SUPPLEMENTING ANTI-ISLANDING PROTECTION APPLICATIONS IN DISTRIBUTED GENERATION INTERCONNECTIONS

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Abstract – In certain low voltage distributed generation (DG) networks, inverters do not detect unintentional islanding caused by voltage imbalances. This condition violates IEEE-1547 requirements that the networks detect and isolate an island within two seconds of its formation. This paper provides practical application of phase loss detection to inverter protection schemes using transformer networks to address voltage drop considerations. In these applications, phase loss detection can be shielded by the addition of a transformer impedance network, preventing inverter isolation during low generation conditions. Remote emergency stop initiation via current imbalance detection at the Point of Common Coupling (PCC) can be implemented utilizing a dedicated radio network configured fail safe, providing anti-islanding supplementation to ensure detection. This addition establishes islanding detection under all generation conditions, improving line worker safety by ensuring power injection removal. Transformer network current analysis is considered for various common transformer configurations, with an existing application example.

Index Terms — Anti-Islanding Protection, Distributed Generation, Frequency Shift, IEEE-1547, Impedance Network Masking Phase Loss Phase Loss in Transformers

NOMENCLATURE

DG	distributed generation.
EPS	electric power system.
DER	distributed energy resource.
PCC	point of common coupling
PV	photovoltaic.
SFS	Sandia Frequency Shift.
SMS	Slip-Mode Frequency Shift.
ESTOP	Emergency Stop.
I_0	Zero Sequence Current.

I. INTRODUCTION

Most EPSs in service were not originally designed to accommodate generation at the distribution level [1]. As DG becomes less expensive and more readily available, grid penetration by DERs[1] has created new problems for energy providers. One such problem is the occurrence of islanding. An island is created when a distributed generator continues to power a section of line and its corresponding load despite the absence of a grid. Some power systems, such as microgrids, are designed to be able to connect and disconnect from the grid at planned intervals with a dedicated switch. However, in DG systems that are designed to be grid-connected, unintentional islanding is a grid stability and safety concern.

Per IEEE 1547-2018, “for an unintentional island in which the energizes a portion of the Area EPS through the PCC the DER shall detect the island, cease to energize the Area EPS, and trip within 2 s of the formation of an island [1].” However, the protection on the DER must not be so sensitive that it creates false positives because that would be a failure to meet the voltage ride-through[2] requirements of the standard [1].

Single-phasing, or the loss of one phase of a three-phase system, occurs more frequently in rural, medium voltage feeders than in urban areas [2]. Fusing and service laterals can increase the likelihood of single-phasing. DG sites are frequently located in rural areas with long distribution lines where utility protective schemes rely on fuses. Subsequently, these sites are more likely to see the loss of a single phase, which may become an undetected and unintended islanding event.

[1] DG is generation that occurs on the distribution level of the grid. DERs is a broader term that references resources that are connected to the grid, such as synchronous machines, induction machines, power inverters/converters, etc. [1].

[2] Ride-through requirements are in place for DER to prevent tripping during a short-term fluctuation in voltage. If one DER were to trip it could cause other devices to trip, creating a chain reaction.

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Single-phasing of a transformer may be more likely with lines implementing single phase reclosing or fusing, which can result in a partially islanded condition. When transformers lose a phase, protective relays need to detect the phase loss and immediately operate to prevent damage to the transformer, a voltage drop on one side of the transformer, unintentional islanding, or damage to three-phase equipment.

II. PROBLEM

A. Transformer Masking Loss of Phase Detection

Under normal operating conditions, protective relays will de-energize a line after detecting the changes in voltage and currents caused by loss of a phase. However, in some interconnections the transformer network may prevent the inverter from recognizing the loss of a phase. The loss of phase will be seen at the inverter as voltage sag instead of single phasing. In inverters set for undervoltage protection, this sag will not reach the threshold needed to trip. Low voltage interconnections are most likely to encounter these installation practices, based on standard three phase interconnection behind the meter at 480VAC. This paper will examine phase loss in the *Yg*-Δ (Grounded Wye high side, Delta low side) transformer as well as ungrounded high side configurations. This configuration was used for the application explored in this paper.

