

Are Current Unintentional Islanding Prevention Practices Sufficient for Future Needs?

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Overview

In the electric power system, islanding occurs when a portion of the system (the island) becomes disconnected from the grid and continues to operate. Generally an island includes one or more generators and loads, along with the wires, transformers, and protective devices necessary to connect them together. IEEE defines both *intentional* and *unintentional islanding*. Intentional islanding may be desirable in some cases, such as in a microgrid designed to run independently during a weather event or unforeseen outage. Unintentional islanding (simply called islanding in this brief) is not planned and is considered undesirable because line worker practices, protective equipment, and grid control systems are not designed for those conditions.

The advent of new types and applications of grid-connected distributed generators (DG) and storage has led to connection standards¹ that are typically satisfied by *onboard* anti-islanding. Further concern for the future widespread deployments of these technologies has raised the question, “Will feeder-level and *utility-controlled* anti-islanding be required to supplement individual DG onboard anti-islanding?” This EPRI tech brief discusses current anti-islanding practices and addresses the need for supplemental islanding prevention in the future.

Why be Concerned about Unintentional Islanding?

The primary risks most often cited and considered include:

Danger to line workers and the public – An unintended island may result in a portion of a distribution circuit being energized unexpectedly, affecting maintenance practices and increasing the risk of accidental contact with live equipment during maintenance and repair operations. If a DG unit energizes downed conductors, this could potentially pose a risk to the general public as well.

Damage to customer or utility equipment – Unintended islands are not guaranteed to properly regulate voltage and frequency, to maintain effective grounding, and to limit harmonic distortion, any or all of which may upset or damage equipment.

Misoperation of protective equipment – An unintended island could result in poor coordination or desensitization of protective devices, as well as the potential for an out-of-phase reclosing event. Either condition could result in damage of synchronous

motors or generators, sensitive electronic equipment, or industrial process loads.

Depending on the specific conditions, these concerns may be more or less warranted or severe. The duration of the island is also an important factor. For instance, the safety of a line worker is by far the most important concern, but it may take several seconds or minutes after an island is formed before a worker would be in danger. Conversely, the effect of out-of-phase reclosing may be limited to only a few synchronous machines or filter banks, though the consequences are potentially severe. Prevention by anti-islanding alone requires a faster response than the utility’s reclosing times, which may be as short as 30 cycles.²

Putting Unintended Islanding in Perspective

For relatively small DG that are not dispatchable, such as solar PV, unintended islanding has not been a practical problem. Even in Europe with more significant deployments, reported cases are rare, and enforcing preventive measures beyond installing sensors and protection at individual generators has not occurred. On-board anti-islanding protection, certified during the safety listing of equipment, has been an effective first level of defense. Additional protective relaying and changes in line worker practices can further reduce islanding likelihood and concerns. Still, there is consensus among distribution engineers that growing levels and broadening types of distributed generation will increase the threat of unintended islanding. In most practical cases, the probability of a dangerous or damaging island is rare for the following reasons:

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This white paper was prepared by Ben York and Tom Key of EPRI

¹ “IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems,” IEEE Std 1547-2003, July 2003

² D. Williston and D. Finney, “Consequences of Out-of-Phase Reclosing on Feeders With Distributed Generators,” Whitepaper. Williston & Associates Inc, 2010.



