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***Abstract*—Solar-energy-based photovoltaic (PV) systems are a quickly growing source of distributed generation (DG) and connect to the power distribution system. PV-based DG poses challenges to grid reliability and power quality. One critical challenge is islanding control. Research is underway to devise best practice methods for anti-islanding for all power mismatch conditions. Synchrophasors provide an accurate means to detect islanding conditions by enabling precise, time-synchronized wide-area measurements. This paper presents an islanding detection system for PV-based DG. The system utilizes synchrophasor data collected from local and remote locations to detect the islanded condition. The paper shows how synchrophasors are used to control the DG during such conditions. It also discusses the power system modeling using a Real Time Digital Simulator (RTDS®) and closed-loop testing of the synchrophasor-based islanding detection system, which includes the PV-based inverter and the power distribution system. The effectiveness of the system was experimentally tested on a live power system.**

I. Introduction

In the last decade, the total United States solar capacity has increased by more than 300 percent to 2 GW. In the next five years, an additional 2.5 GW of installed capacity is required simply to meet state-mandated renewable energy portfolios [1]. In 2009, worldwide solar capacity increased by 7 GW to a total of 22 GW. Connecting this new energy source to the existing power system is an important engineering challenge. A solar-energy-based generator does not respond to changing electrical system conditions in the same way as a traditional hydrocarbon-based synchronous generator. Even in the absence of electrical transients, the solar source has unique characteristics, such as high-speed response (low inertia) and large power ramp rates. Widespread installation of photovoltaic (PV) sources requires more reliable means for bulk power grid interconnection.

Recently, the U.S. Department of Energy coordinated several engineering teams to develop these new grid connection technologies. This Solar Energy Grid Integration Systems (SEGIS) program intends to make high-density solar generation possible through a system approach that is focused on highly reliable and advanced inverters, controllers, balanced system hardware, and energy management systems. PV Powered, a manufacturer of grid-tied solar inverters, assembled a cross-functional team, consisting of an equipment supplier, a communications company, an engineering consulting firm, and a utility, to enhance inverter reliability, increase system efficiency using improved maximum power point tracking, improve solar power forecasting, advance system visibility, and design smarter islanding detection and control systems.

Islanding control is one of the main topics of this paper. When the portion of the power system connected to a PV source is islanded from the bulk transmission system, the source must also disconnect from the islanded portion of the electric network. Failure to trip the source risks personnel safety, power quality, and out-of-phase reclosing. The IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems defines the requirements for integrating distributed sources that have an aggregate capacity of 10 MVA or less with the bulk power grid. IEEE 1547 specifies that a source must disconnect from the islanded system within 2 seconds.

II. Islanding Control Methods

Better islanding detection and control are particularly pressing needs because the existing approaches for meeting IEEE 1547 requirements were developed based on the assumption that distributed generation (DG) represented a small percentage of the total generation capacity. Solar-based generation growth rates have the potential to negate the validity of this assumption. For the existing approaches, solar generation inverters make islanding decisions using local data, such as frequency and voltage, without using wide-area information. Therefore, it is difficult to improve existing approaches, such as enabling the inverter to distinguish between a utility outage, which requires anti-islanding, and a transient disturbance, which could be aided by keeping the solar-based generator online. The wide-area information available from time-synchronized phasors, or synchrophasors, provides the measurements needed to improve these methods [2].

The use of synchrophasor technology for islanding control has advantages over existing approaches. For example, one existing islanding detection method for distributed PV systems uses a perturb-and-observe approach. The inverter actively pushes on a signal component, such as frequency. When connected to the grid, this perturbation has little effect. When disconnected from the grid, the frequency changes according to the perturbation and the inverter. The inverter, upon detecting the excessive frequency, declares an islanded condition. One problem with this approach is its negative effect on power quality. Another problem with this approach is that as the number of PV generators increases, frequency-shift coupling between them can lead to false islanding detection. A final problem is that this approach may not detect islanding fast enough for all power mismatch conditions. It is difficult for local detection schemes to detect islanding in a timely manner if the power (real and reactive) mismatch between the source and the local load is small.

A second existing method utilizes breaker status communication, open-phase detectors, and trip commands to detect islanding and isolate the source. This transfer trip scheme is simple in concept but must be adapted to topology changes in the power system. As more solar generators are connected to the system, reliability suffers because of the additional communications links. With this method, the only information available on the state of the distribution line between the inverter and the source is its connectivity, not signal magnitude and angle. Therefore, this method does not provide the information for future improvements where the inverter provides grid support functions.

Synchrophasors improve these methods because wide-area information is available to each inverter. Using information obtained from a larger area results in better control decisions. Also, the communications paths are simplified because, within the wide area, only a few select signals need to be monitored. Finally, a system using synchrophasor measurements does not require unnatural forcing of the connected frequency, power, or voltages.