Unintentional islanding represents a safety concern for utility workers. If workers believe that an energized portion of line is de-energized, they may attempt to work on that portion of the line and become injured or killed. Islanding situations can quickly pose a threat to safety, and islands must be detected and de-energized within seconds of their formation to prevent accidents. An undetected island can also cause damage if the islanded segment of the system recloses onto the grid out of phase. Additionally, heavy machinery, such as motors that rely on three phases, may be damaged by the loss of a phase due to negative sequence heating.

This paper will examine a specific application where an inverter was unable to detect unintentional islanding due to loss of a phase being masked by a transformer. The installation is a photovoltaic (PV) site with a radially tapped inverter feeding in low levels of generation to a utility distribution line as shown in Fig. 1. The inverter was set to trip at undervoltage conditions, which would be detected by a either voltage drop or a frequency shift. At night, generation levels would drop to zero and in the morning slowly begin to increase. At these low levels of generation (<20% of nameplate), a frequency shift due to loss of a phase would not occur, and the transformer impedance network would mask the loss so that the inverter saw almost no voltage drop. Subsequently, islanding would go undetected and the inverter-only protection was insufficient to comply with the anti-islanding requirements of IEEE 1547-2018.

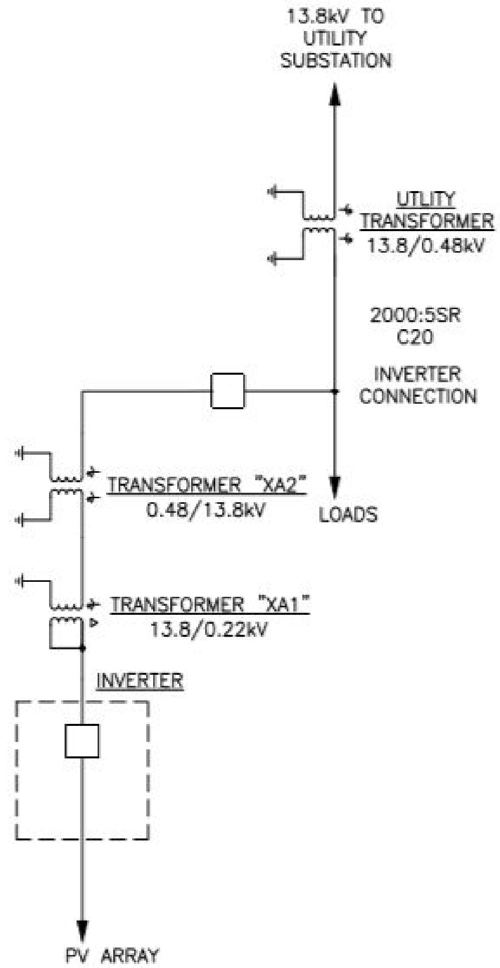

Fig. 1 Single Line Interconnection with Transformer Network to Mitigate Voltage Drop

B. Loss of Phase Effects in Various Transformer Configurations

Open phase on the high side of a transformer may be masked on the low side due to self-excitation. The first step to assessing electrical behavior is to look at how voltage on the high side of a transformer induces voltage on the low side. From Ohm's law, voltage equals current divided by resistance. In a three-phase transformer, voltages on the high side will be equal during balanced conditions. The core or cores will be of equal resistance, so currents on the high side will also be equal. Equations (1) and (2) show the relationship of current to magnetic flux in a transformer.

$$B = \frac{I\mu_0\mu_r}{2\pi r} \tag{1}$$

$$\phi = BA \tag{2}$$

where

I	current
μ_0	permeability of free space
μ_r	permeability of the core
r	distance of the magnetic field from the wire
ϕ	magnetic flux
B	magnetic field strength
A	area perpendicular to the magnetic field

The magnetic flux circles the core of the transformer, inducing a current and voltage on the low side that is dictated by the ratio of the windings (turns ratio).

