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Project Title: **ASSESSMENT OF THE UNIVERSAL FEASIBILITY OF USING POWER SYSTEM HARMONICS AS LOSS OF MAINS DETECTION FOR DISTRIBUTED ENERGY RESOURCES**

Contract number:	**RDF 3-21**	Milestone number:	**14**	Report date:	**11/28/2012 (v2)**

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FINAL REPORT

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11/28/2012: This is the second draft of this report. The first draft was submitted on November 09, 2012, and extensive revisions were requested.

List of acronyms:

CCB	Correlation Coefficient Based (method)
DG	Distributed Generator or Distributed Generation
DTT	Direct Transfer Trip
HS-LOMD	Harmonic Signature Loss Of Mains Detection
LOMD	Loss Of Mains Detection
NPPT	Northern Plains Power Technologies
PLCC	Power Line Carrier Communications
PMU	Phasor Measurement Unit
PV	Photovoltaic
RDF	Renewable Development Fund
RoCoF	Rate of Change of Frequency
RoCoF-H	Rate of Change of Frequency-Histogram (method)
SB-LOMD	Synchrophasor-Based Loss Of Mains Detection
WAM	Wide Area Method

Definitions of key terms:

Distributed Generator (DG): a generator connected to the low-voltage distribution network, as opposed to a generator connected at the transmission level. DGs tend to have ratings of 10 MVA or less.

Islanding: self-excitation of a section of the power system. In other words, if a section of the power system has its own generation and loads and enters a stand-alone mode on its own power, that section of the power system is said to be islanding.

Loss of Mains Detection (LOMD): detection of a loss of mains that leads to formation of an island, especially an unintentionally-formed island supported by DGs.

Phasor: a specialized type of voltage or current measurement often used in power systems.

Selectivity: the ability of a sensing function to differentiate between different conditions. In this document, "selectivity" typically refers to the ability of passive LOMD methods to differentiate between LOMD events in which DGs should trip off line, and grid-tied events in which it is desired that DGs not trip off line.

Sensitivity: the ability of a sensing function to detect very low levels of whatever is being sensed. In this document, "sensitivity" typically refers to the ability of passive LOMD methods to detect all islands, no matter what the level of real and reactive power mismatch.

Synchrophasor: a phasor measurement that is time-stamped using a globally synchronized time reference, such as the GPS clock.

Overview/Executive Summary:

Through a grant from its Renewable Development Fund (RDF), Xcel Energy supported Northern Plains Power Technologies (NPPT) on a project that had the goal of determining the feasibility of two methods for loss-of-mains detection (LOMD): detection based on changes in harmonic signatures, or detection based on changes in the relationship between synchrophasors.

The "detection" referred to here is detection of an unintentional island, which occurs if a section of the utility system continues to be energized by a distributed generator (DG) without being connected to the grid ("loss of mains", as seen from the unintentional island). Consider the generic distribution feeder shown schematically in Figure 1. This feeder is fed by a utility source at the left. The substation transformer is shown, along with a feeder circuit breaker. The feeder then serves a number of loads through cables with some impedance, as shown in the figure. The feeder may also have capacitors to supply reactive power support, reclosers that can isolate faults on subsections of the feeder, or sectionalizers or other types of switch that allow reconfiguration of the feeder, or perhaps even switching of some part of the feeder over to another substation (not shown). This generic feeder also contains two DGs, which in this example are shown as photovoltaic (PV) systems. Imagine a case in which the real and reactive power demand of all the loads on this feeder were very closely matched to the real and reactive power output of the DGs and the capacitors. In this condition, there is essentially no power flowing through the substation breaker; all of the feeder's power needs are coming from elements on the feeder itself, and not from the utility source. If the feeder breaker were opened in this case, that breaker is not interrupting any power flow, so the voltage on the feeder will remain approximately the same as when the breaker was closed. The feeder has thus become an island, and if this condition was not planned for, then the feeder has become an unintentional island.

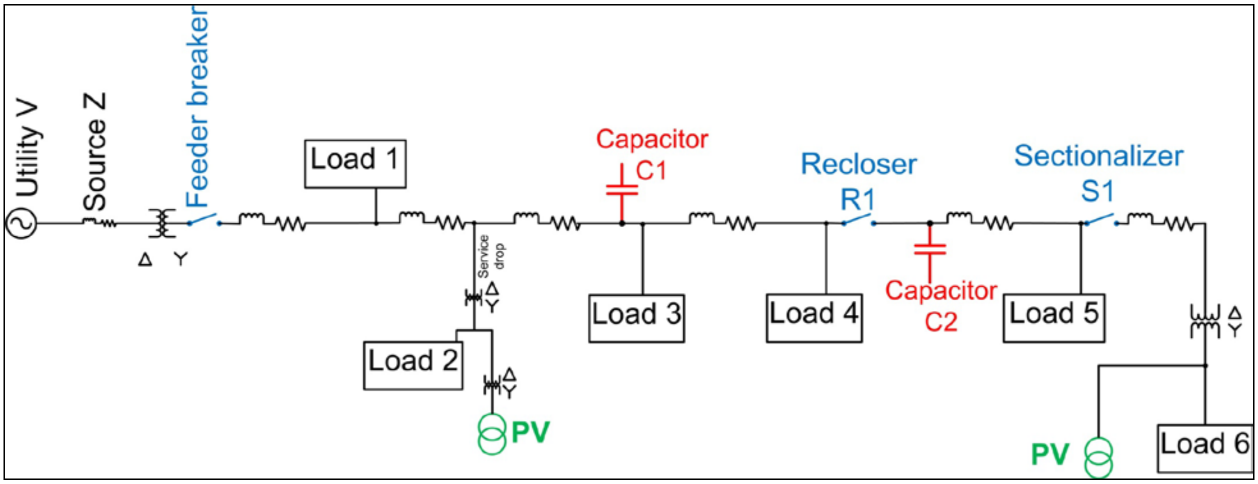

Figure 1. Schematic diagram of a generic distribution feeder, for use in understanding islanding.

Unintentional islands created under these conditions are very unlikely, but if they do occur the severity of the problems they can cause to customer or utility equipment or to human health and safety is high. Thus, the risk posed by unintentional islands is non-negligible, and effective LOMD is important for all DGs. Today, so-called "active anti-islanding" LOMD methods are used on nearly all inverter-based DG. These are quite effective as long as the amount of DG in any part of the system is relatively low, a situation referred to as a "low-penetration" scenario. When higher penetration scenarios are reached, the DG must assume a different role within system operations and behave more like a conventional generation asset by providing what has been termed "grid support functions". Unfortunately, because of the physics of the system and the limited number of data inputs to the DG when only local information is available, the grid support functions are in some ways in fundamental conflict with the way today's active anti-islanding techniques work. This creates the potential for an unfavorable tradeoff between realizing the benefits of DG and maintaining system security. Thus, there is a clear need for effective alternatives to today's active anti-islanding, and that need is the one being addressed by this Xcel-supported project.

Loss of mains detection based on harmonic signatures falls within the family of "passive LOMD", in which LOMD is implemented by monitoring the voltage at the DG terminals and using that voltage information to decide when the DG has permission to operate. The harmonic signature-based LOMD (HS-LOMD) use subtle changes in the shape of the voltage waveform at the terminals of a DG to detect when that DG may be supporting an unintentional island. Detection of these subtle changes requires specialized signal processing techniques, and interpretation of the changes (in other words, deciding which indicate a loss of mains and which don't) requires specialized algorithms.

Loss of mains detection based on synchrophasors is an entirely different concept that falls within the family of "communications-based LOMD. Members of this family use communications with the utility to provide situational awareness and LOMD. A "phasor" is a specific type of voltage or current measurement, and a "synchrophasor" is a set of phasor measurements that have been time-synchronized using the GPS clock timing signal. Synchrophasor-based LOMD (SB-LOMD) is implemented using the configuration shown in Figure 2. A Reference PMU (Phasor Measurement Unit), shown at the left, is GPS time-synchronized with the Local PMU at the right. The Reference PMU makes its phasor measurements, then broadcasts them downstream to a processing unit collocated with the Local PMU. (Wireless broadcasts are implied in Figure 2, but other communications channels have been used.) The processing unit at the Local PMU uses any of a number of algorithms to compare the Reference and Local phasors, and uses that comparison to determine whether an unintentional island has been formed.

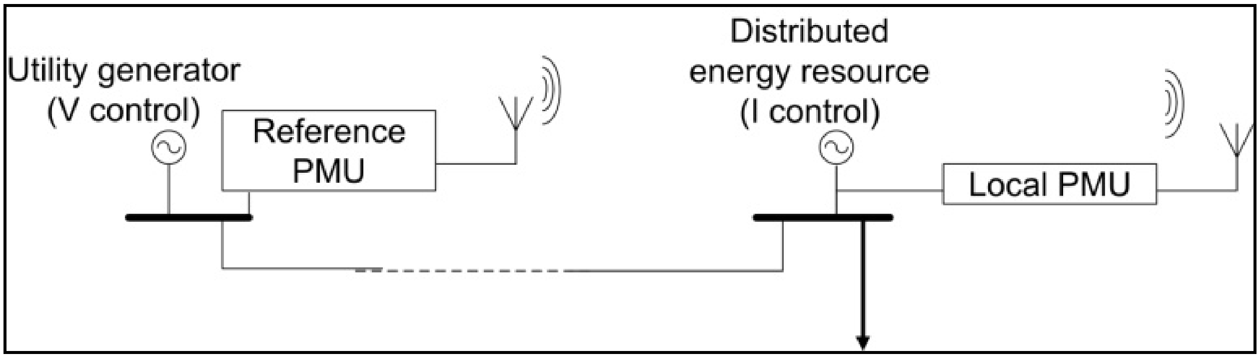

Figure 2. Configuration of a system for use in synchrophasor-based LOMD.

Passive methods in general, and HS-LOMD in particular, have historically suffered from a common problem: there is some overlap between the set of conditions that indicates island formation, and the set of conditions in which one would like the generator to "ride through" (continue to operate). This means that passive LOMD has traditionally suffered from a poor tradeoff between ***sensitivity*** (ability to "see" even small differences that might indicate an island) and ***selectivity*** (ability to differentiate between cases in which the DG should stop or run).

For the communications-based methods like SB-LOMD, the primary obstacle has always been cost. These methods require upstream instrumentation and a communications channel between the utility and the DG. When all equipment, substation engineering, and other utility engineering costs are factored in, the cost of communications-based LOMD has historically been sufficient as to kill DG projects. For example, consider direct transfer trip (DTT), in which the status of the feeder breaker or another circuit switch is directly transmitted via a communications link to the DG. If the feeder breaker opens, or "trips", the trip signal is sent to the DG (the trip is transferred), and the DG can cease operation. DTT is effective and fast, and it is a mature technology that has been used by utilities for decades. However, because of the high substation engineering costs, communications channel costs, and the schedule delays that come along with the need to modify utility equipment, a DTT requirement on a project is widely viewed by DG owners and developers as the "kiss of death" for that project. It is critical that new communications-based methods be developed that take advantage of various mechanisms to reduce cost and delays.

In light of all of these factors, this Xcel-sponsored RDF project was undertaken with the goal of determining the feasibility of HS-LOMD and SB-LOMD. There were five specific deliverables to be produced:

1. A computer model of the power system at the distribution level including load nonlinearities and accurate models of distributed energy resources.
2. A feasibility analysis of HS-LOMD and SB-LOMD, and either recommendations for implementation or an explanation of why they will not work.
3. A process to implement an optimal power line carrier communications (PLCC) signal for LOMD purposes.
4. Recommended changes to codes and standards to enable HS-LOMD and SB-LOMD.
5. Presentations to appropriate Engineering Societies and Underwriters' Laboratories.

All five deliverables have been produced and will be described in detail in following sections. In brief, the results are summarized as follows:

1.) Using data graciously provided by Xcel Energy's Distribution Engineering group, highly computer models of three Xcel Energy distribution feeders, a strong feeder, a weak feeder, and one of in-between strength, were developed in the EMTP-RV environment. These models were validated by comparing fault current calculations from NPPT and Xcel. Also, highly detailed models of several different types of DG and their controllers, including those believed to be most likely to appear in Minnesota (Type I, II, III and IV wind turbines, PV, and engine-gensets as would be used with anaerobic digesters), have been developed.
2.) The feasibility of HS-LOMD and SB-LOMD has been extensively studied.
    a. For HS-LOMD, it does appear that feasibility can be achieved if in addition to ***sensitivity*** and ***selectivity***, the ***speed*** (how quickly the condition is detected) is also used as a parameter. Adding this third parameter gives additional degrees of freedom that allow a more favorable tradeoff to be reached. Specifically, if the required speed of response can be reduced somewhat, then selectivity and sensitivity can be simultaneously improved, and several advanced types of HS-LOMD appear to have a great deal of promise.
    b. During this work, SB-LOMD was shown to be highly effective in islanding prevention, compatible with grid support functions, and able to ride though grid events successfully as desired. In addition, during this work several promising paths to low-cost implementation have been identified.
3.) NPPT has studied PLCC-based LOMD in detail. This work is ongoing, but a number of key issues and potential solutions have been identified, along with a set of criteria for selecting a PLCC technology best suited to the LOMD application.
4.) NPPT investigators developed a detailed set of recommended changes to the applicable standard, which is IEEE 1547 and its sub-parts. Those recommendations are under discussion by the IEEE 1547 committees at present.
5.) Presentations on the results of this work were made at the IEEE Power and Energy Society General Meeting, the IEEE Photovoltaics Specialists Conference, and the Minnesota Power Systems Conference, all in CY 2012. In addition, NPPT investigators attended three IEEE 1547 meetings and presented project results there.

Project Benefits:

As noted in NPPT's proposal, the primary benefit of this project is in the elimination of a barrier to higher penetration levels of DG in utility systems and the facilitation of DG participation in supporting better grid operation. Many forms of DG, particularly the renewables such as PV and wind, enjoy high levels of public support, which in turn has led to favorable policies that are driving increases in the number of DGs seen on feeders. The penetration level is usually defined as the ratio of the total DG rating to the total load (noting that "total load" may be defined in several different ways), and in some locales, penetration levels are exceeding 100% under certain conditions. As penetration levels rise, DG must behave more as a generation asset, and not as a somewhat odd negative load as is the case at very low penetration levels. Generation assets must participate in system frequency support, local voltage regulation, and a variety of other system integrity protection schemes, collectively referred to as "grid support functions". DG is particularly valuable in this role because of its proximity to the load, which enables DG to provide just the type of support that is needed, right where it is needed. At the same time, DG must not support unintentional islands, for safety and equipment integrity reasons. Today, DG use active LOMD techniques to detect unintentional islands, and these techniques are highly effective in low-penetration scenarios, but the fundamental problem is that the needed grid support functions tend to conflict with these active LOMD techniques. This combination of circumstances will eventually lead to a constraint on the amount of DG the system can host (i.e., penetration levels must be kept low), unless new LOMD means can be developed. The purpose of this project was to investigate two specific families of alternative LOMD that would allow the penetration level constraints to be lifted and enable the benefits of DG to be fully realized.

In our proposal, we identified two benefits that were specific to Minnesota: the facilitation of higher deployment levels of agricultural waste-based DG, such as anaerobic digesters, and the opening of markets for a Minnesota employer, Hunt Technologies of Pequot Lakes, MN, which is a producer of power line carrier communications equipment. The primary challenge with the ag-based DG is that most of it is based on synchronous generators, not inverters. It is relatively easy to implement modern active anti-islanding in inverters, but it is quite difficult to do so effectively in synchronous machines because of differences in physics and dynamics between synchronous machines and inverters. In the absence of effective anti-islanding for synchronous machines, the total amount of DG based on synchronous generators that can be allowed on a feeder is typically kept to less than one-third of the peak feeder loading—in other words, islanding is prevented by keeping the amount of DG so small that the DG cannot produce enough power to support an island. The problem becomes even worse if different types of DG (inverter based combined with DG based on either synchronous or asynchronous generators) are combined on the same feeder, as they tend to interact in such a way as to make unintentional islands persist longer. However, both the communications-based and the passive LOMD can work well in both synchronous generators and inverters, or with the two in combination. Thus, this work clearly represents a significant step toward eliminating this problem, and the penetration constraint that accompanies it.

Regarding the second benefit, opening a market for Hunt Technologies, power line carrier communications (PLCC) is a part of the family of communications-based methods, and NPPT investigators have been successful in stimulating considerable interest in PLCC-based and other communications-based forms of LOMD. NPPT continues to work with Hunt, although it should be noted that during the course of this project Hunt Technologies was acquired by Landis + Gyr. One of Hunt Technologies' systems has been identified as one of only four leading contenders for the PLCC application among all of the power line carrier products on the market today. NPPT's PLCC-LOMD work is ongoing.

Project Lessons Learned:
The key lessons learned can be summarized as follows. More details can be found in the papers included in the Appendices to this report.