III. Synchrophasors for PV Islanding Control

Synchrophasor-based anti-islanding schemes for DG have been reported in previous literature, including [3]. The results in this paper extend earlier work to the distribution system and include the effects of an inverter instead of a synchronous machine, detailed Electromagnetic Transients Program (EMTP) and Real Time Digital Simulator (RTDS®) modeling, and a field test of the algorithms at Portland General Electric (PGE).

Previous work on this synchrophasor-based anti-islanding scheme focused on synchronous generator-based systems [3] [4]. Solar generation typically uses inverter-based power conversion. Solar power plants are typically considered small in terms of output power, and they connect to secondary feeders instead of primary feeders in the power distribution system. Because of the small power ratings and the nature of the power electronic devices used, these sources respond quickly to system changes. The special nature of solar generation is considered in this paper when configuring the characteristic of the islanding control algorithm.

Fig. 1 shows the basic system layout. Both bulk power system and DG locations supply data for the algorithm. The relays in Fig. 1 acquire voltage phasor measurements from their corresponding sites. Relay 1 and Relay 2 send synchrophasor messages to the control device, a synchrophasor vector processor (SVP), at specific time intervals (60 messages per second). The SVP receives the synchrophasor data from the relays and calculates the difference between the local and remote synchrophasor angle values, which is defined as δ_k in (1):

$$\delta_k = \angle V_k^{(1)} - \angle V_k^{(2)} \tag{1}$$

where:

$\angle V_k^{(1)}$ and $\angle V_k^{(2)}$ are the positive-sequence voltage angles of Relay 1 and Relay 2, at the *k* processing interval.

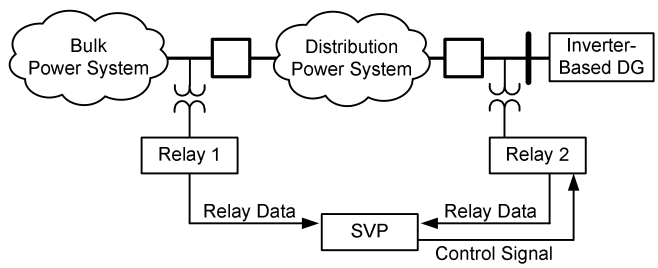

Fig. 1. System layout

The change of δ_k, with respect to time, defines the slip frequency, S_k, as shown in (2). The change of slip frequency, with respect to time, defines the acceleration between the two terminals, A_k, as shown in (3).

$$S_k = \left(\delta_k - \delta_{k-1}\right)\frac{\text{MRATE}}{360} \tag{2}$$

$$A_k = (S_k - S_{k-1})\text{MRATE} \tag{3}$$

where:

S_k is the slip frequency at the *k* processing interval.

A_k is the acceleration at the *k* processing interval.

MRATE is the synchrophasor message rate.

The islanding detection algorithm consists of two components. First, the angle difference (1) is compared to a threshold. For the islanded system, any slip between the local and remote systems results in an integration of the angle difference. Over time, this steadily increasing change causes the angle to exceed the threshold. When the threshold is crossed for an appropriate duration of time, an islanded condition is declared.

The second component combines slip and acceleration in a linear relationship. Fig. 2 shows the islanding detection characteristic. In steady state, the angle difference between the two measured points is constant; therefore, slip and acceleration are zero, and the operating point is at (0, 0) of the islanding detection characteristic. When a distributed source separates from the bulk power system, generally, there is both slip and acceleration. The magnitude of either can push the operating quantity into the operate region of the characteristic. The linear relationship between the slip and acceleration characteristics results in an algorithm that operates for values below the individual thresholds when both are changing simultaneously.

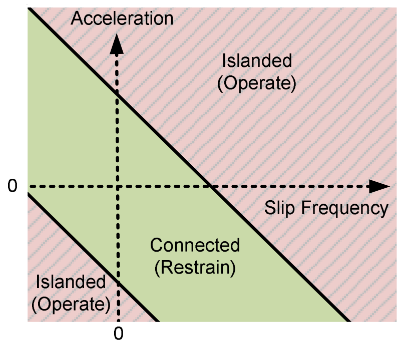

Fig. 2. Islanding detection characteristic using slip and acceleration

IV. EMTP Modeling

Generic computer modeling of this technique for a variety of system configurations was performed using the EMTP simulator. The purpose of the simulation was to provide guidelines on the constraint regions. In these simulations, the PV inverter was represented by its averaged model, but the controls were represented in detail, including the dynamics of the phase-locked loop from which the sine wave reference was derived [5]. The phasor measurement units (PMUs) were modeled by phasor measurement blocks coupled with appropriate anti-aliasing filters, and the modeled PMU sampling rates were set to match the actual PMUs used in the live demonstration system. As a model, the IEEE 34-bus radial distribution feeder was used [6]. The 34-bus feeder model used in this simulation included linear transformers (magnetization current was not modeled) and constant-impedance load models. Four cases were tested in EMTP-RV, as listed in Table I.

