LESSONS LEARNED IN IMPLEMENTING BATTERY INVERTER SYSTEM CONTROLS IN LOW-INERTIA SYSTEMS

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ABSTRACT

Low-inertia systems, which would include emergency power systems, microgrids, and most island or other off-grid power systems, are becoming more numerous. Simple emergency power systems have been around for decades and are well-known, but backup power system topologies are becoming more complex, and many are being asked to perform on-grid functions as well (i.e., the backup power system is becoming a microgrid). It is often the desire of owners of systems of this type to incorporate more renewable energy, in particular photovoltaics (PV). It is becoming more common for such systems to include a battery-inverter system (BIS).

Deployment of a BIS system within a low-inertia power system still requires a significant number of engineering decisions, and a great deal of craftsmanship in the design and implementation of the controls and protection. This paper/presentation will present two case studies in the design of BIS controls for low-inertia systems. The issues to be addressed, the design of the controller, and simulation results will be presented. The main risk factors encountered, and means for dealing with them, will be discussed. This presentation will be of interest to anyone dealing with BIS controls, or with microgrids, emergency power systems, or other off-grid low-inertia systems, in particular those including PV.

I. Nomenclature

BIS	Battery-Inverter System
EPS	Electric Power System
NPPT	Northern Plains Power Technologies
SoC	State of Charge (of a battery)
UFLS	Under Frequency Load Shedding

II. Introduction

LOW-INERTIA electric power systems (EPSs) are EPSs in which the rotating inertia is sufficiently small that the total system inertial constant H has a value of less than 5 s. Typically, such systems serve peak loads of 20 MW or less. Islands, remote communities, resource extraction operations, and military bases are commonly served by low-inertia EPSs. There is also rapidly-rising interest in operating sections of distribution networks as microgrids, which when off-grid are also typically low-inertia EPSs.

In low-inertia EPSs, frequency regulation is a significant challenge. There is an inherent mismatch between the rate at which loads can ramp, which is very fast (effectively in steps, as they switch on and off), and the rate at which generators can ramp, which is much slower due to rotating inertias and the response times of governors, fuel systems and engines. When a load switches on, for the first few moments thereafter before the speed controller responds, the extra energy required to power that load is extracted from the energy stored in the spinning mass of the synchronous generator rotor. As that energy is extracted, the rotor slows down, and the electrical frequency drops. The generator's speed controls will react to bring the speed back to the nominal value at a new power output level. For high-inertia systems, the amount of energy stored in the rotating mass of the rotor(s) even significant load changes lead to relatively small and slow changes in electrical frequency. However, for low inertia systems, relatively small load changes lead to much larger fluctuations in frequency, and as a result frequency regulation can be a significant challenge in low-inertia EPSs.

In many low-inertia EPSs, it is desirable to integrate significant amounts of renewable resources, especially PV. This may be done for a variety of reasons, such as reducing costs by reducing fuel usage, reducing noise during critical hours, or to meet emissions or RPS goals. While PV definitely does help with these objectives, it unfortunately creates some challenges as well.

- One of the primary challenges is mass tripping during frequency transients. Until recently, applicable standards such as IEEE 1547 required that PV inverters for grid interconnection utilize relatively tight under and over-frequency (81U and 81O) relays. In North America, the under-frequency trip threshold has traditionally been set to 59.3 Hz and the over-frequency threshold to 60.5 Hz, both with a maximum time to trip of 160 ms. As noted earlier, frequency regulation in low-inertia systems is much "looser" than is the case for any of the high-inertia North American systems, and frequency excursions beyond these traditional over/under-frequency relaying limits are common in low-inertia systems. Each time such an excursion happens, a mass simultaneous tripping of all of the PV inverters on the low-inertia system can take place, which can significantly destabilize the system.
- Another key challenge is that high penetrations of PV increase the stiffness of low-inertia systems. Inverters provide no inertial energy storage, and traditional PV inverters have historically not included any form of droop controls. In any case, most PV plants are operated at their maximum power points at all times, and thus in the event of a loss of generation they are unable to increase their power output to help support the system. The result of all of this is that the frequency response of the system to governor actions in the rotating generation will be exaggerated; a small governor adjustment will lead to a much larger frequency change in the system than would have been the case without the PV. In other words, the frequency regulation loop of the low-inertia system begins to look like a high-gain control loop as more PV is added.
- Detection of unintentional islands can also be a significant challenge. Most (but not all) commercially-available PV inverters utilize active islanding detection methods in which some form of perturbation or positive feedback on frequency error is used to destabilize any unintentional island that may form. Essentially, these methods rely on the fact that the area EPS is usually a high-inertia system, and unintentional islands are very low-inertia systems. Obviously, the use of such methods in a low-inertia EPS can lead to a number of problems, including false tripping of the PV plants and destabilization of the low-inertia EPS.