1. There needs to be further discussion of the 2-second run-on time limit presently written into IEEE-1547. This standard is currently under review and revision, and in the discussions that are part of that process it has become clear that there are two camps. One camp believes the 2-second limit is too long, and the driver toward shorter allowable run-on times is asynchronous reclosure, which can occur if a recloser's first reclose interval is shorter than the run-on time of the DG. In asynchronous reclosure, what happens is the recloser opens briefly in order to clear a fault, but the DG rides through the breaker opening, and during that ride-through the DG drifts out of phase with the utility. Then, when the recloser attempts to reclose, it is connecting two systems that are significantly out of phase (asynchronous). The utility, being much stronger, will "jerk" the island back into synchronism, but this process can severely damage any motor load in the island, and there can also be large surge currents that flow during the asynchronous reclosure. Clearly, the concern about asynchronous reclosure is valid, but note that this occurs only in a case in which there is a fault in the island. When the fault is present, it causes characteristic changes in the system that can be detected, independently from LOMD. The other camp in the 2-second limit discussion believes that the limit is unnecessarily short. This camp is looking primarily at the personnel safety aspects, and is thus concerned primarily with islands that do NOT contain faults, but instead have a generation-load balance. It is nearly impossible to obtain a generation-load balance in a faulted island because of the very high demand of the fault, and

also because the fault's power draw tends to be nearly entirely inductive in most cases. Both camps have valid concerns that need to be addressed. The two concerns can be decoupled if *fault* detection is required separately from *island* detection. LOMD techniques, like the ones explored in this RDF project, deal primarily with detection of balanced, unfaulted islands, because this is an especially difficult case to detect: the voltage created by the load's response to the DG output current (essentially the Ohm's Law response) is indistinguishable from the normal utility voltage if the generation-load balance is sufficiently close. However, as noted earlier, in the faulted case the fault creates abnormal voltages and currents, with the specific abnormalities depending on the type of fault and its location on the feeder relative to the DG. Many utility engineers are worried about fault detection at the DG because traditional overcurrent protection will not work, especially for inverter-based sources that operate as current sources and thus source very little fault current, but symmetrical component and harmonics-based techniques should be able to largely overcome these issues, and thus separate fault detection and LOMD should be technically feasible. Separating these two functions should be a focus of the next round of IEEE 1547 revisions and of industry R&D. In that case, the *fault* detection time could be much shorter than two seconds (and would prevent asynchronous reclosure), and the *island* detection time could be longer (as long as 10 seconds has been discussed in IEEE 1547 committee meetings).

2. It seems likely that the LOMD technique of the future, when DG penetrations become high, will be communications-based. There is a need for a technique that is effective in island detection for all combinations of DG at all penetration levels, and is compatible with grid-support functions. Several communications-based candidates meet this need, but their primary drawback is cost. The results of this work suggest that synchrophasor-based LOMD may have superior potential from both technical and market perspectives. Two specific synchrophasor-based techniques, the Wide Area Method (WAM) and the Correlation Coefficient Based (CCB) method, were studied as part of this RDF project. The WAM was developed by Schweitzer Engineering Laboratories (SEL) and studied in this project; the CCB method was invented by NPPT and has been developed and characterized in this project. A third method was independently developed by NPPT and SEL and was called Integral of Frequency Error (IFE) by NPPT, and Absolute Phase Angle Difference (APAD) by SEL. In this document the term IFE will be used. This third method predates the RDF project and thus was not extensively studied in this work. The WAM, CCB and IFE all have strengths and weaknesses, but it appears that the use of all three in combination is exceptionally effective and could lead to a technique that fully meets the technical needs, leaving only cost issues to be solved.
3. One problem with the synchrophasor-based LOMD methods, and all LOMD methods using broadband communications, is the problem of what to do if the communications are lost. If longer than two seconds can be allowed for LOMD (which, as just noted, should be the case if separate fault detection is used), then certain more advanced passive LOMD techniques can be successful. Although they probably will never match the effectiveness of the communications-based methods, if the 2-second limit can be relaxed they could make suitable backup methods during loss of communications. In this way passive methods could yet play a significant role in anti-islanding going forward.

Usefulness of Project Findings:

The usefulness of this project lies primarily in the fact that its benefits will be realized in the industry, in the form of new LOMD methods, actual submitted recommendations to the IEEE 1547 committees, and improved fundamental understanding that will inform utility planning and screening processes. In other words, this was always envisioned as a project to benefit the utility and DG industry, and not as an academic investigation whose results would end up on a shelf. New LOMD methods have been developed, the state of the art of LOMD has been advanced, and NPPT and its collaborators are working on moving these developments into the field and on low-cost implementations. Specific recommendations (described in detail below) have been made to the IEEE 1547 committee, and the timing was fortuitous because others had many of the same concerns and even made some of the same recommendations. Those discussions are moving forward and have supported improvements now being made in the IEEE 1547 base standard, as well as in the IEEE 1547.8 extension currently being written (NPPT investigators are members of the 1547.8 writing committee, which was made possible by Xcel support). Finally, this project has fed results and discussion points into the utility community that are continuing to ripple outward, leading to improvements in the efficiency of discussions between utilities, DG developers, and equipment manufacturers on the subject of LOMD.

Technical Progress:
One focus of this work was on the universal applicability of HS-LOMD techniques, where "universal applicability" was defined as the ability of the HS-LOMD technique to effectively detect islands without causing nuisance trips, for all combinations of DG and all feeder configurations—in other words, as it was worded in the proposal, that the HS-LOMD would work "all the time, everywhere". The other focus of this work was on SB-LOMD. Two specific SB-LOMD methods were explored in detail.

SB-LOMD
The two SB-LOMD methods explored here are called the Wide Area Method (WAM), and the Correlation Coefficient Based (CCB) method. Both of these methods use synchrophasors to achieve loss of mains detection. The use of synchrophasors in this application is demonstrated in Figure 2 above. The reader will recall that in SB-LOMD, a Reference PMU is located at an upstream point on the system, perhaps at the distribution substation, somewhere on the transmission network, or even farther upstream. The Reference PMU measures the frequency and the voltage phasor at its location, and this information is broadcast to all DG by any of several means (radio, LAN and Internet have all been demonstrated, and a demonstration using 4G cellular is in the works). The Reference PMU signal is received at the DG location by a receiver and processing unit, which also receives phasor and frequency data from a Local PMU that takes its measurements from the Point of Interconnection (PoI) of the DG. At the DG, the Reference and Local synchrophasors are compared in any of several ways to make a determination regarding whether the DG is islanded. It is the type of comparison done that distinguishes one SB-LOMD method from another.

The WAM and CCB are two such methods. Both of these methods were investigated in the course of this project. (A third, Integral of Frequency Error (IFE), has also been investigated by the NPPT team, but that was not part of this project.) These methods were investigated in simulation, in the laboratory, and in the field. The simulations were conducted using detailed inverter, generator, load and feeder models in the MATLAB/Simulink and EMTP-RV environments. The focus was on four particular feeder models: the IEEE 34-bus distribution feeder (a feeder modeling case developed by the IEEE and for which Common Information Model data are available on the web), and three feeders for which NPPT built models based on Xcel Energy-supplied feeder data from Xcel's Synergee GIS-based feeder database. One of the three Xcel feeders was a short feeder with a low source impedance (high available fault current) and serving primarily industrial load, and was called the "strong" feeder. Another was a long, high-impedance feeder serving mostly rural load, and this one was denoted a "weak" feeder. The third was in between, and was denoted an "average" feeder in this project.
As discussed above, to be successful a LOMD method must detect all islands, but not issue a false detection during a local or system event that is not actually an island. For our work, this property was tested by simulating each LOMD method using four test cases.

- Test Case 1: multi-inverter case. In this case, 100-kW inverters are distributed along the length of the feeder until the aggregate total of the inverters balances the real power requirement of the load (the feeder loading was assumed to be an average loading level for each feeder). Then, capacitors were added to balance the VArs. This is an island detection case; this multi-inverter feeder would be carefully balanced in terms of watts and VArs, then isolated from the mains to see whether the LOMD under test could see the loss of mains event.

- Test Case 2: multi-inverter plus engine-genset case. Another factor that is known to make island detection difficult is the inclusion of a large synchronous generator in the island, because its inertia and controls cause the synchronous generator to appear more like the grid than other inverter-based DG would. Thus, in Test Case 2, ten of the 100-kW inverters used in Test Case 1 were replaced by a 1 MVA synchronous engine-generator set. As discussed earlier, this could represent an anaerobic digester case.
- Test Case 3: the "Italian blackout" case. Test Cases 1 and 2 examine the ability of the LOMD to detect an island. Test Case 3 is the first of two ride-through cases that probe the LOMD's false-trip immunity. The idea behind Test Case 3 was to subject the feeder to a systemwide frequency event caused by a loss of generation. To do this, real-world frequency event data were sought, and the most well-documented case available to the project team was the Italian blackout of 2003, for which detailed frequency vs. time data were available for several locations on the grid. These data were scaled to 60 Hz (the frequency values were multiplied by 1.2) and the resulting frequency vs. time trajectory was fed into an NPPT-developed variable-frequency source. This creates a case in which the rate of change of frequency is a bit larger than might be expected on the North American grid, and thus it could be considered a worst-case scenario and is useful for present purposes. The LOMD method under test was monitored as the feeder's grid source underwent this scaled frequency event, and its ability or failure to successfully ride through the event was recorded. Note that there is no island formed throughout this test; the DG remains grid-tied at all times.
- Test Case 4: large motor start case. Test Case 3 represents a severe systemwide event, to test whether an LOMD can ride through such an event when there is no island. Test Case 4 was designed to see whether the LOMD under test could distinguish between a major local event and an island by successfully riding through the former. The event chosen here was a large motor start, with the motor connected next to the DG on the feeder.

The WAM and results on it are described in the paper included here as Appendix A. The CCB and its results are presented in the papers included here as Appendices B and C. The results of these papers can be summed up as follows. Both the CCB and the WAM appear highly promising in terms of their ability to detect islands without false trips, and to be compatible with grid support functions. The WAM detected all of the Test Case 1 islands on all four feeders, and successfully rode through the event in all of the simulations of Test Cases 3 and 4. The WAM missed a small number of islands under Test Case 2. The CCB scored 100% marks in all four test cases, but was often slower to detect the island than the WAM, and because the CCB is based on statistical processes, the run-on times seen with the CCB are nondeterministic. IFE also worked very well, detecting nearly all cases, but in some cases with both inverters and rotating machines the IFE sometimes took very long to detect (many tens of seconds in some cases). Because they are complementary to one another and use the same input data, it is the conclusion of the NPPT team that the three synchrophasor-based methods, IFE, WAM and CCB, should be used in combination. Figure 3 qualitatively illustrates the relative coverage of the three methods, versus their detection speed. The WAM tends to react most quickly, but does not cover all cases. IFE covers a few more cases than the WAM, but is a bit slower to react. The CCB appears to cover all cases, but in some cases is the slowest to respond. The three together offer the best overall combination of reaction speed and case coverage. This type of situation is common in protection situations: one method is used because it is fastest but it may not cover all cases, and another method is used that may be slower but it "fills in the gaps" of the faster method.

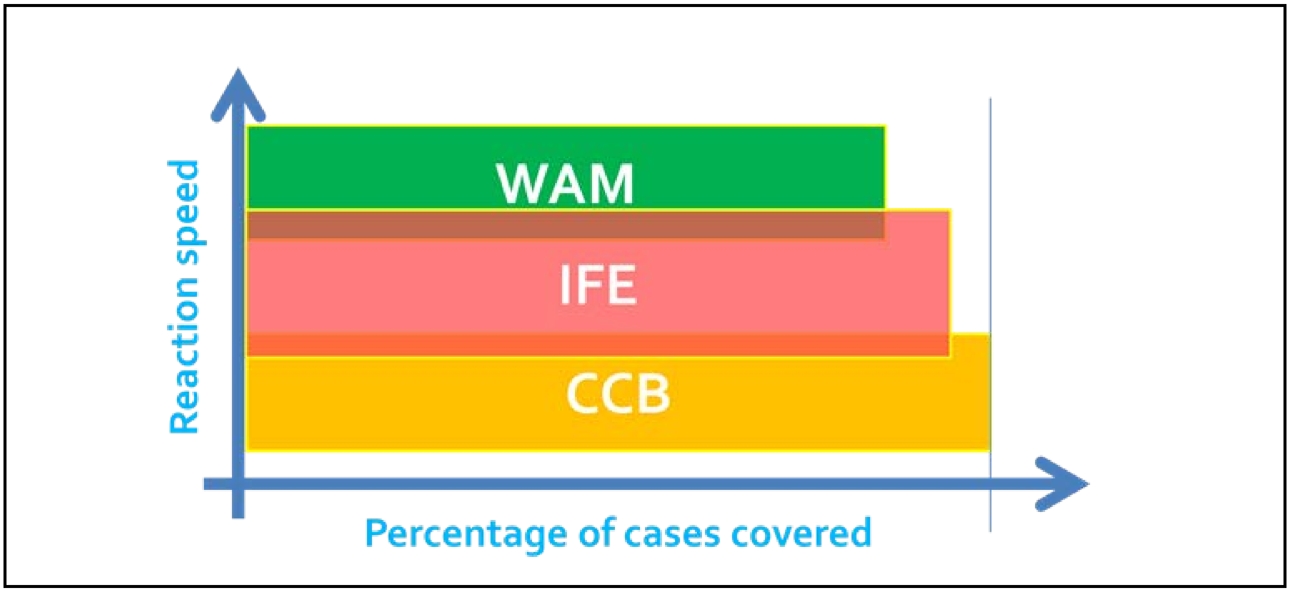

Figure 3. Conceptual diagram showing the relative coverage areas and reaction speeds of the three synchrophasor-based LOMD techniques.

HS-LOMD

As noted earlier, all passive methods struggle to simultaneously obtain high sensitivity, high selectivity, and high speed. The reason is that there is simply too much overlap between the parameter values in islanded and non-islanded cases to enable a quick yet accurate detection of loss of mains based on those parameters. In fact, most investigators had written off passive methods, believing they could never achieve a satisfactory tradeoff, and attempting to answer this question is one of the main reasons why NPPT proposed the present project.

In the course of this project, HS-LOMD was studied in simulation using the same four Test Cases outlined above, and by extensively studying the literature. Two key findings were made that give one cause to conclude that the answer to the question of whether passive methods can be feasible for LOMD is a qualified "yes". Those findings can be summarized as follows.

1. Some passive LOMD methods, specifically the HS-LOMD methods, do have potential to be effective and do appear to be feasible. There are two key factors that make these particular HS-LOMD methods viable. The first is that they incorporate more intelligence into their signal processing and decision making, and this intelligence improves some simultaneous improvement of sensitivity and selectivity. The other key factor is that there actually is a third factor in the tradeoff that is commonly overlooked: speed. As noted above, if the 2-second limit can be relaxed somewhat in the case of an unfaulted island, then adding speed as a third factor permits one to simultaneously increase the sensitivity and selectivity of HS-LOMD methods.
2. Passive methods may find an important market niche as backup methods to communications-based methods like the SB-LOMD described above. The backup is required in the case of loss of communications. The DG cannot revert back to active anti-islanding, and it is probably not desirable for the DG to trip when communications are lost. Thus, passive techniques are really the only remaining alternative provided that effectiveness can be improved, and as noted above, for HS-LOMD effectiveness *can* be improved through a combination of advanced signal processing and allowance of more time to detect the (unfaulted) island condition.

Because it is so critical to the effectiveness of HS-LOMD, a bit more discussion of the speed factor is warranted. Historically, the 2-second speed requirement first appeared in the IEEE 929 standard for PV interconnection. That limit was carried over into the more general IEEE 1547 standard, but it has always been the result of a compromise between two sets of concerns: one for personnel safety, and one about asynchronous reclosure. Personnel safety could be compromised if maintenance or repair personnel disconnected a section of the system and expected it to be "cold", but were unaware that the same section was being energized from the customer side. The 2 second requirement seems extremely short when viewed from this perspective. On the other hand, the asynchronous reclosure concern arises because a might open during a fault, temporarily islanding a section of a feeder containing a DG and a fault. If the DG does not detect that it is islanded (and does not detect the fault) but instead rides through the recloser interval, it will almost certainly drift out of phase with the rest of the system because of the abnormal voltage resulting from the fault. When the recloser attempts to reclose onto the out-of-phase island, which is the condition known as asynchronous reclosure, the much stronger grid will "jerk" the island voltage back into phase with the utility. This sudden phase jump in the island voltage usually does not harm inverter-based DG, but it can seriously damage any rotating machines, including synchronous or asynchronous generator-based DG as well as motors in customer equipment. Clearly, asynchronous reclosure must be prevented, but many utilities use first recloser intervals considerably shorter than two seconds, and thus the 2-second requirement is too long from this perspective.