In transformers with a three-legged core with healthy voltages on each phase, $|V_A| = |V_B| = |V_C|$, and subsequently $\phi_A \cos(\omega t) + \phi_B \cos(\omega t) + \phi_C \cos(\omega t) = 0$. When voltage is lost on phase A, voltages on phase B and C will still be roughly equivalent to their previous values and the induced flux, ϕ_B and ϕ_C will also remain the same [2]. Due to the structure of the core, the only return path for ϕ_A and ϕ_B will be through the phase that has lost voltage [2]. When $V_A = 0$, $\phi_A = -\phi_B - \phi_C$, which is equivalent to the flux, $\phi_A + \phi_B + \phi_C = 0$ that was seen with healthy voltages on all three phases [2]. Consequently, the induced voltage, V_A, on the low side of the transformer will be equivalent to the voltage present without a disconnected phase.

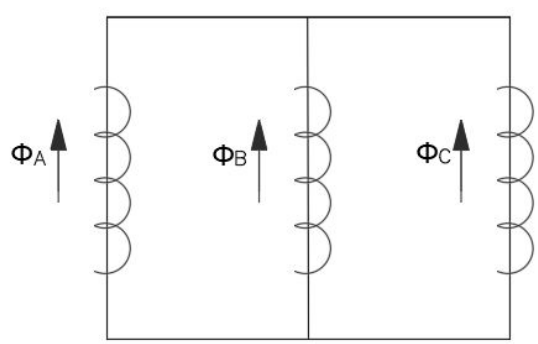

Fig. 2 Flux and Voltage in a Three-Legged Core [2]

A similar low-side voltage regeneration will occur in transformers that have three single-phase banks as well, due to the interaction of primary and secondary coils [2].

The results of phase loss in both an ungrounded delta and an ungrounded wye on the high side of a transformer are similar and independent of core construction. [2] Fig. 2 and Fig. 3 illustrate an ungrounded high-side delta and wye, respectively, with a loss of voltage and current in the B phase.

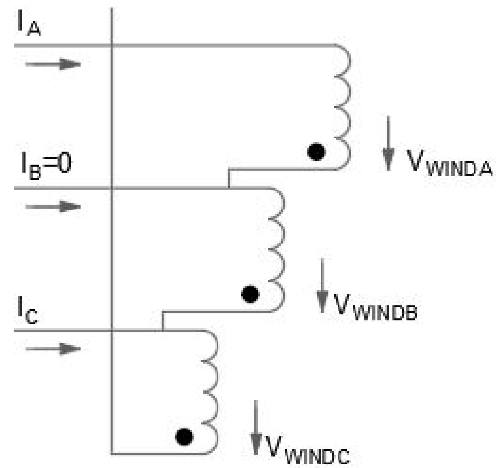

Fig. 3 High Side Delta with Loss of Phase B [2]

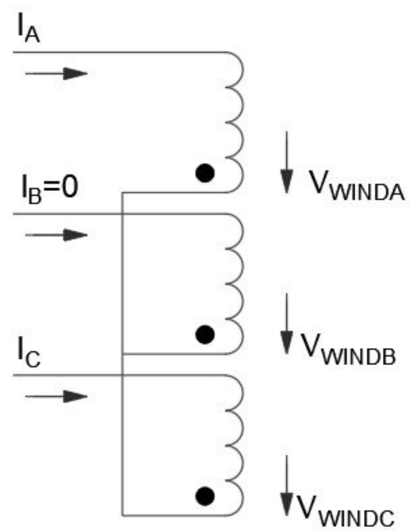

Fig. 4 High Side Wye with Loss of Phase B [2]

Under healthy voltage conditions, $a = \angle 120$ and the high-side sequence currents, I_1= full load amps and $I_2 = 0$. Upon loss of phase, $a = \angle 180$ and the high-side sequence currents, $I_1 = I_2$.