Table I
Cases Simulated in EMTP-RV

Case Number	Condition	Desired Result
1	Multi-inverter case	Detect and trip
2	Multi-inverter case with engine-generator set	Detect and trip
3	System-wide frequency event	Ride through
4	Large, local load-switching event	Ride through

Case 1 involved 18 PV inverters—one at each three-phase load bus in the 34-bus feeder. Case 2 involved 12 PV inverters and a 1 MVA engine-generator set using a synchronous generator. This is a difficult case for islanding detection because the slow dynamics of the engine-generator set resemble those of the grid from a synchrophasor standpoint. In Case 1 and Case 2, the real and reactive power were kept closely matched (to within about 0.2 percent), and the effective quality factor of the load was kept at or above 1.0. A higher quality factor makes it more difficult for the traditional frequency shift approach to detect an island because it takes more energy to move an islanded frequency away from the resonant frequency of the load. In Case 3, the frequency trajectory observed in the Italian blackout of 2003 was scaled to 60 Hz and used to simulate a wide-area frequency event in which a ride through is desired [7]. Finally, in Case 4, a large motor was placed distally on the feeder and switched on during the simulation. Case 4 was another instance in which it was desired that the local system not trip.

Fig. 3 aggregates the results, showing a scatter plot of the peak slip and acceleration values obtained in these cases. The red squares in Fig. 3 illustrate the slip and acceleration points that should be outside of the connected region and, therefore, result in a trip for Cases 1 and 2. The green asterisks represent the slip and acceleration values from Case 3 and Case 4 that must lie inside the connected region. The scatter plot provides guidance in selecting the connected versus islanded regions, which are shown in Fig. 2.

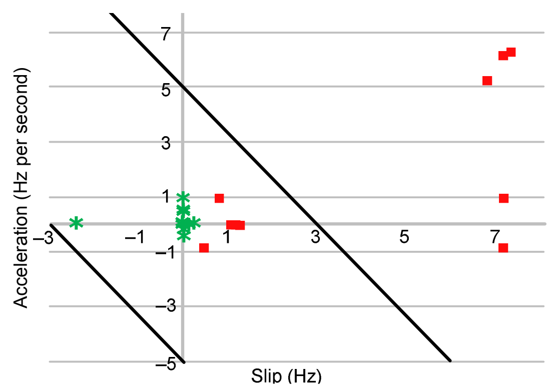

Fig. 3. Plot of the results of the EMTP-RV modeling and the recommended slip and acceleration boundaries

Most of the ride-through cases (green asterisks) lie close to the origin; however, there is an outlier, one of the large motor switching cases, which shows a large negative slip. Also, one set of the detect-and-trip cases (red squares) is located in the upper-right portion of the plot. Therefore, it seems reasonable that a set of constraint regions can be drawn that separate the ride-through cases from the detect-and-trip cases.

There are also a few detect-and-trip cases that are quite close in proximity to the ride-through cases on the slip horizontal axis point, near 1 Hz. These points, which represent the engine-generator set case, present difficulties in designing appropriate constraint regions. As expected for inverters electrically near the distributed synchronous generator, the generator dynamics resemble those of the grid closely enough that islanding threshold selection is more challenging. These results indicate that when an engine-generator set is present, different thresholds that trade reliability for safety are necessary. In addition, the EMTP-RV simulation results suggest that the time dynamics of the islanded engine-generator set case are sufficiently different from the ride-through cases. This detection challenge could be overcome with additional signal processing, statistical analysis, or pattern recognition. Based on the results of this section and considering that the live demonstration system does not include engine generators, the restraint region is selected with a maximum acceleration of 5 Hz per second and a maximum slip of 3 Hz.

V. RTDS Modeling

To verify the synchrophasor-based algorithm, an inverter-based DG model was developed and tested using the RTDS. Fig. 4 shows the system model. The inverter source on the left drives the distribution portion of the system through the point of common coupling at Bus B1. The main power system is to the right of Circuit Breaker CB1 and Bus B2. During an islanded condition, CB1 is open.

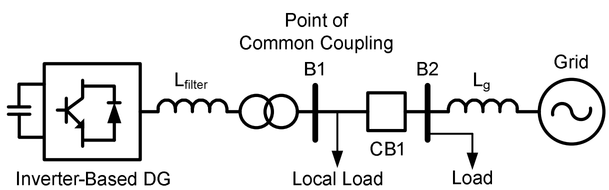

Fig. 4. System model for RTDS

In Fig. 4, the inverter real power output and the local load are modeled in such a way that their power generation and consumption closely match. This case provides the biggest challenge for the algorithm. The grid is modeled as an infinite source behind small impedance. In steady state, the currents supplied by the grid are zero so that no power is imported from the grid.