This problem can be solved if fault detection is separated from LOMD. Further research is needed on that topic, but it seems likely that a combination of harmonic and symmetrical component-based methods should be able to successfully detect most faults based on measurements made at the DG point of interconnection. Thus, the tradeoff in speed seems reasonable, and HS-LOMD should be able to achieve better performance given the increase in reaction time.

In this project, one such method was developed. It is a statistically-based HS-LOMD method called RoCoF-H. "RoCoF" stands for Rate of Change of Frequency, which is a time-honored islanding detection technique at the transmission level but which has struggled with poor effectiveness in distribution. The technique developed by the NPPT team during this work uses a histogram of rates of change of frequency, and thus the name RoCoF-H ("H" for histogram). The RoCoF-H technique is described in the publication attached as Appendix D.

Appendix A

Solar Generation Control With Time-Synchronized Phasors

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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):

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

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.

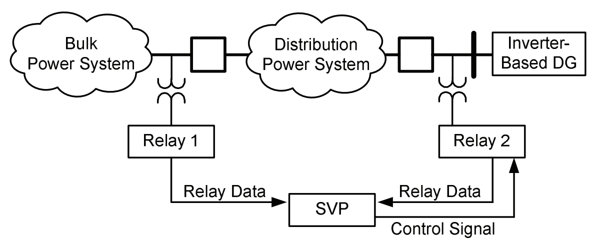

Fig. 1. System layout

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).

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

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

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.

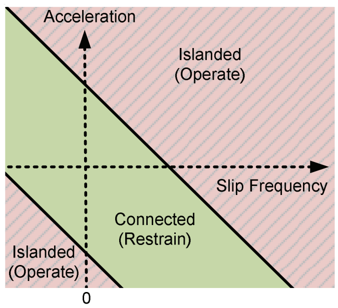

Fig. 2. Islanding detection characteristic using slip and acceleration

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.

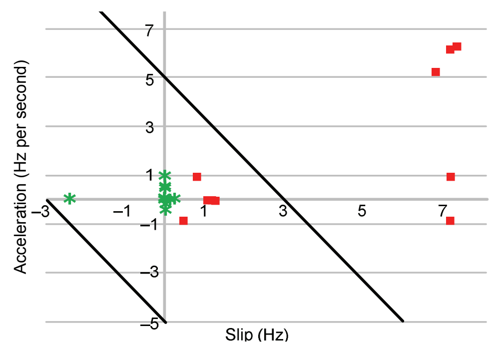

Fig. 3. Plot of the results of the EMTP-RV modeling and the recommended slip and acceleration boundaries

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.

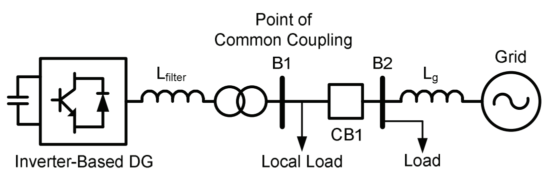

Fig. 4. System model for RTDS

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.

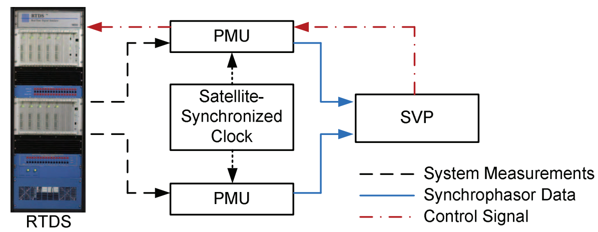

Fig. 5. RTDS simulation setup

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.

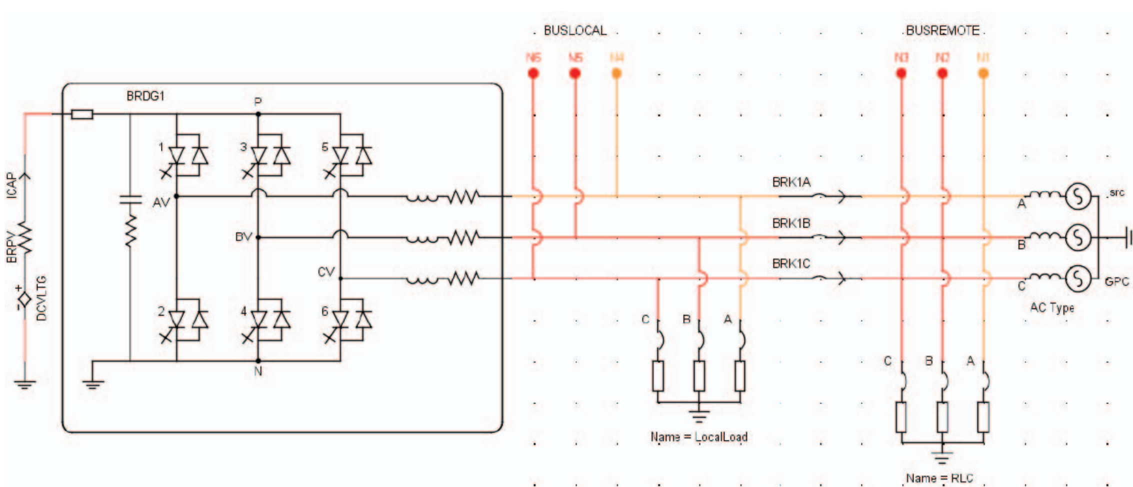

Fig. 6. System diagram from RTDS

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.

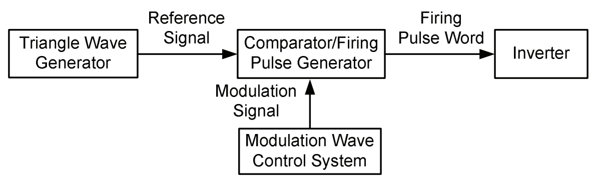

Fig. 7. Block diagram of the PWM control algorithm

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.

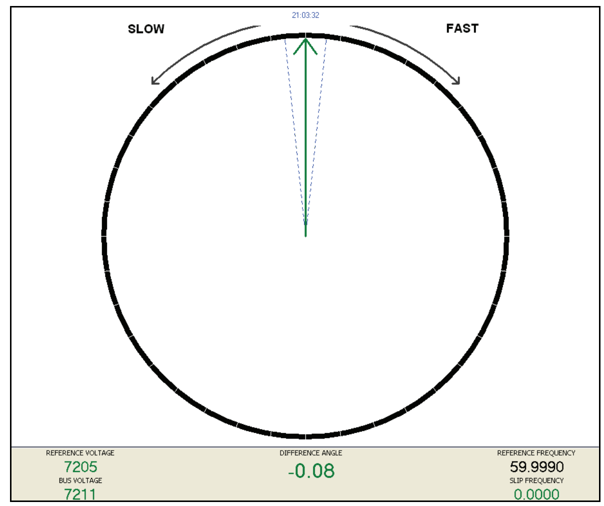

Fig. 8. Synchrophasor-based synchroscope display for connected system

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.

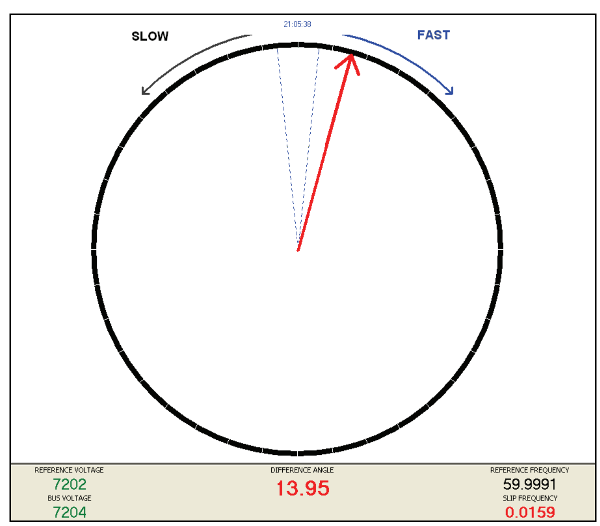

Fig. 9. Snapshot of the synchrophasor-based synchroscope display during disconnected state

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.

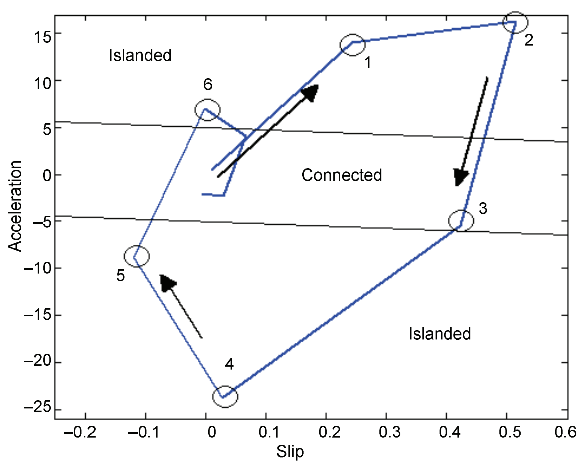

Fig. 10. X/Y plot of slip and acceleration values

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.

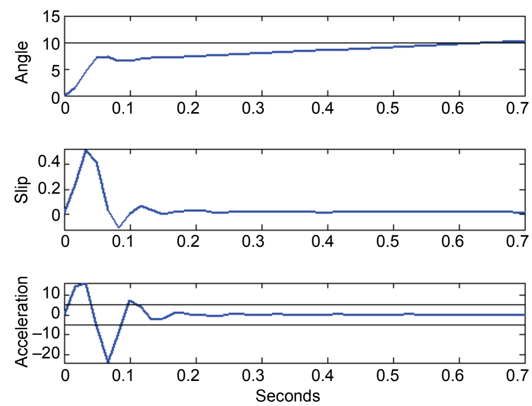

Fig. 11. Angle difference, slip, and acceleration results from the RTDS

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.

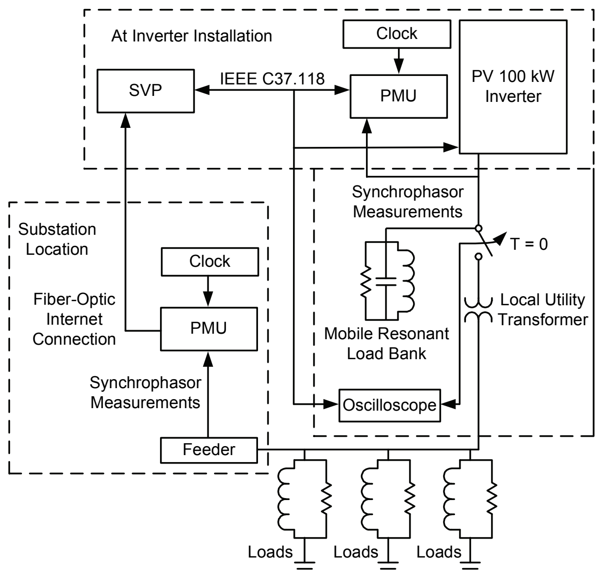

Fig. 12. PGE live demonstration system layout

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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Appendix B

A Statistically-Based Method of Control of Distributed Photovoltaics Using Synchrophasors

M. E. Ropp, D. Joshi, M. Mills-Price ,S. G. Hummel, M. Scharf, C. Steeprow, M. Osborn, K. Gubba Ravikumar, G. Zweigle

***Abstract*—Despite many years of effort in the distributed energy resources (DER) industry, there remains a need for an islanding detection method that a) facilitates, rather than conflicts with, DER participation in grid support functions; b) does not degrade power quality; and c) reliably detects a loss of mains without nuisance trips. This paper describes a method that can meet this challenge. The method is a communications-based method that uses statistical analysis on synchrophasor data measured in two locations, an upstream reference point and at the DER bus. Simulation results, and laboratory and field test results are presented for one very simple implementation of the method. It is shown that the method works very well, even in its simplest form.**

***Index Terms*—synchrophasors, islanding detection, photovoltaics, distribution system protection, distributed generation, distributed energy resources.**

I. Nomenclature

CCB Correlation Coefficient-Based (method)
DER Distributed Energy Resource
NDZ Nondetection Zone
PCC Point of Common Coupling
PMU Phasor Measurement Unit

II. Introduction

ISLANDING occurs when a section of the power system including generation and loads (and potentially storage) becomes electrically isolated from the main grid and enters a "stand alone", or microgrid, mode of operation. Generally, unintentional islanding supported by distributed energy resources (DERs) outside of utility control is undesirable for several reasons, including its potential to cause damage to customer, system or DER equipment, and the potential for safety hazards.

Applicable codes and standards, such as IEEE 1547™, require that DERs include means to prevent unintentional islanding [1]. Over the years, industry has responded to this requirement with a wide variety of methods to achieve this [2-4]. Broadly, the methods are subdivided into three categories: passive methods, which rely on changes in DER terminal measurements to detect island formation; active methods, in which the DER perturbs its output current in some way that creates a measurable change upon island formation; and communications-based methods, in which system status information is communicated to the DER and used to detect an island. Passive methods are attractive because of their lack of impact on the system and ease of implementation, but they generally encounter difficulty in maintaining islanding detection effectiveness without false trips. Today's active methods are cost-effective and work well in low-penetration scenarios, but in recent years their efficacy has been questioned for several reasons. One key reason is that there is mounting evidence, including some from the field, that these methods may fail in certain cases with multiple DERs [5,6]. Another important challenge is that they tend to conflict with grid support functions such as low-voltage ride-through. They degrade power quality, and some of the most effective methods can have significant power quality impacts on weak feeders. Finally, a seamless transition into an intentional island (microgrid) is not possible, because the method relies on the creation of a voltage transient to indicate the loss of mains.

Therefore, a need remains for an anti-islanding method that a) facilitates, rather than conflicts with, grid support functions; b) does not degrade power quality; and c) reliably detects a loss of mains without false or nuisance trips. Communications-based methods have the potential to meet this need, if cost effectiveness issues can be overcome. This paper describes recent work to develop a communications-based method that uses local and remote synchrophasor data to achieve islanding detection. The work was done by one of several teams coordinated by the U.S. Department of Energy under its Solar Energy Grid Integration Systems (SEGIS) program. This SEGIS team, assembled and led by PV Powered (an Advanced Energy company) and including Northern Plains Power Technologies, Schweitzer Engineering Laboratories, and Portland General Electric, has been investigating two different methods of preventing islanding using synchrophasors. One of these, the "wide-area network" method that relies on the slip and acceleration between the local and remote synchrophasors, is highly promising and has been described elsewhere [7]. This paper focuses on the

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alternate method, which uses statistical analysis of the local and remote synchrophasor data and pattern recognition to detect and prevent unintentional islanding.

Several investigators have previously proposed statistically-based islanding detection methods. However, most of these [8-11] continue to rely on perturbations of the inverter output current to enable islanding detection, and thus do not meet the need set out above. The method described in [12] is conceptually somewhat similar to the approach taken here, and appears promising; but because it does not utilize an upstream reference, it will likely struggle to maintain islanding detection effectiveness without false trips, and it is unclear whether this method would be able to pass the IEEE 1547 test. The method proposed here does not require external perturbation, and it will be shown that it is able to pass the IEEE 1547 test.

It should also be noted that island detection based on time-aligned voltage measurements prevention is not a new idea; in fact, it has been applied in the field, to both windpower [13] and photovoltaics [14]. However, both of these are at the transmission level, and [14] uses a phase angle difference technique that likely would not work at the distribution level.

III. Description of the Proposed Method

The proposed method relies on the statistical relationship between the frequencies measured by a local PMU, collocated with the DER, and a reference PMU located at a substation or other upstream reference point, as shown in Fig. 1. The concept is straightforward: the reference PMU covers a chosen territory, measures the frequency at its location, and time-stamps the frequency value according to a time reference that is shared between the reference and local PMUs. The reference PMU then broadcasts these time-stamped frequency values to all DERs in its territory. The local PMU measures its own local frequency and similarly applies a time stamp. Each local PMU also receives the time-stamped frequency value from the reference PMU, time-aligns the values, and then performs a statistical comparison of the data. When the island forms, clear differences in the statistical relationship between local and reference frequencies are expected, and this is the basis of the proposed detection method. This method should be effective for any combination of DERs and loads, with the primary challenges being speed of operation, and implementation cost.

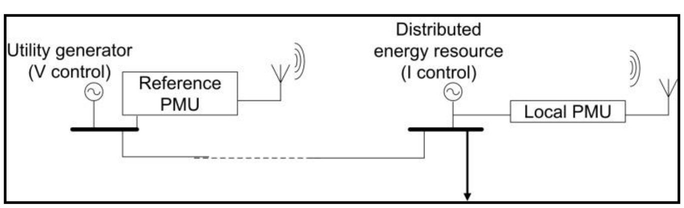

Fig. 1. Configuration of the system used to implement synchrophasor-based control of DERs.