$$I_1 = \frac{1}{3}(I_A + aI_B + a^2 I_C) \tag{3}$$

$$I_2 = \frac{1}{3}(I_A + a^2 I_B + aI_C) \tag{4}$$

When $I_A = 0$, $I_1 = \frac{1}{3}(aI_B + a^2 I_C)$ and $I_2 = \frac{1}{3}(a^2 I_B + aI_C)$ [2]. This decrease of sequence current values on the high side of the transformer will result in lower induced voltages on the low side of the transformer, which will be detected by inverters and relays.

While an ungrounded high side has the advantage of showing a voltage drop or loss on the low side of a transformer, the *Yg*-Δ configuration will continue to be prevalent in DG applications. The advantage of this configuration is that the grounded wye on the high side will prevent the low side of the transformer from seeing a ground fault from a grid, whereas if a fault occurs upstream of the transformer it will be seen on the wye and can be sensed by protective relays or inverters, and complies with most utility requirements to be solidly grounded [2]. Despite the advantages of winding configuration, voltage-based protection may be insufficient for the inverter to correctly identify the islanding condition. To mitigate this detection concern, inverters customarily rely on frequency shift detection rather than undervoltage detection. This method of islanding detection works in many instances, but additional protection is necessary under some conditions [5].

C. Impact on Inverter Detection

Grid-connected inverters are required to match the voltage, frequency, and phase of the grid that they are connected to [4]. These inverters will also detect islanding via a frequency shift and automatically stop powering their load. PV inverters commonly rely on one of two methods for frequency shift detection: the SFS or SMS [4]-[6]. The inverters normally operate at unity power factor, and the phase angle between the inverter output current and PCC voltage is as close to zero as possible [4]. Under the SFS method, a waveform of a current injected into a designated node “a” by the PV inverter is continuously distorted so that the frequency of the voltage will constantly drift [4]. When the inverter is connected to a utility grid, the grid stability will prevent change in the frequency [4]. When the inverter is disconnected from the utility, the frequency error increases until the frequency protection is tripped [4]. The SMS method also uses positive feedback to destabilize the inverter when it is disconnected from a utility grid [4]. Feedback is applied to the phase of voltage V_a at the PCC, shifting the frequency and causing the phase angle of the inverter to be a function of V_a [4]. The line frequency of the inverter becomes inherently unstable unless it is connected to a utility [4].

At low generation conditions, frequency shift may not occur, and healthy voltage will be seen at the inverter, making islanding undetectable by the SMS and SFS methods. To achieve detection, measurable reactive power flow is needed [5]. At low values of generation current magnitude can be too low to achieve measurable change in phase angle between voltage and current. Without this ability to detect the change in angles reliably can the reactive power be measured, which is then used in discerning the change in grid conditions [5].

After inverters are installed, they will be calibrated by connecting the inverter to a simulated three-phase utility source and applying a balanced resonant load at unity power factor, as seen in Fig. 5 [3].

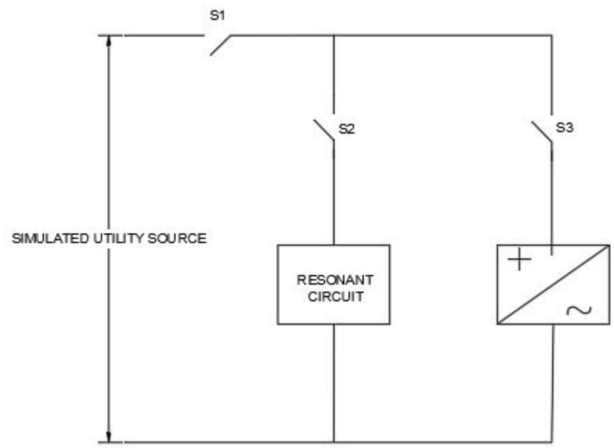

Fig. 5 Inverter Anti-Islanding Test with Balanced Load [3]