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- A stable island requires continuous balance of both real and reactive power from generators and loads connected to the island. The vast majority of DG units, such as solar PV, do not regulate real or reactive power output, and optimize energy production from the source instead. Given a limited inertia, even in a fully loaded distribution feeder, the highly probable mismatch between generation and load will quickly collapse a potential island.³
- A short-duration island, typically less than 15 cycles, is more likely than a long-duration island but less concerning. For example, short-duration islands would not present hazards to line workers, and any resulting under- or over-voltages would likely remain within the voltage-tolerance envelopes of connected loads. Out-of-phase reclosing is usually not a concern. When it is, certain relaying packages (such as synch-check or voltage detection) can be added to prevent reclosing into an unintentional island.
- From a power quality standpoint, unintentional islands occur where a breaker or fuse has already operated. Without the DG present, the downstream customer would typically experience some sort of momentary upset or interruption. Thus, process upset issues are not particularly relevant because they would happen with or without the presence of DG.
- Longer-lasting islands are less likely to be stable due to imbalance between load and generation. This leads to abnormal voltage or frequency and causes DG to disconnect per the normal trip limits set by IEEE 1547 and UL 1741. With the introduction of inverter ride-through into future codes and standards, a particular DG unit will take longer to trip but is not necessarily more likely to island. Ongoing research and testing with so-called smart inverters should help to answer any lingering concerns about the effects of ride-through.

No matter how unlikely unintended islanding is, the safety of line workers and the public will continue to be the primary concern. The issue is not to prevent every island that may happen in the normal operation of the grid. The goal should be preventing a short-duration event from cascading into a long-duration is-

land. Supplemental anti-islanding schemes discussed in this tech brief are being considered primarily due to these cascading safety issues with higher DG penetrations.

Existing Practices to Prevent Unintentional Islanding

Currently, there are two prevailing approaches to prevent individual distributed generation from creating unintended islanding. The primary approach utilizes onboard anti-islanding protection at each DG system. In certain situations, feeder-level protection may be used to directly trip individual DG in coordination with utility operations.

For larger DG systems, the interface commonly found on rotating generators usually involves a combination of a multi-function relaying package at the generator, additional feeder protection systems at the substation, and a direct-transfer-trip (DTT) scheme designed to disconnect the DG unit if an upstream breaker is opened.⁴ According to a recent EPRI survey, islanding concerns were the stimulus for greater than 90% of the installations of DTT.⁵ These technologies have a long history of use and are considered effective where they have been installed. They can be relatively expensive,⁶ particularly for smaller DG where relaying can exceed the cost of the generator. Beyond the cost issue is the added complexity of communication, because most DTT schemes are point-to-point and require a separate transmitter dedicated to each DG installation. This becomes even more complex when feeders are reconfigured to accommodate change load or to restore service after an outage.

For smaller DG systems, which are mostly inverter-based, onboard anti-islanding detection schemes are much less expensive to implement than DTT. These approaches all revolve around searching for certain abnormalities in local voltage or frequency that would indicate an unintentional island at their location.⁷ According to the prevailing standards, if a DG unit can successfully detect an island in under two seconds from when it is separated from the grid, it is deemed compliant. In order to pass

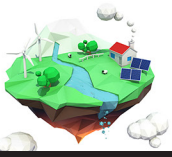
³ B. Verhoeven, "Probability of Islanding in Utility Networks Due to Grid Connected Photovoltaic Power Systems: Task V - Grid Interconnection of Building Integrated and Other Dispersed Photovoltaic Power Systems," International Energy Agency (IEA). Arnhem, NL, 2002.

⁴ M. Davis, *Distributed Resources Task Force Interconnection Study*. Edison Electric Institute (EEI). 2000.

⁵ *Protecting the Modern Distribution Grid: EPRI Survey on Distribution Protection with Emphasis on Distributed Generation Integration Practices*. EPRI, Palo Alto, CA: 2013. 3002001277.

⁶ J. A. Gonzalez, A. Dysko, et al., *The Impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation: Working Group B5.34*. CIGRE, 2010.

⁷ W. El-Khattam, T. S. Sidhu, and R. Seethapathy, "Evaluation of Two Anti-Islanding Schemes for a Radial Distribution System Equipped With Self-Excited Induction Generator Wind Turbines," *IEEE Transactions on Energy Conversion*, vol. 25, no. 1, pp. 107–117, 2010.