The mass tripping problem has recently been significantly mitigated by the introduction of frequency ride through capability into grid-tie PV inverters. Such ride-through capability is being required by Hawaiian utilities and by the new version of California's Rule 21, and thus is becoming widely available in commercial products. In low-inertia systems, the 81U and 81O relay trip thresholds can be set much wider than before, which significantly helps with false tripping but is likely to adversely impact the ability to detect unintentional islands. Thus, changing the trip thresholds is helpful but it is not a complete solution to the problem.

A more complete solution can be realized by including a battery-inverter system (BIS) in the low-inertia EPS. A BIS has a much faster response time than a synchronous generator, and can provide the desired inertial response and fast-acting frequency support that can limit frequency excursions and improve the transient performance of low-inertia EPSs. However, controls design for such a BIS is a nontrivial exercise. This paper describes the design of a controller for a BIS tasked with frequency support in a specific low-inertia system, describes the design and its testing, and details some lessons learned.

III. Procedure and Methodology

A. System description and key challenge to be solved

The system considered in this paper is located on an island and is thus isolated from any larger grid. It serves a roughly 5 MW peak load. The heart of the system is a multi-unit diesel fired plant utilizing 2 MW baseload units and smaller load-following units. Typically, at any given time three diesel units are in operation, to provide redundancy. The PV penetration on this system is becoming quite high; in high-irradiance, low-load periods, the system is receiving about 90% of its power from distributed PV plants. Most of these are "legacy" PV plants in the sense that their inverters utilize the default narrow frequency trips (i.e., 59.3 Hz and 60.5 Hz) and do not include droop functions such as volt-VAr, volt-watt, or frequency-watt functions. Along with issues such as violations of minimum diesel loading constraints, this low-inertia EPS is clearly reaching the point at which the mass tripping, frequency regulation and islanding detection issues mentioned above are all manifesting themselves.

It is planned to add a 2 MW, 400 kWh BIS to this system to solve the frequency regulation and mass tripping problems. The fundamental problem to be solved here is to design, implement and test a controller that meets the following requirements:

- The BIS will keep the system frequency between 59.3 and 60.5 Hz, to avoid mass tripping of the legacy PV units. The BIS should also prevent the system's under frequency load shedding (UFLS) scheme from being required to trip load.
- The BIS may not connect to the controls of the existing generator plant; it must use its own measurements and may not "tap" any of the existing generator control signals.
- The BIS must maintain stability at all times.
- The BIS must not degrade the fault response of the existing system.

B. System modeling

The first step in designing and testing the controller was to develop a reliable model of the existing low-inertia EPS. Figure 1 shows the model developed for this work. The model was created in the MATLAB-Simulink environment using the SimPowerSystems blockset. Circuit impedances were obtained from the system operator's distribution circuit databases, and were imported, checked and corrected using in-house tools.

C. Generator modeling

The synchronous generators themselves were modeled using MATLAB's built-in sixth-order synchronous machine model, with parameter values supplied by the manufacturers. The diesel engines themselves, and the throttles and fuel delivery systems, were each represented separately in simplified form using first-order transfer functions. The models of the speed controllers and automatic voltage regulators (AVRs) were developed in collaboration with the manufacturers, and settings were provided by the system operator. These models were vetted against historical data sets, but unfortunately, because of their age and some unique circumstances surrounding their commissioning, transient test data were not available for these specific units.

D. Load modeling

Because system dynamics are at the heart of this work, it was not appropriate to use a constant-impedance or constant-power load model. Instead, the model shown in Figure 2 was used. This is a "ZIP-motor" aggregate load model that includes constant impedance (Z), constant current (I), constant power (P), and motor load portions. The motor load portion is especially critical in this type of work. Normally, this model would include three- and single-phase induction motor loads, but for this specific system nearly all of the three-phase motor load was concentrated in one location (the pumps shown in Figure 1). Thus, the distributed system load was modeled using only single-phase induction machines, and the mechanical load on these machines is assumed to be linear with speed, emulating a compressor load (refrigeration and air conditioning). The relative fractions of each component of the ZIP-motor load are given in Table 1. The EPS's UFLS scheme was also represented. Relays were inserted at all load shed points and were programmed according to the system operator's UFLS specification.