When Switch 1 (S1) is opened, the inverter will stop exporting power within two seconds [3]. The inverter’s response to this condition is tested by changing either the capacitive or reactive load in in increments of one percent to confirm that the inverter will not operate without a stable utility source [3]. However, this test does not consider the impedance or magnetizing current of the transformer in the circuit [4]. The drawback of this test is that it will detect a loss of voltage or current, but it will not detect singe-phasing that is masked by voltage regeneration within the transformer. In the application described in this paper, healthy voltages and healthy currents were seen at the inverter, and testing the inverter failed to identify the defect in the protection scheme. Additionally, the test generates false positives, referred to as the “non-detection zone” that must be balanced with the ride-through requirements of IEEE-1547.

III. SOLUTION

A. Case Study – Initial Installation Failure

The authors of this paper implemented a solution to a scenario where islanding was not detectable under all conditions using inverter only protection. This manifested itself during initial site acceptance testing which was a coordinated effort between the facility owner, utility, and solar installation contractor. Fig. 6 shows the final installation single line for reference. At the utility interface, an existing *Yg-Yg* transformer was installed to provide utility service, with upstream padmount switches with load break elbows. This was used to simulate loss of phase conditions on incoming power at the medium voltage side of the utility transformer. A radial tap was connected to the existing LV bus and run through fused disconnect with ground fault detection for the new DG installation. Due to distance to the solar array, a combination of 13.8kV *Yg-Yg* and *Yg*-Δ transformers were installed to mitigate voltage drop.

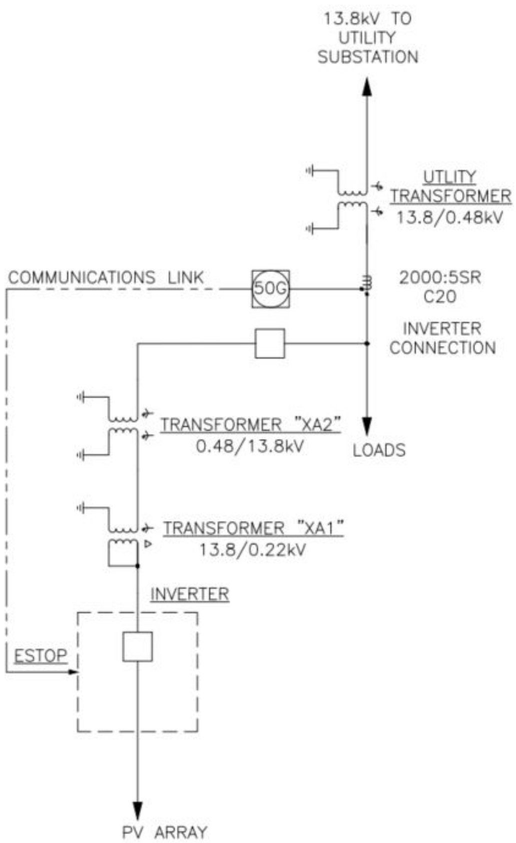

Fig. 6 System Single Line Diagram

Facility load was transferred to site backup diesel generators for the purpose of testing, allowing power export to the grid for test purposes. Power export was limited to less than 20% by opening combiner box disconnects to limit current while disconnecting the load break elbows. Upon opening a single load break elbow at the utility transformer high-side, power export continued from site indicating that the inverter had not detected the islanding condition.

This inability of the inverter to detect the loss of phase at low generation identified that traditional islanding detection can potentially prevent detection under all conditions in this interconnection. The inverter vendor confirmed that frequency shift was the principal route of islanding detection, with undervoltage being a backup means. Both failed in this interconnection due to the transformer impedance network installation. It is notable that when the loss of phase occurred at low generation, the phase loss was undetectable due to the delta, and as the inverter continued to source three phase current, increasing I_0 at the point of interconnection as shown in Fig. 7.