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the islanding test, inverters typically require a combination of a passive scheme, which looks for abnormalities caused by external sources, and an active anti-islanding behavior. Active schemes modulate the inverter's output at regular intervals and attempt to create a voltage or frequency disturbance. If the inverter is still connected to the larger grid, these disturbances will have little or no measureable effect on power quality. If the installation has been islanded over a small enough portion of the system, these techniques will cause a detectable change in local voltage or frequency.⁸

Future Concerns for Onboard Anti-islanding

While onboard anti-islanding techniques are considered effective for the current state of DG deployment, a number of changing conditions are increasing the potential risk of unintentional islanding:

1. Because DG capacity is increasing faster than the load demand in many distribution systems the probability of having sufficient generation to supply the local load for a given period of time is rising.⁹
2. With the large number and variety of inverter technologies, the likelihood of one method of active islanding detection negatively impacting the effectiveness of another is increased. However, a variety of approaches does reduce the risk of a single technique proving ineffective later on.
3. New IEEE voltage and frequency ride-through requirements for inverter will delay tripping during feeder events. Volt-var functionality will increase the available DG reactive power compensation. Whether or not these control changes increase the generator's likelihood to sustain an unintentional island¹⁰ remains to be seen.
4. Mixing existing synchronous, rotating DG (with a significant inertia) with deployment of inverter-based generation may reduce the effectiveness of active anti-islanding

methods. These methods depend on the inverter being able to create a disturbance in frequency or voltage in order to detect an island, an ability that is countered by the inertia and short-circuit strength of surrounding rotating DG.

The Search for More Advanced Islanding Protection

There is not a clear answer to the question of whether onboard anti-islanding methods alone will be sufficient to protect the distribution system and ensure appropriate safety. Case-by-case analysis will yield different probabilities and risks. These have to be weighed, often on a circuit-by-circuit as well as generator installation-to-installation basis. If the risk of having only onboard anti-islanding protection becomes sufficient enough, it could limit the amount or type of DG that could be installed on a feeder.

There are several technical solutions, however, that could help mitigate the risk imposed by islanding, without requiring full DTT systems at each residential PV system. They each provide the utility with direct means to establish control over generation by either signaling the units or forcing them offline. Depending on the circuit, the DG, the existing utility equipment and practices, as well as the individual vendor solutions, each technique will have its own complexity, cost, and effectiveness.¹¹

Candidate Solutions

Power-Line Carrier (PLC)

The concept of using power lines for communication as well as energy delivery may be nearly as old as the power system itself. High-frequency PLC signals (those greater than 600 Hz) are used extensively on the transmission system for reliability functions (such as blocking reclosing of breakers in certain situations).^{12,13} Low-frequency PLC (less than 60 Hz) has a history of use in distribution for applications like automated meter reading (AMR). The first example of low-frequency PLC, Two-Way Automatic Communications System (TWACS), is still

⁸ W. Bower and M. Ropp, *Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems*, Sandia National Laboratory, 2002.

⁹ M. Ropp and A. Ellis, "Suggested Guidelines for Assessment of DG Unintentional Islanding Risk," Sandia National Laboratory, Albuquerque, NM, 2012.

¹⁰ G. Kerber, G. Kaestle, and F. Oechsle, "Strategies for Coping with Unintentional Islanding as a Result of Robust Grid Connection Rules for Distributed Generation," in *Internationaler ETG-Kongress*, 2013.

¹¹ "IEEE Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547," IEEE P1547.8/D8, July 2014

¹² "IEEE Guide for Power-Line Carrier Applications," *IEEE Std 643-2004*, pp. 1–134, 2005.

¹³ M. P. Sanders, J. Appleyard, et al., "Special Considerations in Applying Power Line Carrier for Protective Relaying," in *Protective Relay Engineers, 57th Annual Conference for*, 2004, pp. 247–281.