When connected to the grid, the voltage and frequency at the point of common coupling are maintained by the grid. During this condition, the DG is designed to supply constant current and inject maximum power. Presently, most DG sources inject maximum real power, and the reactive power is driven to zero by the inverter [4] [8]. When disconnected from the grid, the inverter operates in an islanded condition. In this case, the frequency is determined by the load resonating frequency. In the RTDS islanding simulations presented in this paper, the ratio of generation power to load power is in the range of 0.95 to 1.05. Such cases are hard to detect because of the small mismatch in frequency.

Fig. 5 shows the test setup. The RTDS enables use of actual hardware coupled to a software model of the inverter and electric power system.

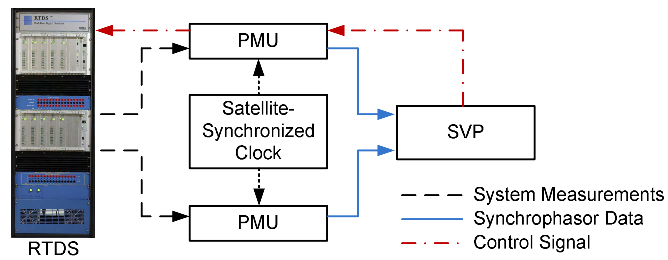

Fig. 5. RTDS simulation setup

Fig. 6 shows the software model of the inverter and electric power system. In Fig. 6, the PV panels (left) are modeled with a constant voltage source. The dc signal is modulated by the switch-mode inverter, consisting of six gate turn-off thyristor-diodes (GTO-diodes). There are two GTO-diodes for each phase. Each GTO-diode switch is controlled by a dc signal to either a conducting or nonconducting state. For each of the three-phase power system components (A, B, or C), when the upper switch is conducting, the lower switch is always nonconducting. In this case, a positive voltage is produced.

When the upper switch is nonconducting and the lower switch is conducting, a negative voltage is applied to the output. The resulting square wave signal is smoothed with the low-pass analog filter. The resulting signal consists of the fundamental component. The right portion of Fig. 6 shows the local distribution load and the breaker connecting to the grid. The breaker in Fig. 6 is the same as CB1 in Fig. 4.

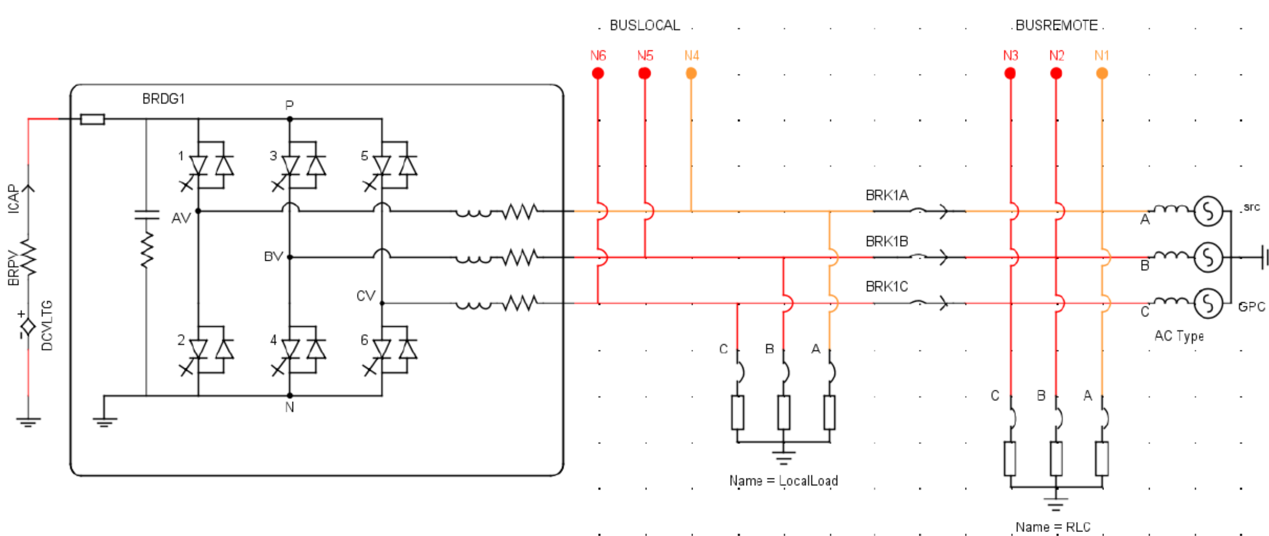

Fig. 6. System diagram from RTDS

Control of the GTO-diode switches is based on a pulse-width modulation (PWM) scheme [9]. Fig. 7 shows a block diagram of the PWM control algorithm. First, a triangle wave is generated with a fixed frequency of 4 kHz. Faster switching decreases harmonic distortion of the filtered switch-mode converter output but loses efficiency because the GTO-diodes cannot perfectly switch from conducting to nonconducting and some overlap current is always present. A fixed frequency of 4 kHz is typical for many commercial PV inverters.

