a connection risk or in violation of grid code requirements, the response could be analyzed by the generation owner and OEM to determine if retuning or some other mitigation (as listed below) technique needs to be applied.

The risks to the system of these PSS driven behaviors can include driving unacceptable voltages that result in other protective relay actions. (Note for example, that the terminal voltage of the unit in Figure 8 is driven to almost 115%. This is not likely to cause a trip, but in a system with lower short circuit strength, this level of over-driving the machine field could result in high voltage induced tripping. This could also cause the over-flux (V/Hz) protection to trip. Other problems could arise from these extreme swings, including over current, under-voltages and unexpected impacts of relays.

Such returning would need to be done with consideration of trying to maintain the original PSS designed response of damping MW oscillations. The strength of the grid can also greatly affect this response, where it may become noticeable even during small RoCoF events.

3.3.2.1 Testing of Integral of Accelerating Power PSS During RoCoF Events

Inventory and testing could be done by generator owners and operators working with the voltage regulator/PSS. OEMs would determine what type of PSS is installed on the machine and if it will respond unacceptably to RoCoF events.

Transient and dynamic simulations of expected frequency events or grid code requirements can be used to determine this response. The full electrical plant model would need to be developed, including the auxiliary system topology. Models have been known to inadequately capture practical implementation problems, such as poor resolution or high latency measurement signals. Field verification is prudent.

Voltage and reactive power swings are generated by the PSS action, and may need to be checked. If they are substantial, the generator owners and operators need to determine the effect of these swings on various aspects of the plant, including but not limited to:

Generator Over-Voltage (59G) and Under-Voltage (27G) Protection Settings

Generator Over-Fluxing (24G) or V/Hz Protection Settings

Excitation System OEL, UEL, HXL Limiters and Protection Settings

Auxiliary System Protection and/or Motor Off-Nominal Voltage and Frequency Limits

Grid Stability Issues

The generator owners and operators would then need work with the OEM and system operator to determine if any mitigation techniques need to be applied.

3.3.3 Improvements for Integral of Accelerating Power PSS Response

If the generator owner determines that a disconnection risk or protective action is possible due to the PSS response, changes to the generator or auxiliary system protection settings may be possible, as long as they do not affect the risk of damage to existing equipment.

If the generator owner or the system operator determines that the unit response has a negative effect on unit or grid stability, the OEM may need to determine a way to mitigate the negative PSS response. Options may include:

> PSS Limit Reduction: This can reduce the voltage and reactive power swings, but will not necessarily eliminate them.
>
> Turn off the PSS: This may or may not be an option as this will eliminate any MW inter-area oscillation damping provided by this unit.
>
> PSS Blocking Schemes: This can remove the response of the PSS during a RoCoF event, but will require the OEM to develop various algorithms to determine if a RoCoF event is being experienced and when to turn the PSS back on in a timely manner that is not going to cause the undesired effect it is trying to eliminate. This also means every OEM will have different methodologies which may cause other issues.

While it is believed that RoCoF event durations will not cause the units to trip, the events could be large enough to start relay timers and therefore may need review. If there is a remote chance that a certain loading condition could cause relay action, the generator owner could either change protection settings, or work with the system operator to determine operating constraints for the unit.

3.4 Synchronous Generation Plant Protective Relaying

The protective functions mentioned above represent some specific concerns. In general, standard generator protective and limiter functions include (at least) protection against external faults [51V], overloads [49,51], unbalance [46], reverse power [32], off-nominal frequency [81], under/over-voltage [27,59], loss of field [40], overflux [24]. (parenthetical numbers are ANSI std device numbers). Of these relays, frequency [81] and V/Hz (overflux) [24] are most directly concerned with frequency. But reverse power and overcurrent can also be in play for RoCoF events.

3.4.1 Overflux (V/Hz) protection

Typically, V/Hz relays are quite slow, being mostly aimed at managing thermal concerns that accompany over-fluxing magnetic equipment. However, if low frequency is accompanied by high voltages, these relays can activate.

For example, one OEM specifies that V/Hz should be set at 118% for 2 seconds. A frequency depression to 49Hz effectively lowers that threshold to 115.6%. This means that a less extreme voltage swing will enter the trip timer. At a timing threshold of 2 seconds, it would take a substantial and sustained frequency excursion to make a difference. For overflux relays that are set to be more sensitive, this is a credible concern. Further, given that there are concerns about over-voltages immediately following under-frequency load-shedding, the combination of high-voltage and low-frequency represents a credible concern.

3.4.2 Reverse Power Protection

During a RoCoF rise event, the electrical MWs on all synchronous machines will rapidly decrease during the first transient swing. If the unit is at a low load condition, there is a strong possibility that the electrical MW swing will go negative. Depending on how low this loading condition is and the severity of the RoCoF event, there is a possibility of generator or turbine reverse power protection tripping the unit.

The figure below shows the electrical MW response for a unit at minimum operating condition for a 1 Hz/sec RoCoF event. Note that the MWs did not go negative, but had the minimum operating condition been lower or the RoCoF event more severe, the risk is credible. Testing (by simulation) for encroachment on reverse power protection should be done at minimum load. Reverse power relays are usually relatively slow, requiring negative power for on the order of 2 to 4 seconds. Note that in the example simulation, the downswing is less than a second.

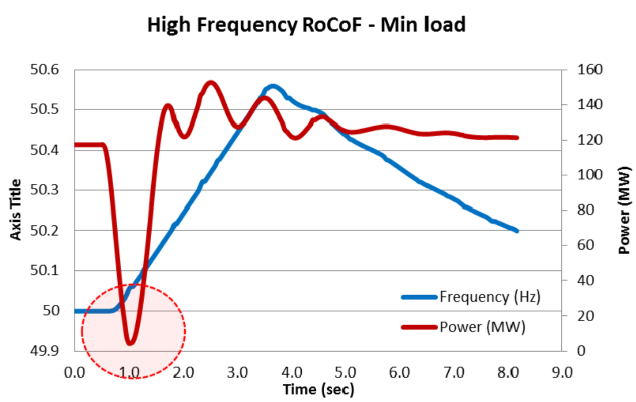

Figure 9 GT response to High RoCoF from Min Load

3.4.3 Over-current Protection

During a negative RoCoF drop event, the electrical MWs will rapidly increase during the first transient swing. If the unit is at a high load condition with a high reactive power leading or lagging power factor, there is a strong possibility that the generator current could be 1.5 to 2.0 times the normal rating. Depending on how high this loading condition is and the severity of the RoCoF event, there is a possibility of generator overcurrent protection tripping the unit.

Figure 10 shows the terminal current response for a heavily loaded unit for a -1 Hz/sec RoCoF event. The terminal current went to 1.5 per unit which was enough to start the inverse curve timer of the overcurrent protection; the duration till trip was not enough (roughly 10 seconds), but had the operating condition been higher or the RoCoF event more severe, the risk is credible.

Prudent protection settings will avoid this risk. The caution here, as with most of the protection discussion, is whether this condition was considered when the relays were set.

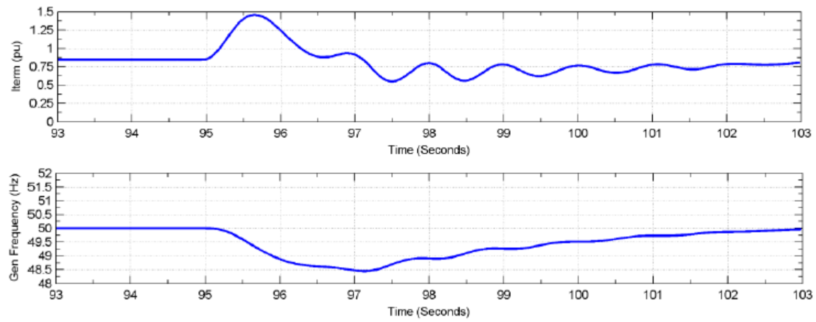

Figure 10 Over-current Illustration (simulations)

3.4.4 Frequency Relays

Frequency relays should have been set in accordance with Australian standards, and should not represent a significant risk. Some less common relays, for example acceleration relays [18] present some risk of poor coordination with high expected RoCoF.

3.4.5 Testing of Generation Protection Response to RoCoF

When in doubt, relay testing is appropriate. The challenge of testing generator protection for response to RoCoF has aspects and challenges like those of testing performance of the power plants themselves. Specifically, the various relays can be bench tested with voltage and current waveforms consistent with high RoCoF, but in the field, these waveforms will tend to be dominated by the response of the generator being protected.

The expected risk of misbehavior for generator protection for devices *that have settings consistent with high RoCoF* is considered low (by the experts consulted for this effort).

3.5 Wind Power Plants

3.5.1 Physics of Wind Power Plant Response to RoCoF

The fact that wind generation is asynchronous makes the relationship between grid frequency and the generator speed immensely different from synchronous machines. In the time frame of the high RoCoF conditions that are the subject of this document (i.e. mostly well within the first second of a disturbance), the electrical behavior of modern type 3 and type 4 wind turbines is completely dominated by the enabling power electronics. Therefore, unlike synchronous machines, the wind turbine generator speed has very little impact on power injected to the grid. In this regard, other inverter-based resources, (i.e. those devices that depend on power converters to deliver AC power to the grid) have some common characteristics.

3.5.2 PLL Theory and Practice

To control their current injection, all inverter-based resources must observe the fundamental frequency voltage waveform. Firing (gating) of valves (i.e. allowing current to conduct, and, in the case of transistors, interrupting the current in the semiconductor) results in currents of a desired magnitude, and most important, phase relationship to the system voltage. Most inverter-base technologies use some variation on a "phase-locked loop", PLL, to perform this measurement. The phasor angle between the injected current and receiving system voltage dictates the amount of active and reactive power delivered (for a given current amplitude) – the single most important aspect of control.

The necessity for a PLL is illustrated in the following figure[5], in which a switching operation causes a 20-degree phase jump. In this particular illustration, Figure 11, ideally the PLL would instantly recognize that the frequency has, in fact, not changed and that there has been a 20-degree step in angle. However, this perfect understanding is only possible in hindsight. The continuous measurement of the sinewave shows one half-wave of current of greatly extended duration, i.e. much lower frequency.

Figure 12 shows a simple representation of a PLL. In practice, PLLs are customized by OEMs for their specific products. But, there are two key elements common to PLLs that are important for the discussion of RoCoF performance. First, and most important, is the filter. This filter is needed for stability, as the very simple example from Figure 11 illustrates. Design of the filter must strike a compromise on speed (and therefore bandwidth) and stability. A PLL that is too fast will respond to noise in the signal (like the phase jump), and cause stability problems. A PLL that is too slow, will result in phase errors for the current injection. This has the practical impact of causing the current injection to be incorrectly phased with the system voltage. The consequences can be significant from a systemic perspective: current that is supposed to deliver active current (i.e. kW) may by reactive, and vise-versa. For conditions of high RoCoF,

[5] Technology Capabilities for Fast Frequency Response. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf

the delivery of active power may be substantially degraded as the PLL falls behind the dropping frequency.

A second concern for high RoCoF, is that some converters may have protective functions that are based on high PLL error. The red arrow in the figure is illustrative of where controls may inspect the PLL error to test for dynamic conditions that put the equipment at risk. It is possible that converter controls for specific wind turbines (as well as PV, BESS, etc.) will block operation – i.e. trip – for excessive PLL error, alternatively controls may switch to other defensive control modes. They may resume after the PLL error drops inside a tolerance, assuming resumption is still possible.