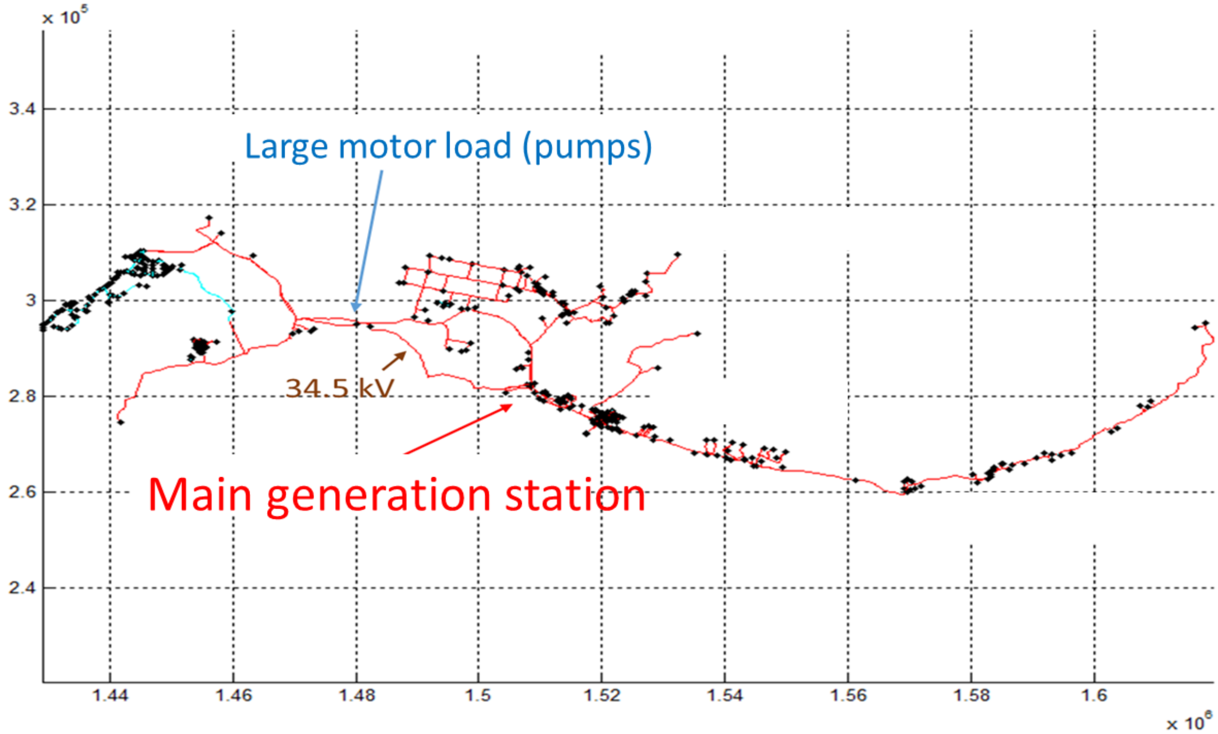

Figure 1. Diagram of the model of the low-inertia EPS, showing key features.

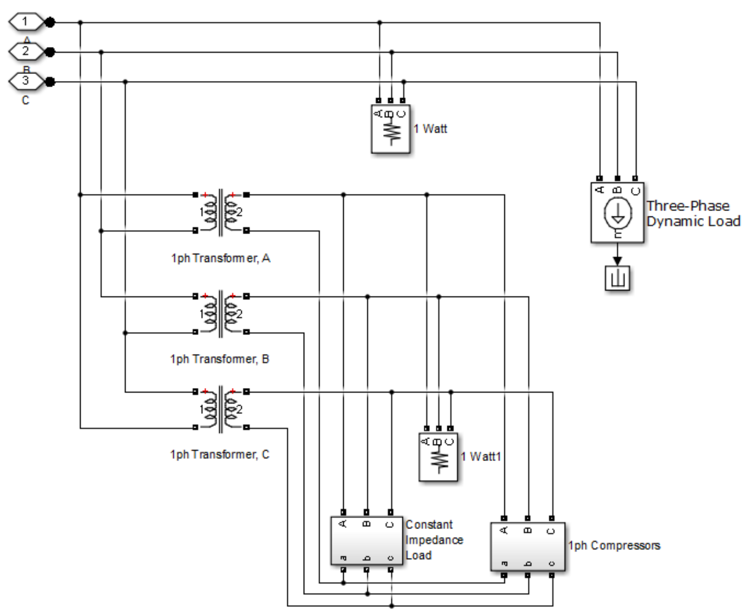

Figure 2. Block diagram of the ZIP-motor load used in this work.

Table 1. Makeup of the ZIP-motor load used in this work.