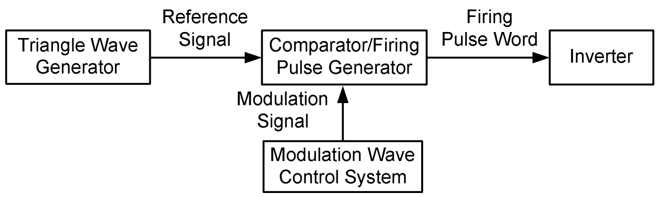

Fig. 7. Block diagram of the PWM control algorithm

The triangle wave is compared to a reference sinusoidal signal in the comparator/firing pulse generator block shown in Fig. 7. When the triangle wave value exceeds the reference sinusoidal signal value, the control to the switch-mode converter is set for the lower switch to conduct and the upper switch to remain nonconducting. When the triangle wave is less than the reference sinusoidal value, the switches are set to the opposite state.

The triangle wave method results in a control value with an instantaneous duty cycle proportional to the corresponding reference signal magnitude [9]. The switches convert this control value to a bipolar signal, which is filtered to recover the original reference signal.

The reference signal for this model is derived directly from the inverter output. Therefore, the PV inverter output is under the control of the external power system. When islanded, the reference signal frequency is driven by the resonance frequency of the local load.

Because of their electronic control, inverter-based generation sources respond quickly to changes in the power system, as compared with a synchronous machine. The frequency of a synchronous machine is constrained by the machine inertia and the dynamics of the generator mechanical controls. In contrast, the inverter has no mechanical constraints. It responds to system changes simply by the change in the reference signal against a high-frequency, internally generated triangle wave. When the distribution system islands, the PV inverter changes its frequency in response to the reference signal control algorithm. These control algorithms are not limited by mechanical constraints.

For this test, closed-loop simulation was performed by connecting the PMUs to the analog interface of the RTDS and generating the required time-synchronized measurements with the inverter and power system numerical models. The measurements from the PMUs were sent to the control device, where the synchrophasor-based islanding detection algorithm was implemented. Once the algorithm detected an island and output a trip signal, the signal was wired back into the RTDS to open the breaker, thus isolating the inverter from the local island. Two cases were considered—closed and open CB1.

A. Closed CB1

Fig. 8 shows the positive-sequence voltage angle difference between the local and remote sites when CB1 is closed. The two systems are intact and are not slipping against each other. The display screen shows the bus voltage magnitude of both the local and remote locations, along with the reference frequency of the grid.

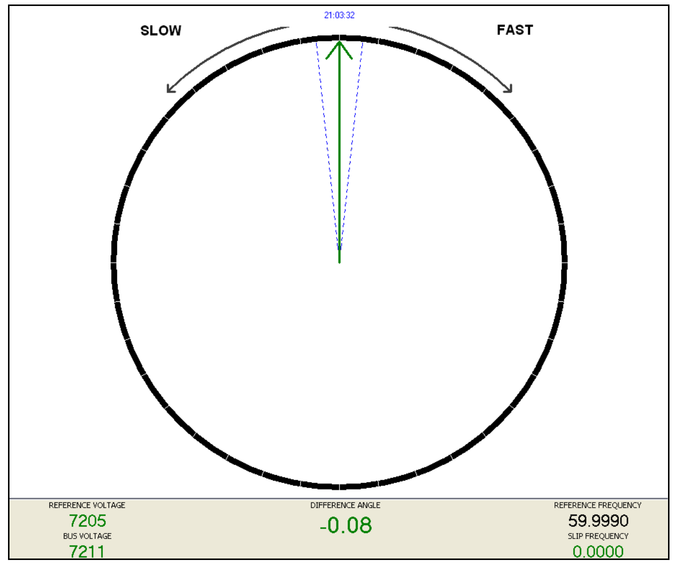

Fig. 8. Synchrophasor-based synchroscope display for connected system

B. Open CB1

Fig. 9 shows the angle difference and the slip frequency between the local and remote sites when CB1 is open and local load is closely matched with the DG output. During the disconnected state, the angle difference steadily increases as the two systems slip in frequency with respect to each other. A threshold of 10 degrees is selected for the angle difference. To avoid false island declaration, the threshold must be set high enough to avoid declaring an island during normal system transients.