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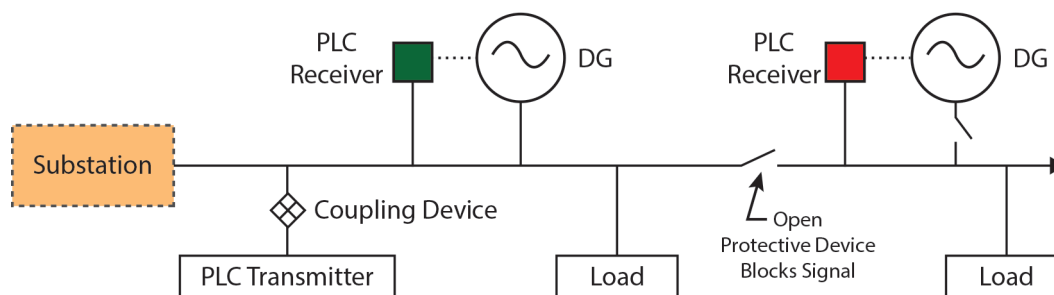


Figure 1 – A PLCP System is Naturally Interrupted by Protective Devices, but Sensitive to Distribution System Conditions

the dominant operating concept of low-frequency PLC today.¹⁴ Extensions of both of these forms of PLC have been proposed for anti-islanding applications.¹⁵

When either modulation scheme is used for anti-islanding, a single transmitter is placed at the substation and receivers are co-located at each DG site. The transmitter places a “tone” on the line, indicating that the DG has permission to operate. This has led to some referring to this technique as *power line carrier permissive*, or PLCP. If the DG unit can detect the tone, then it continues operating normally. If the tone disappears (leaving a pure 60-Hz sinusoid), then the assumption is that the DG has become islanded from the substation and must disconnect from the line.

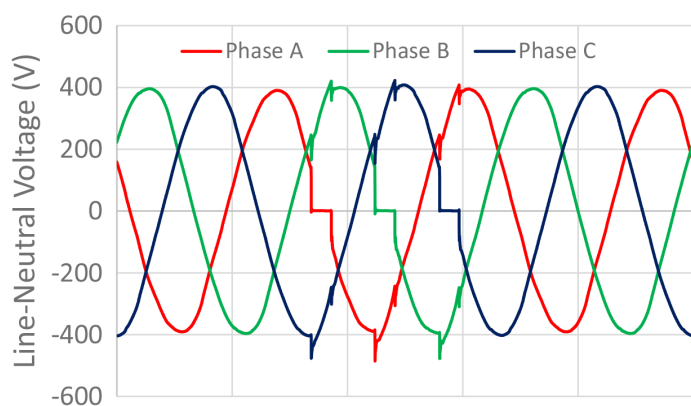


Figure 2 – Using the TWACS Concept for Anti-islanding Produces a Small Voltage Distortion that is Detected by Receivers Downstream

Strengths

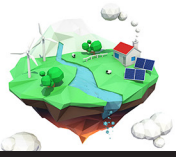
- **Naturally single point-to-multipoint** – This reduces the cost and complexity of addressing multiple DG systems from the same transmitter. If the receiver can be made low-cost (which may not be true for all PLC technologies), this can result in an option much less costly than installing multiple DTT systems.
- **Compatible with “independent” protection systems** – Although the PLC transmitter is typically coordinated with the feeder breaker, it may not be the only protection system that is active. If inline reclosers or lateral fuses operate before the substation breaker, they naturally interrupt the PLC signal. This allows the anti-islanding system to function appropriately without communication with every protective element that is being employed.

Weaknesses

- **Sensitive to distribution system conditions** – Unlike the transmission system, where long spans of line present uniform impedances for many miles, distribution systems are a heterogeneous mixture of conductor sizes, splices, laterals, and with both overhead and underground sections. These variations can both reflect and attenuate PLC signals. This can be a debilitating characteristic, especially for high-frequency carriers—decreasing range and increasing the number of filtering devices like line traps that must be employed.¹³ Even low-frequency carriers can become attenuated by capacitive underground lines or trapped by delta windings on service transformers. This makes the distribution system a much more challenging place to employ PLC.

¹⁴ TWACS - From the Beginning, Aclara Technologies, LLC. Available: http://www.aclaratech.org/NewsLetter/TWACS_FromTheBeginning.pdf.