It is assumed that the DER in Figure 1 is connected at distribution voltage. However, in theory, the bus to which the reference PMU is attached may be at the distribution substation or anywhere upstream of the DER, with the choice of location involving a tradeoff between the amount of the power system to be covered, the required speed of islanding detection, and the cost of getting the reference signal to the local endpoints. Note that the data transmission is unidirectional in this system; the reference values are transmitted downstream, and the processing and time alignment of this signal are distributed at the endpoints, so there is no need for a phasor data collector or data aggregator. Also, the bandwidth requirements are relatively low; a transmission rate in the range of 28 kbps is sufficient for message rates up to 30 messages/sec.

A. *Correlation coefficient*

Two different correlation coefficients were investigated in this work: Pearson's and Spearman's [15]. When one speaks generically of a correlation coefficient, Pearson's is the one that is normally meant. This parameter operates on data sets X and Y with elements x and y, and describes how the variation in X is like the variation in Y. The coefficient takes on values in the range of -1 to +1. A value of +1 means that the two data sets are perfectly linearly correlated; that is, when one increases, the other increases proportionally. A value of -1 means the two data sets are perfectly linearly anticorrelated; that is, if X increases, then Y decreases proportionally. A value of 0 indicates that there is no correlation between X and Y. In the present application, using Pearson's correlation, it is expected that when the utility and DER buses are connected, the value of the correlation coefficient should be very close to unity. This is because frequency is a globally consistent characteristic of electric power signals due to the physical inertia of the system. As soon as connection is lost, the correlation coefficient should drop to a value close to zero. Pearson's correlation is calculated using Equation (1):

(1)

Spearman's correlation is a rank-based correlation [15]. To compute it, one first ranks data set X in ascending order, and the computation examines how well the ranks of Y correlate to the ranks of X—in other words, it checks whether, if $x_k > x_{k+1}$, that $y_k > y_{k+1}$. Spearman's coefficient is more computationally complex, but offers improved abilities in detecting nonlinear correlations relative to Pearson's. In the end, Pearson's coefficient proved adequate and was selected because of its lower computational burden.

Pearson's correlation was also chosen for another more fundamental reason: it tends to be sensitive to outliers. This is often a disadvantage in statistical analysis, but turns out to be an advantage in this application where speed of response is critical. Any correlation-based technique of this type will be highly sensitive to noise in the two data sets, because the noise is uncorrelated. The noise can be controlled by using slow filters, but these would also slow the islanding detection. It might be possible to apply less slow filtering and capitalize on the sensitivity of Pearson's correlation instead.

IV. Simulation Procedure and Results

The CCB method was tested extensively in simulation using MATLAB/SimPowerSystems and EMTP-RV. Simulations have been conducted using a generic feeder model, the IEEE 34-bus distribution feeder [16], and three real-world feeders of varying stiffness (one very stiff, one weak, and one of average stiffness). The simulation procedure was designed to probe the behavior of the method in some of the most challenging islanding detection situations, and utilized the following four use cases:

- A multi-inverter case (Fig. 2). In this case, the feeder load was balanced by adding many three- and single-phase inverters. On the IEEE 34-bus system, 18 three-phase inverters were added, one on each three-phase load bus. The objective of this test is to see whether the method can detect loss of mains in the presence of multiple inverters.
- A multi-inverter case plus an engine-genset (Fig. 3). Cases with synchronous generation as part of the DER mix are known to be problematic because the synchronous generator appears much like the grid to the inverter-based DERs. Thus, simulations were run in which some of the inverter-based DERs were replaced with an engine-genset. On the IEEE 34-bus feeder, 12 inverters and one engine-genset were simulated. The objective of this test is to ensure that the method can still detect loss of mains with this DER mix.
- A systemwide frequency event (Fig. 4). In this case, the objective is not loss of mains detection, but to test whether the method can differentiate between this case and a loss of mains and properly ride through the system-level event. To simulate the systemwide event, the frequency trajectory observed during the Italian blackout of 2003 (scaled to 60 Hz) was utilized. To enable the performance of this test, a programmable-frequency voltage source model was developed and used.
- A local switching event (Fig. 5). As in the previous case, here the objective is not loss of mains detection, but rather to test whether the method can differentiate between this case and an islanding case, and not falsely trip. In this work, the event chosen was a large (200 hp) three-phase induction motor starting directly across the line at a point electrically distant from the substation.

In these simulations, the update rate of the reference synchrophasor data was taken to be 20 messages/sec. All inverter-based DERs were assumed to be photovoltaic systems. Perturb-and-observe maximum power point tracking was simulated, but all over/undervoltage and over/underfrequency relaying, as well as all other anti-islanding provisions, were turned "off". Line synchronization was achieved with a phase-locked loop that supplies the sine-wave reference. The modeled inverter power stages use hysteresis control and were represented by an averaged model.

Figures 2-5 show a representative set of simulation results, from the stiff real-world feeder, from each of the four test cases described above, with the correlation computed over 200 data points (N = 200). The CCB detects both of the island cases (recognized as the step change in correlation value at approximately 52 seconds in Fig. 2 and 3) in less than 0.5 sec, and rides through the false trip immunity tests (Fig. 4 and 5).

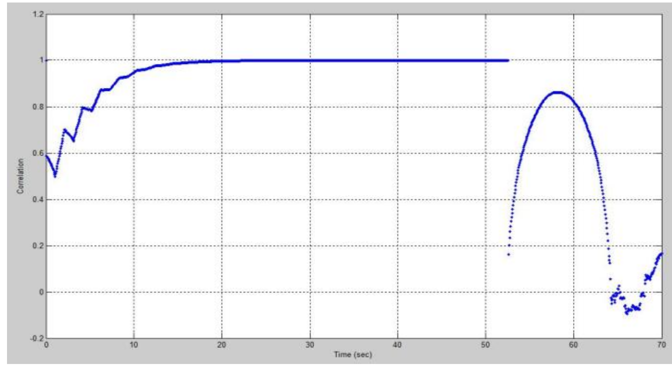

Fig. 2. EMTP-RV simulation result with multiple inverters.

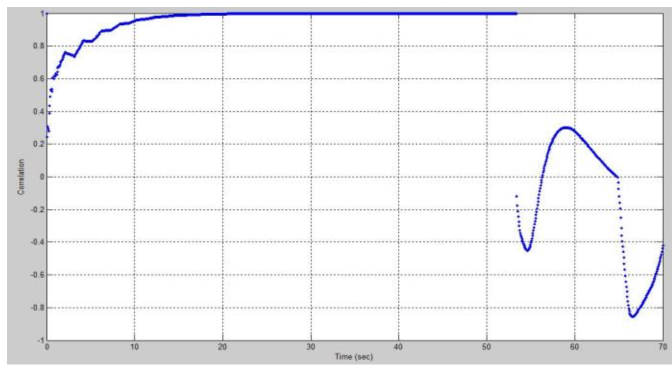

Fig. 3. EMTP-RV simulation result with multiple inverters and an engine-genset.

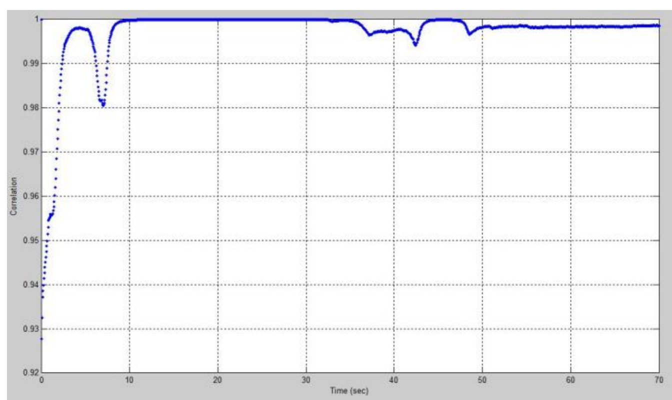

Fig. 4. EMTP-RV simulation result in the "Italian blackout" case.

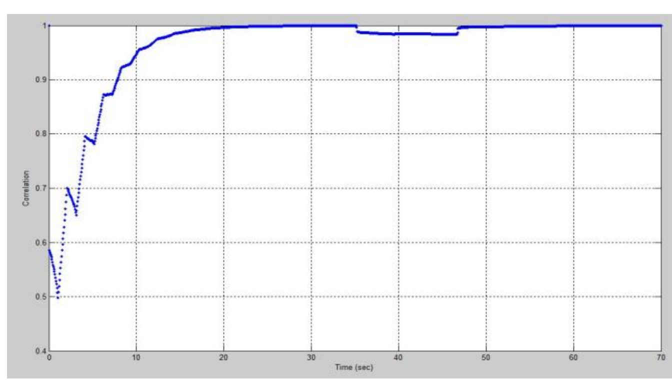

Fig. 5. EMTP-RV simulation result in the large motor load switching case.

V. Laboratory Experimental Procedure and Results

The CCB method was subjected to laboratory testing at Advanced Energy's facilities in Bend, OR. These tests used a 100 kW three-phase PV inverter and an apparatus designed to implement the IEEE 1547 test, as shown in Fig. 6.

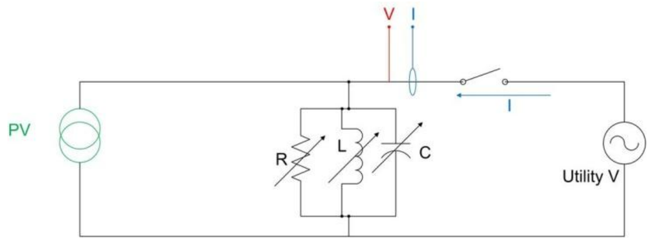

Fig. 6. Generic system diagram of the apparatus used for the IEEE 1547 anti-islanding test.

To perform the test, the RLC load components are adjusted until the current I flowing from the utility source is zero; that is, until the local generator (the PV system on the left) is producing exactly the same real and reactive power as is being consumed by the RLC load, within the constraint that the quality factor Q of the resonant RLC load be kept at ≈ 1.

In the laboratory, the tests were performed with a single 100 kW three-phase PV inverter and RLC components selected for tunability and linearity. All of the inverter's active and passive loss of mains detection systems were disabled. Frequency data were recorded at 60 samples/sec, and processed using a MATLAB script. Representative results of the laboratory testing are shown in Figs. 7-9. These Figures show three different computations performed on a single set of laboratory data, using three different window lengths: N = 480 N = 1200, and N = 2400 data points. The time scale is misleading; the islanding event occurs at the same moment in all three tests, but the t = 0 point is different because the MATLAB script starts counting time at the moment at which the buffer of points over which the correlation is to be computed is filled. The onset of islanding is immediately visible in all three figures; the correlation is nearly unity while the grid is connected, but as soon as the island is formed, the correlation drops precipitously. Table I gives the run-on times (defined as the time between breaker opening and detection) allowed by the method for the three window lengths used, assuming only a simple threshold set to 0.4 is used to make the island/no island determination.

TABLE I
Run-on Times Allowed by CCB Method as a Function of Window Length, Correlation Threshold = 0.4

Window length, number of points	Run-on time, msec (correlation threshold = 0.4)
480	150
1200	150
2400	250

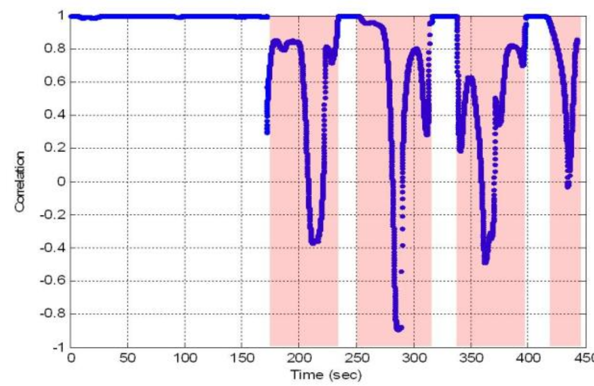

Fig. 7. Correlation coefficient computed during four laboratory anti-islanding tests (shaded in red), N = 480.

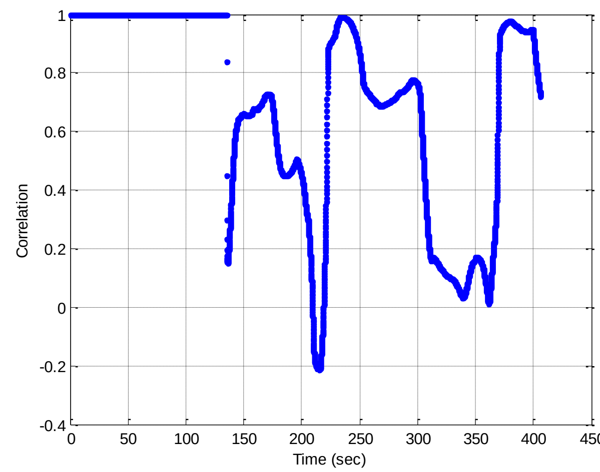

Figure 8. Correlation coefficient computed during laboratory anti-islanding test, N = 1200.

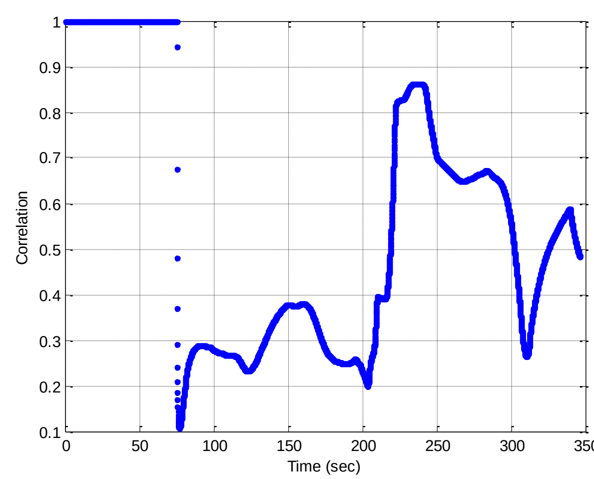

Figure 9. Correlation coefficient computed during laboratory anti-islanding test, N = 2400.

VI. Field Experimental Procedure and Results

Field tests of the CCB method were also conducted, on a live Portland General Electric (PGE) feeder that includes a 100 kW three-phase PV system. For the test, the SEGIS team built a mobile RLC load bank capable of creating on this feeder the conditions of the IEEE 1547 test shown in Fig. 6; installed a Schweitzer Engineering Laboratories (SEL)

Synchrophasor Vector Processor (SVP) at the inverter site; activated the PMU capability of the SEL relay in the PGE substation; and linked all of the elements together using PGE's GenOnSys distributed generation control system, which uses a fiber optic backbone. The mobile load bank was tuned to achieve precise generation-load balance, and the utility breaker was tripped to form the island. This process was repeated several times, for several values of quality factor Q. The correlation coefficient between the local and reference frequencies was calculated using a MATLAB script

The team first sought to determine the window length required to best alleviate the impact of noise. Figs. 10-12 show Pearson's correlation computed over a data set that includes no islanding events (normal system operation). In Fig. 10, N = 480; in Fig. 11, N = 1200; and in Fig. 12, N = 2400. A shorter window length is much more strongly affected by noise, and even without an islanding event the correlation coefficient drops as low as 0.83. The N = 1200 window improves the situation, and for N = 2400, the correlation coefficient is effectively unity throughout the steady-state test, as desired.

Based on this result, N = 2400 was chosen. Islanding tests were performed for quality factors of approximately 1 and 3, and the results are shown in Figs 13-15 and Table II.

TABLE II
RUN-ON TIMES ALLOWED BY CCB METHOD DURING FIELD TESTS, FOR TWO DIFFERENT CORRELATION THRESHOLDS

Event number	Load quality factor	Run-on time, msec Threshold = 0.4	Run-on time, msec Threshold = 0.8
1	1	583	317
2	1	817	450
3	1	783	433
4	1	500	250
5	1*	1117	533
6	1	117	67
7	3	10416	767
8	3	5683	1100

*The quality factor used in this test is not clear; corroborating evidence suggests that it may have been higher than 1.

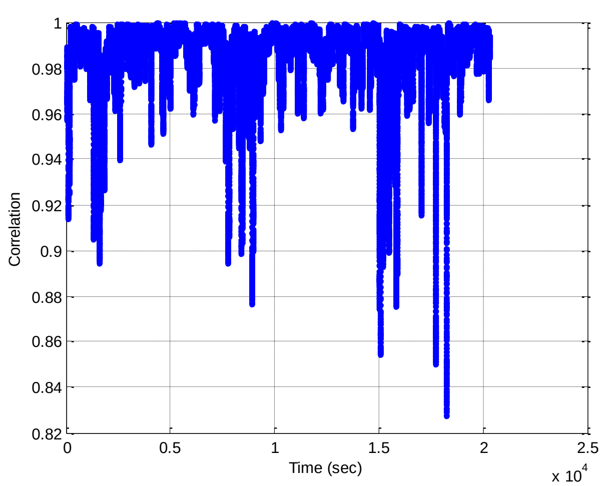

Figure 10. Correlation coefficient computed during field steady-state (no island) test, N = 480.