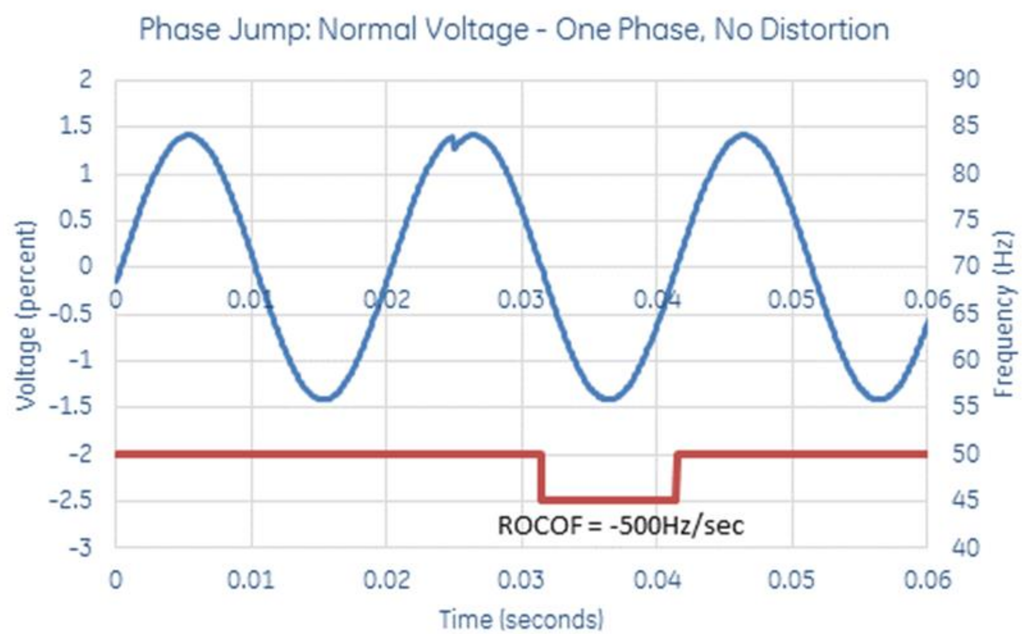

Figure 11 Phase Jump in a single phase voltage

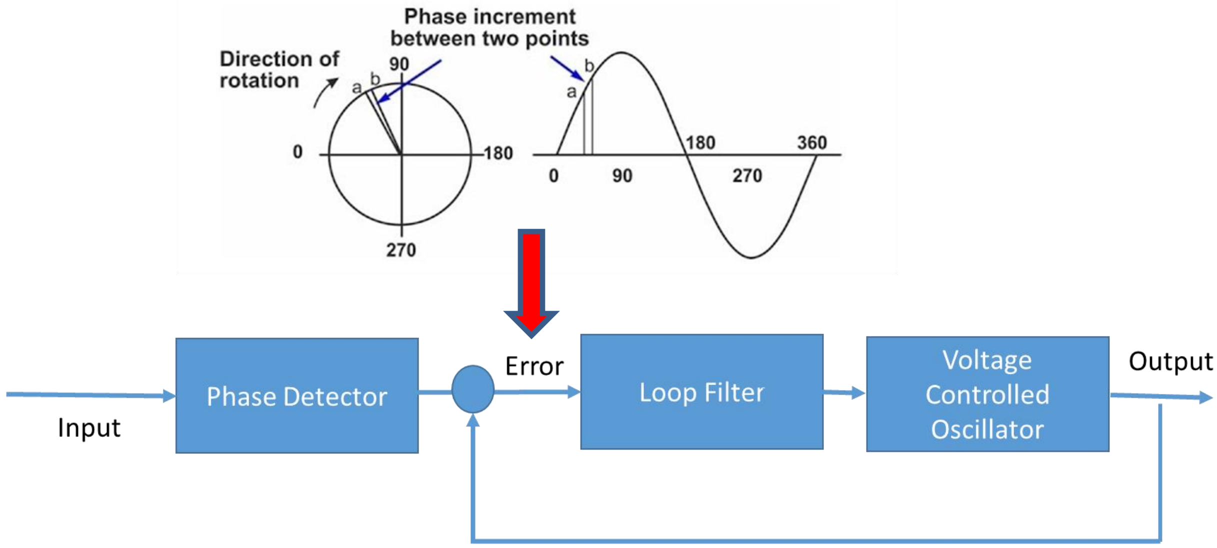

Figure 12 Simple PLL Representation

3.5.3 Simulation of Type 3 Wind Power Plant Response to RoCoF

The behavior of a current state-of-the-art wind turbine with double-fed (type 3) generator topology is shown by detailed design software simulation in the following sequence.

In Figure 13, the turbine is subject to a frequency drop at 1 Hz/sec, down to -1Hz from nominal (the level of UFLS for the NEM). The turbine handles the rapid frequency drop well, and for such an extreme RoCoF maintains a relatively steady output. Nevertheless, notice that the active power (3rd trace) is affected slightly, starting about 50ms into the event. Power drops about 1.5%, recovering to normal after about ½ second. From a practical perspective, this is quite small power deviation. Obviously, had the WTG had frequency response controls enabled – either inertia based FFR ("synthetic inertia") or primary frequency response control ("governor response"), the active power output would have increased. This deviation from fixed active power output is related to the control trying to track the system phase angle, which is moving very rapidly for this acute RoCoF.

For rapidly increasing frequency, the control has a little more trouble following. After holding steady for a few cycles, the active power drops about 16% (3rd trace) , then recovers over about ¼ second. The depression of active power during the frequency rise is, in general, a desirable response.

This report is intended to address RoCoF issues. However, frequency drops can follow system faults that result in active power unbalance. In Figure 15, a 100ms fault preceeds the -1Hz/sec RoCoF (of Figure 13). The active power suppression that must accompany the voltage depression of the fault results in about a 50% drop. The active power recovers to its pre-fault level in about another 100ms. This is a quite fast recovery. In systems with much lower short-circuit strength, the recovery must be slower. (This is not a RoCoF issue, and detailed discussion of this important performance characteristic of inverter-based resources is outside the scope of this document.)

