RISK OF UNINTENTIONAL ISLANDING IN THE PRESENCE OF MULTIPLE INVERTERS OR MIXED GENERATION TYPES

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ABSTRACT

Generally, codes and standards require that distributed generators detect when they have been separated from the main grid, and cease to energize any part of the local electric power system in that case. Industry has responded by developing a variety of means for preventing unintentional islands, which are generally highly effective in cases with small numbers of inverters from a single manufacturer. However, as deployment levels of distributed generators increase, utilities are becoming concerned that islanding detection schemes may lose effectiveness on feeders on which there are inverters from multiple manufacturers, or if there is a mixture of inverters and rotating machines. This paper reviews the latest in islanding detection schemes, presents a number of study results in which these two problem cases are examined, and briefly discuss the future of islanding detection and how this problem will ultimately be solved. The two key conclusions of the paper are: a) that the two cases mentioned above sometimes do lead to elevated run-on times and concerns about these cases are legitimate; and b) the ultimate solution to the islanding detection problem is likely to be a communications-based method, backed up by advanced passive methods used in combination.

I. NOMENCLATURE

DER	Distributed Energy Resource
EPS	Electric Power System
NDZ	Non-Detection Zone
NPPT	Northern Plains Power Technologies
PLCP	Power Line Carrier Permissive
ROT	Run-On Time
SBID	Synchrophasor-Based Island Detection

II. INTRODUCTION

A distributed energy resource (DER) island is defined in IEEE 1547.4 as a local electric power system (EPS) that can disconnect from the area EPS and supply its own loads from its own sources. DER islands can be planned (i.e. microgrids), in which case provisions are made for their protection, voltage and frequency regulation, resynchronization and reconnection to the area EPS, and achievement of the desired level of availability. However, most DERs in distribution circuits are not designed to provide these services. Islands formed with this type of DER are referred to as unintentional islands, and because unintentional islands do not provide the services just mentioned, they cannot be allowed to operate for any prolonged period of time. The run-on time (ROT) is defined as the time between the moment at which a switch opens to form the unintentional island, and the moment when the DERs detect the existence of the unintentional island and de-energize it. IEEE 1547 requires that DERs limit ROTs to no longer than 2 s.

Any DER that produces either DC or variable-frequency AC, such as photovoltaics (PV), variable-speed or DC wind turbines, fuel cells, batteries, and flywheels, is connected to its distribution circuit through an inverter, and the responsibility for detecting an unintentional island lies with the inverter. Many methods for detecting unintentional

islands have been developed over the years. Most commercially-available DER interface inverters today use an active island detection method, because these have a superior combination of speed, sensitivity, selectivity, and cost. Active methods generally work by acting to destabilize an unintentional island. This approach has worked very well at low penetration levels, but as more and more DERs are deployed, new situations are beginning to challenge this effectiveness. Four specific situations are often raised as concerns:

- Islands containing large numbers of inverters
- Islands containing mixtures of different makes/models of inverters
- Islands containing both inverter-based and rotating machine-based DERs
- Islands containing inverters that do not utilize positive feedback on frequency or phase error

The purpose of this paper is to present new simulation results regarding these cases of concern, indicate which cases may not be of concern after all, and suggest long-term strategies for dealing with those cases that are shown to be problematic. All of the results presented here were obtained using well-vetted models developed in the MATLAB/Simulink/SimPowerSystems environment.

It should be noted that there is actually an additional case of concern: requiring inverters to provide voltage and frequency ride-through services may also degrade islanding detection capability. However, work on this issue is still ongoing, and it will be dealt with in a future publication.

III. PROCEDURE AND METHODOLOGY

A. Feeder modeling

For the work described here, all distribution circuit models were built in MATLAB/Simulink using data provided by the utilities. Circuit information came from the GIS database files for the feeder, and were imported using in-house tools. The circuit impedances are represented using primitive impedance matrices calculated using the cable data from the database, the feeder conductor spacings and configurations, and Carson's equations [1]. The circuit impedances are validated against the utility's own fault current calculations by comparing the utility values against those predicted by the MATLAB/Simulink feeder model for LLL and LG faults. The acceptance criteria commonly used are that the LLL fault currents should match to within 5%, and the LG fault currents should match to within 20%. More error is allowed in LG fault currents for two reasons: one, the zero sequence impedance is *usually* of minimal importance during an island event because no fault is present; and two, there is a wide range of variation in what factors are included by utilities in LG fault current calculations, and in many cases a very conservative worst-case approach is followed by the utility that results in very high LG fault current predictions. All tap-changing regulators, fixed inline transformers, and fixed and switched capacitors are represented in the model. Three-phase, two-phase and single-phase loads are all represented in the MATLAB/Simulink model as they appear in the GIS database. The results shown in this paper were all obtained using constant-impedance (Z) loads. This is a standard starting point that is adopted to simplify and speed up the modeling process. If the results obtained using Z loads indicate a borderline case, then that case is re-run using dynamic loads that include constant impedance, constant power, and motor load portions.