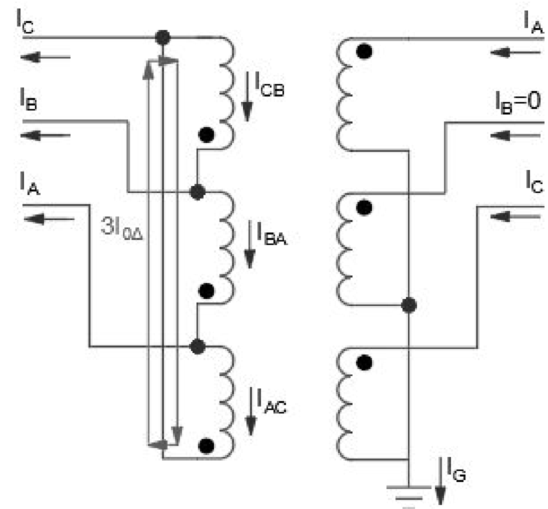

Fig. 7 Open Phase, Yg-Δ Transformer [2]

The connection diagram shown in Fig. 8 demonstrates that even with loss of I_B, current will still flow from that branch to I_G, exciting I_0 in the delta windings. This allows for unbalanced phase currents to flow from the inverter per the following relationships:

$$I_a = I_{ba} - I_{ac} \tag{5}$$

$$I_b = I_{cb} - I_{ba} \tag{6}$$

$$I_c = I_{ac} - I_{cb} \tag{7}$$

$$I_{ba} + I_{ac} + I_{cb} = 3I_{0\Delta} \tag{8}$$

$$I_a + I_b + I_c = 0 \tag{9}$$

Equations (5), (6), (7), (8), and (9) can be reduced to individual phase currents, where n is the transformer turns ratio.

$$I_a = \frac{\sqrt{3}}{n} I_{ba} \tag{10}$$

$$I_b = \frac{\sqrt{3}}{n} I_{cb} \tag{11}$$

$$I_c = \frac{\sqrt{3}}{n} I_{ac} \tag{12}$$

As shown by (11), there will be current on phase B, so current will be present on all three phases [2], preventing the inverter islanding detection from operating at low generation.

As generation was increased, I_0 also increased due to higher phase imbalance. Eventually, I_0 exceeded fault protection setpoints, resulting in a protective tripping of the fused disconnect installed to protect the radial feed to the inverter. This was a concern as it indicated that under certain conditions detection of an islanded condition would be masked, potentially creating a hazardous condition that could be sustained beyond IEEE 1547-2018 limitations of this condition.

When the same conditions were tested at higher generation levels, the islanding protection detected the loss of phase. It was determined that in this particular case, at levels exceeding approximately 50% generator nameplate the inverter islanding detection was effective. This was important for the determination of adding supplemental detection to the system, detailed in the next section.

B. System Modification – Anti-Islanding Supplemental Detection

The system modification implemented made use of basic protection fundamentals using an instantaneous ground fault as the mechanism of detection. As detailed in Fig. 6, split core protection class CTs were installed at the point of interconnection to allow for detection of incoming current from the utility source. A multifunction overcurrent relay was used for providing instantaneous ground fault overcurrent detection via a 50G element. A review of historical facility load was conducted to confirm that pickups were set to detect during a loss of phase condition based on the zero-sequence current that would be seen during this condition. This was conducted based on minimum historical loading, and then set to 20% of full load amps. 50G was not used for protection, but only for islanding detection. This was done due to the inherent time delays associated with the RF communications link. To assure islanding detection within IEEE 1547-2018 two second requirement, the additional time delay associated with a 51G was not utilized. Directional 50G was not used, as the added complexity to set was not needed to adequately detect the I_0 contribution during low generation conditions. In addition, load imbalance was negligible, also negating the need for directional sensing.