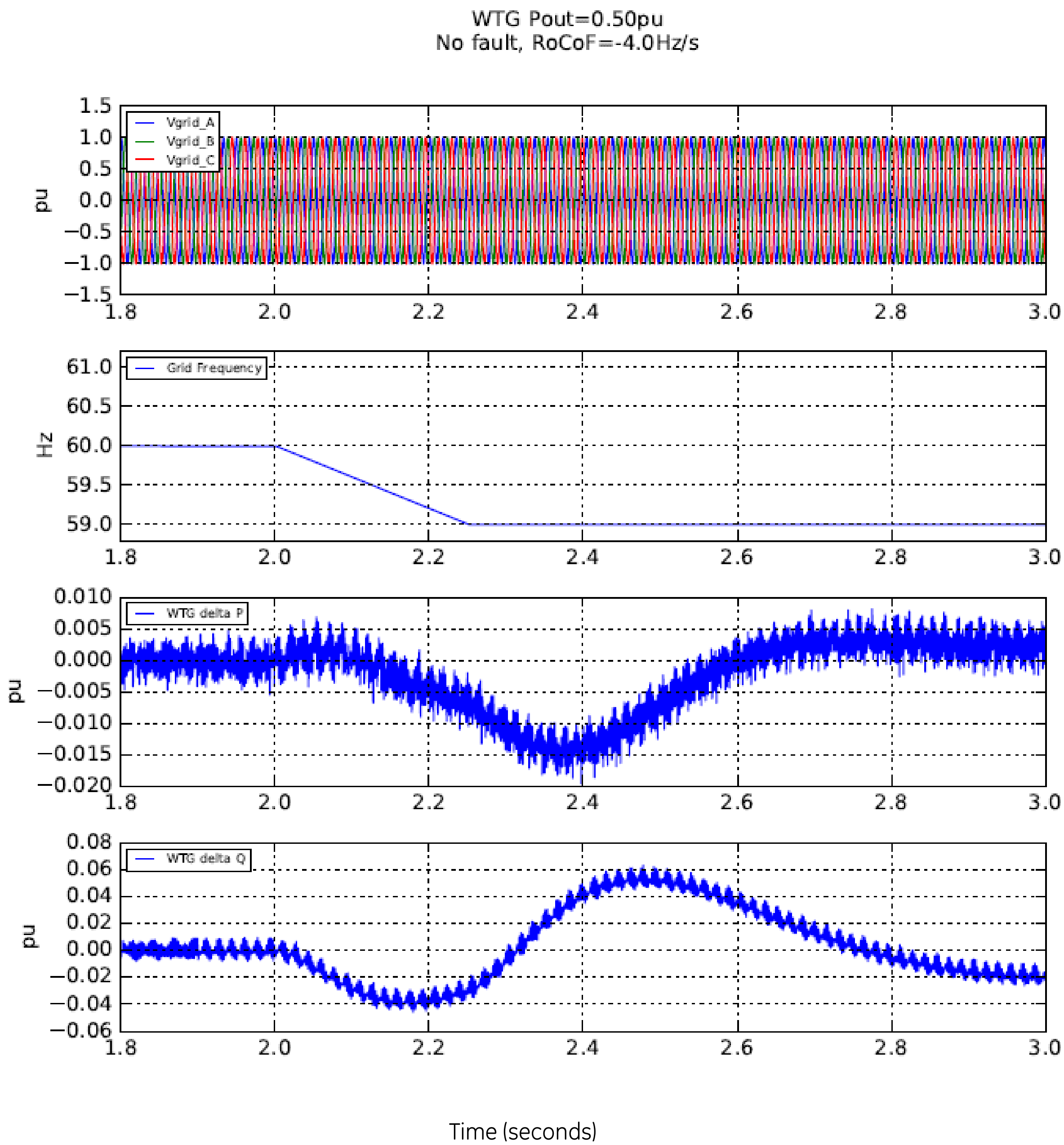

Figure 13 High RoCoF Frequency drop for Type 3 WTG

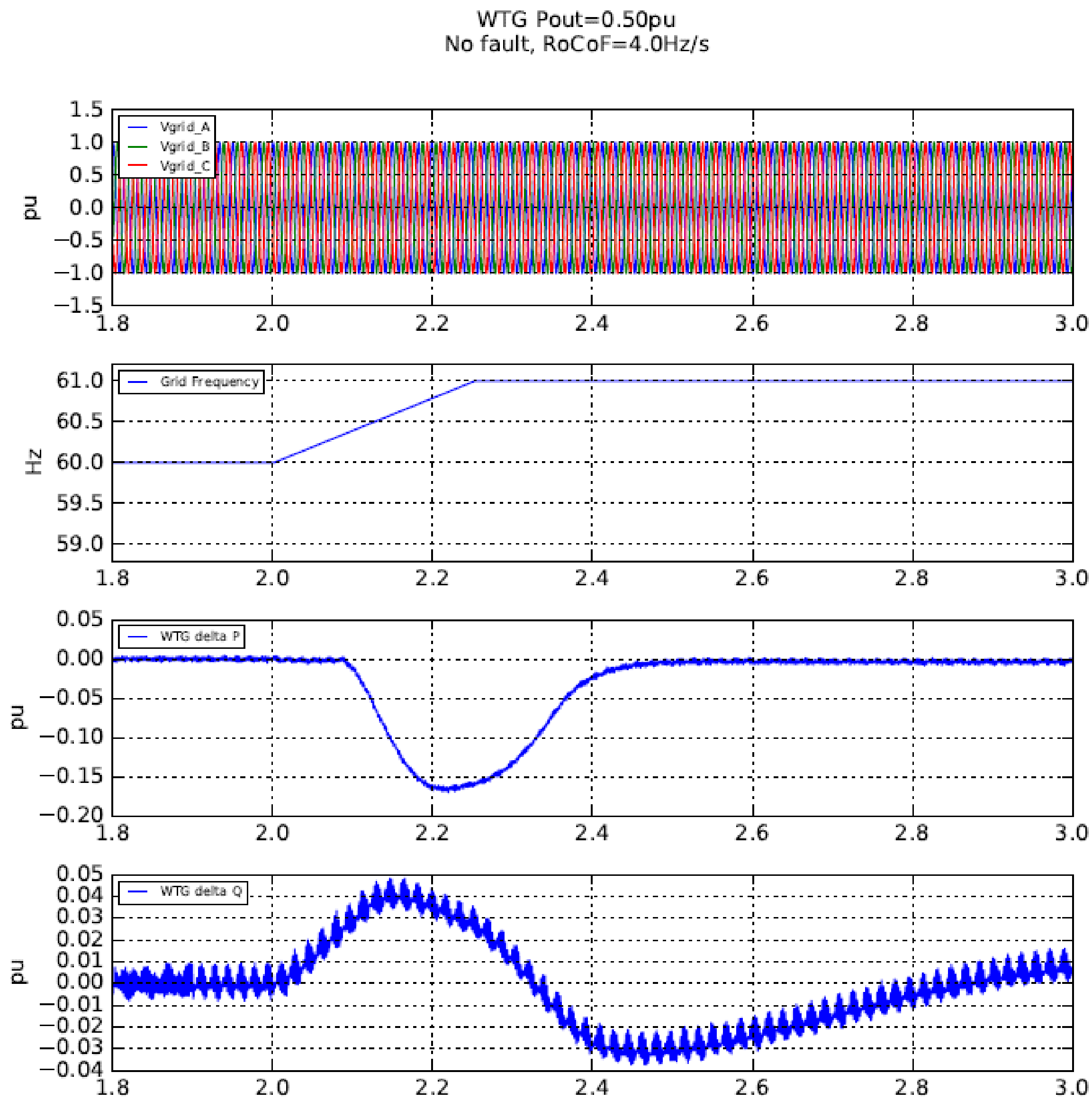

Figure 14 High RoCoF Frequency Rise for Type 3 WTG

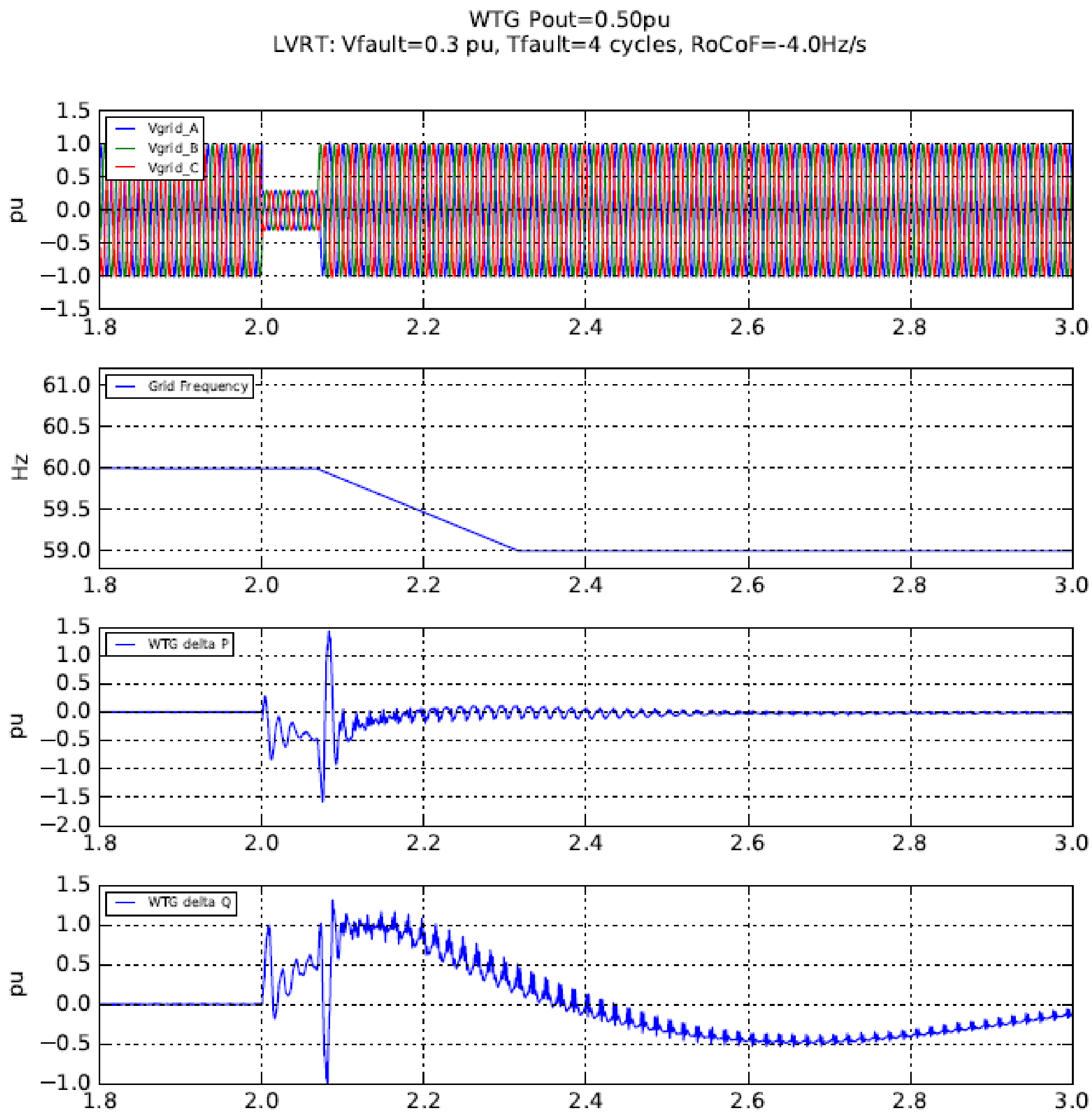

Figure 15 Grid Fault followed by High RoCoF decline for Type 3 WTG

3.5.4 Simulation of Type 4 Wind Power Plant Response to RoCoF

The behavior of a current state-of-the-art wind turbine with full converter (type 4) generator topology is shown by detailed design software simulation in the following sequence. The power signal in these tests is somewhat noisier than for the type 3 machines, since 100% of the generator power is delivered to the grid through the converter. But, the power signal (which is a deviation from the initial power) shows no deviation that can be discerned in the signal. The reactive current responds by a few percent. As with the type 3 example, it must be emphasized that this is illustrative, and not representative of specific or all type 4 WTGs.

The same issues of frequency tracking by PLL or other functionally equivalent means still applies. Nevertheless, wind turbines should be able to track high rates of change of frequency with relative ease.

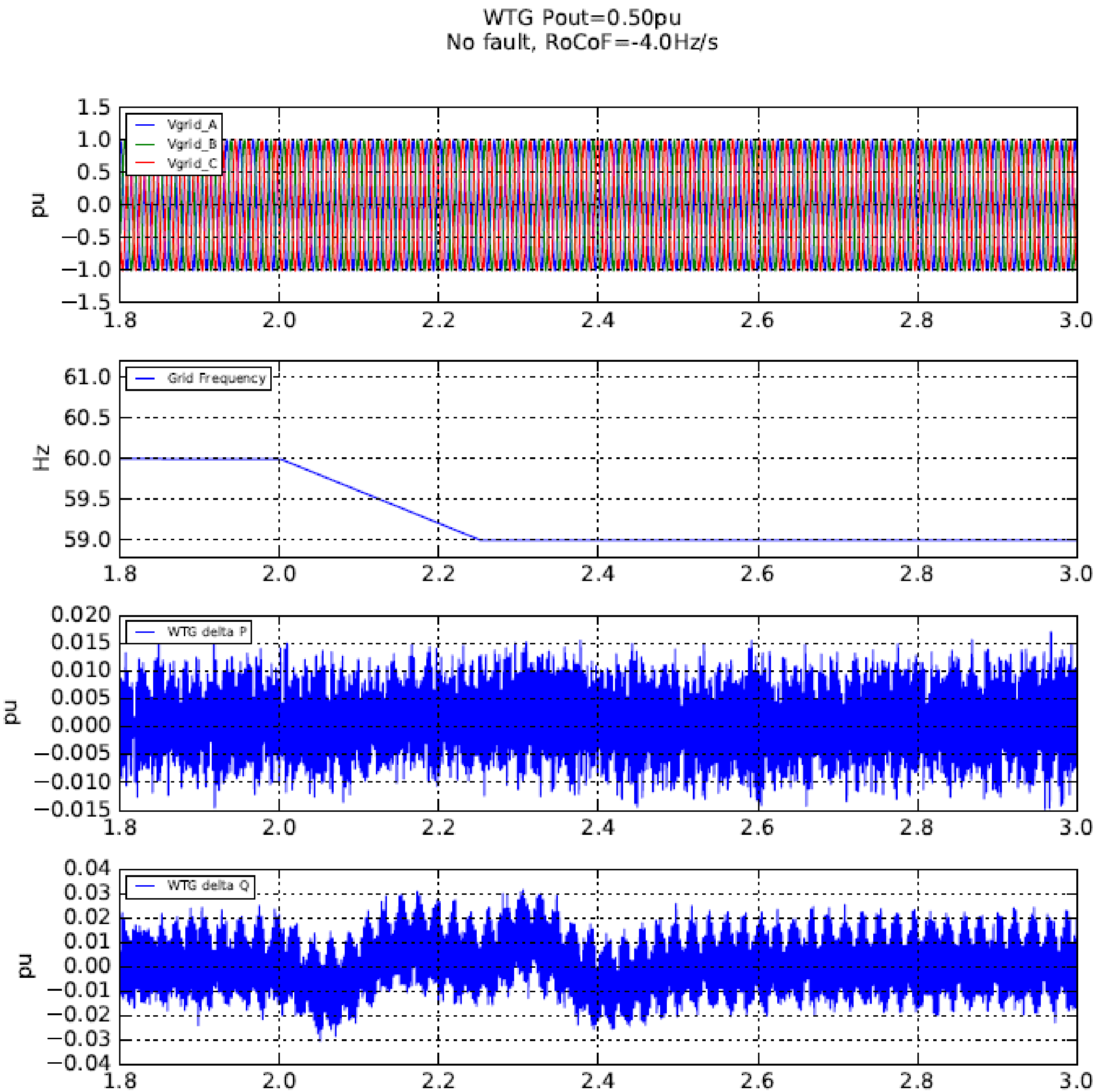

Figure 16 Response of High RoCoF decline for Type 4 WTG

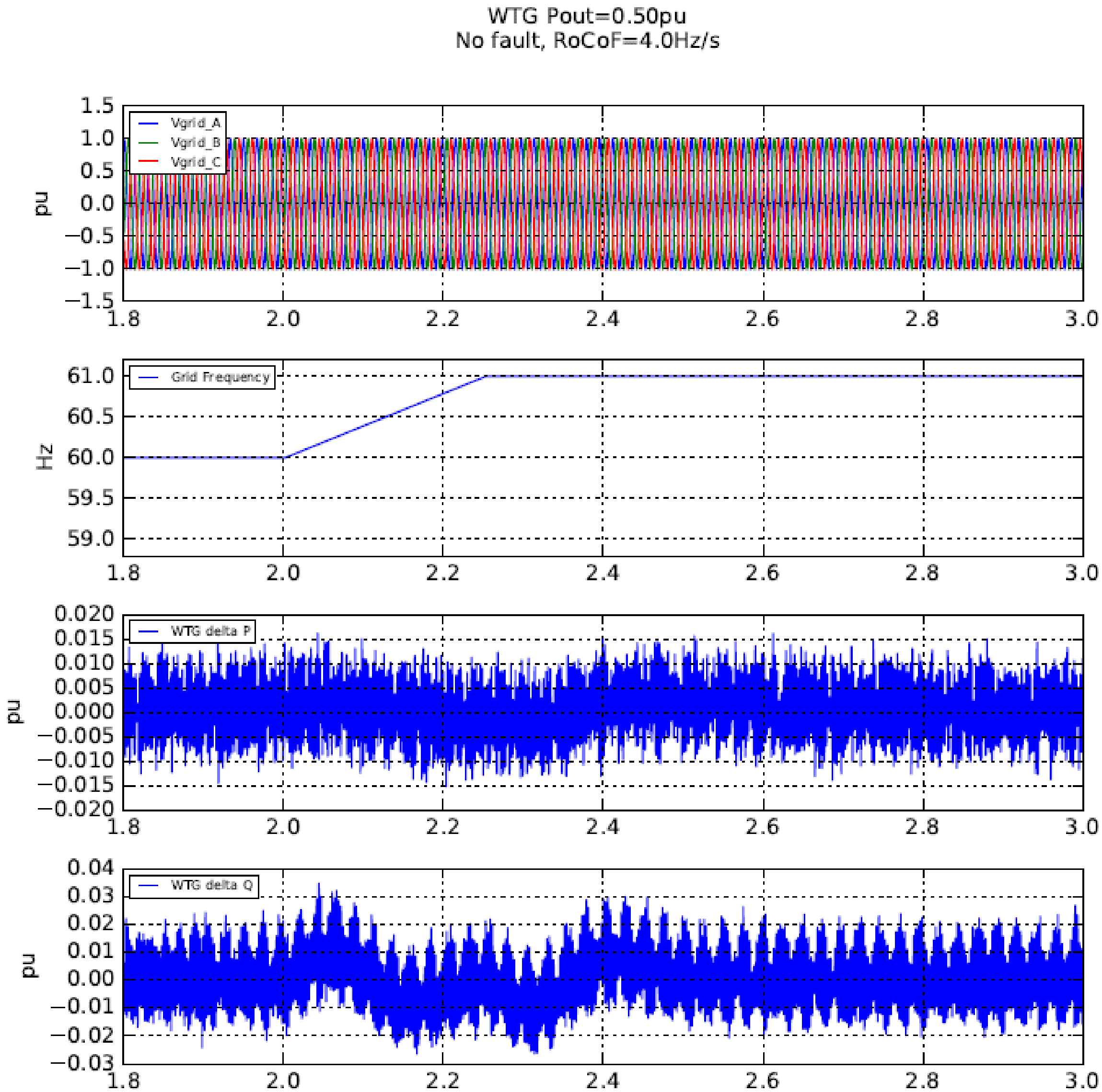

Figure 17 Response for High RoCoF increase for type 4 WTG

The behavior of high RoCoF immediately following a fault for this type 4 machine is shown in Figure 18. This is similar to Figure 15. The during fault active power suppression is a bit more, and the active power recovery is a bit faster. Individual OEMs, and very possibly different models of turbine from the same OEM, will exhibit different behaviors.