B. Inverter and generator modeling

All of the inverters modeled in the work shown here are UL-1741 listed units utilizing manufacturer-specific proprietary anti-islanding controls. Details of the anti-islanding controls sufficient to meet due-diligence needs have been provided to NPPT by the manufacturers under nondisclosure agreements, and these controls are represented in detail in the models, along with key details of the current regulators and line synchronization means (PLLs). Manufacturer-specific models are used in all cases, in order to ensure that any interactions between dissimilar makes/models of inverters are realistically captured. In most cases, the models were developed by NPPT in collaboration with the manufacturer, and in a limited number of cases a manufacturer-supplied "black box" model was used after testing and verification by NPPT. For PV plants with multiple inverters, each inverter is represented individually, to avoid any loss of fidelity in the transient behavior of the plant.

The generator step-up transformers for all DER plants are explicitly represented, including their winding configurations. All internal and redundant external relaying is also represented.

Most inverters contain some nonlinear decision points, such as perturbations for maximum power point trackers, application of output anti-islanding pulses, and the start times of control loops. In simulation, NPPT takes steps to ensure that these nonlinear decision points are not artificially synchronized, by using MATLAB's random number generator to randomize their start times. (If the decision points actually ARE synchronized between inverters via communications links or some other means, that synchronization is represented.)

For synchronous generators, the generator itself is represented using MATLAB's built-in sixth-order machine model, with parameter values from the manufacturers' datasheets. NPPT uses manufacturer-specific speed controller and AVR models where possible (developed in collaboration with the manufacturers), and where not possible, a set of generic models are used that have been vetted against laboratory data for a wide range of different products, and provide reasonable matches to generic behaviors. NPPT's synchronous generator controller models do include f/W and V/Hz droops and saturation limits, and these are set up (or disabled) according to the data provided for the specific site. NPPT's exciter model includes a power system stabilizer (PSS), but for most grid-tied synchronous generator applications this feature is disabled.

Most synchronous generators are deployed with over/undervoltage, over/underfrequency, rate-of-change-of-frequency (RoCoF) and negative sequence relaying, and occasionally with phase jump or vector shift relaying. All relays used on any specific site are included in the model.

C. Simulation plan

The standard procedure for a risk-of-islanding study is to first select a breaker, switch or other device that can form an island that includes the DER under study. Then, the real and reactive power levels at which the output of all real and reactive power sources in the island matches the demand of the loads in the island (the "balance point") is determined. Once that point is located, a batch-mode parametric sweep is run over the range of loading fractions (LFs) and power factors (PFs) over which the distribution circuit under study is expected to operate in the field. For all LF and PF pairs in the batch, a simulation is run in which an island is formed *without a fault* by opening a breaker of interest, and the resulting run-on time (ROT) is recorded. In this study, ROT is defined as the time from opening of the switch that forms the island, to operation of the relay that isolates the island from the rest of its source circuit. A nondetection zone (NDZ) is defined as the range of loads over which the ROTs of the PV plant are longer than the IEEE 1547 limit of 2 sec. Once any NDZ is located, batches utilizing finer resolution are run to determine the peak ROT values and refine the prediction of the shape of the NDZ in the LF-PF space. Finally, once the NDZ location or lack of an NDZ has been determined with suitable confidence and the maximum ROTs are known, NPPT and utility engineers confer to decide whether the NDZ is such that the risk of islanding is negligible, or whether it represents a realistic loading scenario and additional mitigation is needed. This process is repeated for each breaker, switch or interrupter that can form an island including the DG under study.

IV. RESULTS AND DISCUSSION

A. Brief summary of results

The results of these simulations can be briefly summarized as follows.
- If all of the inverters in an island are of the same make/model, and that make/model is UL listed and uses positive feedback on frequency error, then the risk of formation of an island lasting longer than 2 s is extremely remote, and the risk of formation of a stable island is practically zero. This conclusion holds no matter how many inverters are in the island, as long as they meet the description above.
- When mixtures of different manufacturers' products are used, there can sometimes be adverse interactions between them that degrades the ability of the inverters to detect island formation.
- When both inverters and synchronous generators are present in an island, there can be adverse interactions that lead to extended run-on times, and in some cases even stable islands.
- For inverters that do *not* use positive feedback on frequency or phase error, the risk of formation of a long-lasting island is much higher.
- Simulation studies can be used to aid in the determination of whether additional mitigation is needed based on a risk of islanding.