The complication of using relatively simple detection methods to initiate remote inverter shutdown was overcome by addition of a remote contact communicating via a wireless radio link. The RF link implemented direct transfer of a hardwired status. Utilization of the wireless data link allowed for a relay output to initiate remote shutdown to the inverter by mirroring the contact status. The relay was configured to maintain a contact closed (failsafe) during permissible operations conditions. This was done to allow for remote shutdown for both detection of islanding and loss of communications. The remote (inverter end) transceiver contact was wired into the ESTOP circuit with a set of dry contacts. This allowed for initiating an ESTOP remotely via the remote transceiver. The basis for the RF link equipment was simply chosen for practical purposes, as the facility installation was completed without fiber optic cable installed for communication to the inverter and installation was not possible. Installations of this type may benefit from installation of fiber to preclude this concern, as then higher speed communications with increased security would be possible.

C. Test Results

Proof of concept testing was accomplished prior to live testing with the utility. A functional test was accomplished upon installation of all equipment with temporary authorization from the utility to allow generation to the grid. Test injection was accomplished directly to the relays installed to confirm two second timing could be met per IEEE 1547-2018 for islanding detection and isolation. This preliminary testing was accomplished to confirm detection and timing were adequate for live testing with utility personnel.

Upon completion of the live test, utility linemen and engineering representatives supported live testing similar to the initial test by initiating single phase loss via load break elbows. Facility load was again transferred to standby generation to prevent outage and mitigate any electrical transients.

The test was conducted at varying generation levels to verify detection was possible based on the point of interconnection. It is important to note that properly locating the sensing CT is key in ensuing proper detection. Placing the sensing CT at the utility point of interconnection accomplishes maximum sensing during low generation, as shown in Fig. 6. It is possible for misoperation due to unbalanced facility loads, so the settings were adjusted to account for this condition.

Variable generation was controlled by limiting DC power available to the inverter by incrementally switching DC combiner boxes on and off to regulate available generation. All testing was performed at peak irradiance so that generator output would be at its peak.

Upon initiation of live testing using the load break elbows installed on the line side of the utility transformer it was determined that detection based on 20% of minimum facility load was adequate for backup, as at higher levels of generation the inverter was capable of determining the islanded condition, so setting this level of detection ensured that at 50% or less of generation the supplemental detection would reliably operate.

IV. CONCLUSIONS

The scenario outlined in this paper is an example of one instance where conditions on a DG site may cause an unintentional island to go undetected. DG installations behind the meter in low voltage applications are very common. To mitigate voltage drop considerations use of a step up/step down transformer network is frequently utilized for interconnections where distance to the solar array is required. Given this, it is quite possible to encounter new or existing interconnections that may pose a similar potential of being unable to detect a loss of phase islanding condition under all levels of generation. Testing verification should be conducted at multiple generation levels to confirm proper operation of the supplemental islanding detection. It is relatively simple to retrofit existing installations if assessment that a potential inability to detect islanding may exist, as the system implemented with this application required retrofit with the least possible impact. Avoidance of additional civil construction had to be avoided due to cost, so the wireless control system was chosen and implemented to reduce facility impact.

Further system modeling of phase conditions of this installation as well as real time data capture are both recommended for future work. As DG is added to an aging infrastructure, it is critical for the power industry to meet the standards set forth in IEEE 1547-2018 and to provide solutions for systems where there is a potential violation risk. Identifying applications where inverter-based detection should be supplemented with standard relaying design will benefit utilities as they grapple with increased levels of DG and will arm design engineers with data to assess when and if alternate phase loss detection should be considered.

Principal concerns for islanding detection from the authors' standpoints were echoed from the utility. Electrical line workers conducting routing maintenance on their electrical system need to guarantee that positive control of DG is ensured during routine operation, and that the requirements to prevent inadvertent energization of a system and to be able to detect and island [1] are reliably implemented. This facilitates IEEE 1547-2018 compliance, and most importantly maximizes safe working conditions. Knowing that a system will disconnect when it is required to do is key to providing this added layer of protection to establish the safest possible working conditions

V. ACKNOWLEDGEMENTS

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VII. VITAE

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