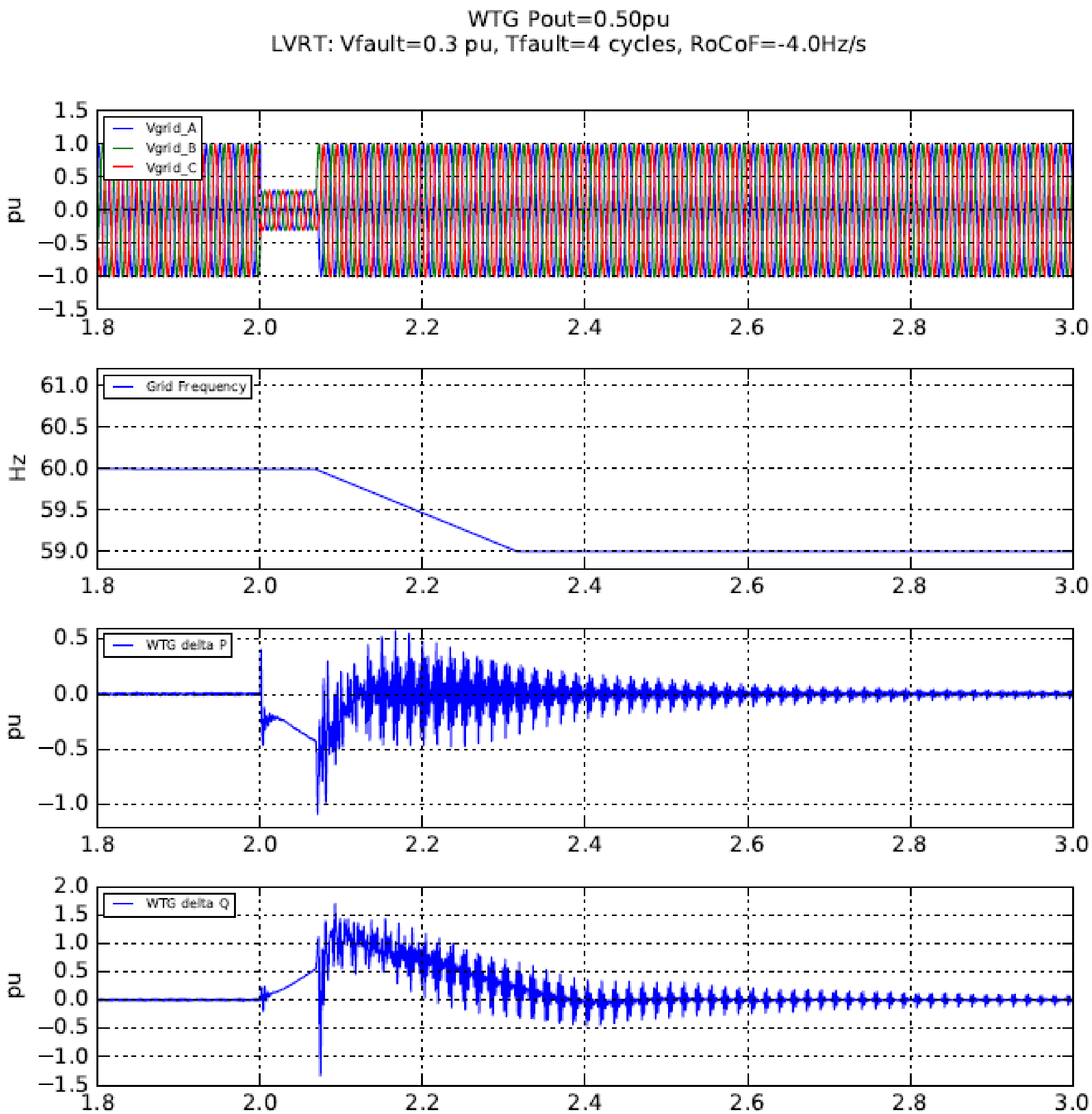

Figure 18 Response to Grid Fault and High RoCoF decrease for type 4 WTG

The reader is cautioned that these 6 simulation examples are illustrative of the performance of a relatively new class of type 3 and type 4 wind turbines. Further, these are for a particular version of a particular OEM's equipment. As has been noted repeatedly in this document, there will be differences in performance across both vintage and OEM. In general, the authors expect that there is a higher risk of poor RoCoF performance for older vintage type 3 and type 4 wind turbines.

Other frequency sensitive controls, such as primary frequency control or inertia-based fast frequency response (IBFFR… aka "synthetic inertia") are designed and tuned for applications. These controls are the subject of the report on Fast Frequency Response[6] .

3.5.4.1 Field Testing for RoCoF

As noted above in Section 2.3, it is difficult to stage frequency tests. At least some manufacturers do isolated tests on components and drivetrains, but not full WTGs. However, NREL's new CGI allows such tests. Recent, yet to be published tests performed step tests of actual frequency (as opposed to control F error inputs tests, which are common – per discussion in Section 2.3 above). A step test in frequency, in this environment, is equivalent to infinite RoCoF. Steps of minus then plus ~800mHz were run. These were to test the control response of active power controls, both IBFFR and primary frequency response functions, on a commercial type 3 wind turbine. The intent was not explicitly to check for RoCoF ride-through, but the tests are very meaningful, if not exhaustive, in this regard. The WTGs had no problem tracking the frequency change. And indeed, this is a relatively easy challenge compared to maintaining control stability during a fault and clear sequence.

It is worth noting that, as would be expected, the rapid application and release of incremental torque on the drive train of the WTGs resulted in torsional oscillations. This is as expected, but nevertheless reinforces the observation made earlier (in the manufacturers perspectives of the report on Fast Frequency Response) that extremely rapid changes in electric power output of a wind turbine has mechanical consequences for the turbine. The testers were surprised at the response; the manufacturer was not.

3.5.5 Older Induction Generator based Wind Turbine-Generators

There are very few induction generators being offered for utility-scale generation today. The Australian system has some older machines, including those with resistive field control (type 2).

Unlike type 3 and type 4 machines, induction machines will have a significant response to rapidly dropping frequency. There will be an increase in electrical torque and current while the frequency is dropping. During this stage, that response is beneficial to the grid, but places additional stress on the wind turbine. While there is relatively little risk of control mis-operation, high currents and torques could lead to protection actuation.

3.5.6 Improving Wind Power Plant Response to RoCoF

There are two general classes of actions that can harden wind turbines against mis-operation under conditions of high RoCoF:

1. Upgrade and tune controls, particularly improving PLL response to high RoCoF and check for satisfactory torque and pitch control subject to fast changes in frequency
2. Verify and refine, as necessary, protective functions.

[6] GE Report on Fast Frequency Response

The first step is highly specific to each OEM, and would follow testing that showed inadequate performance. The second element, check for protective conflicts, covers not only the turbine equipment, but frequency sensitive protection on substation and feeder equipment, and control house auxiliaries.

The control tuning recommendation is specifically aimed at avoiding mis-operation. This is distinct from frequency sensitive controls that are intended to help the grid manage acute frequency change and high RoCoF, which is discussed in the report on Fast Frequency Response.

3.6 Utility-Scale Solar PV Power Plants

Utility-scale solar PV generation relies on self-commutating four quadrant converters for grid interface. Like all inverter-based resources, these inverters rely on phase-locked loops to maintain synchronism with the grid. Consequently, they are subject to the same class of limitations described above in 3.5.2. The challenge of getting the controls right for PV is somewhat less than for wind turbines, as there are no torque consequences (nothing is moving). Nevertheless, it is possible to cause some degradation of adherence to active and reactive power commands.

3.6.1 Testing of Solar PV Plant Response to RoCoF

Bench tests of solar PV inverters are very meaningful, and generally should be sufficient to test for RoCoF performance. Unlike wind turbines and rotating equipment, the mechanisms for electro-mechanical interaction are limited. Some of the behavioral characteristics of PV will be found in other inverter-based resources that have no dynamic devices. Illustrative simulations are shown in the next section.

3.7 Battery Energy Storage Systems (BESS)

The behavior of a battery energy storage system (BESS) subject to high RoCoF is shown in the following pair of figures. In these cases, the BESS has an aggressive frequency sensitive control. In both figures, the control keeps extremely close adherence to the frequency droop. This is representative of the possible performance of inverter-based resources for controlling frequency. The under-frequency response in Figure 19 also illustrates a risk: in this case the control, which begins to respond within 10-20 ms after the frequency ramp starts, results in saturation of the converter current capability. This is an error in the control settings (for the simulation), but represents the kind of problems that can occur with inverter based resources, if control performance is inadequately vetted. [It is worth noting that this is a subset of the class of problem that needs to be considered in 100% inverter systems (per discussion in the Fast Frequency Response report).] The same drop in frequency is shown following a fault (in a similar case to that shown in Figure 15 and Figure 18) in Figure 20. The case shows the necessary drop in active power, and recovery. In his case again, the recovery takes about 100ms. And again, as the converter approaches maximum power, it misbehaves as it approaches full power.

Behavior for a rapid rise in frequency is shown in Figure 19. In this case, the performance is nearly perfect, with the drop in active power tracking the frequency rise with only about a cycle delay.

The overall conclusion from these illustrations is that the performance of inverters can, and *should,* be excellent for high RoCoF, but controls must be tuned (and tested).