Component	Fraction of the total load
Constant Z	0.4
Constant I	0.0
Constant P	0.4
Single-phase asynchronous machine	0.2

E. PV plant modeling

A generic model, based on the one presented in [1], was used to represent the distributed PV plants. This is an averaged model that represents the plants as power-controlled three-phase current sources. This model includes:

- A detailed representation of the current controls, in the dq0 reference frame.
- Anti-islanding, using a method that combines a small VAr perturbation (impedance detection) and positive feedback on frequency error ("Sandia Frequency Shift"). There is a 40 mHz deadband within which the positive feedback is not applied, and there is a maximum allowed phase shift of 15^{o}.
- Standard relaying, using the settings in Table 2.

Table 2. Relay settings used in the generic PV plants.

Setting	Threshold value	Pickup time
Undervoltage Fast	0.5 pu	160 ms
Undervoltage Slow	0.88 pu	2 s
Overvoltage Slow	1.1 pu	1 s
Overvoltage Fast	1.2 pu	160 ms
Underfrequency	59.3 Hz	160 ms
Overfrequency	60.5 Hz	160 ms

F. BIS modeling

The BIS itself is modeled using manufacturer-specific detailed models of both the battery and the inverter. The inverter model was developed in collaboration with the manufacturer, and validated using data from transient tests performed on the inverter. The 2 MW inverter consists of five 400-kW inverter blocks, and each of these blocks is modeled individually. The controls are modeled in the dq0 reference frame in detail, and the AC and DC side filter elements are explicitly represented. The switch bridge is represented by an averaged model. The battery model was based on battery characterization tests performed by Sandia National Laboratories, and accurately represents the voltage versus state of charge (SoC) behavior of the battery. For this work, a constant-impedance model was used (i.e., the dependence of battery cell impedance on SoC was not included).

G. Model validation

The model was subjected to several levels of testing.

- The circuit impedances were verified by comparison between the fault currents calculated at various points in the system by the system operator, versus those predicted by the model.
- The parts of the BIS model were validated using measured test data sets from the manufacturers and third-party testing laboratories, and the overall BIS was subjected to "sanity tests" by NPPT, the equipment manufacturers, and the system operator.
- The PV plant generic model is a well-vetted model that has been tested over several years' worth of comparisons against measured behaviors.
- The generator dynamics, and the overall model dynamics, were verified by comparing real-world measured transient responses of the system against those of the model under the same conditions.

H. Simulation test plan

After validation, the completed system model was used to test the response of the system with and without the BIS to four key contingency events, listed in Table 3. In addition to these four cases, the impact of the BIS on the fault response of the system was tested.

Table 3. Contingency cases under which the BIS impact on the system performance was tested.

Case number	Event	Load level
1	Loss of generator	Peak
2	Loss of generator	Minimum
3	Loss of load	Peak
4	Loss of load	Minimum

IV. Results and Discussion

A. Controller design

Initially, the intention was to control the BIS using the IEC 61850-90-7 FW22 frequency-watt droop function [2]. However, given the frequency tolerance specifications that had to be met and the dynamics of the diesel generators, a simple f-W droop function led to the formation of limit cycles in several cases. The simulation results suggested that a multirate controller was needed that allowed the BIS to wait for the generators to "catch up" during a transient. Thus, a multirate controller was designed, and a basic state transition diagram of that controller is shown in Figure 3.