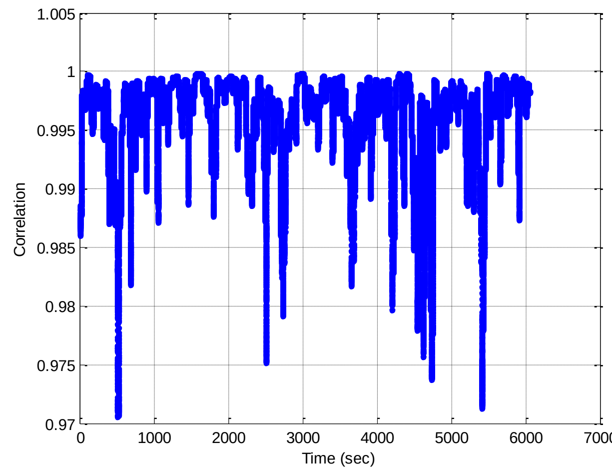

Figure 11. Correlation coefficient computed during field steady-state (no island) test, N = 1200.

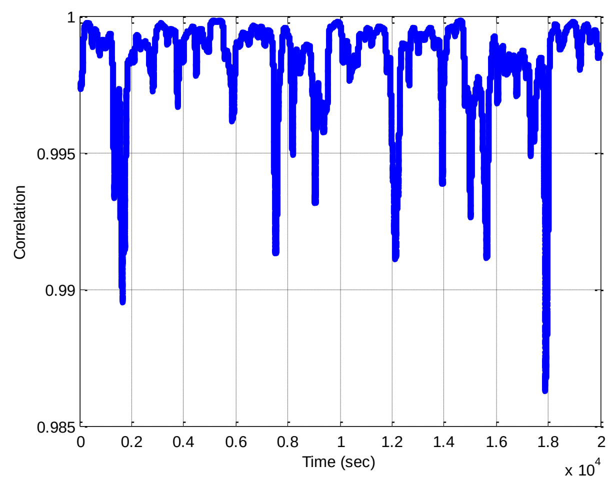

Figure 12. Correlation coefficient computed during field steady-state (no island) test, N = 2400.

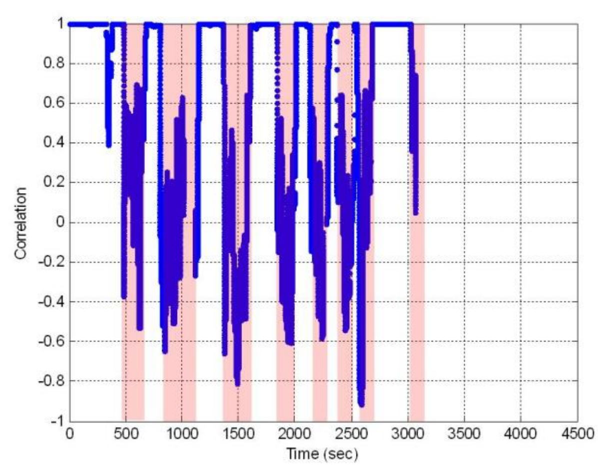

Fig. 13. Field test result of CCB method, N = 2400. This test includes eight separate islanding events, and all eight are clearly visible (red shaded areas).

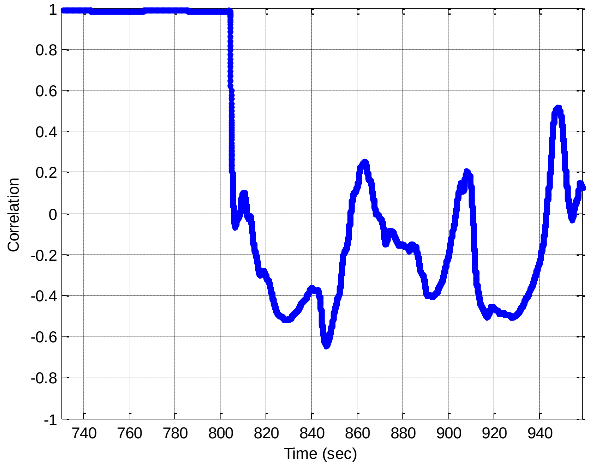

Fig. 14. Zoomed-in view of one of the islanding events in Fig. 13.

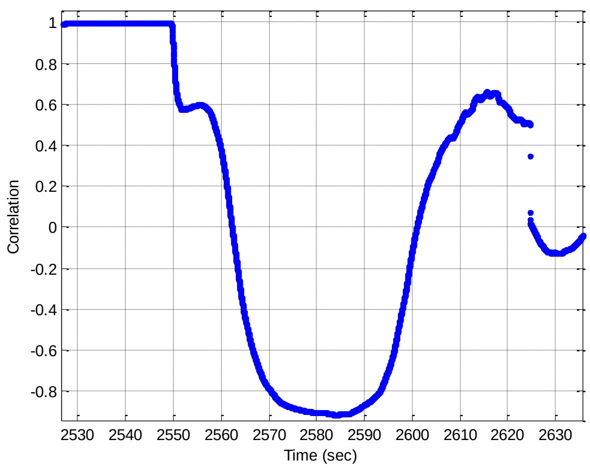

Fig. 15. Correlation coefficient computed during Event Number 7. The reason for the very long run-on for the 0.4 threshold is evident.

VII. Discussion

The CCB method appears to provide highly effective islanding detection. However, the response speed of this method may be too slow to be practical. Because communications latencies will always be a factor with a communications-based method, the work reported here has focused on ensuring that the method itself works quickly once the data are received.

Our results indicate that meeting the IEEE 1547 two-second limit is possible. Because of phenomena such as temporary overvoltage and avoidance of out-of-phase reclosure, it would be advantageous if an island could be detected in only a few cycles; however, it should be noted that these are not *island* situations with generation-load balance, but rather are *fault* conditions, and the required speed can be obtained via fault detection techniques. The CCB does not provide the speed of detection required for local equipment protection, but does provide a robust method for detection of unintentional islands with local generation-load balance in high penetration PV environments, even when advanced utility controls such as dynamic VAr compensation and low voltage ride through are employed. More sophisticated pattern recognition techniques will likely enable significantly faster detection. The SEGIS team has developed a proprietary statistical analysis method that, based on the data collected here, consistently results in run-on times of less than 200 msec, even in the Q = 3 case, and there is reason to believe that this figure can be improved. Refinement of this technique is in progress.

VIII. Conclusions

A new method of island detection based on synchrophasors and utilizing statistical relationships between local and remote frequency values has been described. The method has been extensively tested in simulation, and preliminarily tested in the laboratory and field. The results summarized to date suggest that this method has exceptionally high promise for enabling effective island detection without compromising false trip immunity, and while facilitating grid support functions.

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X. Biographies

Michael Ropp (M 2000) was born on Ellsworth AFB, South Dakota, in 1967. He received the BS in Music from the University of Nebraska in 1991, and the Masters and PhD in Electrical Engineering from Georgia Tech in 1996 and 1998, respectively. He served on the faculty at South Dakota State University for ten years, and is currently the President and Principal Engineer of Northern Plains Power Technologies in Brookings, SD. He is a licensed Professional Engineer in South Dakota and Hawaii. Dr. Ropp's current work focuses on computer simulation of distributed power systems; microgrid and distribution system protection, automation and control; and systems integration.

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 form Northern Plains Power Technologies. His experience includes EMTP modeling of distributed generation and distribution systems, and modeling, analysis, and model-based design of advanced automation and control strategies for distributed generation. His primary interest areas are electrical distribution systems, photovoltaic systems, and islanding detection.

Steven G. Hummel (SM 1997) is the vice-president of engineering at Advanced Energy's Solar Energy business unit, bringing 31 years of experience in high-technology innovation and product development. Prior to Advanced Energy and 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 90 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.

Mesa Scharf was born in Roseburg, OR in 1975. He graduated with honors from Oregon State University in 1998 with a Bachelor of Science in Electrical Engineering. Mesa has spent his entire career in the energy industry specializing in systems integration for nearly 15 years. Mesa started his career in a small company whose focus was early warning detection for impending failure of utility scale power transformers. He then worked at IdaTech, a leading fuel cell system development company where he contributed as a systems integration specialist. His work led to the authorship of six patents. In 2006 Mesa joined PV Powered, now part of Advanced Energy, a leading provider of residential, commercial and utility scale solar solutions. As Director of Solutions Engineering, Mesa is responsible for the development of new systems and solutions, which includes oversight of Advanced Energy's Solar Energy Grid Integration System program, funded by the DOE. The SEGIS program is focused on lowering the cost of solar generation while enabling high penetration of photovoltaics on the utility grid. Mesa's innovative approaches have led to the development of key partnerships and technologies needed to address the challenges of high penetration PV on the utility grid. Mesa is a member of the IEEE.

Michael Mills-Price (M'2000) received his Masters of Science and Bachelor of Science in Electrical Engineering from Oregon State University. He is presently a member of the technical staff as well as an engineering manager at Advanced Energy Inc. in Bend, Oregon. Michael is a registered Professional Engineer and has been focusing his design efforts on PV systems with emphasis on inverter control and utility integration techniques to proliferate distributed generation installation. Michael leads a project team working to develop next generation integration and control technologies, while focusing on energy harvest and grid support functionality. Michael is currently the SEGIS program manager and technical lead for Advanced Energy. Prior to joining Advanced Energy (formerly PV Powered) in 2005, Michael focused his engineering efforts on designing electric vehicle drive systems. He is an active member in the IEEE, as well as the Professional Engineers of Oregon.

Chris Steeprow is presently a member of the technical staff for Portland General Electric's Specialized Programs Operations Department. Chris has twenty years of experience in information technologies, SCADA, and process control fields. Chris has been working for Portland General Electric since 2001. His Primary role at Portland General Electric is the development and support of the Specialized Programs control system for Dispatatchable Generation, Solar integration, Demand Response, and Smart Grid.

Mark Osborn was born in Portland, OR in 1954. He graduated from Western Oregon University with a Bachelor of Science in Natural Sciences (Earth & Integrated Science); attended Oregon State University in their engineering program; and obtained a Master of Business Administration (Finance/Marketing) from Portland State University. Mr. Osborn was hired by PacifiCorp in 1978 as an Energy Consultant and served as Pricing Analyst, Power Resource Analyst and in Program/Product Manager positions. He served on PacifiCorp's creative team that developed the Edison Electric Institute award winning Energy FinAnswer program for energy service innovation. In June 1996 he became Manager of Project Marketing and Development for PacifiCorp Energy Services, Inc., a company he helped develop, and later joined EnergyWorks (a Bechtel Company) as Manager of Market Development. In March, 2000, Mr. Osborn moved to Portland General Electric as Distributed Resources Manager. Osborn developed and currently manages PGE's Distributed Resources Department consisting of PGE's Solar Photovoltaic Development; dispatchable standby generation program; and Net metering, Solar Payment Option and Small Generator Interconnection Programs, and since 2009, he has been directing PGE's unique battery storage project as part of the Pacific Northwest Smart Grid Demonstration project, an ARRA funded demonstration with Battelle. Mr. Osborn has authored several award-winning and invited publications. For his work on America's 1st Solar Highway project, he received the Solar Pioneer Award from the Oregon Department of Energy in 2008.

Krishnanjan Gubba Ravikumar received his Master's degree in Electrical Engineering from Mississippi State University in 2009 and his BS Electrical and Electronics Engineering degree from Anna University, India in 2007. He focused his graduate studies on power engineering and worked as a research assistant in the Power & Energy Research Lab at Mississippi State University. He was the recipient of the Mississippi State Research Assistant of the Year Award for 2009. He is presently working as a power engineer at Schweitzer Engineering Laboratories, Inc., focusing on development and operation of synchrophasor-based power systems. His research interests include real-time power system modeling and simulation, substation automation, synchrophasors and their applications, power system stability, and power electronic applications. He is a member of the IEEE and Eta Kappa Nu Honor Society.

Greg Zweigle received his Master's of Science in Electrical Engineering and Master's of Science in Chemistry degrees from Washington State University. Also, he received a Bachelor's of Science Physics degree from Northwest Nazarene University. He is presently a principal research engineer at Schweitzer Engineering Laboratories, Inc. He is a member of the IEEE and the ACS.

Appendix C

Synchrophasors for Island Detection

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***Abstract* -- Detection and prevention of unintentional islands powered by distributed generators like photovoltaics remains a key concern of utility protection engineers, especially in high-penetration and grid-support environments. These evolving circumstances dictate that new island detection tools are needed. Synchrophasors are highly promising in this regard, but some in the community remain skeptical about them due to costs. This paper discusses synchrophasors, how they may be used to detect islands, their cost-reducing value-added features, and synchrophasor-based island detection methods.**

I. INTRODUCTION

The formation of unintentional islands powered by distributed generators (DGs) like PV remains a prominent concern among utility protection engineers, particularly as penetration levels of DG in distribution systems rise and as certain grid support functions such as low-voltage ride-through (LVRT) and VAr support are implemented. The addition of grid-support functions is particularly problematic from an island detection perspective because most modern island detection techniques are incompatible with the highest-value grid support functions.

Island detection techniques can be grouped into three categories: passive techniques, which monitor grid conditions and use signal processing to detect abnormalities that signal island formation; active techniques, which work to create abnormalities in grid conditions that can be used to detect islands; and communications-based methods, that communicate with upstream devices to gain situational awareness that can be used to detect an island. An excellent overview of available methods is given in [1]. Passive techniques are mostly unused today because, in general, they tend to have larger nondetection zones (NDZs) than other options, although there may be potential to use passive methods as backups to newer techniques, particularly the communications-based methods. Active techniques are standard in most of today's PV inverters and can be applied to other types of DG, but they rely on creation of abnormal voltages and frequencies to detect islands. Conversely, grid support functions are intended to mitigate abnormal voltages and frequencies, so there is a conflict between the two functions, and many in the field believe that this creates a fundamental need for alternatives to active techniques.

Communications-based island detection (CBID) methods seem likely to be that alternative. There are several reasons. First, CBID does not conflict with grid-support functions, and as will be discussed below can actually be used to improve them or implement new ones. Second, CBID methods generally do not require a sacrifice in terms of island detection effectiveness. For example, the most commonly-applied CBID today is direct transfer-trip (DTT), which relies on direct communication of the status of the substation breaker (or other circuit interrupter) to the downstream DGs. DTT has been implemented using twisted pair, fiber optics, and microwave links. DTT, in theory, has no nondetection zone (NDZ); it can detect islands for any combination of DG and loads, although it requires instrumentation on every circuit interrupter in series between the utility source (substation) and all DG sites. A promising variant on DTT is the power line carrier permissive (PLCP) method [2-5], in which the status signal is simply a "heartbeat" or "tone" sent down the power conductors themselves. In this case, the absence of the PLCP signal indicates island formation.

For all their promise, at this time CBID methods still tend to be considered undesirable by project developers because of their cost. In many cases, requiring a CBID method damages the economics of a PV project sufficiently that the project cannot go forward. This is particularly true for DTT—although it is a mature technology and trusted by the utilities, depending on the distance between the DG and substation, the number of series switches between the DG and substation, and the utility's speed requirements, DTT installation can add hundreds of thousands of dollars to the installation cost of a DG plant, and in some cases even more. For this reason, a DTT requirement is often the "kiss of death" for a DG project. PLCP has some potential to reduce this cost, but at present PLCP transmitters suitable for the anti-islanding application are not widely available, and those that are can still be costly and power-inefficient because of the frequencies at which they must operate to be effective.

The challenge, then, is clear: grid-support functions are needed to facilitate high-penetration DG and continued market growth, and CBID is needed to facilitate grid support functions, but CBID comes at too high of a price at present. It is thus important to the continued rate of DG deployment that cost effective CBID technology be available.

One means to reduced cost will of course be technological: as the technology improves, costs will be reduced. Increasing market maturity and market size will also play an important role, as they do for essentially all new technologies. However, it is equally important to pursue "value added"—in other words, that the communications infrastructure or data have multiple uses, so that the cost may be spread over multiple applications. Such value added will be critically important to making CBID methods viable in industry.

One intriguing technique that addresses many of the aforementioned challenges is the use of synchrophasors for island detection. It is already well-known that synchrophasors are valuable at the transmission level for a variety of off- and on-line applications [6,7], and they may find widespread use at the distribution level as well [8]. This means that synchrophasors used for island detection could bring with them considerable added value that makes a significant contribution to the cost reduction of CBID. Added value functionality includes such items as leveraging the synchrophasor information to perform micro-grid functionality down to the distribution feeder level with capabilities for synchronized reclosure of the main breaker once system is again "live". Alternately, optimization of the distributed resources can be performed leveraging peer-to-peer communications of the system state relying on relatively low-bandwidth secure communications.