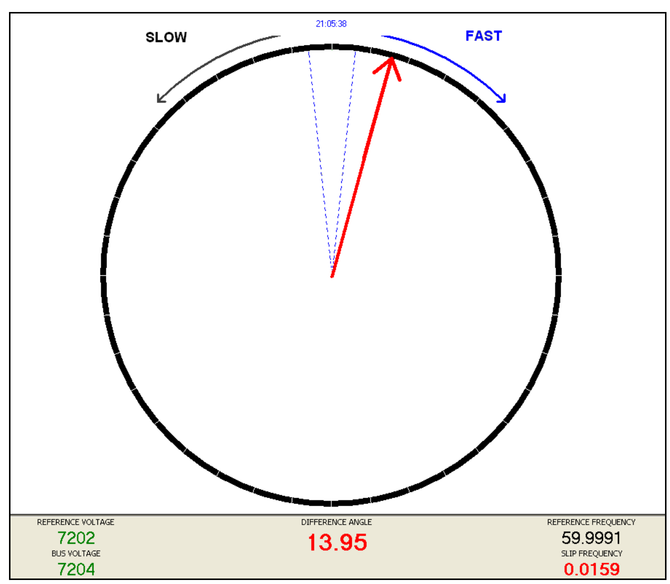

Fig. 9. Snapshot of the synchrophasor-based synchroscope display during disconnected state

Fig. 10 shows the plot of slip versus acceleration, which is obtained from the synchrophasor data received from the PMUs. The slip threshold is set to 3 Hz, and the acceleration threshold is set to 5 Hz per second, according to the EMTP-RV simulation results. Setting larger thresholds makes the system more secure; the system is less likely to false trip. Setting smaller thresholds makes the system more reliable because it is more likely to trip for an islanded case. Given the distribution bus location of many PV systems, it is expected that slip and acceleration can have wide swings. However, the power electronic nature of the inverter means that these swings have a very short time duration. In Fig. 10, Points 1, 2, 4, 5, and 6 are in the islanded region and can be used for generating a trip signal to disconnect the inverter from the local island for which it is providing power. The time increment between each point is equal to the synchrophasor message period of 16.67 milliseconds (60 messages per second). Although the signals swing into the islanding characteristic, it is for a very short time. For example, even if Point 3 were in the islanded region, the total time spent outside of the connected constraint region is only 80 milliseconds. This is different than a synchronous-machine DG system. For synchronous machines, the slip and acceleration sustain beyond the thresholds for longer times [4]. This is because of the system inertia and rotating characteristics of the synchronous machines. For inverter-based DG with power electronic control, the slip and acceleration change much faster.

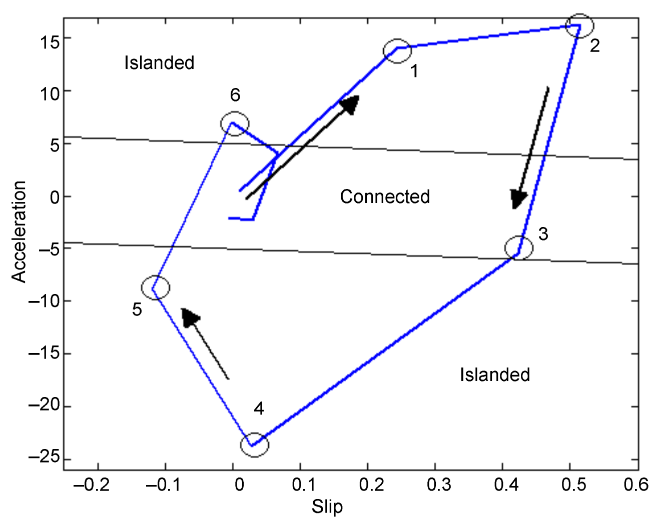

Fig. 10. X/Y plot of slip and acceleration values

For this simulation case, the angle difference output detects the island. So the combination of the angle difference scheme along with the slip-acceleration scheme provides a reliable islanding detection method for inverter-based islanding detection. The difficult case, when generation power is close to load power, is eventually detected, because some slip persists between the systems.

The behavioral characteristics and response times of the inverter-based DG are significantly different from traditional synchronous-machine DG because of the power electronics involved. Fig. 11 shows the combined angle difference, slip, and acceleration results from the RTDS simulation. Notice the fast nature of slip and acceleration transients. They settle within 200 milliseconds. For security, a pickup timer on the slip-acceleration islanded indication is set to greater than 200 milliseconds. For this case, the slip-acceleration condition does not result in the declaration of an islanded condition.

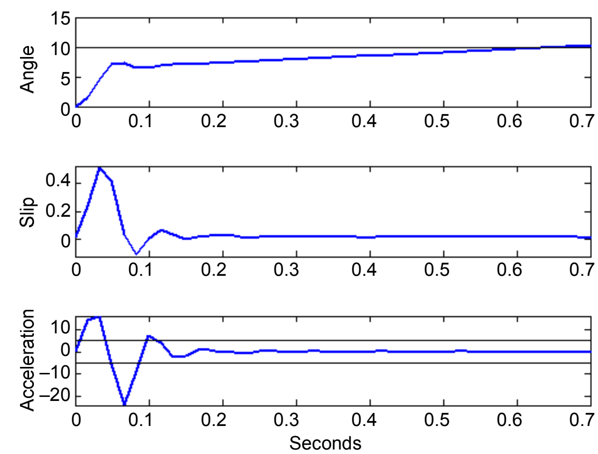

Fig. 11. Angle difference, slip, and acceleration results from the RTDS

The slip settles to a non-zero value; therefore, the angle integrates until eventually hitting the 10-degree threshold and declaring an islanded condition. Fig. 11 represents settling to a 0.02 Hz mismatch. In this case, the angle reaches a 10-degree threshold, and an island is declared at 700 milliseconds. This is well within the IEEE 1547 limit of 2 seconds. Thus, even for this case of closely matched power, the island is detected.