¹⁵ W. Xu, G. Zhang, et al., “A Power Line Signaling Based Technique for Anti-Islanding Protection of Distributed Generators—Part I: Scheme and Analysis,” *IEEE Transactions on Power Delivery*, vol. 22, no. 3, pp. 1758–1766, 2007.



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- **Signal strength varies from feeder to feeder** – Given the varied nature of the distribution system, it is also very difficult to apply one PLC system uniformly across multiple feeders, because each feeder has its own unique characteristics. Especially at higher frequencies, extensive path or RF analysis may be necessary to ensure that the PLC signal is transmitted and interpreted reliably. Low-frequency PLC (under the TWACS model) operates by “shorting” the utility line near the zero crossing. Thus signal quality is subject to the impedance of the system, substation, feeder, and service transformer at each installation, as well as the expected DG and load conditions at various points throughout the day.¹⁶
- **Requires transmitters at each substation for reconfigurable systems** – Reconfiguration can be a challenge for PLC-based systems. In addition to separate path analysis, if the DG is transferred to another feeder or substation, that circuit must also have a functioning transmitter for the DG to continue operating.
- **Compatibility with other PLC-based systems** – Just like radio communication, there is a certain limited amount of bandwidth available on the power line. Especially for low-frequency PLC, use of the line must be carefully coordinated to ensure that AMR, direct-load-control (DLC), and anti-

islanding programming do not conflict with one another. In the event that these solutions come from different vendors, it may be extremely difficult to ensure compatibility if the same frequency band or conduction interval is being used by multiple services.

General Transfer-Trip Schemes (Wired or Wireless)

Instead of using the power line as a communication medium, transfer-trip schemes substitute a separate communication channel between the utility and a DG unit. These could be either wired or wirelessly connected. Wired connectivity is typically fiber-optic, while wireless transceivers may operate over a number of radio or cellular bands. Conventional DTT connects a single protective device to a single (usually large) DG unit or facility.¹⁷ While this solution works well in certain applications, future growth of small-scale (residential or small commercial) DG presents a new application for transfer-trip technologies: simultaneously connecting multiple protective devices (such as reclosers) to multiple DG units simultaneously. In future applications, the signaling unit may not be a protective device at all, but rather a synchrophasor¹⁸ or other measurement device.

Low-Frequency PLC at National Grid

National Grid has implemented a low-frequency PLC system as a replacement for DTT at one of its substations in New York State. The technology provider is DX3 Enterprises Ltd, whose system uses the TWACS concept to generate a PLCP signal that is detected by a receiver near the rotating generator downstream of the substation. The system creates a detectable notch every four line cycles. If the signal is lost for four intervals (16 cycles total), the generator is disconnected. Future plans for the demonstration include extending the interval as well as adding additional machines to the feeder.



Figure 3 – National Grid has Installed the DX3 Pulsar PLC System at a Substation in Upstate New York (Photo Courtesy of National Grid)

¹⁶ M. Ropp, D. Joshi, et al., “New Results for Power Line Carrier-Based Islanding Detection and an Updated Strengths and Weaknesses Discussion,” in *37th IEEE Photovoltaic Specialists Conference (PVSC)*, 2011, pp. 2584–2587.

¹⁷ Walling, R.A., “Application of direct transfer trip for prevention of DG islanding,” Power and Energy Society General Meeting, pp. 24-29 July 2011

¹⁸ Mills-Price, M.; Scharf, et. al., “Solar generation control with time-synchronized phasors,” Protective Relay Engineers, 64th Annual Conference for, April 2011