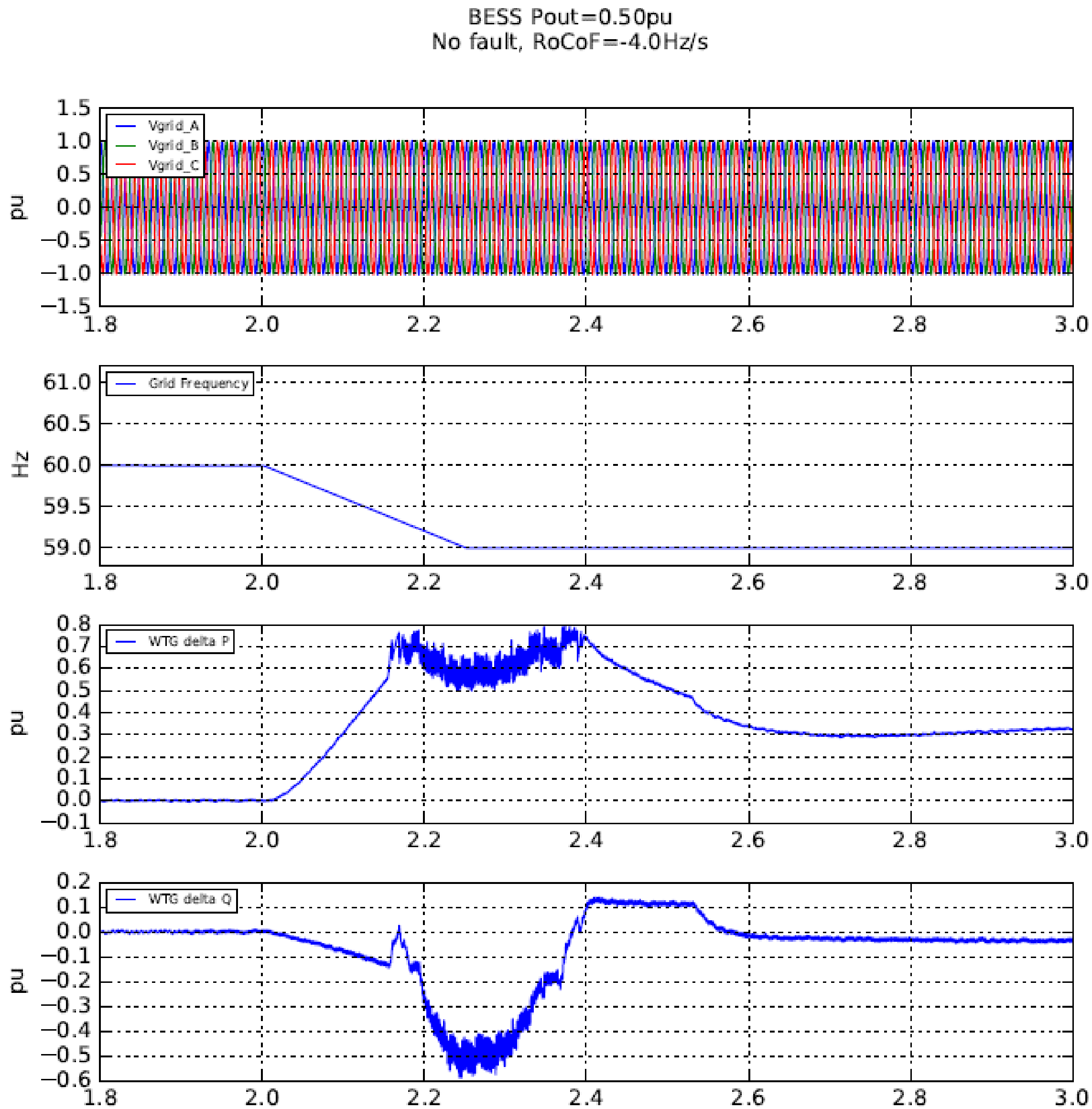

Figure 19 BESS Response to High RoCoF decrease

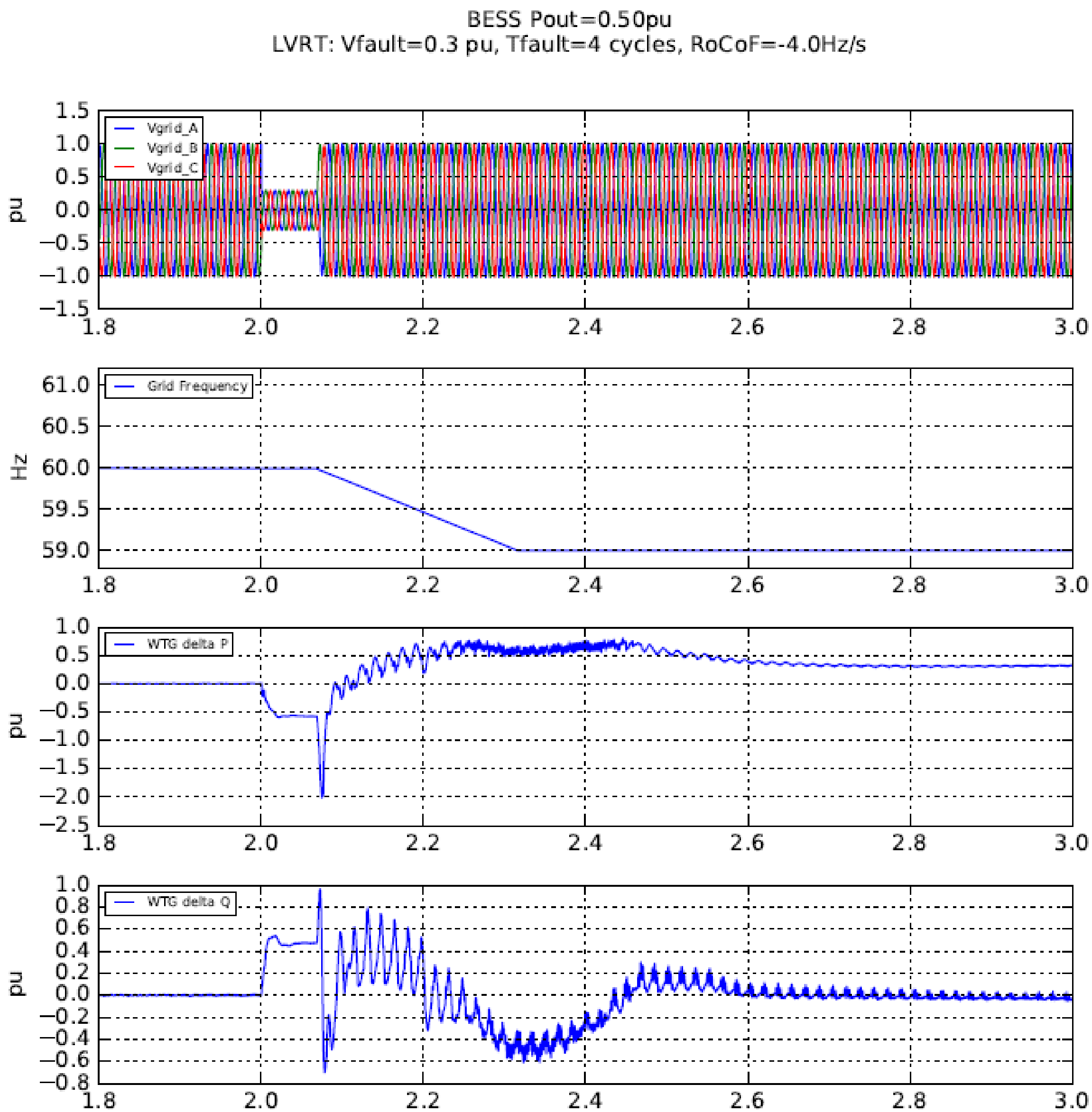

Figure 20 BESS Response to Grid Fault and High RoCoF decrease

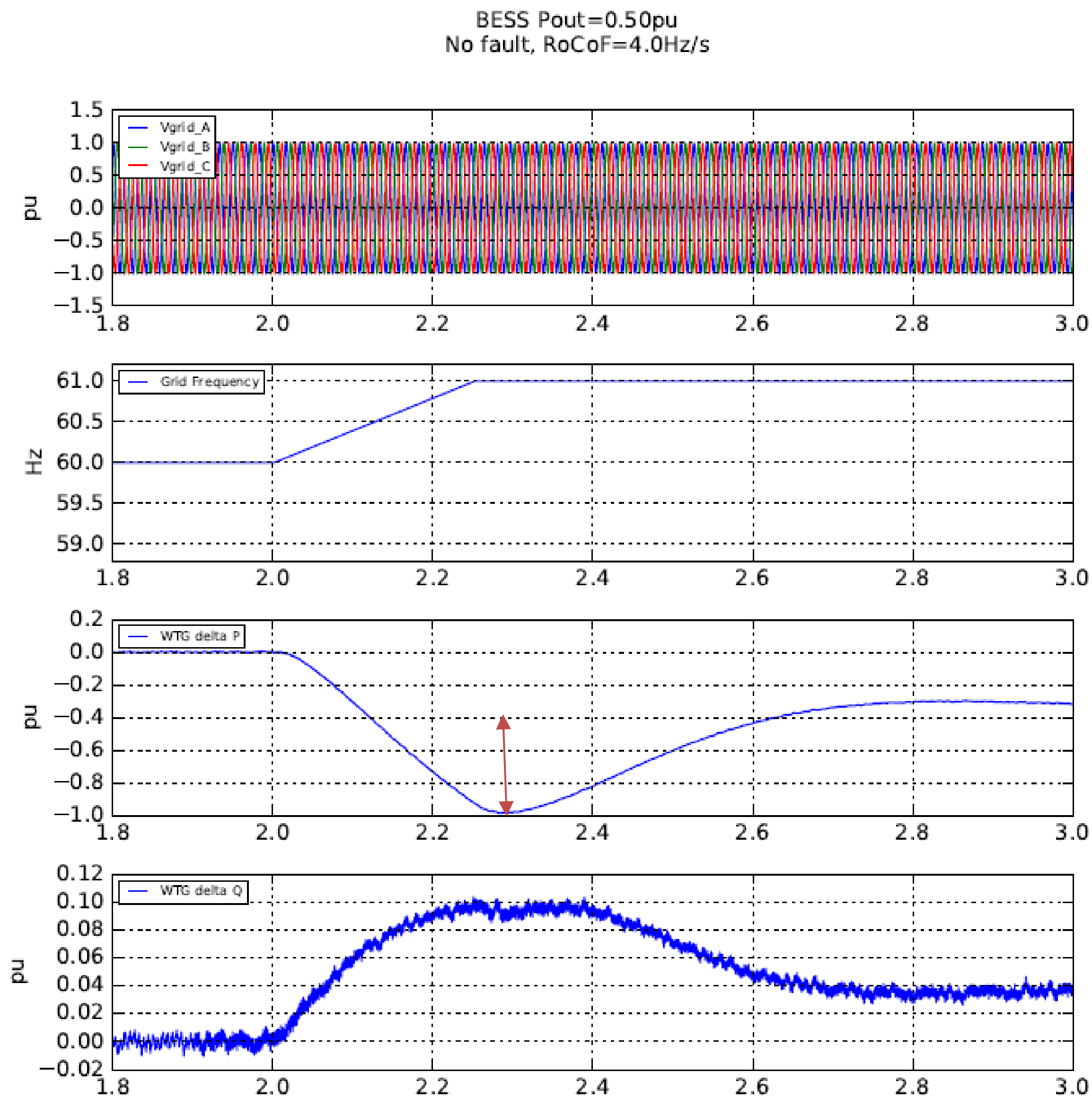

Figure 21 BESS response to high positive RoCoF

4 TRANSMISSION

4.1 Protective Relaying

Modern digital protective relaying is generally expected to be relatively insensitive to RoCoF (or moderate frequency deviations).

The same cannot be said for electro-mechanical relays, which are known to perform poorly for significant frequency deviations. Information on sensitivity to RoCoF is scarce, but a consensus from relays experts interviewed for this work is that electro-mechanical relays in critical applications (relative to security for large frequency events) should be bench tested.

4.1.1 Digital Relaying

Frequency performance of relays has gotten considerable attention in the US since the 2003 blackout. [7]

All modern digital relays have algorithms specific to the OEMs. Nevertheless, there is a degree of commonality. A typical modern digital relay performs *Frequency Tracking* by measuring the period of a highly-filtered fundamental frequency. Based on the measured period, the sampling interval of the AC waveform is adjusted such that there are always an integer number (e.g. 64) samples per cycle collected for the fundamental frequency. The sample interval is updated on a cycle-to-cycle basis. As a result, calculation of RMS and Phasor are always corrected for the actual system frequency. Normally, even during severe system events, the frequency changes are well within the design limits of the relay frequency tracking/ compensation mechanism, allowing it to catch up to the system frequency and maintain correct measurements. Specifications for (one particular) present technology digital relay has frequency measurement accurate to +/- 0.001 Hz.

There are several phasor estimation techniques used for protective relaying purposes, such as the Discrete Fourier Transform, Cosine algorithm, Least Squares algorithm, Kalman filter and Wavelet transform. Most of the relays are using either the Discrete Fourier Transform or Cosine algorithm. Once signal phasors are estimated, protection algorithms are executed. All of these processes use frequency tracking or a compensating scheme.

The adjustments for off-nominal frequencies are typically able to follow the system frequency rate of change that is limited by the system inertia. Often, various inhibiting or security conditions are implemented to prevent erroneous frequency measurements under faults and other abnormal conditions that could lead to anomalies in signal phase.

Under stressed system conditions, the various implementations of the frequency tracking/compensating schemes may respond differently. In particular under a large rate of change of frequency some implementations may either refuse to track, or lag considerably

[7] M. Adamiak, I. Voloh, D. Finney, "Impact of Frequency Deviations on Protection Functions" IEEE International Conference on Advanced Power system Automation and Protection (APAP) 2009.

the actual and fast changing system frequency. Some implementations may stop tracking at certain upper or lower limits. In cases where frequency tracking is poor or blocked, substantial errors in measured quantities will occur,and relay misoperation is a risk. However, for events that are only RoCoF, and not more complex combinations of events (e.g. faults, over-voltages, acute unbalances), tracking is expected to be satisfactory (beyond 4 Hz/sec).

In a simple case of straight current differential function implemented on a per-phase basis, errors in phasors due to off-nominal frequencies are not consequential.

The above optimistic observation does not apply to harmonics used for inrush or overexcitation inhibit, or to mixed-mode differential functions. Also, if some of the currents are measured using different frequency tracking, extra errors will be created.

Microprocessor-based differential relays are exposed to a variety of problems during off-nominal frequencies. However, the reality is that these relays support frequency tracking / compensation and by the virtue of it are actually less prone to problems compared with analog relays. The situation of off-nominal frequency must be understood as a period when the relay frequency tracking mechanism is lagging the actual system frequency. Once the relay has measured the frequency accurately, it regains its theoretical precision even though the system frequency is not nominal. As a result, the off-nominal frequency issues occur practically only during fast frequency changes when the relay may apply security averaging and as a result adjust tracking frequency intentionally slower than the changes in the power system. For example some of the islands during the 2003 blackout showed frequency changes in excess of 30Hz/sec for a duration of 100-200ms during system break up. Some relays did not allow such rapid changes in their tracking frequency, which led to a temporary lag between the system and tracking frequencies. But normally, even during severe system events, the frequency changes are well within the design limits of the relay frequency tracking / compensation mechanism allowing it to catch up to the system frequency and maintain correct measurements. It is only during moments where frequency changes fast enough to disable frequency tracking, or during the absence of the signal selected for tracking, that problems can occur. In these situations, some risks are present as follows:

- Instantaneous phase overcurrent protection: Errors on the order of 1-2%/Hz are possible.
- Time-delayed phase overcurrent protection: limited impact.
- Voltage protection: Risk of underestimating voltage.
- Directional protection: errors in voltage and current angle measurements mostly cancel out. Risk of loss of directionality with sustained memorized voltage.
- Bus differential protection: interference with CT saturation restraints are possible.
- Transformer differential protection: risk of delayed operation due to harmonics from inrush or overexcitation.
- Line current differential: Risk of spurious negative sequence measurements in asymmetric schemes.
- Distance protection: Memory polarization (using pre-fault voltage measurements) can cause spurious pickup during long disturbances coupled with fast frequency swing.

With rates larger than 10Hz/sec, the frequency tracking mechanism may lag the actual frequency causing off-nominal frequency errors proportional to the difference between the tracking and actual system frequencies.

4.1.2 Electro-Mechanical Relays

Electro-mechanical relays are analog devices that have inductive elements. Shift in fundamental frequency alters the impedance of these inductive elements, changing their response. Whether the deviation in response is significant, from a protective perspective, depends on the application. The degree of sensitivity to off-nominal frequency is a function of the circuit topology, which varies with application and OEM. The default assumption should be that EM relays have relatively poor accuracy for substantial RoCoF. In any application where precision is required or, more important, misoperation has a significant security impact, they should be tested.

4.1.3 Testing of Relays

Testing for impact of frequency deviations can be performed, to see how well a relay can cope with off-nominal conditions (including high RoCoF). The following steps can be considered to test relay operations:

- Examination of the relay's frequency tracking/compensation mechanism per manufacturer literature and specifications to evaluate impact on the relays performance.

- Measurement of the highest and lowest frequency for which the relay can measure/track/compensate to determine if it meets application requirements.

- Frequency ramp up and ramp down (RoCoF) tests at different frequency rate of change, for example 0.1Hz/sec, 0.5Hz/sec, 1Hz/sec, 3Hz/sec, 5Hz/sec, 10Hz/sec with measurement of the voltage and current phasors error.