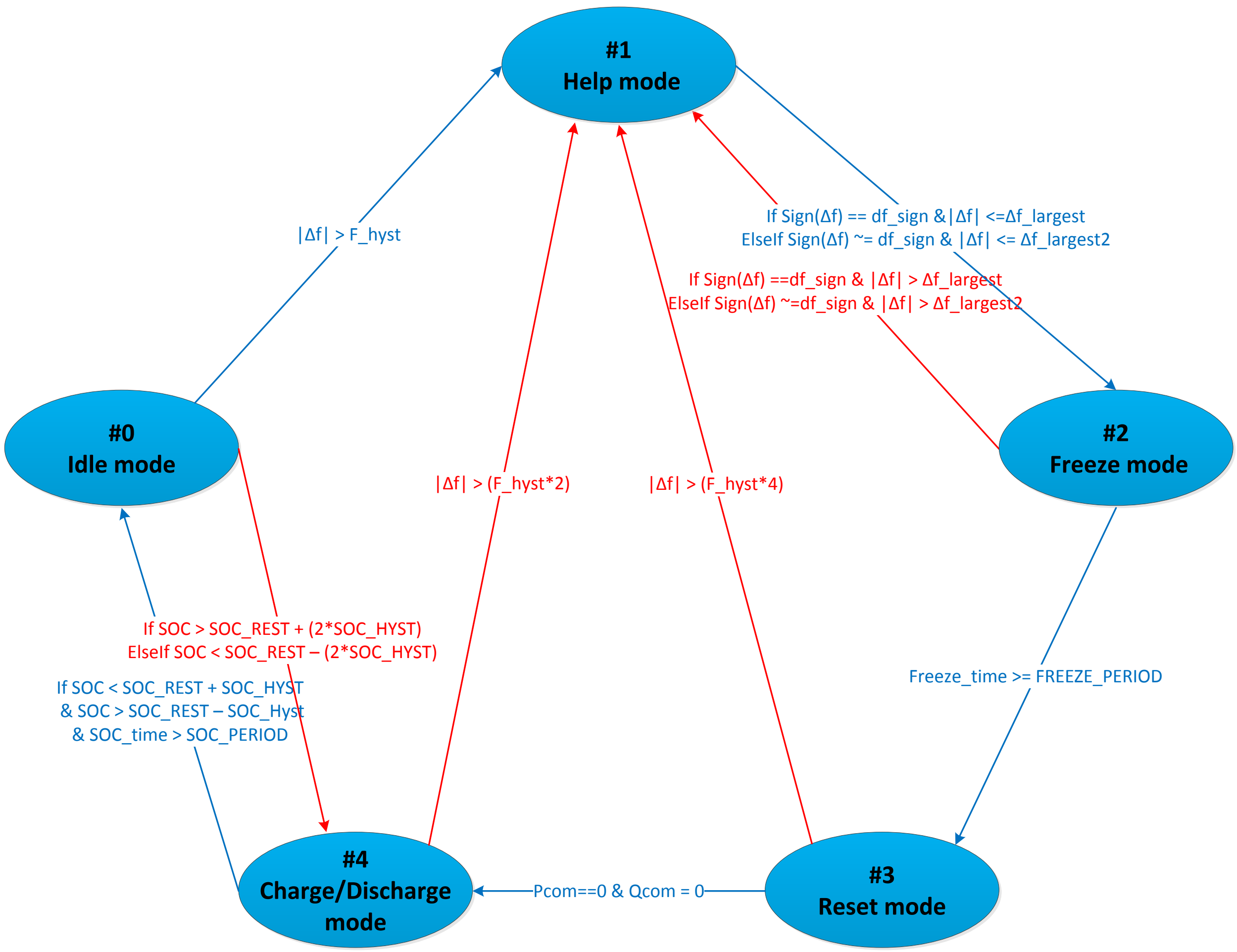

Figure 3. Basic state transition diagram of the BIS controller.

The controller starts in Mode #0, Idle Mode, at the center left. The battery SoC is held to a "ready" level (SOC_REST) so that the BIS is prepared to respond to a frequency event in either direction[1]. The BIS continues to maintain its "ready" SoC until the frequency deviates from nominal by more than a selected value (F_hyst). Once a frequency deviation is detected, the controller transitions to Mode #1, Help Mode, which is essentially a traditional frequency-watt droop response; the BIS produces an increasing level of output power as the frequency error increases. The BIS remains in Help Mode as long as the frequency continues to move away from nominal. As soon as the frequency begins to recover (i.e., df/dt goes to zero and then reverses algebraic sign), the BIS enters Mode #2, Freeze Mode, in which the BIS holds the output it was producing when it left Mode #1, until the system frequency error drops back below the error threshold F_hyst. The Freeze Mode manages the difference in speed of response between the BIS and the diesel generators. It enables the BIS to continue to support the system while the generators increase or decrease their output power in response to the event, or while additional diesel generation is started and brought online. The Freeze mode causes the BIS controls to have a multi-rate structure; the BIS responds very quickly during the frequency excursion, but much more slowly during the recovery, so that the generators have a chance to "catch up".

[1] The maintenance of the "ready" SoC actually involves transitions between Modes #0 and #4, as shown on the diagram. Mode #4 is explained below.

Once the EPS frequency has recovered to the point at which the frequency error drops below a user-settable threshold and remains below that threshold for a fixed time (FREEZE_PERIOD in Figure 3), the BIS moves to Mode #3, Reset Mode. In Reset Mode, the BIS begins slowly handing off its load to the diesel generators by ramping down its power output. As it does so, the frequency will once again begin to change as the diesels assume the BIS load, and when the frequency error reaches a user-settable level, the BIS recycles through the Help and Freeze Modes to allow the diesels to once again "catch up". The BIS continues this procedure until the diesels have assumed the full system load, and then the BIS goes into Mode #4, Charge/Discharge Mode, in which the BIS charges or discharges at a low rate to return the battery to its ready SoC. Once the BIS reaches its ready SoC, it re-enters Mode #0, and continues to transition between Modes #0 and #4 to maintain the ready SoC until the next event. This controller was extensively tested in simulation. Due to space restrictions, only representative results will be shown here.