B. Unintentional islands in which there is not a generation:load balance

The voltage and frequency within an unintentional island depend on how well the real and reactive power sources and sinks in the island are matched [2,3]. The real and reactive power consumed in an island, P_{load} and Q_{load}, are given by Equations (1) and (2).

$$P_{load} = V_a \frac{V_a}{R}$$

Equation (1)

$$Q_{load} = V_a \left[\frac{V_a}{\omega L} - V_a \omega C \right]$$

Equation (2)

Here, V_a is the voltage phasor applied to the load, ω is the electrical frequency, and R, L and C are the resistance, inductance and capacitance of the load, respectively. When the island is connected to the grid, the grid determines V_a, and P_{load} and Q_{load} are fixed. When an island forms, the local generation and loads must come into balance. If the island is generation-deficient in real power, the voltage V_a will fall until P_{load} equals the generator output. In other words, if there is more load then generation, the generation will not be able to supply enough real power to support the voltage at nominal levels, and the voltage drops upon island formation. Similarly, if Q_{load} is not balanced with the reactive power sources in the island, then the island frequency will drift until the reactive power comes into balance. For DERs operating at unity power factor, the frequency will shift to the resonant frequency of the load, at which point Q_{load} is zero.

It is clear from the foregoing that an island that always has a sufficiently large mismatch in either real or reactive power cannot form a stable island. If the load real and reactive power demand are sufficiently large relative to all sources, in the island, then islanding is not a concern. The amount of mismatch required to guarantee that islanding will not occur depends on the thresholds and times-to-trip of the undervoltage and over/underfrequency relays.

C. Unintentional islands containing only inverters of the same type

Figure 1 shows a representative example of ROTs versus LF and PF for a case with large numbers of inverters, but only one type of inverter in the island. In this case, the island is on a distribution circuit containing 192 inverters, but all of the inverters are the same UL-listed make and model. The voltage and frequency relays in this case are set to IEEE 1547 default values. In spite of the large number of inverters, the islanding detection remains effective, with little to no degradation.
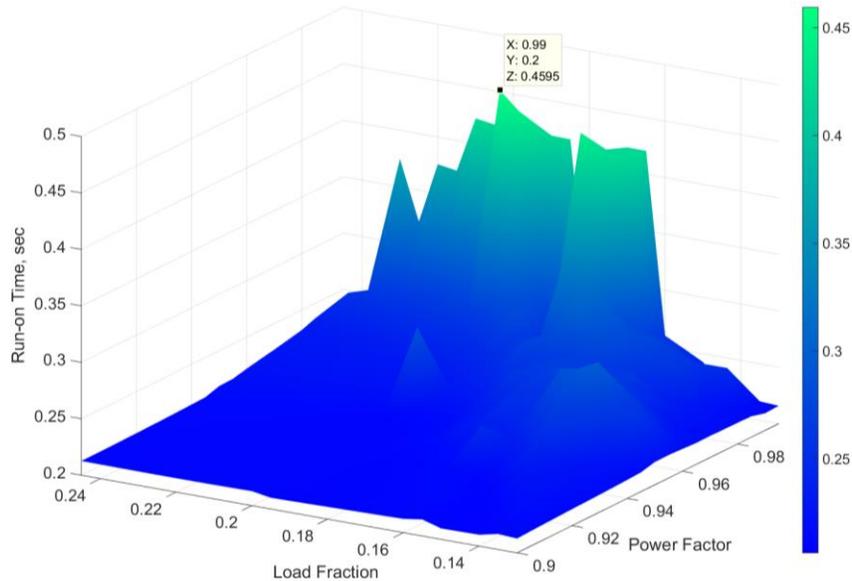

Figure 1. ROT vs. LF and PF for an island containing 192 inverters, but all of the same make/model.

D. *Unintentional islands containing both inverters and rotating generators*

When an island contains both synchronous machines and inverters, there is generally an adverse interaction between the two that causes ROTs of islands to increase. Inverters are most sensitive to reactive power imbalances, and will act quickly to change the frequency in the island during such imbalance, as explained above. However, due to their rotating inertia, synchronous generators will generally oppose a rapid change in frequency, thereby desensitizing the inverters' ability to change frequency and detect island formation. On the other hand, synchronous generators are generally protected using RoCoF relays or vector shift relays [4]. These relays are often effective because the synchronous generator cannot execute rapid changes in frequency or phase, again due to its rotating inertia, but inverters have no such inertia and can change much more quickly, desensitizing the RoCoF or vector shift relays. Because of this interaction, it becomes possible that islands containing both inverters and rotating machines can run on for longer than 2 s, and in some cases *much* longer, with stable islands that will run on until externally perturbed being possible for islands with very precise generation:load balance.

Figure 2 shows one such case. This figure shows ROTs vs. LF and PF for a circuit containing three PV plants, one small Type IV wind turbine, and a large synchronous machine comprising about 30% of the DER in the island. All of the inverters are UL 1741 listed and utilize positive feedback. The DERs are spread out across the island. Due to the adverse interaction described above, there is a fairly broad plateau of elevated ROTs, and right in the center is a large peak that includes a very small range of stable points (indefinite ROTs)[1].