This paper describes a set of affordable, effective CBID methods using synchrophasors, and the value-added proposition of synchrophasors in this application. Three methods of synchrophasor-based island detection that are currently under active investigation [9,10] are reviewed, and the results to date on each are summarized.

II. BACKGROUND AND THEORY

A. Synchrophasor theory

The use of phasors is a well-documented method of analyzing power flows in and the state of an electric power delivery system [11]. Synchrophasors are simply time-synchronized phasor measurements made at locations across a power system [12]. It has been possible for some time to measure phasor quantities across systems and use these to estimate the system state and power flows, but until the advent of the Global Positioning System (GPS) and its Coordinated Universal Time (UTC) signal there was no practical way to time-synchronize measurements made at far-apart locations. Now, the UTC can provide an absolute reference that makes this type of time synchronization practical, and today there is a wide array of phasor measurement units (PMUs) capable of making, recording and communicating time-synchronized phasor, or "synchrophasor", measurements.

Figure 1 demonstrates how the UTC can be used to determine the phase angle between two sinusoidal signals at locations A and B [6]. The availability of the time reference signals means that the phase angle of each signal (θ and φ respestively) can be measured relative to a fixed and known reference, and thus the phase angle σ between the signals at the two nodes can be determined with high accuracy:

$$\sigma = \theta - \varphi \qquad (1)$$

This can be seen in Fig 2.

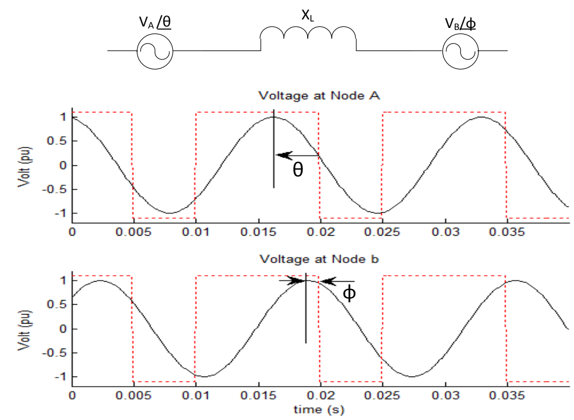

Fig 1. Two nodes of a network and their voltage measurements relative to the UTC signal.

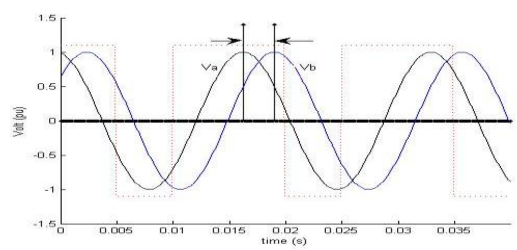

Fig 2. Direct comparison of V_A to V_B is possible due to UTC reference signal.

Also, it is obvious that any phase shift present between two nodes must be related to the impedance between the nodes, X_L, which can be calculated using the phasor data [11].

B. Application of synchrophasors in distribution

There are many well-documented applications for synchrophasor technology at the transmission level, including transmission line modeling [11]; state estimation, bad data detection, and power systems control [12]; and power system communication and wide-area protection and control [6]. To date there has been little deployment of synchrophasors at the distribution level, but the technology could provide some sufficiently compelling benefits in several applications that one day the costs of distribution-level synchrophasors may be well justified by the added value. This section discusses several examples of these applications.

One example with near-term benefits is the use of PMU measurements for angle, frequency, and voltage in the characterization of distribution-level systems and dynamics. Synchrophasors enable detailed post-mortem analyses of faults and other events [8], which is invaluable in improving the fundamental understanding of distribution systems. Also, as is the case in transmission, state space estimation can be improved with PMU measurements and due to its time synchronization ability fewer points are required [8].

Synchrophasors also enable the identification of phases without de-energizing the cable under test [13]. This capability could be highly useful in distribution system automation schemes and for load control, although the data acquisition and transmission rates will likely limit the applicability of synchrophasors in this area. Also, the phase identification capability should improve the fidelity of electric facility maps, and will reduce phasing errors in the field.

Synchrophasor data can also be applied to the control of DG to create so-called "active distribution networks," which [14] describes as "networks in which embedded generation is actively used by the energy management system in order to achieve the operation objectives." PMU data are able to assist in maximizing system efficiency, increasing the effectiveness of load control, and network stability control, thereby providing a higher level of energy accounting, better coordination between generation and consumption, and providing a higher level of reliability for decision-making [8]. One DG-specific example: it is becoming increasingly clear that it is desirable that DG incorporate certain grid support functions, such as voltage support/regulation via VAr control, and low-voltage ride-through (LVRT). The system-level situational awareness afforded by synchophasor data would open a considerable range of opportunities to optimize these grid-support functions that would be very difficult to coordinate without the synchrophasors. While grid-tied, synchrophasors could enable optimized Intentional islanding and microgrids are prime examples.

PMU data could also be used to support intentional islands and microgrids, Such data would support system operators to perform islanding and back-synchronization maneuvers thereby allowing a particular network to be intentionally islanded upon command and then re-introduced to the main grid when appropriate. By using PMUs to hold islanded networks in synchronism, damage to loads or DG due to asynchronous reclosure can be avoided [15]. This can also aid in system restoration for network areas isolated for maintenance or due to system faults, and to enable microgrids to provide optimal black-start support.

C. Synchrophasor-based islanding detection

The authors have recently experimented with three means by which synchrophasors may be used to detect unintentional island formation. These are:

- Absolute phase angle difference (APAD)
- Wide Area Method (WAM)
- Correlation Coefficient Based (CCB) method

Synchrophasor-based islanding detection uses the hardware configuration shown in Figure 3. A reference point is defined at some location on the grid upstream from the DG. PMUs are installed at the reference point (the "Reference PMU") and at all DG plants (the "Local PMUs"). The Reference PMU signal is broadcast to all endpoints, and a local computer resident at the DG compares the reference and local PMU data in order to determine whether the DG is still grid-tied. The three methods listed above represent different methods of comparing the two sets of phasor data, and different run/trip decision criteria.

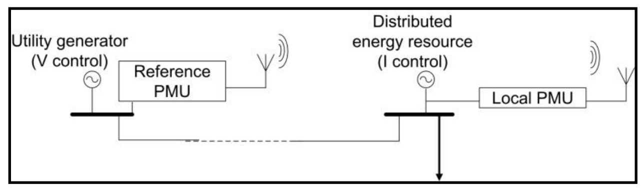

Fig 3. System configuration for CBID using synchrophasors.

The absolute phase angle difference (APAD) method has been used in transmission for some time as a method of detecting island formation at that level [15]. It works in much the same way in distribution. Because there will nearly always be some small difference between the frequencies in the island and on the grid, eventually the relative phase angle between the island and grid will become sufficiently large that an island would be indicated. APAD works well as a "backstop" to either of the other two methods mentioned above. Its disadvantages are that it can be slow to detect in cases with rotating DG because the frequency deviations may be small, and it can theoretically miss some islands in cases with both inverters and rotating DG, where the frequency may oscillate about the nominal value, preventing the buildup of an absolute phase error.

The WAM approach, described in [16], collects data from both the reference and local PMUs at specific time intervals to determine the difference in phase, δ_k, between the two points at the k^{th} time-interval, such that:

$$\delta_k = \angle V_k^{(r)} - \angle V_k^{(l)} \quad (2)$$

where $\angle V_k^{(r)}$ and $\angle V_k^{(l)}$ are the positive-sequence voltage angles of the reference and local PMUs in degrees.

The change of δ_k is defines the "slip frequency," S_k, (3) and the change of S_k defines the slip acceleration, A_k, (4).

$$S_k = (\delta_k - \delta_{k-1}) \div \frac{Mrate}{360} \quad (3)$$

$$A_k = (S_k - S_{k-1}) \div Mrate \quad (4)$$

where:

S_k is the slip frequency at the k^{th} processing interval.

A_k is the acceleration at the k^{th} processing interval.
Mrate is the synchrophasor message rate.

A run/trip decision threshold can then be defined in a slip vs. acceleration space [16]. The concept is based on the assumption that when the DGs are grid-tied, the (stiff) utility system will force S_k and A_k to be near zero and the operating point is near the origin. This should remain true even during system transients because the conditions at the remote and local PMU sites should change together. When an island forms, even if the generation and load are relatively well-matched, there should be a transient change in frequency at the moment of disconnection that would cause the S_k/A_k pair to exceed the trip thresholds, and the island would still be detected.

The CCB method relies on the statistical relationship between the frequencies measured by a local PMU and the reference. In the implementation described in [17], a correlation coefficient between the local and remote PMU frequencies is calculated. While grid-tied, the local and remote frequencies should be highly correlated. When an island forms, the two frequencies are independently controlled and thus become uncorrelated, and the correlation coefficient should drop. Several types of correlation have been explored, but in [17], it was found that the CCB performed very well using Pearson's coefficient as it provided adequate ability to detect non-linear correlation, and required less computational overhead than alternatives. Also, it is well known that Pearson's correlation is disproportionately sensitive to outliers. In most statistical work this is a problem, but for the anti-islanding application it is actually an advantage as it improves the sensitivity of the method.

III. PROCEDURE

A. Simulation procedure

For any CBID method, the goals are as follows:

- Achieve a high degree of sensitivity: must be able to detect all island cases.
- Achieve a high degree of selectivity: must ensure the ability to differentiate between island cases and cases in which ride-through is desired.
- Achieve fast response speed: must ensure that all islands are detected quickly (ideally in less than 2 sec).

In order to probe these aspects of the synchrophasor-based methods, the four cases described in Table 1 were simulated in the MATLAB/Simulink and EMTP-RV environments. Two of the four cases, Cases 1 and 2, are known to cause difficulty for island detection methods, and should thus represent worst-case scenarios that provide a rigorous test of the methods. In Case 1, multiple inverters are simulated, and in Case 2, part of the inverters are replaced with a diesel-driven synchronous generator. Cases 3 and 4 do not involve islanding; they represent transient events in which a ride-through is desired. Case 3 is a system-level frequency event, simulated using actual frequency trajectory data from the Italian blackout of 2003 (scaled to 60 Hz). Case 4 involves the startup of a large induction motor.

Table 1.
Cases Simulated

Case Number	Condition	Desired Results
1	Multi-inverter (PV)	Detect and trip
2	Multi-inverter with engine generator set	Detect and trip
3	System-wide frequency event	Ride through
4	Local load-switching event	Ride through

In Cases 1 and 2, the generation and local load were balanced before the island was formed by adjusting the total load level while maintaining a constant power factor, and then balancing the reactive power by adding an appropriately-sized capacitor inside the island.

All four cases were simulated on four feeders: the IEEE 34-bus distribution feeder, and three real-world feeders modeled using data from Xcel Energy. The inverter and generator models were validated against experimental data, and the feeder models were validated using available fault-current calculations from the utility.

B. Experimental procedure

The WAM was field-tested at Portland General Electric (PGE) on a live distribution feeder including a 104 kW PV plant. The experiment is described in detail in [16]. An IEEE 1547 anti-islanding test was conducted using a purpose-built RLC resonant load bank mounted in a truck. The substation already included a Schweitzer Engineering Laboratories (SEL) relay with built-in PMU capability, so for this test another SEL PMU-capable relay was installed at the PV site. Communication of the reference PMU to the DG was achieved via fiber link. The load was intentionally tuned to create a load/generation balance at 60 Hz, with a resonant frequency at 60 Hz and a quality factor of approximately 1. An island was initiated by separating the grid from a PV system that included this load bank.

The CCB was tested using data gathered during the above-described field testing of the WAM. To perform these tests, the time-synchronized frequency vs. time data from the island events were run through the CCB algorithm in MATLAB.

IV. RESULTS

A. Simulation results

Simulation results for the WAM are shown in Fig 4, which is a plot of the slip vs. acceleration space with the trip/run thresholds shown as a pair of heavy diagonal black lines. If the slip/acceleration pair falls between those lines, the DG is allowed to run; otherwise, a trip is commanded. In Fig. 4, sixteen results—all four cases in Table 1 simulated on all four of the above-described feeders—are collected. The most off-nominal slip and acceleration pairs from simulations of Cases 1 and 2 (island cases in which a trip should occur) are shown as red diamonds, and pairs from simulations of Cases 3 and 4 (ride-through cases) are shown as green diamonds. Ideally, all red diamonds would be outside the heavy black lines, and all green diamonds would fall between the lines. For the most part, this is what happens, except that there are three red diamonds falling inside the lines. All of these are from Case 2, and they occur because the synchronous generator-based DG limits the slip and acceleration in those three cases. (For the sake of completeness, it should be noted that two of these three Case 2 events would eventually have been detected by APAD, although the detection times would have been greater than 10 sec.)

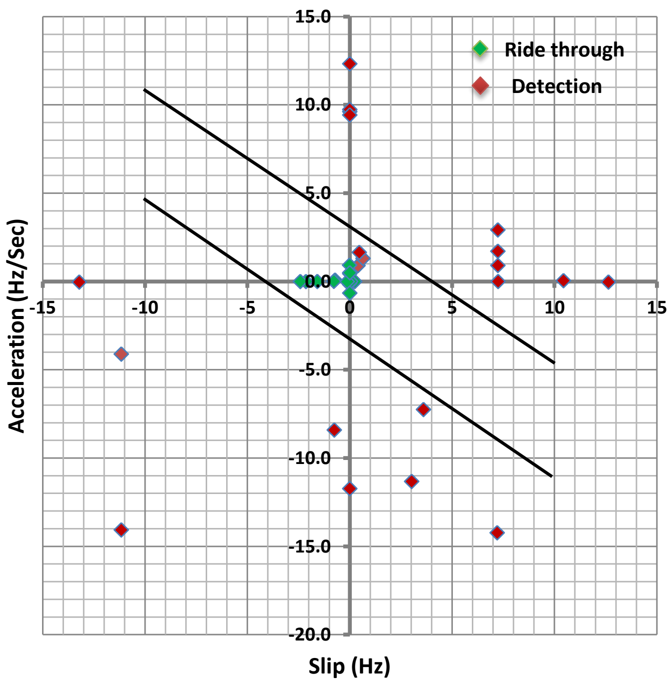

Fig 4. Simulation results obtained using the WAM.

Representative simulation results for the CCB method are shown in Figures 5 and 6. Fig. 5 shows the correlation coefficient vs. time from a Case 2 simulation on the weak rural feeder model. An island was initiated at approximately 53 s. The CCB method recognized the island within 0.5 s. Fig. 6 shows a Case 3 simulation result on the same feeder. The minimum value of the correlation coefficient in this result is about 0.97, and thus the CCB successfully rides through the disturbance.

B. Experimental results

The results of the field demonstration of the WAM are detailed in [16]. A large number of tests were conducted, and all islands were detected in considerably less than the 2 s required by IEEE 1547, including some in which the quality factor of the RLC load was set as high as 3.0. Based on lab testing, the authors believe that islanding events could be detected even faster than was achieved in these field tests through refinement of the trip threshold criteria. The experimental results for the CCB are detailed in [17]. After some adjustment of the correlation thresholds, the CCB also detected all of the islands, with the longest run-on time being 1.1 sec.

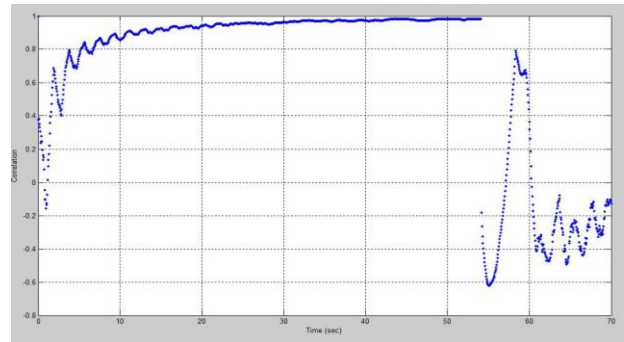

Fig. 5. Simulation results obtained for the CCB: weak feeder, island forms at 50 sec with DG comprised of PV plus an engine-genset.

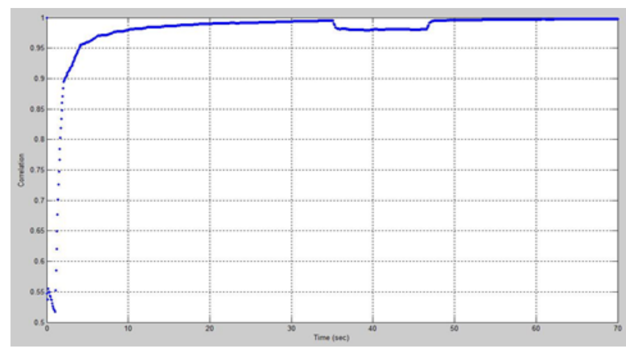

Fig. 6. Simulation results obtained for the CCB: weak feeder, local switching event (large motor startup - ride-through desired).