B. Case 1

The frequency response of the low-inertia EPS to the Case 1 contingency is shown in Figure 4. In the "No BIS" case (blue trace), the frequency undergoes a significant transient that breaches both the over- and under-frequency trip thresholds of all of the PV plants on the island. As a result, all of the PV mass-trips at approximately t = 31 s. The additional loss of generation causes the frequency to decline further, and at t = 31.44 s the UFLS scheme trips a block of load offline, followed by another block load trip at 31.97 s, which is then followed by two additional UFLS block load trips. With the last of these the system is able to recover. When the BIS is added (dashed red trace), the BIS with the above-described controller is able to keep the frequency within the specified limits. The PV does not trip, and no load is shed. Figure 5 shows the RMS line-ground phase voltages at the main generation plant 4.16 kV bus, again during the Case 1 contingency, with and without the BIS. In the no-BIS case (solid lines), the PV plants trip at 31 s, and the sudden addition of load to the generators causes their bus voltage to begin to drop. Then there is the first block load trip at 31.44 s that begins the voltage recovery. In the case with the BIS (dashed traces), the voltage excursions are much smaller because the PV mass trip and the UFLS events are all prevented.

C. Case 2

Figure 6 shows the frequency response of the low-inertia EPS to the Case 2 contingency event, with and without the BIS. The overall behavior is similar to that in Case 1: without the BIS there is a large frequency excursion, all of the PV mass-trips, and there are four UFLS block load trips. When the BIS is active, it is able to keep the frequency much more well-regulated, the PV plants do not trip, and no load is shed. Note that the frequency nadir is actually lower in Case 2 (light load) than in Case 1 (heavy load). This is attributed to the fact that the relative impact of the loss of PV is larger in Case 2 (the PV is still at full power and thus the effective PV penetration level is higher in Case 2 than in Case 1), and the reduced effectiveness of the UFLS because of the lighter loading in each UFLS load block.

D. Case 3

Figure 7 shows the frequency response of the low-inertia EPS during the Case 3 contingency, with and without the BIS. This is a loss of load case (no fault). Without the BIS (solid trace), as expected the sudden unloading of the generators causes a rotor acceleration and rapid frequency rise that goes well above the 60.5 Hz overfrequency trip threshold, leading to a PV mass trip. When the BIS is added (dashed trace), the BIS is able to absorb the extra generator output until the generators have a chance to adjust, and the frequency transient is kept within the required limits.

E. Case 4

Figure 8 shows the frequency response of the low-inertia EPS to the Case 4 contingency, with and without the BIS. The response in this case is similar to that in Case 3; without the BIS there is a large increase in frequency due to the sudden unloading of the synchronous generators, but when the BIS is included it acts as a "shock absorber" and absorbs the extra generator output until the controls can recover.

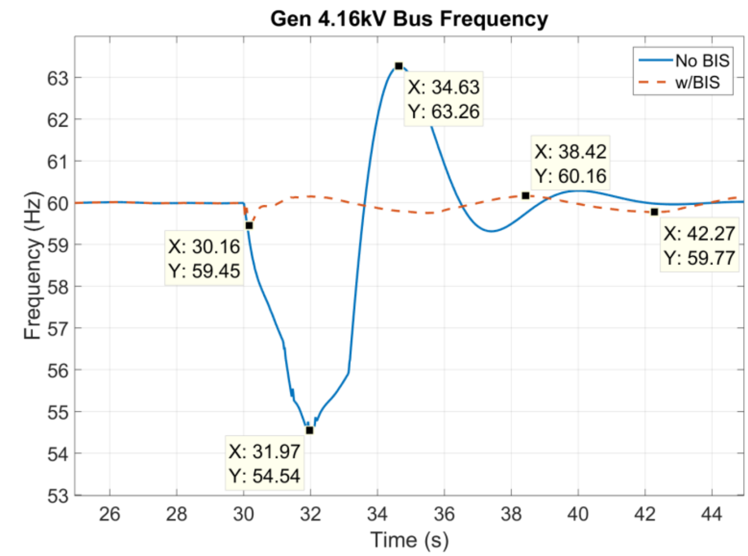

Figure 4. Frequency response during the Case 1 contingency, with and without the BIS.