- Step change in the frequency, for example 0.1Hz, 0.5Hz, 1Hz, 2Hz to determine how quickly and accurately the relay can adjust its sampling frequency to match the system frequency-this may dictate necessary elements delays.

- Measurement of phasor errors during off-nominal frequencies such as power swings, sub-synchronous oscillations, harmonics, electrical noise.

- Measurement and estimation of various elements of interest behave during off-nominal frequency conditions.

- Evaluation of distance and directional elements memory voltage functionality; memory voltage delays, ways to reset memory voltage, to force self-polarization. For example, if significant frequency change is detected (by underfrequency or overfrequency elements), or frequency is changing at the high rate (frequency rate of change element), then distance has to be become self-polarized in order to avoid nuisance operation.

Relay OEMs and other power equipment testing facilities can bench test relays. Relays are normally tested by feeding in signals to exercise different functions. These signals can come from field measurements, simulations on EMT and RTS type simulators, and from signal generators (as was demonstrated in Section 3.)

4.2 Transmission Equipment

Aside from protective functions, transmission equipment is generally inured to RoCoF.

4.2.1 SVCs and STATCOMs

These devices use variations on PLLs to manage current control. STATCOMs are topologically identical to PV, BESS and other devices with inverters. As illustrated in 3.7, performance for high RoCoF is expected to be satisfactory. Tests can be performed by the OEM.

4.2.2 Series Compensation

There is no expected impact of high RoCoF on series compensation. Distance protection for series compensated lines may handle memory polarization (as mentioned above) differently.

4.2.3 HVDC

HVDC system controls are all highly customized and proprietary. Again, firing of HVDC valves is dependent on PLL tracking of voltage and current waveforms. HVDC systems are generally tolerant of rapid frequency swings. However, the high levels of RoCoF here may challenge systems that were not designed with this as a performance objective.

Validation of ability to track high levels of RoCoF can normally only be performed by the OEM.

5 END USER AND DISTRIBUTION EQUIPMENT

5.1 Distribution equipment

Distribution network equipment will be subject to similar concerns to those outlined in the section on transmission equipment, regarding protection relays. While the risk of distribution protection mis-operating should be considered, the level of concern is moderated by the fact that most distribution protection is relatively simple, e.g. over-current or voltage based, and not very dependent on high precision measurements or actions to provide the necessary protection.

5.2 Loads and Demand

The behavior of individual loads to changes in frequency varies tremendously. For example, power electronic devices which rely on switched mode power supplies are relatively impervious to changes in frequency. Whereas conventional electric motors, both induction and synchronous machines, will experience speed changes with frequency. The resultant change in mechanical torque as shaft speed changes can range from relatively small to large. For example, in the case of viscous loads, the torque will vary with the square of speed. The dynamic response of individual loads, i.e. their sensitivity to RoCoF is even more complex.

From the perspective of bulk power system dynamics, it is only the aggregate response, as it affects the active and reactive power consumption presented to the grid that is of concern. The potential for damage to end user equipment under high RoCoF conditions is also of concern, but given the very limited data available, this has not been addressed in this study.

5.2.1 Load Modeling

For bulk power system security and stability analysis, loads are aggregated into single equivalents connected to the bulk power system model at a single point. This is standard practice, that means, for example, that all of the customers (residential, commercial and industrial) in (say) a small city, will be represented as a single equivalent. So, for example, all the components illustrated in Figure 22 are reduced to a single simple algebraic equation. The modeling of load dynamics (i.e. time sensitivity, represented with differential equations) has been the subject of interest and research for decades. But, it is relatively common practice for the modeling of load dynamics for evaluation of bulk power system performance to be ignored. In fact, so-called ZIP loads, with simple algebraic dependence on voltage at the transmission bus, are often used for dynamic simulations. Thus, possibly thousands of customers are represented as (for example) a linear current sink. Without dynamic representation, questions related to the RoCoF behavior of loads and its impact on the bulk system can not be meaningfully addressed.

The power industry has long accepted this modeling compromise between complexity and accuracy. The degree of modeling uncertainty inherent to system analysis, and the need to exercise conservative practice, has generally served the industry well. Nevertheless, the fact that load dynamics can hugely affect the results of planning simulations for systems that are highly stressed is cause for concern.

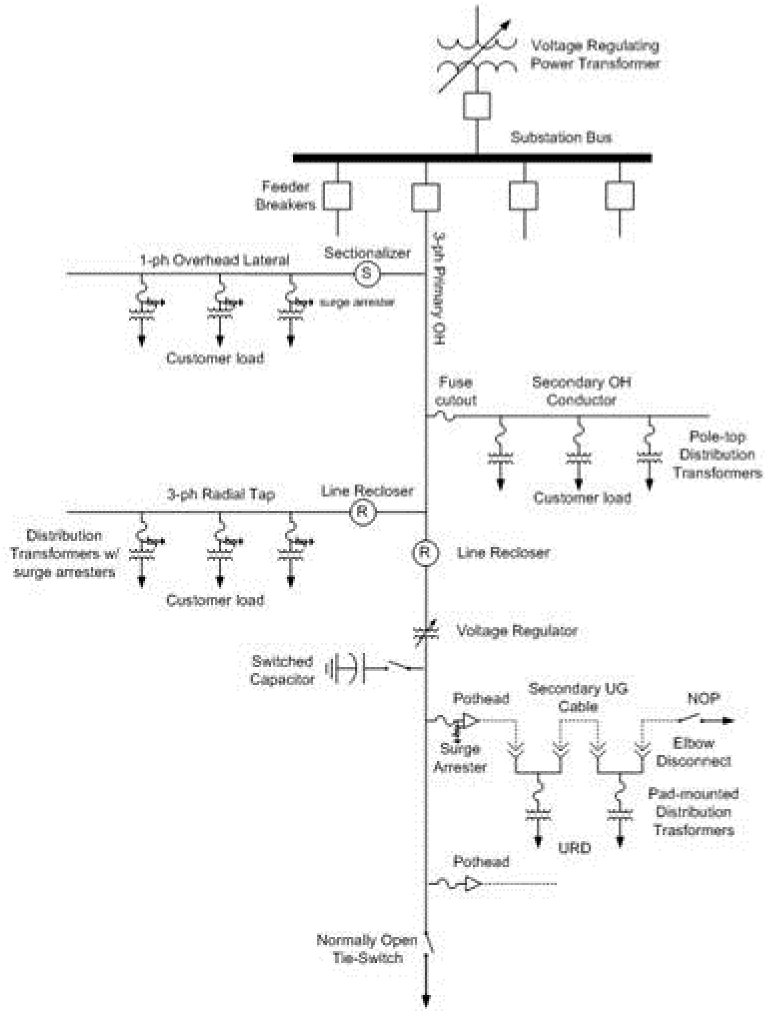

Figure 22 Schematic of a Distribution System

In Figure 23, the equation by which the equivalent load is modeled shows only simple algebraic sensitivity to voltage (V, normalized to the initial voltage, V_0). The active and reactive load (P and Q) are initialized from a static loadflow and connected to a transmission voltage bus (or the low side of a substation transformer). The point is that this an extraordinarily simple representation of essentially half of the power system. Sometimes this representation also includes a linear frequency term, which in theory, improves the fidelity for frequency events slightly. The industry has long used these models, not so much because they are believed to be accurate, but rather because they are easy and believed to be adequate. With conditions of high RoCoF, this assumption may or may not continue to hold.

$$P_{ZIP} = P_{baseZIP}\left[a_0 + a_1\left(\frac{V}{V_0}\right) + a_2\left(\frac{V}{V_0}\right)^2\right]$$
$$Q_{ZIP} = Q_{baseZIP}\left[b_0 + b_1\left(\frac{V}{V_0}\right) + b_2\left(\frac{V}{V_0}\right)^2\right]$$

Figure 23 A typical ZIP Load for Stability Simulation

5.2.2 Composite Load Modeling

One avenue for improved fidelity representation of distgribution system and load equivalents that is gaining acceptance (particularly in the US) is so-called composite load modeling. In this class of modeling, the types of loads served are extracted (usually from customer databases used for distribution system planning), and used to populate more complex equivalent load models.

In these models, it is possible to make a better, if still imperfect, distinction between types of loads. For example, water pumping loads are distinct from air conditioning, switched mode electrics from incandescent lighting, etc. One general structure that is in the process of being adapted in the western US is shown in Figure 24. The structure allows a somewhat better ability to capture system dynamics that may be of concern. [The embedded solar PV block, shown in red, will be discussed below.]

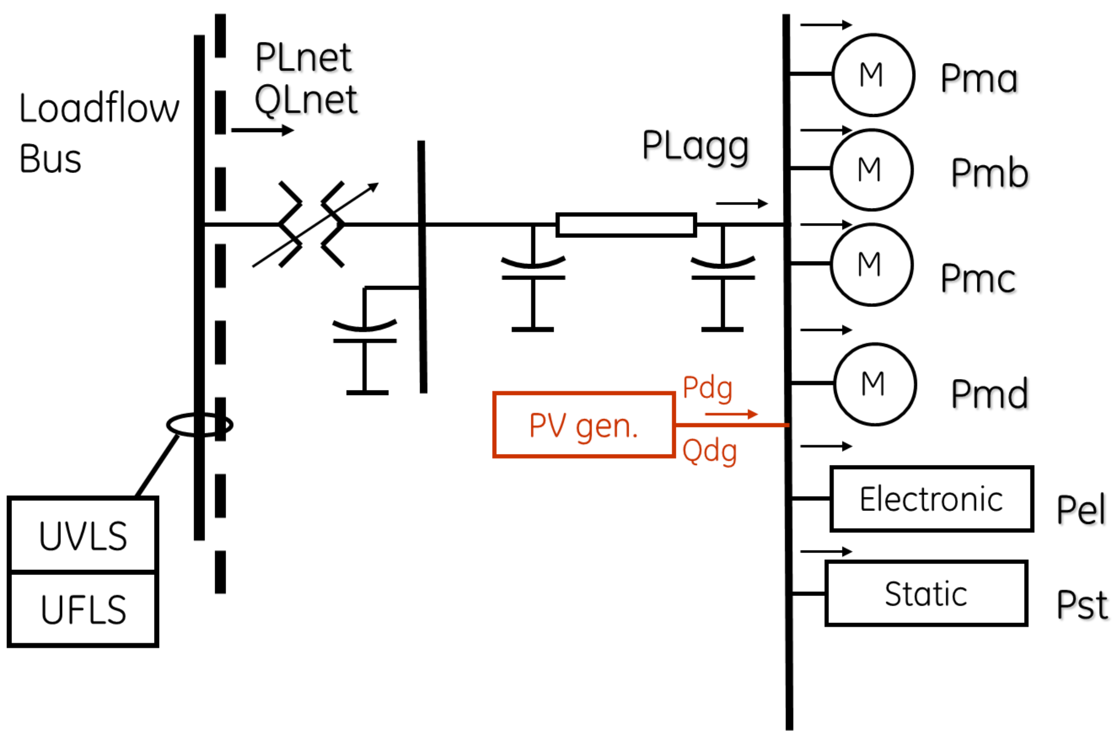

Figure 24 Composite Load Model

It is worth noting that a main concern of utilities, particularly those with relatively geographically diverse (sparse) systems, is fault induced delayed voltage recovery (FIDVR). This is mainly a voltage dynamic concern, in which the recovery of loads from depressed voltage during system faults causes the system to have difficulty or failure to recover. It is not, per se, a RoCoF issue. In Figure 25, a pair of simulations of a severe transmission fault in electrical proximity to substantial load centers (in California) is shown. The only difference between the cases is the load modeling.