VI. Live Demonstration at PGE

The islanding control algorithm was tested at PGE on a live feeder powering customer loads. The SEGIS team built a mobile resistive-inductive-capacitive (RLC) resonant load bank capable of islanding the inverter at full output power without disrupting these important loads. Relays that include PMU functionality were installed at the site location, as well as at the governing substation. This allowed the PMU data to be readily passed from the substation to the inverter to determine if the PV system was connected to the feeder. A wide-area control device (SVP) was installed at the endpoint and performed all anti-islanding control algorithms. Fig. 12 shows the system layout. The substation contained a PMU and a clock. The synchrophasor measurements from the substation were sent to the SVP at the inverter location. The inverter location also included a PMU and a clock. An oscilloscope provided measurements for the live test. The mobile resonant load bank was a local load that was varied according to the test conditions.

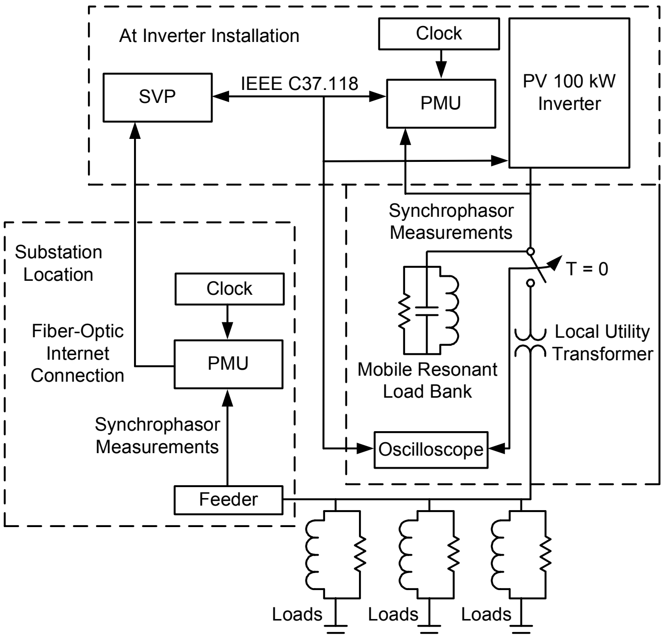

Fig. 12. PGE live demonstration system layout

The RLC load bank was tuned to 60 Hz at the representative available output power level of the PV system. During this time, the PV system and tuned RLC load bank were connected directly to the grid. To ensure the system was properly tuned, the grid-side currents were monitored and verified to be zero (real and reactive power from the substation were zero). The island was initiated with a contactor, which separated the grid from the PV DG system and RLC load bank, and the island formed. The islanding event was detected by setting the output relay on the local PMU device to write a logical 1 to an oscilloscope when the SVP determined that the slip or acceleration passed the thresholds developed for islanding. This allowed the team to capture the event.

Fig. 13 shows the islanding event. The yellow trace shows the start of the islanding event. A change of state (in this case, a 5 V signal going to 0 V) occurred when the switch opened the contactor to the grid, and the island was initiated. The green trace is the output of the PMU and is controlled by the SVP to change state when the islanding event is detected. The time required to recognize and respond to the islanding event for this case was 1.12 seconds.

Fig. 13. Live system islanding event results

Multiple islanding events were tested on the system for a quality factor of 1.0, as specified in IEEE 1547. To probe the limits of the technique, an island test was also performed with a quality factor of 3.0. For each islanded case, the synchrophasor-based technique determined that the distributed PV system was islanded in less than 2 seconds. The 2-second threshold is important because it represents current timing restraints set forth in IEEE 1547 governing safety functions for DG systems.

Tuning of the system parameters has produced a much faster response in lab testing, and the team believes that, with further refinement of the threshold settings, islanding event detection could be much faster than what was demonstrated at the PGE site.

VII. Conclusion

Synchrophasors are a viable approach to help solve the problem of PV-based DG islanding detection and control. Future work will incorporate more wide-area control algorithms into the controller. Improving the ability of the PV inverter to ride through low voltages is one example of a future application for synchrophasors. Similar to the anti-islanding case, providing the PV inverter with time-aligned, wide-area information opens new opportunities to use this information for improved control algorithms. These improved algorithms are one of the key innovations to increase use of PV systems in the future.