However, not *all* islands containing rotating and inverter-based DER will exhibit indefinite ROTs. Figure 3 shows a different island, also containing multiple PV plants and a large rotating machine comprising about 28% of the total DER on the circuit. All of the PV plants are at approximately the same location, and the specific inverters in use here utilize particularly aggressive positive feedback-based islanding detection. Also, the specific synchronous generator in use has a lower rotating inertia than the previous example due to the specifics of its design. Here, the longest ROTs seen are just under 1 s, comfortably below the IEEE 1547 2 s limit.

Assuming that the inverters use positive feedback on phase or frequency in their islanding detection, the rule-of-thumb that is recommended is that it would be prudent to study the island and check for extended run-on times if the rotating generation comprises 25% or more of the total DER on the circuit [5]. If the synchronous generation represents less than 25% of the aggregate DER, and again assuming the inverters in the island utilize positive feedback, then the inverters will "win out" over the synchronous generator and the inverters' islanding detection will generally still be effective.
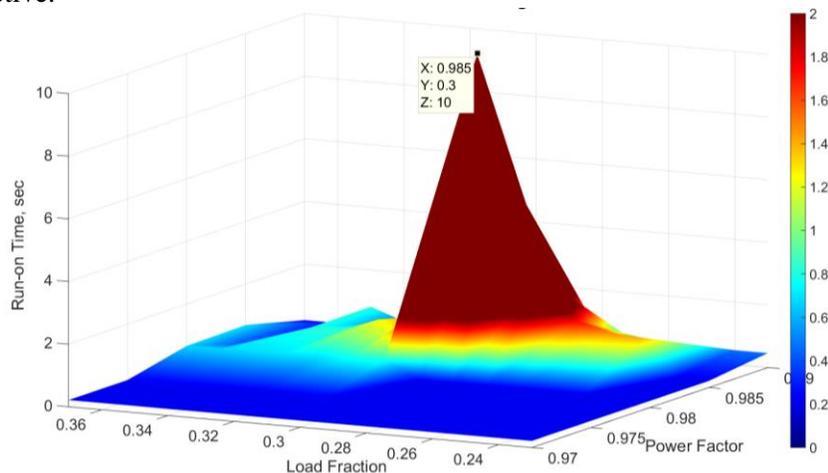

Figure 2. ROTs vs LF and PF for an island containing both synchronous generators and inverters, in which the synchronous generation comprises more than 25% of the aggregate DER. This example shows an unfavorable interaction between inverters and synchronous generation that results in a region of IEEE 1547 2 s violations.

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[1] The plot indicates a 10 s ROT at the cursor location. 10 s was the length of time for which this simulation was run, and thus 10 s was recorded as the ending time of the island. The island itself was stable and would run on indefinitely.
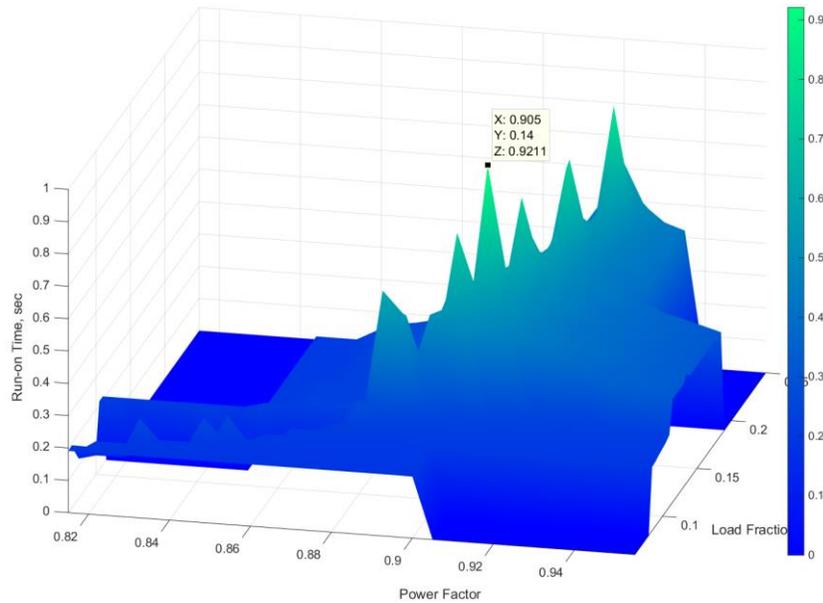
Figure 3. ROTs vs LF and PF for an island containing both synchronous generators and inverters, in which the synchronous generation comprises more than 25% of the aggregate DER. In this example, there is much less of an unfavorable interaction between inverters and synchronous generation, and no violations result.