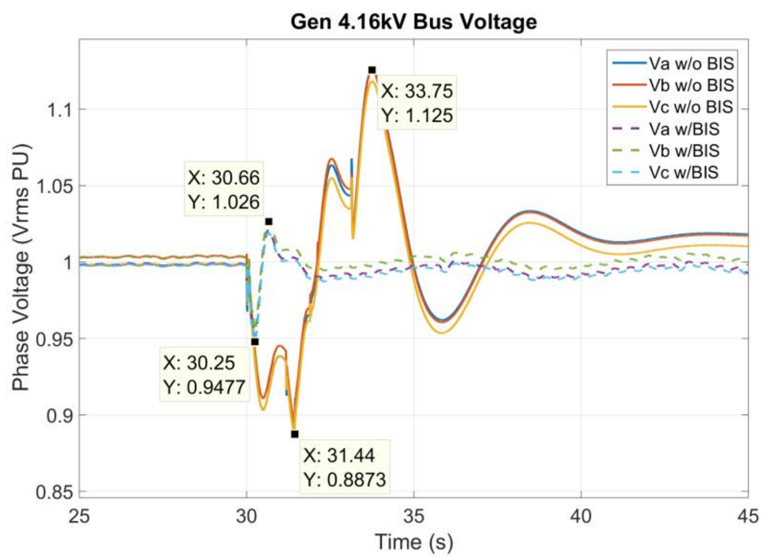

Figure 5. Generator bus LG voltages during the Case 1 contingency event, with and without the BIS.

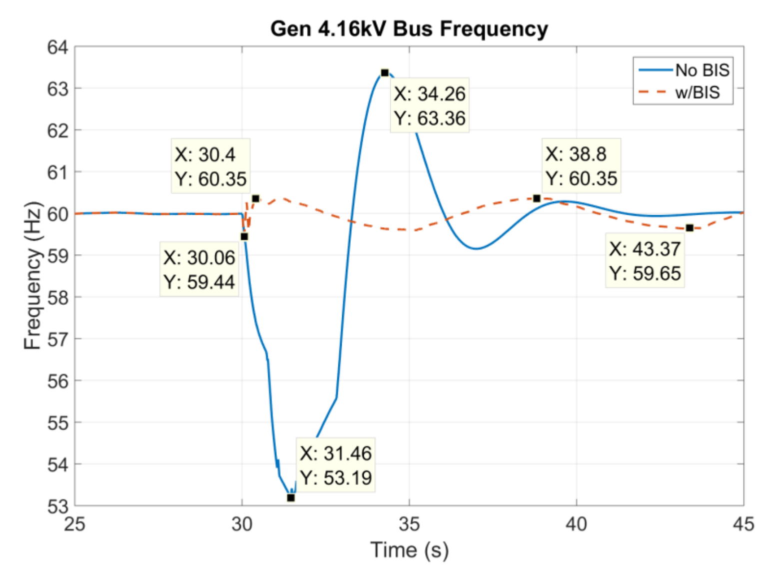

Figure 6. Frequency response during the Case 2 contingency, with and without the BIS.

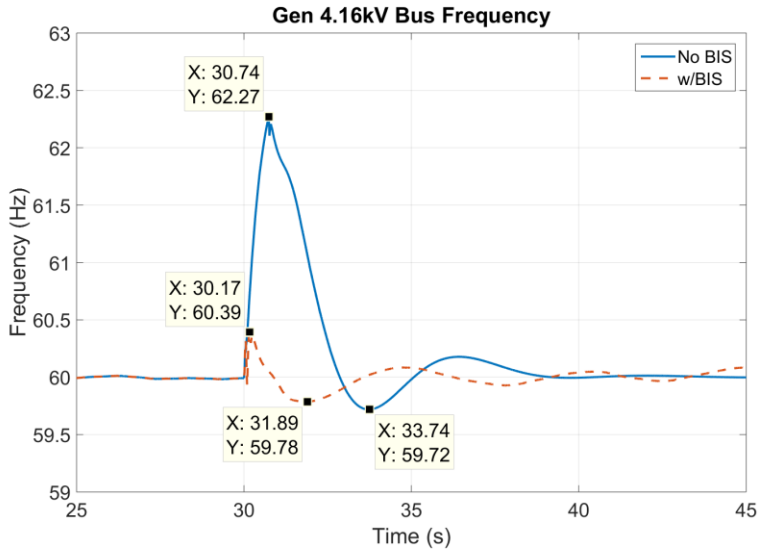

Figure 7. Frequency response during the Case 3 contingency, with and without the BIS.