V. DISCUSSION

The results suggest that all three synchrophasor-based islanding detection methods are highly effective in detecting islands, while maintaining a high degree of false-trip immunity (i.e., they achieve both sensitivity and selectivity). APAD and the WAM are both generally very fast-acting, but there is a small range of conditions under which they are slow to act, and a subset of those cases in which they may fail to detect the island. Out of all the cases tested, the CCB never failed to detect an island, but as a statistically-based method its run-on time is not deterministic, and the CCB can in some cases be slower to react than the other two methods. It is important to note that the three synchrophasor-based CBID methods described here can be used together. The evidence suggests that the three methods together would in general eliminate any practical risk of unintentional islanding of DG.

If further testing and demonstration continues to show the effectiveness of these methods, it appears that the primary barrier to widespread acceptance of these methods will be the availability of PMU reference signals, which depends on the cost of implementing the reference PMUs and the broadcast communications capability. The value-added proposition of the PMU data and communications infrastructure will be critical factors in whether PMU reference signals will become widely available. As noted above, the value-added proposition appears very promising, suggesting that there may be many reasons to provide reference PMU data.

The cost of other options is also a key factor. The primary competitor for synchrophasor-based CBID is likely the PLCP method mentioned earlier. Properly-configured PLCP-based CBID performs extremely well in terms of its islanding detection effectiveness and immunity to false trips [2]. In terms of communications costs, PLCP could enjoy some advantage over synchrophasor-based methods because the communications channel is the existing feeder conductors. However, the value-added proposition of PLCP, particularly in the low frequency range in which PLCP works best, is much less clear. PLCP has some other key weaknesses [2], and it is thus not yet clear whether PLCP or synchrophasor-based CBID makes the most sense.

VI. CONCLUSIONS

Synchrophasors provide many possibilities to improve upon existing island detection methods. Results are extremely promising and suggest the ability to enable effective island detection without compromising grid support functions such as low voltage ride through or false trip immunity, and will not affect power quality. The value-added potential of synchrophasors means that it is realistic to expect that reference synchrophasors should one day be widely available.

VII. ACKNOWLEDGMENTS

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Appendix D

THE FUTURE ROLE OF PASSIVE METHODS FOR DETECTING UNINTENTIONAL ISLAND FORMATION

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ABSTRACT

AS increasing numbers of distributed generators (DGs) are deployed, utilities are becoming more concerned that these DGs may be able to support unintentional islands. Unintentional islands can be formed when any utility switching device isolates a portion of the area electric power system (EPS) that contains roughly equal amounts of sources and loads, and they potentially pose safety risks to personnel and integrity risks to customer equipment.
Methods to detect the formation of unintentional islands can be subdivided into passive, active, and communications-based categories. Most DGs today rely on active methods, but unfortunately the time is soon coming when this approach will no longer work. The reason is because of the need for DGs to supply grid support functions as DGs, and these grid support functions interfere with the operation of active island detection. This means that in the future there will be a much larger role for passive and communications-based island detection methods.

This paper will briefly explain the fundamentals of the island formation problem; discuss why grid support may spell the end for active anti-islanding; lay out the options for passive and communications-based island detection, with a brief strengths-and-weaknesses comparison for both categories; and delve into the challenges, strengths, and opportunities in passive island detection. A new, promising passive method will also be presented and used to highlight the challenges of passive island detection.

The work being reported in this paper was supported by the customers of Xcel Energy through a grant from the Renewable Development Fund.

I. NOMENCLATURE

DER	Distributed Energy Resource
DTT	Direct Transfer Trip
NDZ	Non-Detection Zone
PCC	Point of Common Coupling
PLCC	Power Line Carrier Communications
PLCP	Power Line Carrier Permissive
PLL	Phase-Locked Loop
RoCoF	Rate of Change of Frequency (df/dt)
SCADA	Supervisory Control And Data Acquisition

II. INTRODUCTION

ISLANDING occurs when a section of the power system including generation and loads (and potentially storage) becomes electrically isolated from the main grid and enters a "stand alone", or microgrid, mode of operation. Generally, unintentional islanding supported by distributed energy resources (DERs) outside of utility control is undesirable for several reasons, including its potential to cause damage to customer, system or DER equipment, and the potential for safety hazards.

Applicable codes and standards, such as IEEE 1547™, require that DERs include means to prevent unintentional islanding [1]. Over the years, industry has responded to this requirement with a wide variety of methods to achieve this [2-4]. Broadly, the methods are subdivided into three categories: passive methods, which rely on changes in DER terminal measurements to detect island formation; active methods, in which the DER perturbs its output current in some way that creates a visible change upon island formation; and communications-based methods, in which system status information is communicated to the DER and used to detect an island. Passive methods are attractive because of their lack of impact on the system and ease of implementation, but they generally encounter difficulty in eliminating nondetection zones (NDZs) without false trips—in other words, they struggle to achieve both *sensitivity* and *selectivity* within the IEEE 1547-mandated trip times. Today's active methods are cost-effective and have extremely small NDZs in low-penetration cases, but they are increasingly seen as unsuited for high-penetration situations. Reasons include that there is mounting evidence, including some from the field, that they may fail in certain cases with multiple DERs [5,6], and they can also cause power quality problems, but the key problems with active island detection today are that a) they tend to conflict with the grid-support functions that are becoming critically important as DER penetration levels rise; and b) they may degrade system transient response at high penetration levels.

Communications-based methods are likely the best future candidates to be the first line of defense in unintentional island prevention. These include synchrophasor-based methods [5-7], power line carrier communications (PLCC) or power line carrier permissive (PLCP) [8-10], SCADA integration [3,11], and direct transfer trip (DTT). In general, it is well accepted that the NDZs of these methods can be extremely small, although their island detection and cost effectiveness are still under investigation. One aspect of communications-based methods that must be dealt with is communications reliability—specifically, that DER functionality should be compromised as little as possible if communications are lost, and thus there needs to be a "fallback" island detection method in the case of loss of communications. This paper discusses the reasons why passive island detection is likely to be the ultimate selection as the fallback method, and describes some candidate passive methods that have high promise for this application.

It is instructive to note that for some communications-based methods, the meaning of "fallback technique" is different. For example, for PLCP, a fallback technique upon loss of signal cannot be used, because loss of signal is the indication that an island has been formed. Instead, "fallback" in this case means that there must be an island detection method available in cases in which there is no PLCP transmitter installed.

III. PASSIVE ANTI-ISLANDING AS THE SOLUTION

The selection of fallback method involves a tradeoff between island detection effectiveness and compatibility with high penetration. There will need to be considerable discussion among the power systems community to decide how this tradeoff is best handled, especially bearing in mind that what is being discussed is the *second* line of defense, not the primary.

In the near term, it is likely that most manufacturers would use their current anti-islanding scheme as the fallback, meaning that most inverters would revert to active anti-islanding. However, as previously noted, in the long term this strategy is probably unacceptable because of the lack of compatibility with grid support functions—grid support relies on DERs working to mitigate abnormal voltages, while active anti-islanding relies on exacerbating abnormal voltages. Using active anti-islanding as the fallback would cause DER grid support to become intermittent, which is likely not acceptable to system operators.

Passive island detection is the only remaining candidate. It does not adversely impact power quality or system transient response, and it can be made to be compatible with most grid support functions by appropriately modifying the run/trip decision criteria. However, even the best passive island detection methods are less effective in detecting islands than active methods. The following two issues are of particular concern:

1. It seems unlikely that any passive anti-islanding method could reliably pass an IEEE 1547-style RLC load anti-islanding test in which a 2-sec maximum time to trip is mandated. In a highly controlled laboratory environment and with an RLC load with a quality factor of 1, it is possible to match the generation and load real and reactive power so precisely that when the island is formed there simply is no detectable change in the PCC or inverter terminal voltage, and no passive criterion would see the island formation for a considerable period of time—in other words, there is a problem with detection *speed*.
2. It is difficult to ensure that a passive island detection method can reliably detect islands while maintaining a high degree of false trip immunity. Essentially, for any parameter that a passive island detection method may detect, if one visualizes a Venn diagram, there will be overlap between the set of values during which it is desired that the DER stay on-line, and the set of values indicating island formation. Using terms from the sensors field, this can be thought of as an issue of *sensitivity* vs. *selectivity*.

In summary, the passive island detection problems deal with *speed*, *sensitivity*, and *selectivity*. Concern #1 can be more readily understood using a schematic of the IEEE 1547 anti-islanding test setup, which is shown in Figure 1. The utility voltage source and its source impedance are at the left, and the Device Under Test (DUT), which may be any type of DER, is at the far right. In between is an R-L-C load and an interrupter of some type, shown here as a switch. To perform the test, the load resistance R_{load} is varied until the load's real power consumption precisely matches the output of the DUT, and then L_{load} and C_{load} are adjusted until the load quality factor is 1.0, and the load's reactive power consumption is equal to and opposite of that of the DUT. When this condition is reached, the current i_{grid} is essentially zero, and when the switch is opened to form the island, the switch is not interrupting anything. It is not difficult to see how this condition, if sufficiently well matched, could create a situation in which the voltage V_{load} does not change enough that any passive method would see the difference between grid-tied and islanded conditions.

Concern #2 was highlighted in a recent paper by Joós et. al. [12] that involved study of a composite passive island detection method utilizing a mixture of sixteen different parameters and a decision tree to determine when the system was islanded or grid-tied. The idea was to choose parameters such that the NDZ of any one parameter was covered by another, such that the composite method would have no NDZ. Although these investigators had an impressive success rate, it was not 100%; even with such a large set of parameters and a sophisticated set of decision criteria, they were not able to detect all islands without false trips—they achieved very good selectivity, but insufficient sensitivity. This paper also points out the important fact that in most *practical* cases, a passive island detection method like the one in [12] that uses a combination of techniques is likely to be able to detect the overwhelming majority of cases that would appear in the real world. Whether this is sufficient revolves around the question of the level of risk utilities are comfortable with, given that this is the *second* line of defense against unintentional islands.

In considering what level of tradeoff is acceptable, it should be remembered that grid support functions will be needed much more frequently than island detection. Thus, a tradeoff that improves DER grid support capability while mildly compromising island detection effectiveness is likely to be logical from operational and risk standpoints, as long as the compromise in island detection effectiveness is not too great.

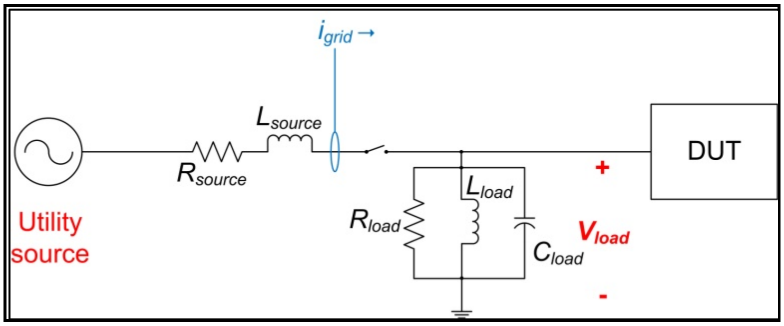

Figure 1. Schematic showing the configuration of the IEEE 1547 anti-islanding test.

However, the tradeoff between *selectivity* and *sensitivity* can be more favorably modified if *speed* is also considered. If one could allow a longer period of time to detect an island, then some passive anti-islanding methods may be able to achieve the needed selectivity and sensitivity. Currently IEEE 1547 mandates that no run-on of longer than 2 sec be permitted, but this may not be necessary if the standard were to allow decoupling of island detection, fault detection, and overvoltage detection. The IEEE 1547 anti-islanding test is designed to mimic a case in which a circuit interrupter opens *without a fault* while the DER output and local loads are closely matched. This case is difficult to detect because the change in the PCC or inverter terminal voltage can be undetectably small, as noted above. However, in a faulted case, there is no generation-load balance, and there are a number of means other than anti-islanding by which the fault may be detected. Because the detection criteria are so different, it is logical to separate fault detection from islanding detection. Fault detection must be quite fast (ideally, faster than the shortest reclosing interval), but there is no need to detect a balanced, unfaulted island so quickly. Thus, the island detection scheme could be given longer than 2 sec to detect a balanced, unfaulted island, so long as there was also fault detection that was reliable and acted much more quickly. Similar logic applies to transient overvoltage detection and prevention. Relaxation of the speed with which an island must be detected would provide a pathway for passive methods to improve sensitivity and selectivity simultaneously.

Also, a similar argument can be made for faults as was made for grid support functions in that faults are an unfortunately frequent occurrence, but balanced DER-load unintentional islands are relatively rare. Thus, a compromise that improves fault detection at the expense of island detection would likely be acceptable from operational and risk standpoints, as long as island detection is not compromised excessively.

One other critical issue with DERs is the problem of asynchronous reclosure, which can lead to severe damage to rotating machines (generators or loads) inside the island. However, asynchronous reclosure is associated with recloser action in the clearing of faults. The risk of asynchronous reclosure can be effectively mitigated by fault detection (if fault and island detection were decoupled) or "hot line blocking" or "dead bus detection" in which the voltage on the downstream side of the recloser is measured and reclosure is blocked if that voltage is too high. Fault detection mitigates asynchronous reclosure because of its speed (often the DER will trip offline before the recloser opens) and hot line blocking could be used if the reclosing interval is extremely short such that fault detection may not be quick enough. Hot line blocking is not prohibitively expensive in most cases; the largest expense is in the required PTs. Again the ramification is that the DERs could be allowed longer than 2 sec to detect a balanced, unfaulted unintentional island, without a risk of asynchronous reclosure, at the cost of a slight decrease in quality of service because of the longer effective recloser interval.

When all of these factors are taken together, it seems clear that a) passive anti-islanding is the preferred backup method to communications-based techniques; b) the performance compromise involved in passive methods may be tolerable, and that there are avenues for improving it; and c) decoupling island detection, fault detection and overvoltage detection would be highly beneficial.

IV. CANDIDATE PASSIVE METHODS

A. Total harmonic distortion-based methods

These methods were pioneered in Japan in the early 1990s [13] and new developments continue to appear periodically [14]. They in essence involve an interaction between harmonic-producing loads and system elements in the island, and the harmonic impedance of the feeder. The idea is that a sudden jump in total harmonic distortion, or in certain harmonics known to be related to certain loads or the inverter, could be used to detect the isolation of the island. Under certain circumstances, this method works reasonably well, but it has two drawbacks. One is intuitive: the level of nonlinear load in the system today has led to a condition in which voltage distortion, while grid-tied, occasionally becomes quite high, making it nearly impossible to select a THD threshold that achieves both selectivity and sensitivity. The other can be understood by considering the generic feeder shown in Figure 2. In this generic feeder, a utility source is shown at the left, along with its source impedance and the substation transformer. Loads are shown as generic load blocks, and two PV systems are shown in green, along with their distribution transformers (shown as Δ-Y in the figure because that is the most common configuration).

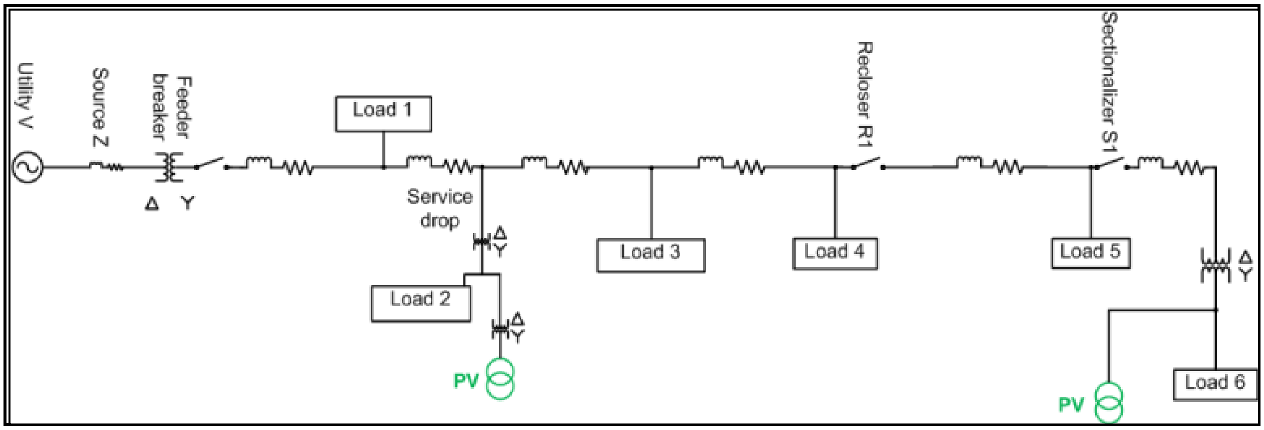

Figure 2. Generalized model of a distribution feeder.