E.   *Unintentional islands containing mixtures of different inverters*

The behavior of islands containing mixtures of different inverter products can become quite complicated. Some mixtures lead to interactions that degrade island detection effectiveness, and some do not. An example of the latter is shown in Figure 4. This island contains four PV plants each using different manufacturers' inverters, but by chance all four are using fairly similar islanding detection means. The maximum ROTs are over 1 s. This is longer than is typically seen when only one type of inverter is used, so it might be deduced that the mixture of products has slightly degraded the anti-islanding effectiveness, but no ROT approaches the 2 s IEEE 1547 limit, and thus the DERs are still able to detect islanding without a problem.

The situation shown in Figure 5 is very different. Here, there are only two PV plants each using different inverter products, but these inverters use unrelated physical mechanisms to try to detect the island: one uses positive feedback on frequency, and one uses positive feedback on the angle separation between adjacent phases. The two PV plants are approximately the same size. The PV plant that is trying to change the angle separation between adjacent phases is opposed by the other inverters, which maintain essentially a positive sequence output, and the plant that is trying to "push" frequency is opposed by the other plant's line synchronization, which tends to hold frequency. The result is that there is a large NDZ in the vicinity of the balance point under which stable islands can be formed, as shown by the dark red region in Figure 5.

One rule of thumb that has been suggested [5] is that if there is a mixture of inverters connected to a circuit and no single make/model of inverter comprises 2/3 or more of the aggregate DER on the feeder, then further study may be prudent.

F.   *Islands containing inverters that do not utilize positive feedback on frequency or phase error*

The most effective islanding detection means used in commercial PV inverters today generally use some type of positive feedback on either frequency or phase error, which is one family of so-called "active anti-islanding" methods. In these types of methods, if there is a frequency or phase error, the inverter reacts in such a way as to make the frequency or phase error worse, and if the inverter is able to drive the frequency or phase error in this way this indicates a loss of connection to the mains. However, not all inverters use active anti-islanding; there are still some on the market that rely on passive anti-islanding. All passive anti-islanding methods that are resident in the inverter have an NDZ, and the question becomes what the likelihood of encountering that NDZ is in practice. Figure

6 shows the results of an LF-PF parametric sweep for an island containing a PV plant using inverters that rely on a specific passive anti-islanding method, and as expected there is a fairly sizeable NDZ in the surface plot over which stable islands can be formed. This NDZ lies in the region around the balance point, which is typical of passive islanding detection methods [2,3].
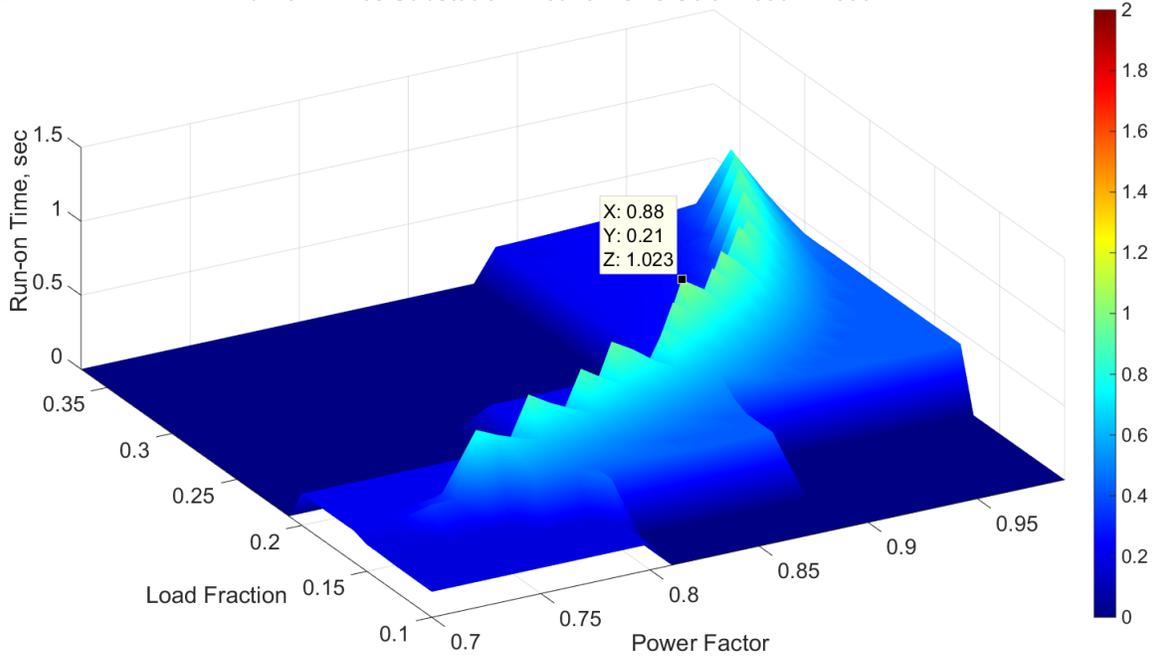