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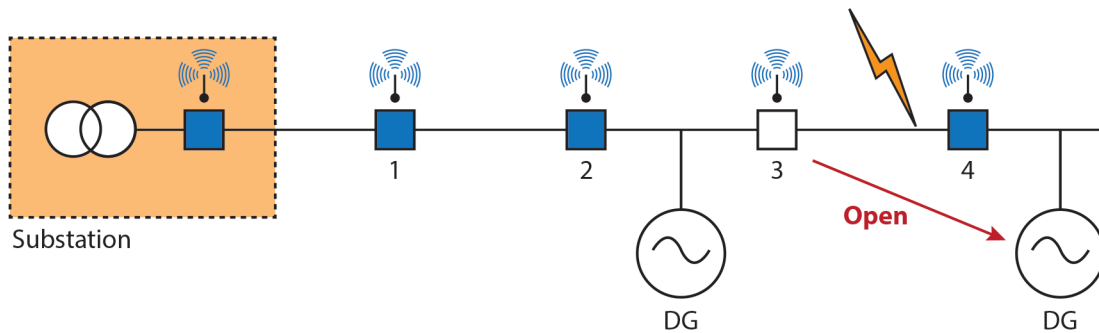


Figure 4 – Future Transfer-trip Schemes Must Connect Multiple DG Units with Multiple Protective Devices

Strengths

- **Not sensitive to grid conditions** – Because transfer-trip introduces an external communication channel, the successful transmission and receipt of signals are largely unrelated to grid conditions or variations in feeder structure. The result is a system that is generally much more predictable than PLC communication, especially given the variety of feeder structures across a utility system.
- **Doesn't impact power quality** – Unlike the PLC approach (and to some extent active anti-islanding) that depends on the successful application and detection of harmonics in the utility voltage, disturbance of power quality is not required for transfer-trip. Although these small disturbances are generally not an issue outside of specific circumstances, transfer-trip avoids power quality issues almost entirely.

Weaknesses

- **Not natively compatible with “independent” downstream protection** – Transfer-trip systems can be complicated because they must incorporate knowledge of the many devices on a distribution feeder. It may be necessary to know the condition of reclosers, switches, or fuses in order to signal the appropriate DG units. If those protective devices are not individually instrumented, the transfer-trip scheme cannot protect against smaller sections (less than the entire feeder, for instance) from becoming islanded. This obstacle may be overcome by using a synchrophasor for coordination, but with a significant increase in complexity and required data transfer.
- **Requires a DMS for proper coordination** – Even if downstream protection is instrumented, some type of DMS is

Transfer-Trip at DTE Energy

After evaluating transfer-trip over cellular bands, engineers at DTE Energy have opted for supplemental anti-islanding over a private wireless mesh network, provided by the ABB subsidiary Tropos. Currently the system connects a local substation to a single utility-owned PV installation. The substation transmitter is controlled by the relay on the feeder

breaker and signals a remote shutdown contact on the PV inverter downstream. This particular method promises lower latency with higher reliability and security than cellular. The future goal of the project is to evaluate several potential communication paths, each with a lower installation cost than traditional DTT.

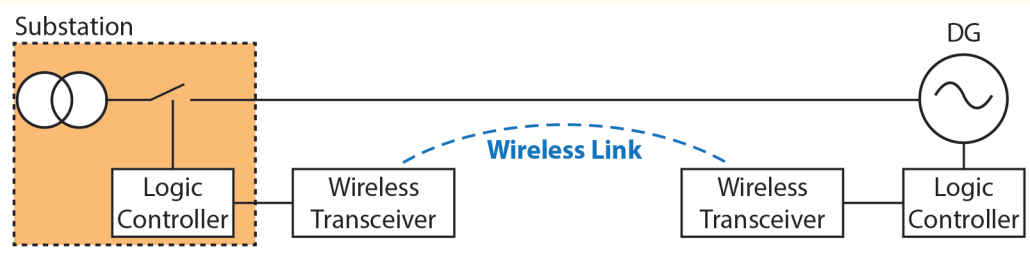
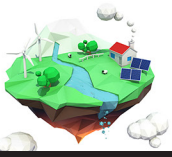


Figure 5 – A Radio Transfer-trip Scheme is being Implemented at DTE Ssubstation



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likely a requirement for multipoint transfer-trip because it must account for the location of each protective device relative to the individual DG units when sending a signal to connect or disconnect.¹⁹ The DMS becomes even more crucial when considering circuits that may be reconfigured, which would significantly alter the positioning of protection and DG.