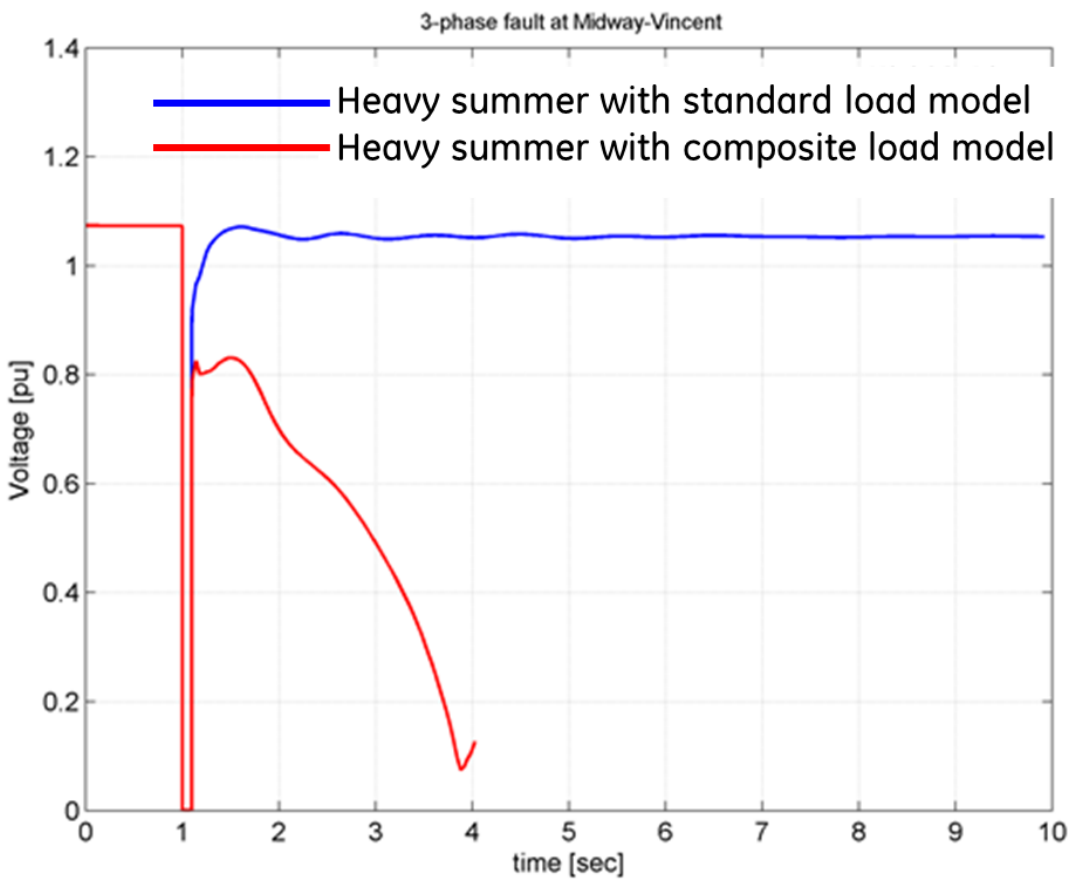

Figure 25 Example of Impact of Load Modeling for a Fault Simulation[8]

The issue of sensitivity to voltage and frequency of loads includes difficult topics such as whether motor contactors drop out on low voltage (giving usually welcome relief) or if they stay in during stall (hugely exacerbating the recovery problem). Issues related to the impact of high RoCoF, beyond the important impact of load inertia, are usually ignored.

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[8] "Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability" http://www.nrel.gov/docs/fy15osti/62906.pdf

5.2.3 Load Model Sensitivity – SA Illustrative Simulation

An illustration of the potential impact of load modeling on system performance analysis is shown in Figure 26. This is the very simple model developed to illustrate performance behaviors in the Fast Frequency Response report; details are discussed there. But for this discussion, we have substituted a simple standard (western US) load model (red trace) for the much more complex composite load model used in that work (green trace). Two elements are of note. First, the standard model has no inertia and RoCoF does not affect the modeled load behavior. Consequently, compared to the case with the composite model, the initial RoCoF is higher. Second, the voltage sensitivity of the simple model is such that model gives more relief, creating a higher, less severe frequency nadir. The point of this exercise is to emphasize that load behavior, particularly in highly stressed systems strongly affects the bulk system dynamics.

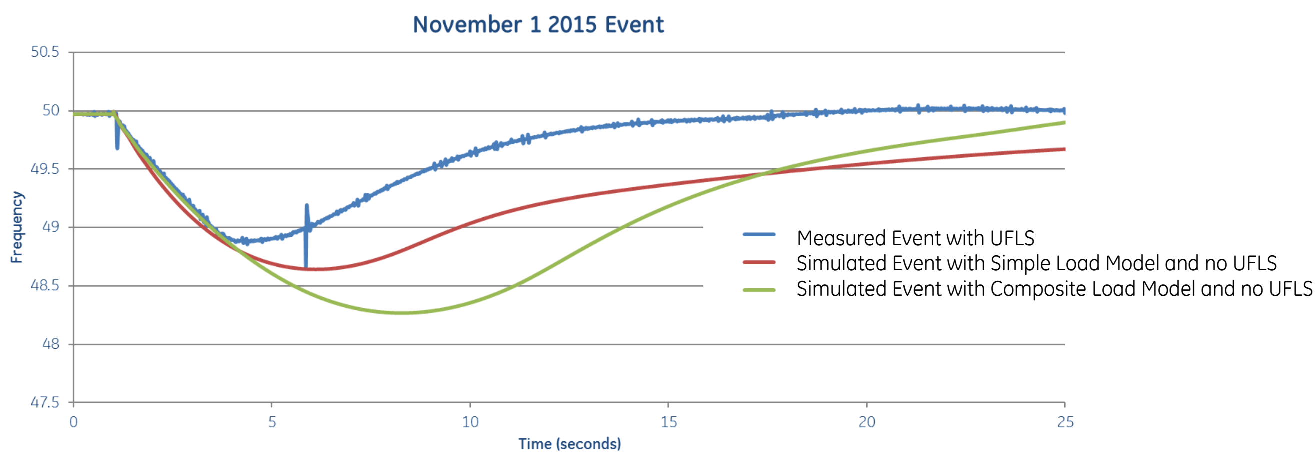

Figure 26 Simulation Illustrative of South Australia

5.2.4 Improving Load Models

This has been subject of extensive industry activity and research – for more than 30 years[9], with astonishingly little progress being made. With the explosion of distributed generation, the topic is getting renewed interest. However, in simple terms, the requirement for good load modeling boils down to the two big components that have always been a challenge:

(1) Knowing what is being served, and
(2) Knowing how that behaves subject to changes in voltage and frequency.

Most current efforts on the first topic involve collecting data on the "type" of loads served on particular distribution feeders (that are equivalenced, per the discussion above). For example, knowing the fraction of load that is single family residences, shopping, office buildings, etc. and having that information in a data base, allows for population of composite loads. The

[9] W. W. Price; K. A. Wirgau; A. Murdoch; J. V. Mitsche; E. Vaahedi; M. El-Kady; "Load modeling for power flow and transient stability computer studies", IEEE Transactions on Power Systems, 1988, Volume: 3, Issue: 1

second challenge is to understand how the composite elements behave. There are two general avenues of investigation. First, testing of constituents. For example, if you know how a single particular class of residential air conditioner behaves, then it is possible to extrapolate to thousands of them. This type of investigation is most commonly done in the laboratory.

However, industry experience with simply adding up the parts has only moderate success. So, the second route, is to instrument and measure actual entire systems – either at the substation or on whole feeders. This can give good insight, but to get large event tests (like for high RoCoF) requires a grid event. Preparation is a key element.

5.3 Load with Embedded Generation

The present reality for most utilities is that distributed generation is largely ignored in bulk system modeling. Planning models typically "net" the contribution of distributed generation by simply reducing the modeled load to the net of the actual power being consumed minus the contribution of distributed generation.

But with the explosive growth of distributed solar PV, this practice is becoming unacceptable. Data about the amount of PV embedded in each equivalent load is needed. Above, in Figure 24, the red block represents the possibility of explicitly modeling a lumped equivalent of the distributed PV in a composite load. The potential impact on the bulk system is explored in the next section.

5.3.1 Embedded Solar PV generation

Distribution connected PV has many physical and performance similarities to larger utility scale PV generation, as discussed above in Section 3.6. In current practice, there are two substantial differences in performance of concern to bulk system performance: fault ride-through and voltage regulation. The distinction for distributed PV stems more from practice and economics than from physics: distributed PV *could* be designed with similar features to utility-scale PV.

The ability of distributed generation, including solar PV, to ride-through faults, is not at present clear or simple. Some PV will trip for voltage or frequency variations. Some will "block", temporarily ceasing to inject any current until the voltage recovers. Others will continue to operate as per their inverter characteristics and the conditions at the terminals of the inverter. The topology of the composite load model still maintains the simplification that all PV "sees" the same voltage and frequency. But in the latest versions of this model, it is possible to assign trip and block characteristics to a fraction of the PV.

The impact on bulk system dynamics can be substantial. A pair of simulations of the US Western interconnection, in which the system is subjected to trip of a critical interconnector is shown in Figure 27. In the blue trace, the distributed PV in the system (several GW, spread across about 1000 nodes) is assumed to have robust ride-through characteristics. In the red trace, the distributed PV is assumed to trip as soon as the voltage drops below 88% (at the inverter terminal). This is very pessimistic representation of behavior that would be allowed under the old IEEEE Std. 1547. In this case, the failure of the PV to tolerate the big voltage swing following the line opening, causes the system to collapse. This simulation is arguably unduly pessimistic, but the point is that sympathetic blocking of distributed PV during events represents some risk.

Note that there is no provision for modeling, or accompanying experience, associated with distributed PV sensitivity to RoCoF. Behavior of distributed inverters subject to high RoCoF is expected to be like that presented above in Section 3.6.

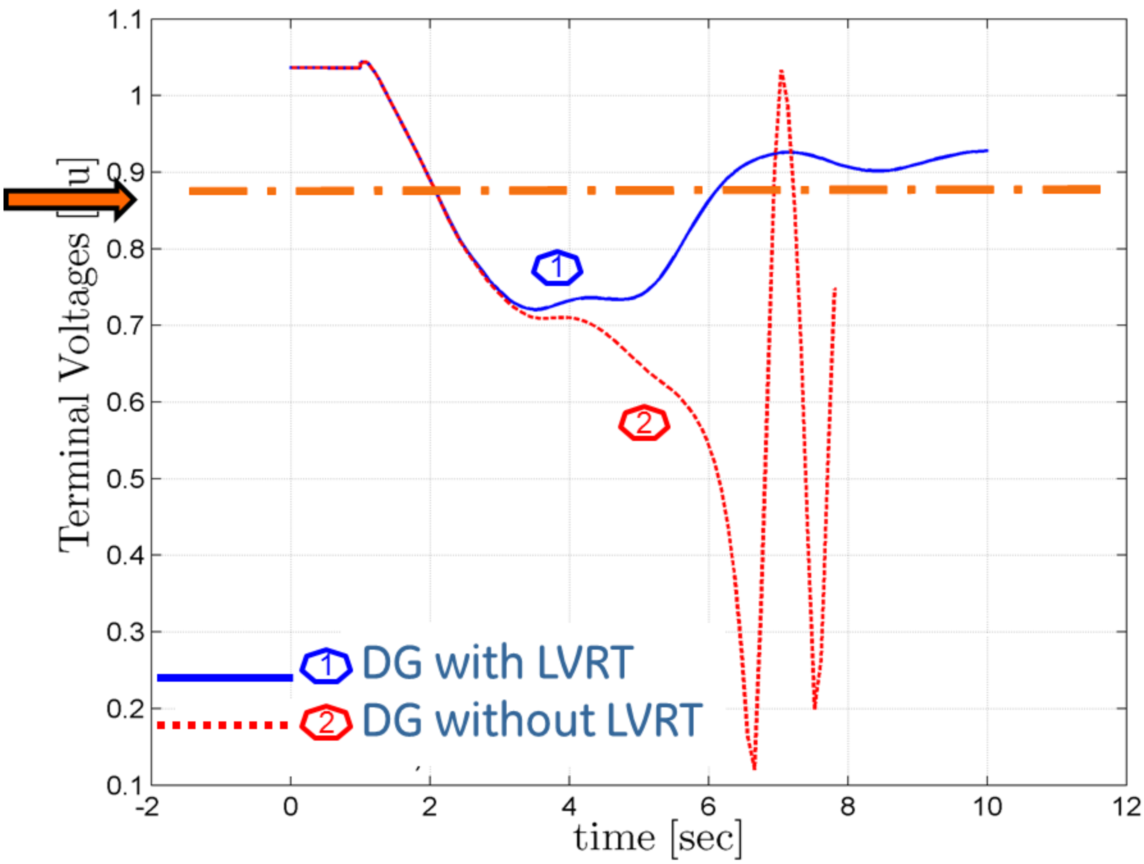

Figure 27 Illustration of Impact of Distributed PV Fault-ride Through on Bulk System

5.3.2 Anti-islanding on PV

One aspect of behavior of distributed PV that may be cause for concern is built-in anti-islanding protection. This is a somewhat separate issue from system protection that is installed by distribution utilities to detect islanding. (e.g. as used in Ireland, causing them to have acute RoCoF concerns). Distributed generation is required in some jurisdictions to have built-in protection that prevents operation in an island. For example, in North America PV inverters are required to demonstrate anti-islanding functionality to comply with the UL requirement[10].

There are a variety of approaches used by manufacturers of PV inverters. These fall into two major categories: passive and active. Active schemes (e.g. UL 1741 compliant) in PV perturb the system with, for example, a pulse of active current, and observe the response. If the system "moves" in a fashion that is characteristic of a very weak or low inertia behavior, the algorithm concludes that the system has islanded and stops the inverter. The three well-known types of frequency-related active anti-islanding schemes are:

- Active Frequency Drift (AFD)
- Sandia Frequency Shift (SFS)
- Slip-Mode Frequency Shift (SMS)

Recently, active schemes that use RoCoF thresholds have been proposed in the literature. For high RoCoF systems, the RoCoF threshold of those active anti-islanding schemes would have to be adjusted based on expected system-wide RoCoF events in the future (e.g. 4Hz/Sec or greater for SA). A recent study commissioned by the German VDE|FNN11 suggests that a RoCoF threshold of 2 Hz/s may be reasonable for anti-islanding detection of PV connected in the Continental Europe region. Clearly that could represent a problem for South Australia. But, state of the art ranges of adjustability of this parameter vary between 0.05 and 10 Hz/s. In small, islanded systems such as on the Hawai'ian islands, one should certainly choose a higher RoCoF threshold to avoid false island detection and PV tripping for system-wide events.