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IX. Biographies

Michael Mills-Price received his MS and BS in Electrical Engineering from Oregon State University. He is presently a senior electrical engineer as well as engineering manager at PV Powered in Bend, Oregon. He is a registered professional engineer and has been focusing his design efforts on photovoltaic (PV) systems with emphasis on inverter control and integration techniques to proliferate distribution generation installations. He leads a project team working to develop next generation integration and control techniques, while focusing on energy harvest and grid support functionality. Prior to joining PV Powered in 2005, he focused his engineering efforts on designing electric vehicle drive systems. He is an active member of IEEE and the Professional Engineers of Oregon.

Mesa Scharf received his BS in Electrical Engineering from Oregon State University in 1998. Mesa has more than ten years of experience working in the energy industry. He started his career at Serveron, where he worked with a team of scientists to develop utility scale transformer monitoring products. After Serveron, he worked for IdaTech, where he successfully automated the company’s first fuel cell system and contributed as a systems integration expert. He was a key contributor to the IP portfolio of IdaTech and currently has six patents pending. In 2006, he joined PV Powered, where he is presently responsible for forward-looking R&D and management of the SEGIS (Solar Energy Grid Integration Systems) program. The SEGIS program is focused on enabling high penetration of photovoltaic on the utility grid, including initiatives such as smart grid, AMI (advanced metering infrastructure), and building energy management systems integration. Mesa is active on the IEEE 1547 standard committee and is a member of the IEEE.

Steve Hummel is the vice president of engineering at PV Powered, bringing 29 years of experience in high-technology innovation and product development. Prior to PV Powered, he held vice president of advanced technology and vice president of marketing roles for Nanometrics and was chief technology officer for Accent Optical Technologies, both global suppliers of semiconductor metrology and process control. He spent 20 years as a research scientist, including experiences at AT&T Bell Labs, Hewlett-Packard and Agilent Labs, and Nova Crystals. He has authored 85 publications and 13 patents. Steve holds a PhD in Electrical Engineering from USC, where he was a Center for Photonic Technology Fellow, and an MS in Electrical Engineering and BA in Chemistry from Rutgers University.

Michael Ropp received a BS in Music from the University of Nebraska-Lincoln in 1992, and an MS and PhD in Electrical Engineering from Georgia Institute of Technology in 1996 and 1998, respectively. He is currently the president and principal engineer of Northern Plains Power Technologies in Brookings, South Dakota, and is a licensed professional engineer in South Dakota. In addition to experience with photovoltaic (PV) devices, he has worked on power system computer modeling and design, grid integration of PV (including islanding detection), control algorithm development, and PV power electronics for over 15 years. His current work focuses on computer simulation of systems, systems integration, controls development, and power electronics design, and his favorite application areas are distributed energy resources and electric transportation. He is active on the IEEE 1547 and IEEE 1809 standard committees.

Dij Joshi received his BS in Electrical Engineering from the Institute of Engineering (IOE), Kathmandu, Nepal, in 2005. He joined the electrical and electronics department of Kathmandu Engineering College, Kathmandu, Nepal, as a lecturer for two years. He is currently a Masters candidate in Electrical Engineering at South Dakota State University, supported by a Power Engineering Fellowship from Northern Plains Power Technologies. His experience includes EMTP modeling of distribution generation (both inverter- and rotating machine-based) and distribution systems, and modeling, analysis, and model-based design of advanced automation and control strategies for distributed generation. His primary areas of interest are electrical distribution systems, photovoltaic systems, and islanding detection.

Greg Zweigle received his MS in Electrical Engineering and MS in Chemistry from Washington State University. Also, he received a BS in Physics from Northwest Nazarene University. He is presently a research and engineering manager at Schweitzer Engineering Laboratories, Inc. (SEL). Previously, he worked as a principal research engineer in the research group and as a senior software developer at SEL. He has been responsible for phasor measurement unit signal processing algorithms, embedded system architectures, and synchrophasor-based power system designs. He holds seven patents and is presently pursuing a PhD focusing on energy systems. He is a member of IEEE and the American Chemical Society (ACS).

Krishnanjan Gubba Ravikumar received his MS in Electrical Engineering from Mississippi State University in 2009 and his BS in Electrical and Electronics Engineering from Anna University, India, in 2007. He focused his MS on power engineering, working as a research assistant in the Power & Energy Research Lab (PERL) of Mississippi State University. He was the recipient of the Mississippi State Research Assistant of the Year Award in 2009. He is presently working as an power engineer at Schweitzer Engineering Laboratories, Inc., where he focuses on development and operations of synchrophasor-based power systems. His research areas of interest include real-time power system modeling and simulation, substation automation, synchrophasors and their applications, power system stability, and supervisory control and data acquisition (SCADA) systems. He is a member of IEEE and the Eta Kappa Nu Honor Society.

Bill Flerchinger is a lead marketing engineer for synchrophasor-based solutions at Schweitzer Engineering Laboratories, Inc. Previously, he worked for Agilent Technologies, Mobile Broadband Division as the product planning manager. He recently completed a Certificate in Transmission and Distribution from Gonzaga University. He received his MS in Engineering Management and a BS in Electrical Engineering from Washington State University.

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