This generic feeder also includes a downstream recloser R1, and a sectionalizing switch S1. It is clear that if the recloser R1 or sectionalizer S1 is opened to isolate the PV system at the far right of the figure, one would expect a dramatic change in the harmonic impedance of the system as seen from the PV. However, if the feeder breaker (at the far left) were the switch that opened to form the island, the harmonic impedance of the substation transformer is already quite high, and one cannot reliably say that opening that breaker would significantly change the harmonic impedances as seen from the PV systems. THD-based methods may become unreliable in a system like this.

B. Deliberate injection of a current harmonic and detection of the corresponding voltage harmonic

Technically, this is an active method because it involves changing the inverter output, but it is included here because it is an obvious extension of the THD-based methods. Note that this method has also been applied to a specific harmonic deliberately injected by the inverter, as a measurement of the harmonic impedance of the feeder at that specific frequency. However, this method has largely fallen into disuse because of its impact on power quality and its reduction in effectiveness in the multiple inverter case. Also, while the deliberately-injected harmonic method can generally achieve good sensitivity in single-inverter cases, it struggles to obtain selectivity on weak grids.

C. Methods based on frequency spectra

Recent activity in the area of passive island detection has largely focused on the use of advanced frequency transforms to attempt to discern when an island forms. Several investigators have published impressive results in this area [15-18]. Wavelet transforms have received special attention because of their potential ability to resolve transient phenomena without excessive window lengths. Methods based on frequency spectra appear to have high promise to improve both selectivity and sensitivity. However, one must still make a tradeoff and either favor selectivity or sensitivity, and many of these methods are highly computationally burdensome and thus difficult or expensive to implement.

D. Methods based on statistical analysis of frequency, and a new proposed method

These methods have been explored primarily in conjunction with deliberately-injected perturbations [19,20]. These methods appear to work reasonably well, although they technically are actually active methods because of the output perturbation required. However, for the past three years as part of an Xcel Energy RDF-supported project, the present authors have been experimenting with harmonic and statistically-based methods without a deliberate output disturbance. One method in particular has shown good promise, a method utilizing the histogram of the rate of change of frequency that has been dubbed RoCoF-H. RoCoF-H relies on the same physical mechanism described above, namely that the frequency controls of the islanded system are significantly different than those of the grid, and thus there should be patterns in the rate of change of frequency (*df/dt*, or RoCoF) that can be detected if given sufficient time. The histogram is the means selected for detecting these changes.

Consider the plots in Figure 3, which show the histogram of the absolute value of the absolute value of *df/dt* during a grid connected situation (left) and for islanded DERs (right). The grid's frequency controls tend to produce a bimodal distribution. Most of the abs(*df/dt*) values are bunched against the left side of the plot because frequency changes on the main grid tend to be governed by the electromechanical properties of many large rotating machines, and are thus very slow. The smaller group appearing at higher abs(*df/dt*) values in the grid-tied plot arises from switching events, which actually cause perturbations in phase that are registered by instrumentation as momentary fast frequency changes. To use this as an island detection method, the approach adopted here has been to use a simple bimodality index *B* defined according to Equation (1):

$$B = \frac{\sum_{Bin2} X_i}{\sum_{Bin1} X_j + \sum_{Bin3} X_k} \tag{1}$$

where *Bin1*, *Bin2*, and *Bin3* are histogram bins with boundaries chosen to correspond to the low, middle and high groupings shown in Figure 3 and X_j, X_i, and X_k are the elements of those bins respectively. When the DERs are grid tied, nearly all of the abs(*df/dt*) values should fall into *Bin1* and *Bin3*, and $B \approx 0$. After the island forms, there is more frequency "jitter" in the island because of the DER frequency controls, some, but not all, of the abs(*df/dt*) values move into *Bin2*, and $B > 0$. For systemwide frequency events, many values will move into *Bin2*, and $B >> 0$. For this work, simulations were used to set the boundaries of the bins.

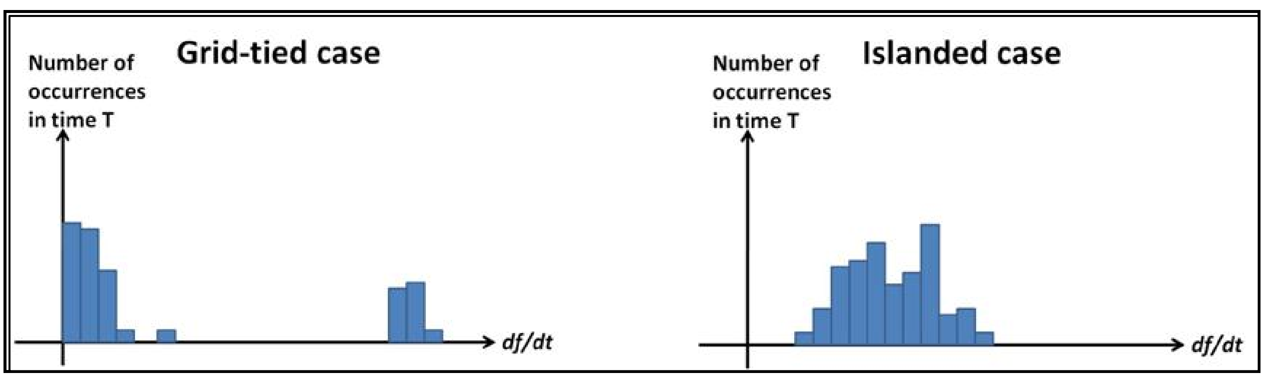

Figure 3. Histograms of frequency during grid-tied (left) and islanded (right) conditions.

As the decision criterion, a "zero time" rule has been adopted, the reason for which will become clear when the simulation results are presented. The "zero time" rule says that an island is said to be detected when the value of *B* is in the range of $0 < B < 10$ over more than 75% of the window length.

V. Simulation procedure

The RoCoF-H and other statistical methods have been extensively tested in EMTP-RV. In this paper, representative results are reported on four feeders. The feeders were the IEEE 34-bus distribution feeder, which is unusually long, mostly overhead, and high-impedance; and three real-world feeders in Xcel Energy's northern territory, using detailed feeder data provided by Xcel. One of the three Xcel feeders is a very stiff (low impedance), short feeder supplying primarily industrial load; one is a very weak (high impedance), long feeder in a rural and agricultural area; and the third is in-between in stiffness (medium impedance) and serves a suburban region.

On each of the four feeders, four cases were simulated. The first two cases were chosen to represent difficult cases for island detection. Case 1 is a multiple-inverter case, in which many three-phase inverters were added to the feeder until a generation-load match could be achieved. As one example, the number of three-phase inverters added to the IEEE 34-bus system was 18. These inverters were spread along the feeder because the inductance between the inverters is believed to exacerbate the loss of anti-islanding effectiveness in the multi-inverter case [21]. Phase-phase balancing was achieved by adding single-phase inverters to the more heavily loaded phases.

Case 2 was a case involving a mixture of types of DER. From an anti-islanding perspective, the most difficult combination of DERs arises when inverter-based DERs are combined with synchronous generators, so that is the case that was selected here. Some of the inverters in the multiple-inverter case were removed to make room for a single 1 MVA synchronous generator.

The latter two cases do not involve islands, but instead are tests of false-trip immunity (i.e., cases in which ride through is desired). Case 3 was a ride-through case simulating a loss of mainline generation resulting in a systemwide frequency event. In this case, it is highly desirable that the island detection method be able to distinguish this case from an islanded case and stay online to support the system. For this work, the frequency trajectory used was the one measured during the major Italian blackout of 2003 [22], scaled to 60 Hz for this work. To implement this frequency trajectory, a programmable variable-frequency source was created in EMTP-RV and programmed to follow this trajectory based on a lookup table.

Case 4 is another ride-through case, this one involving a major local switching event. Again, the anti-islanding system must be able to distinguish such an event from an island to avoid excessive false tripping. To simulate this event, a heavily-loaded 200-hp three-phase induction motor was switched directly across the line at a distal point on the feeder.

In the simulations reported here, the upper edge of *Bin1* was set to 3 mHz/sec, and the upper edge of *Bin2* to 8 mHz/sec. The frequencies were measured by a phase-locked loop.

VI. Results

Example simulation results from EMTP-RV are shown in Figures 4 and 5. Figure 4 shows the results in Cases 1 (left plot) and 2 (right plot) on the IEEE 34-bus feeder. The island forms at 40 sec with the real and reactive power almost perfectly matched. The bimodality index is exactly zero until the island forms, after which point it rises fairly quickly and then exhibits a “noisy” behavior. In Case 1 (left plot), the island is detected in less than 1 sec. In Case 2, the bimodality index again jumps from zero before island formation to a “noisy” nonzero value after island formation, but the bimodality index takes a bit longer to respond in this case relative to Case 1 (longer than 2 sec), but once it does respond, the values of bimodality index seen in Case 2 are higher than those in Case 1.

Figure 5 shows results from Cases 3 (left plot) and 4 (right plot) on the IEEE 34-bus feeder. These are the ride-through cases in which no island is formed. In these cases, the bimodality index is clearly not zero, but it is important to note the vertical axis values, which are much higher than in the islanded case. Figure 5 also shows that the ride-through case results are characterized by high spikes in *B* separated by periods of zero value, whereas under the islanded conditions in Figure 4 *B* does not return to zero for any appreciable time after the island forms. It was this result that led to the adoption of the “zero time” rule as a decision criterion: during systemwide events, as the frequency moves through its transient, the leftmost grouping of *df/dt* values in the grid-tied plot in Figure 3 occasionally slides into *Bin2*, resulting in a large spike in *B*, and then slides back to the left, resulting in *B* dropping back to zero. With the “zero time” criterion, RoCoF-H successfully distinguishes and rides through both of the events in Figure 5 but still catches the islands in Figure 4.

Unfortunately space restrictions prohibit showing all of the results on the three Xcel feeders, but they mirror the results obtained on the IEEE feeder; the plots appear virtually the same as those shown in Figures 4 and 5. In all cases, RoCoF-H detects all of the islands (although the engine-genset case sometimes takes longer than 2 sec) and correctly rides through all of the non-islanded cases, using the “zero time” criterion.

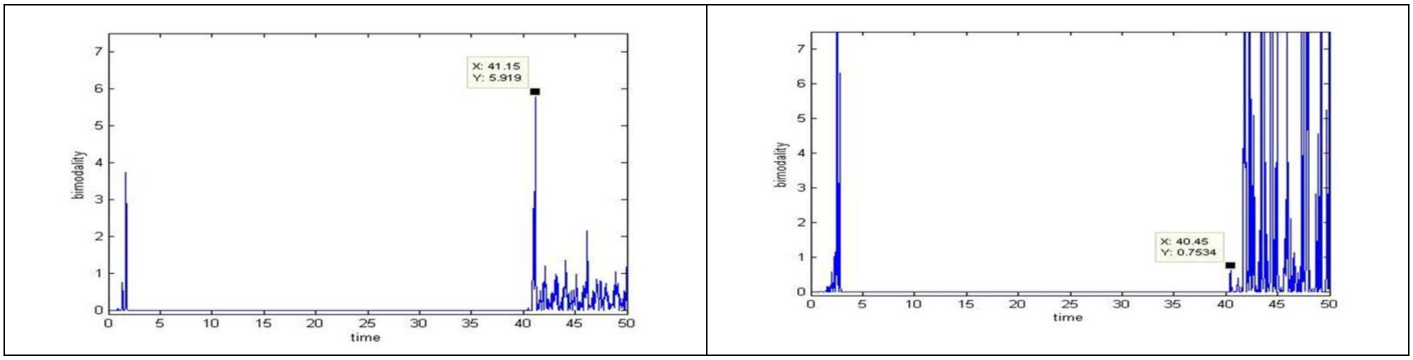

Figure 4. Value of bimodality index during a Case 1 (left) and Case 2 (right) test on the IEEE 34-bus distribution feeder. The island occurs at 40 sec and is detected in < 1 sec on the left and just over 2 sec on the right.

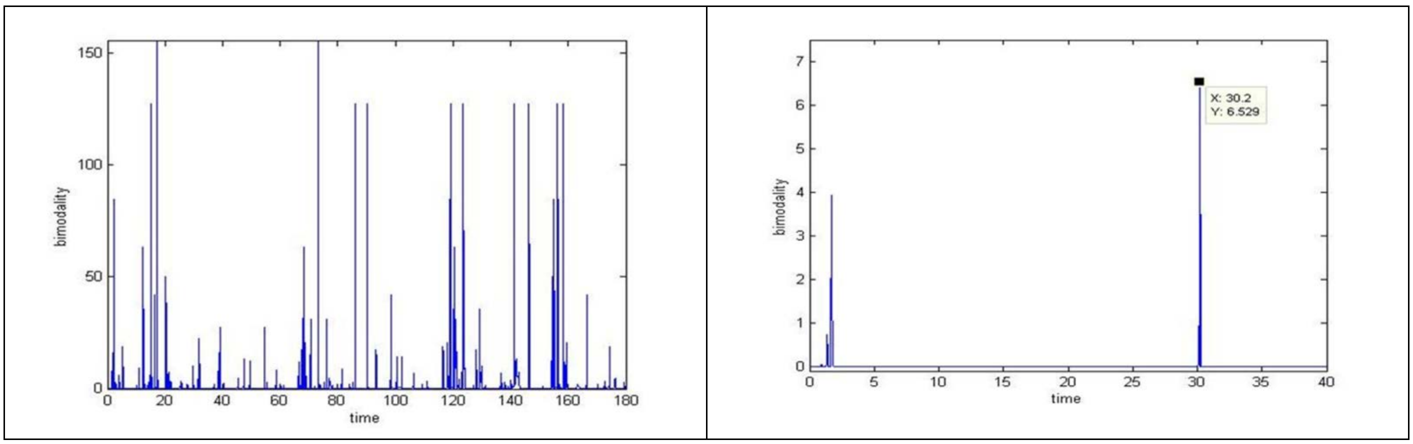

Figure 5. Value of the bimodality index during a Case 3 (left) and Case 4 (right) test on the IEEE 34-bus feeder (no island; ride-through test).

VII. Discussion

The results given here show that this passive method, like many others, has high promise for being effective in practical field situations, particularly if the method is allowed longer than 2 sec to distinguish between ride-through and island events. In the simulation testing thus far, with the "zero time" decision criterion, RoCoF-H has had excellent success in achieving selectivity and sensitivity simultaneously.

In addition to its promise of effectiveness, this method has some other notable advantages as well. One is that while it may seem complicated on the surface, because it does not require extensive signal processing, it is very easy to implement and can be executed on low-cost computational devices. It has shown good effectiveness on a wide variety of feeders with different characteristics, and for a broad range of DER combinations.

The RoCoF-H method does have some weaknesses. One is that while it does appear to give good selectivity and sensitivity, it obtains the improved selectivity at the expense of speed of detection. This is a trait that may be shared with other passive methods [12]: they *could* achieve good selectivity and sensitivity, but only if they are allowed longer than 2 sec to detect an island. Any method with this property would need to be coupled with fast fault detection, as described above. Another is that the values selected for the bin edges will depend on how the frequency is measured. For this work, a phase-locked loop was used, but if a different technique were used—say, a phasor measurement unit—the simulation results suggest that the frequency estimation and measurement characteristics of the measurement unit will need to be taken into account when the bin values are selected. Efforts are currently underway to develop a table of appropriate bin values for different frequency measurement devices and techniques. An additional disadvantage is that the robustness of this method would be adversely impacted if deployed on a weaker grid, such as that in Hawaii, although initial results suggest that the method can still be effective there if the bin values are appropriately adjusted. Finally, the bin values may also depend weakly on the mixture of DERs present on the feeder, particularly on the fraction of DERs that are based on rotating machines. RoCoF-H does work with rotating machines, but simulations and intuition suggest that the positions of the histogram groupings in Figure 3 will move slightly as the ratio of inverter-based to rotating machine-based DER varies. Fortunately, this effect is relatively small, and it does appear that bin values can be selected that work for all combinations of DERs**.**

VIII. Conclusions

Passive anti-islanding, which until recently has been largely dismissed as a first-line defense against unintentional islanding because of its inability to achieve both sensitivity and selectivity, may have a critical role in the future as a backup method to communications-based methods, a role for which active anti-islanding will be unsuited at higher DER penetration levels. This paper argues that passive anti-islanding may perform much better if it can be allowed longer than 2 sec to detect an unfaulted island with generation-load balance, and an argument has been presented that it should be permissible to allow more than 2 sec in this case *if* island detection and fault detection in DERs can be decoupled. Finally, this paper has introduced a new passive island detection method, RoCoF-H, and has shown that this and a number of other passive methods have the potential to achieve the needed sensitivity and selectivity, particularly if they are allowed longer than 2 sec to detect the island. RoCoF-H is relatively easy to implement in inexpensive hardware and requires no output perturbation. In all of the cases simulated, RoCoF-H successfully detected all islands, including multiple inverter islands and islands with rotating generators, while successfully riding through local switching and systemwide frequency transient events.

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X. References

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