The main worry for this discussion is that if these schemes mistakenly interpret high system RoCoF as the creation of an unsanctioned island, they may block inverter operation, exacerbating the generation-load unbalance that is causing the high RoCoF.

A complication is that the aggressiveness of the anti-islanding detection schemes may have to be aligned to the distribution system's characteristics, in order to ensure island detection in the required time. (i.e. per the applicable Australian standard). Hence, there is a trade-off between bulk system security and distribution system safety. Multiple PVs with different active anti-islanding methods or settings, may reduce the effectiveness of the anti-island detection scheme. In the US, the draft P1547 standard does not state any specific anti-islanding schemes but remains completely agnostic as to how to achieve the prescribed clearing time. The way that P1547 ensures that active anti-islanding schemes would not trip PV for RoCoF values expected for system-wide events is by specifying draft requirements on RoCoF ride-through in clause 6.4.2.4 *Rate of change of frequency (RoCoF)*. The most extreme RoCoF considered in that document is 3 Hz/sec. It is careful to not place suppliers in an impossible bind, by providing some relief as follows: "False detection of an unintentional island that does

10 UL Standard 1741 "Standard for Inverters, Converters and Controllers for use in Independent Power Production Systems" 2001

11 HSU HH, Helmut Schmidt University. Wirksame Verfahren zur Inselnetzerkennung in 0,4-kV-Netzen: (Effective methods for islanding detection in 0.4 kV networks). Helmut Schmidt University, Hamburg: 2015. Study commissioned by VDE|FNN.

not actually exist does not justify non-compliance with ride-through requirements."[12] (In other words, if your device has a false positive – thinks there is an island when none exists – your device/algorithm is still compliant.)

A secondary concern is that the aggregate impact of PVs' active anti-islanding schemes can adversely impact system stability (these active algorithms, in essense deliberately try to destabilize the system). These worries have been investigated[13] , and currently do not seem to present a risk. At very high penetrations, it is conceivable that this issue may develop into a problem. (This is a possibly a topic for further research, but we regard it as a remote risk at present.)

Passive schemes watch for deviations in system voltage and current that are indicative of islanded operation. Older ones use an absolute frequency threshold to detect islanded conditions. These are typically set well off the nominal frequency to avoid problems like the 49.5 Hz / 50.2 Hz issue in Germany.

Anti-islanding algorithms are generally proprietary, and, in North America, must be independently tested (by UL certified process). Experts interviewed for this report were unaware of issues related to undesired sensitivity to RoCoF, so this discussion is cautionary and speculative at this point.

5.4 Fossil Reciprocating Engine Generators

Reciprocating engine based generation tends to be quite robust relative to loading and frequency variation. Extremely high positive RoCoF can result in emissions violations, and even back fires (in poorly tuned machines), but not trips. The principle risk for RoCoF is miscoordination of protective relays for the swings that accompany a large frequency event. There is good precedence for expecting reciprocating engines to have good performance and high tolerance for rapidly fluctuating frequencies. Examples of smaller systems, including those in Australia, are common. This does not guarantee that specific units will be free of problems, of course. Reciprocating engines are typically of lower inertia (per MVA) than larger central station generation, but it is possible for them to have superior dynamic response to frequency excursions.

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[12] Thanks to Jens Boemer of EPRI for his insights on AID.

[13] S. Laudahn et al., "Einfluss aktiver Inselnetzerkennung mittels Frequenz-Shift auf den Netzschutz und die Netzstabilität." Internationaler ETG-Kongress 2013 (ETG-FB 139), Berlin, November 2013

6 SUMMARY AND RECOMMENDED AEMO ACTIONS

6.1 Summary of Significant Risks

The following points of risk were judged to warrant further attention.

- Gas-fired generation tripping due to lean blow out (LBO) on high positive RoCoF (rapidly rising frequency), such as might occur after substantial (and excessive) load-shedding or system break-up. There is also some risk associated with possible high positive RoCoF that accompanies the successful recovery of frequency from the nadir following a loss of generation or loss of infeed (e.g. trip of the Heywood Interconnector) event
- Gas-fired generation tripping due to compressor surge on high negative RoCoF (rapidly dropping frequency), such as might occur following an islanding (e.g. trip of the Heywood Interconnector) event. Risk is highest at high or maximum power output, for extremes of ambient temperature, and for large industrial frame gas turbines.
- For all synchronous units, potential misbehavior of power system stabilizers, especially those which calculate accelerating power.
- Protective schemes in critical applications mis-operating because of poor settings; i.e. the relay behaves as instructed, but has settings incompatible with high RoCoF. Any remaining electro-magnetic relays in critical applications should be tested for RoCoF performance.
- This applies to all generators, as well as transmission and distribution equipment.

The following table provides a synopsis of the risks discussed in the report, with a subjective grading and a note on the rationale for the grading. The rationale entry includes a note as to whether the concern is mainly of dropping frequency (- RoCoF), rising frequency (+ RoCoF) or both (+/- RoCoF).

Table 1 Synopsis of Risks

Technology group	Equipment	Risk Description	Risk Level	Rationale
Utility-scale Synchronous Generation	Gas-fired generation	LBO		Observed behavior; high consequence; not easy to anticipate or correct. Mainly a positive RoCoF (frequency rise)/backswing concern.
	Gas-fired	Surge		Mainly a concern at maximum/high power and on large turbines; a negative RoCoF (frequency drop) concern.
	Gas and Steam	Drive-train torques		No history of this being an actual problem (with +/- RoCoF)
	Gas and Steam	PSS		Significant concern for PSS that calculates acceleration. Both +/- RoCoF
	Gas and Steam	Island mode		Only on plants with this feature. Mainly a +RoCoF risk.
	Gas and Steam	Sensors		Part of overall evaluation of RoCoF performance.
	Gas	Encroachment		A general warning.
	Steam	Valves		Mainly a wear and maintenance issue. +/- RoCoF.
	All	V/Hz		Some increased risk with high voltage swings accompanying -RoCoF events
	All	Reverse Power Protection		Mainly a concern at low power and for +RoCoF
	All	Overcurrent		Mainly a concern at high loading and excitation for -RoCoF
Utility-scale Asynchronous generation	Wind Generation	Active and reactive injection errors		Older type 3 & 4 machines may track poorly; high RoCoF has been observed to result in departure from expected active and reactive power.
	Utility-scale Solar PV	Trip on "erroneous" instantaneous Frequency thresholds		Recent, unconfirmed widespread tripping attributed to this. This is not a RoCoF concern, but a FRT problem that looks like a frequency problem. +/- RoCoF
	Wind Generation	Tripping		Similar to preceding concern. "instantaneous" trip settings on frequency, with poor measurement of frequency is a problem that has occurred. +/- RoCoF
Transmission and Power Delivery Equipment	Electro-mechanical relays	Mis-operation; failure to operate		EM relays are known to have errors with frequency. Unlikely that there are EM relays in operation in the NEM, particularly in critical locations. Risk is high if there are any. +/- RoCoF
	Digital Relays	Setting Errors		Problems associated with relays acting properly as set, but with setting incompatable with substantial RoCoF conditions +/- RoCoF
	Digital Relays	Measurement Errors		Modern digital relays employ frequency tracking that should provide good performance. Minor measurement errors possible; a concern for some applications. +/- RoCoF
	FACTS devices	Mis-operation		Measurement errors and tracking errors are possible. No examples within interviewed community. +/- RoCoF
	HVDC	Active and reactive injection errors		Measurement errors and tracking errors are possible. No examples within interviewed community. +/- RoCoF
End User and Distribution Equipment	Loads	Modeling Fidelity		This a known and ongoing concern in the industry. It is well known that changing load modeling assumptions can result in wildly different simulation results. +/- RoCoF
	Distribution PV	Tripping on Frequency		Ongoing concerns about systems (particularly legacy systems) tripping. +/- RoCoF
	Distribution PV	Anti-islanding		Especially a concern if RoCoF based decisions are used. +/- RoCoF.
	Reciprocating Distributed Generation	Mis-operation or tripping		No significant risks were identified.

6.2 Recommendations

Recommendations are summarized as follows: Broadly, the recommendations are grouped under "inventory", "monitor" and "analysis", by which the spirit is a segregation of activities aimed at (1) figuring out what is on the system now and needs more attention, (2) watching how it behaves, and then (3) digging into elements that are determined to be both critical and poorly understood or poorly represented.

6.2.1 Inventory

6.2.1.1 Thermal Generation Capability

Initiate inquiries into the known capability and limitations of synchronous generators that are critical to security following major frequency events. This will likely require engagement not only with plant owners but with equipment OEMs. Items listed (in the table) need to be checked (e.g. does the plant have an island-mode? What type of PSS is on the plant?, etc.)

We do not, at this point, recommend a mandatory, detailed analytical evaluation of RoCoF tolerance for thermal generation. (That is full OEM simulation on equipment's design software platforms). Such a mandate will impose substantial costs on generation owners and may not be required.

6.2.1.2 Distributed Solar PV Inverters and Anti-Islanding Schemes

Investigate whether meaningful bench (or other) tests for RoCoF performance have been performed for PV inverters of common varieties (in the NEM). Investigate potential for mis-operation of anti-islanding protection on distributed generation. Initially, this constitutes an inventory of known behaviors, including protective functions.

6.2.1.3 Relay Exposure

Before meaningful testing of relays can be performed, an inventory of which relays are critical to system security is needed. This is primarily a planning function, in that elements of the system – e.g. lines, transformers, sectionalizers, etc. – that will cause or exacerbate a system disturbance by incorrectly tripping are the highest priority for testing. This can be revealed by study, including simulations. Operations experience can also be useful in highlighting critical elements. This is a non-trivial investigation.

6.2.2 Monitor

Initiate a program of high resolution monitoring of system events, including digital fault recorders (or equivalent), and all the necessary human and data infrastructure to collect, store and (most importantly) process event data. The focus should include a broader spectrum of events than just RoCoF (e.g. faults, phase jumped, over and undervoltages, etc.). The behavior of load and all major power plants should be captured with sufficient resolution to evaluate performance and validate models. This is a substantial research undertaking.

6.2.3 Analysis

6.2.3.1 Thermal Generation Performance

In the event that both the inventory and monitoring aspect of checking on the RoCoF performance of thermal plants, especially gas-fired generation, does not adequately increase confidence that generation will behave satisfactorily, more detailed investigation can be pursued. There is limited industry experience with these investigations, and they can involve substantial costs.

6.2.3.2 PSS

Performance of power system stabilizers for all synchronous machines under expected extremes of frequency and RoCoF needs to be analyzed. This is to assure that they do not create stability or voltage problems on synchronous generation. As discussed, PSS that calculate acceleration are of particular concern. Traditional stability programs may be sufficient. This can be accompanied by state-space analysis, although non-linear effects of signal saturation constitute the major risk, and so small signal analysis is mainly useful as a test that efficacy is not compromised by modified settings.

6.2.3.3 Critical Relays

Settings of critical protective relays on generation, transmission and distribution must be checked for proper behavior during extreme frequency events. Again, traditional stability programs can be a part of this analysis.

However, relay testing of actual devices is a more complete method of testing, since stability models of relays are rather simplified and may not accurately capture the exact relay behavior. Playback of simulated frequency events (from stability programs, EMT programs or real-time simulators) into bench tests with actual relays is best, and should be considered for critical relays. All electro-mechanical relays that are critical to system security for major frequency events should be bench tested this way, as modeling of these devices is notoriously poor.

6.2.3.4 Inverter Behavior

Bench (laboratory) tests of common PV inverters should be considered (if OEMs do not have useful responses to the recommended inquires above).

6.2.3.5 Load models

Load models should be examined and improved (per discussion in Section 5), particularly if monitoring suggests substantially different performance from that observed.

6.3 RoCoF Ranges

One of AEMO's objectives for this work to identify ranges of RoCoF for which AEMO can be confident that there will or will not be security issues. There is no level of negative RoCoF for which there is *confidence* that equipment will behave poorly. This observation must be paired with two important points: First, levels of RoCoF in excess of -2 Hz/sec are extreme for industry experience in interconnected systems of any size, so experience is limited. Second, the physics is complex and each OEM has their own specifics. There is no substitute for experience. Imposing tight systemic RoCoF targets based on generically estimated vulnerabilities is likely to be uneconomic. Operating strategies for gas fired generation that are biased towards keeping units off of maximum dispatch, and that consider more conservative operation during extremes of ambient temperature may be desirable.

Positive RoCoF is a known issue for gas fired generation. The consensus opinion is that levels below +0.5 Hz/sec represent a confident lower bound (below which no RoCoF problems are well assured).