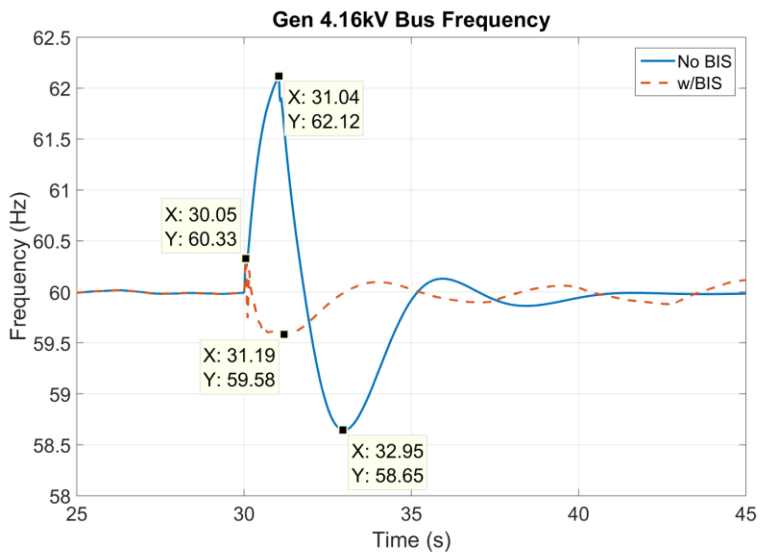

Figure 8. Frequency response during the Case 4 contingency, with and without the BIS.

F. Fault ride-through

The previous cases make clear that the BIS does its frequency support job well, and the controller is working as expected. However, during this study it was also learned that if the BIS controls did not include some form of suppression function during a fault, the BIS could actually significantly degrade the system's fault response. Thus, the BIS controller includes a function that monitors the BIS terminal voltage for indications of the existence of a fault. This can be done because in the loss of generator contingency there is a reduction in voltage (see Figure 5), but in the fault case there is a much *larger* reduction in voltage, and this difference can be used to discriminate between a fault case and a loss of generator case. Figure 9 shows the frequency response of the system during a remote LLLG feeder fault. It is clear that the BIS is able to detect that this is a faulted case, and the generator response is suppressed. Unfortunately there is also a sufficiently large frequency transient that all of the PV would trip. This fault-suppression function obviously can be improved, and work in this area is ongoing.

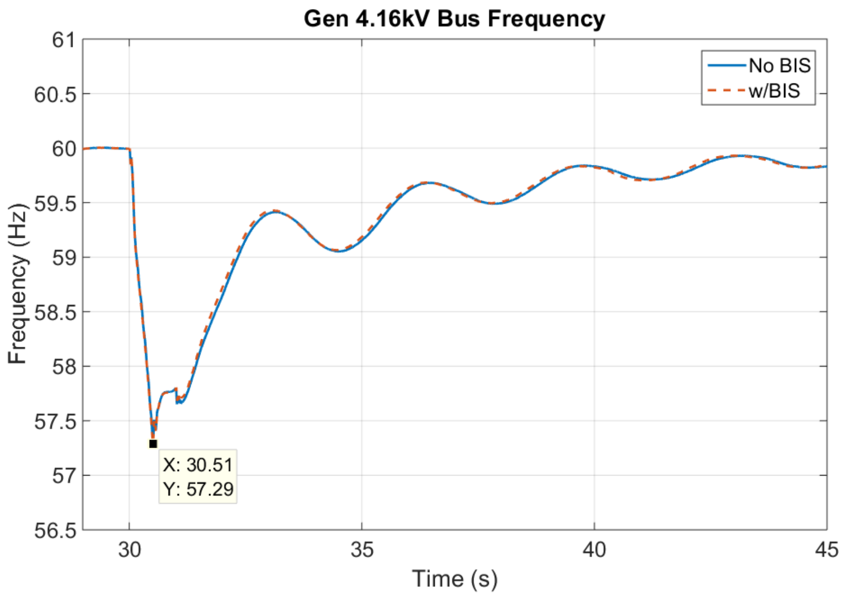

Figure 9. Frequency response during a remote LLLG feeder fault, with and without the BIS.

G. Control path latency

Another lesson learned in this work was that the path latency in the BIS controls needed to be kept to 50 ms or less. If the control path latency rose above 100 ms, the BIS would no longer be able to keep the frequency within limits, and for latencies above 250 ms the system actually became unstable. Pathways to a suitably low latency must consider not only the obvious items such as PLC loop execution rates, but also the reporting and polling rates of meters, and the polling rates of inverter communications.

V. CONCLUSIONS

The BIS was able to make a dramatic positive difference in the frequency response of the low-inertia system, and was able to do so without interfering with the existing generator controls and without degrading the system's existing fault response. However, the control path latency was critical and had to be kept within acceptable limits; otherwise the BIS might not be able to meet its specifications, and if the delay is too long the system may actually become unstable.

VI. REFERENCES

[1] M. Ropp, S. Gonzalez, "Development of a MATLAB/Simulink model of a single-phase grid-connected photovoltaic inverter", *IEEE Transactions on Energy Conversion* **24**(1) March 2009, p. 195-202.

[2] IEC 61850-90-7:2013, "Communication networks and systems for power utility automation - Part 90-7: Object models for power converters in distributed energy resources (DER) systems", International Electrotechnical Commission TC57, published February 21, 2013.