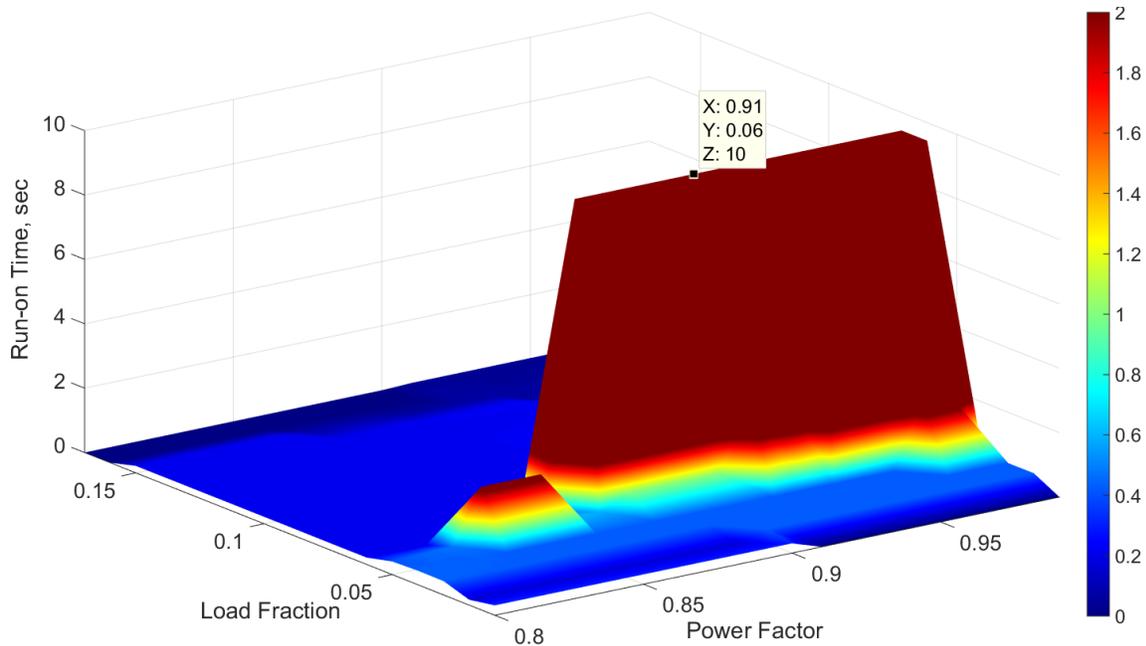**Figure 4. ROI vs. LF and PF for an island containing dissimilar inverters using compatible islanding detection.**

Figure 5. ROT vs. LF and PF for an island containing dissimilar inverters using incompatible islanding detection.
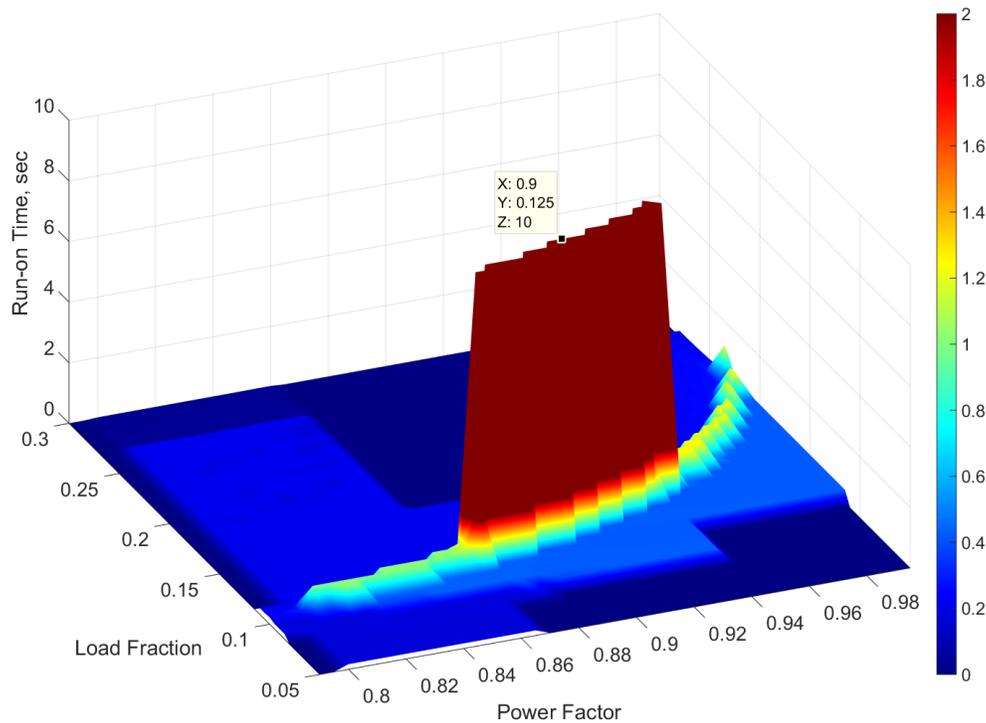
Figure 6. ROT vs. LF and PF for a circuit containing only one PV plant, but using inverters that do not utilize positive feedback on frequency or phase error.