- **Tradeoff reliability, security, and speed of communication versus cost** – As with any communications platform, performance and cost will be a tradeoff for anti-islanding as well. While direct fiber-optic connections from the substation to DG units may be the fastest and most reliable methods, they are unlikely to be the least expensive. Conversely, methods like using public internet may be low-cost, but their speed and reliability would be questionable. Each implementation must also be evaluated for cyber-security risk. Although the capabilities of individual technologies and the requirements of anti-islanding protection are still developing, this tradeoff between cost and performance must be carefully considered in future work.

Shorting Switch

As a supplement to onboard anti-islanding, there is at least one solution that does not require direct communication between the utility and the DG system. This involves using a “shorting switch” (also referred to as a *grounding switch*, *autoground*, or *crowbar*) to effectively ground each current-carrying phase on a distribution feeder. Doing so will trip the DG protection schemes on either under-voltage or over-current and force the systems off-line. In a radial distribution application, this shorting switch would typically be installed just outside the substation and near the head of the feeder.²⁰

Depending on the engineer’s preference, this shorting switch may be either solid or impedance grounding, each with its own advantages. Impedance grounding may be applied slightly before or during breaker operation, while solid grounding must be applied after the breaker opening has been confirmed in order to prevent potentially large short-circuit currents from the upstream system.

Strengths

- **Much less sensitive to feeder or load conditions** – Because this sort of scheme does not rely on actually communicating over the power line, as with PLC, it is much less sensitive to operating conditions. However, it must be coordinated with the DG’s onboard protection such that the reduction in voltage or the increase in generator fault contribution associated with the shorting-switch operation will be sufficient to trigger the DG’s onboard protection to operate.
- **Cost per site can be very low** – Because this solution does not require significant RF analysis or the construction of a new communication channel, the cost per site can be much lower than communication-based solutions. If timing is less critical, a shorting-switch solution can be created with off-the-shelf components.
- **Little or no steady-state burden** – Unlike communication-based solutions, which require continual operation, the shorting switch is only activated once the feeder breaker is opened. Thus there is practically no bandwidth or energy wasted during normal operation, and there is a minimal impact on power quality.

Weaknesses

- **Not effective with independent protection** – Just like the PLC system, the effect of the grounding switch is naturally blocked by fuses or other in-line protective devices. However, because the grounding switch is the opposite logic of PLCP, DG units behind other open breakers or fuses will continue to operate uninfluenced. Unlike the transfer-trip technique, this issue cannot be overcome with a DMS or other means of coordination. As an alternative, designers have suggested placing a shorting switch with each breaker or recloser between the DG and the substation.²⁰
- **Must be adequately sized to the expected feeder fault current** – Shorting switches must be able to handle the expected fault current from each DG unit until they cease operation. This is less of a concern with inverter-based DG but could be a serious planning criteria for feeders with large rotating machines (both generation and load).

¹⁹ P. Tumino, G. Di Lembo, and G. Bianco, “ENEL Smart Grid Projects: DER Management Applications,” *PAC World*, 09/2013. 2013.

²⁰ C. Abbey, Y. Brissette, and P. Venne, “An Autoground System for Anti-Islanding Protection of Distributed Generation,” *IEEE Transactions on Power Systems*, vol. 29, no. 2, pp. 873–880, 2014.



Testing the Shorting Switch Concept at Hydro-Québec

Engineers in Hydro-Québec's research institute (IREQ) have designed, implemented, and demonstrated what they refer to as an "auto-grounding system" at their test facility. They have installed a sectionalizing switch on a test feeder with the shorting switch downstream. The shorting switch uses commercially available vacuum switches that tie the individual phases directly to the neutral conductor. Switch logic and

timing use a Schweitzer SEL-351R relay and are coupled to the sectionalizing switch on an adjacent pole. When tested, the shorting switch successfully caused the 600-kVA rotating DG to disconnect under a number of different conditions, but researchers noted that care must be taken to coordinate with existing protection philosophies.

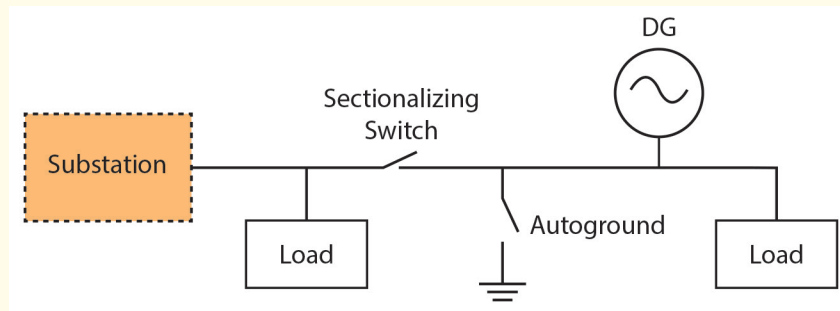


Figure 6 – A Shorting-switch Installation has been Successfully Demonstrated at an IREQ Facility in Canada

- **Not easily adaptable to reconfiguration** – Just like the PLC-based system, feeding the circuit from alternate circuits or substations will require the addition of more shorting switches at each connection point, which are then correctly enabled and correlated with the appropriate circuit breaker. If multiple shorting switches are installed and the wrong one is operated, it may cause additional outages or equipment damage.

Conclusion

Determining the probability and risk of forming an unintended island on a radial distribution feeder is subject to a number of factors, including the DG penetration level, output variability (stochastic nature), and DG technologies represented. Currently, onboard anti-islanding protection is the most widely available solution to prevent stable long-duration islands. The exact risk due to unintentional islanding is not easily quantifiable, but given all the variables that need to align in the formation of a stable island, the probability of personal injury or equipment damage is expected to be relatively small. This probability can be further reduced by advanced relaying functions in utility distribution, such as deadline sensing, and by changing line worker safety

practices to better account for DG. Ultimately, the concerns of the utility industry can be reduced but not eliminated. Improvements to existing protection methods and new ideas for supplemental protections will continue to be discussed.

In the event that supplemental protections are deemed necessary, there are several approaches currently available. This tech brief described and compared three methods. All have positive and negative aspects and will add cost. At this time, there is no clear winner, and limitations will need to be weighed by the utility operator relative to cost, complexity, and overall effectiveness. The operator's preferred approach will depend greatly on the expected DG deployment, knowledge of the local distribution infrastructure, degree of automation available, and individual utility objective or preferences. Future plans should incorporate some form of risk assessment, because decisions to retrofit later are notoriously expensive.

Supplemental anti-islanding is not a complete cure for the risk of unintended islanding, and at this point, improved onboard protection with no supplementary anti-islanding may be the most practical option. Future research in anti-islanding needs

to be accompanied with looking for better options and ideas on coordination of substation protection, relaying, and line worker safety practices. This is especially critical when considering the future role of microgrids and automation in the distribution system. All of these aim to ensure safe and reliable delivery of electricity with the presence of distributed generation.

What's Next for EPRI?

With more research needed to investigate available technology options for supplemental anti-islanding, EPRI has begun a project with several member utilities to evaluate vendor systems side-by-side in both the lab and the field. Technologies include low-frequency PLC and a number of wireless transfer-trip technologies. Field installations of several technologies are planned for early 2015, with data collection throughout the rest of the year. Research goals involve evaluating the installation process, performance, reliability, and response time (latency) of the different systems in a roughly comparable manner.

With the results of this supplemental, the goal is to provide feedback to members regarding the capabilities of the various systems, as well as generate relevant input to ongoing standards and higher-level coordination at both national and international levels.

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