G. Forward-looking solutions and mitigation strategies

The foregoing results indicate that some of the limitations of active island detection approaches are now beginning to manifest themselves as DER deployment levels rise. In the long run, it will be desirable to transition DERs from active islanding detection to another method that maintains speed, selectivity, sensitivity and low cost, but that remains effective for any combination of DERs, at any penetration level. Communications-based islanding detection is the most promising approach for achieving this. Direct transfer trip (DTT) is the prototypical communications-based method, but it has a number of drawbacks, such as its high cost and the requirement that all switches that can form islands, on both primary and secondary source circuits, be included in the DTT system. There are two more promising communications-based approaches: power line carrier permissive (PLCP) and synchrophasor-based islanding detection (SBID).

The concept of PLCP is illustrated in Figure 7. PLCP is simple; a signal is injected into the phase conductors by a transmitter (Tx in Figure 7) outside the island, and the phase conductors carry that signal to a receiver (Rx) inside the island [2,6-9]. In its simplest implementation, a loss of the signal at the receiver location indicates island formation. This method has been tested in simulation, laboratory and field. It has no practical NDZ. Low-frequency (subharmonic) implementations propagate well on phase conductors, but they may take several line cycles to detect loss of signal. High-frequency implementations usually require additional downstream devices to ensure propagation to all DER sites, but they provide much more bandwidth and have the potential to detect islands very quickly. For all PLCP methods, the carrier signal can have multiple uses, such as signaling an operating mode for DERs, switched capacitors, or other devices on the circuit.

An implementation of SBID is shown in Figure 8. In this approach, a reference phasor measurement unit (PMU) is placed outside the island, and the GPS time-stamped phasor measurements made by this PMU are sent over a broadcast channel to all DER sites in a wide-area footprint. At each DER site, there is a local PMU, and a processor that receives the local and remote PMU measurements, time-aligns them according to the GPS time stamps, and uses the relationship between the local and remote phasors to determine whether the DER is islanded. There are several different comparisons that can be made, such as absolute phase angle difference [10], slip frequency between the local and remote PMUs [10], rate of change of slip frequency between the local and remote PMUs [10], or the

statistical correlation between the local and remote frequencies [11]. The techniques in [10] are already in commercial use in the field, and those in [11] have been extensively tested in simulation, laboratory and field and are just beginning to find commercial acceptance. SBID has performed very well to date. Typically, what researchers have found can be summarized as follows [12]. The slip-plus-acceleration and absolute phase angle methods described in [10] tend to detect islands very quickly and they are effective in the vast majority of islanding circumstances, but they do have an NDZ for islands with very close generation-load matching, especially those containing rotating machines, and they may also not be suitable for low-inertia systems. The statistical method described in [11] does not have the detection speed of the methods described in [10], but it does not have an NDZ for precisely-balanced islands, retains effectiveness with rotating generation, and works well in low-inertia systems. Thus, the methods described in [10] and [11] are highly complementary and can be used together.

Between PLCP and SBID methods, it is not yet clear which will be the likely "winner" in the market. Both offer excellent speed, sensitivity and selectivity, and both retain their effectiveness for any combination of inverters and rotating generation, and are not impacted by voltage and frequency ride-through requirements. For both PLCP and SBID, the primary disadvantage is high cost. Thus, the "winner" will probably be the one best able to address the cost challenge.
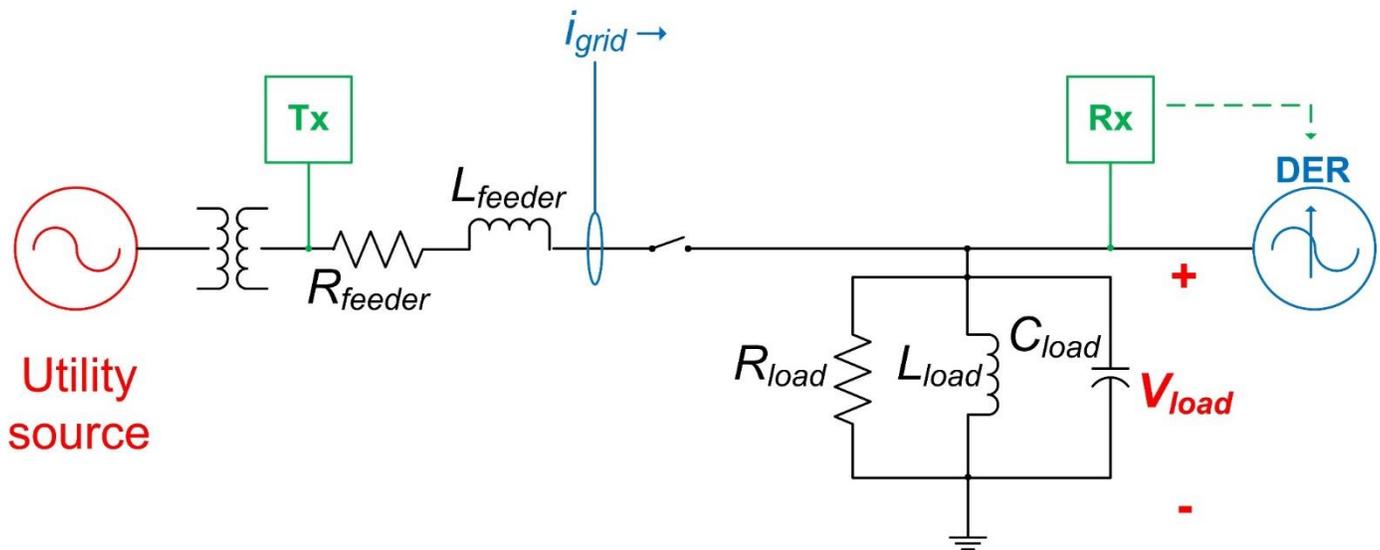
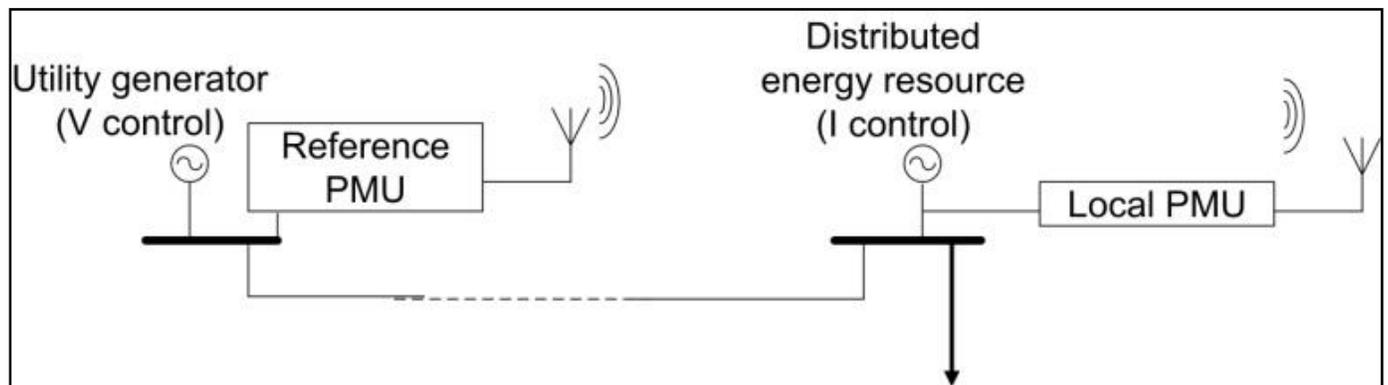Figure 7. Configuration of a basic PLCP island detection approach.

Figure 8. Configuration of a basic synchrophasor-based island detection method.

V. Conclusions

The key conclusion from this paper is as follows. Unintentional islands can sometimes exhibit unacceptable ROTs when the following conditions are met.

1.) For unintentional islands containing only DERs interfaced to the circuit by UL-listed inverters, there must be a generation:load balance in the island, in both real and reactive power. This is a necessary but not sufficient condition; if it is not met, the resulting unintentional island will not run on for longer than 2 s.

2.) Even when there is a generation:load balance in both P and Q within the unintentional island, the presence of large numbers of inverters on the circuit does not *by itself* increase the risk of an elevated ROT. As long as all of the inverters are of the same make/model, or are using compatible island detection methods, then the effectiveness of the islanding detection in inverters of today remains high and is not a function of the number of inverters in the island. The number of inverters was often cited as a concern in the past, but it appears that this concern can be dropped, as long as the inverters are all of the same make/model or are compatible.

3.) When mixtures of inverter makes/models are present on a circuit, often this does not create a problem, but there are certain combinations of products that do lead to degraded islanding detection effectiveness, and in rare cases even stable island formation.

4.) Elevated ROTs can happen, and in fact are fairly common, if the island contains both rotating generators and inverter-based DERs, and islands containing both rotating and inverter-based DERs can form stable islands.

The issue of the impact of voltage and frequency ride-throughs on islanding detection effectiveness is still under study and will be discussed in a future publication.

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