Protecting the Modern Distribution Grid

EPRI Survey on Distribution Protection with Emphasis on Distributed Generation Integration Practices

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Technical Update, December 2013

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Electric Power Research Institute

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NOTE

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PRODUCT DESCRIPTION

The increasing penetration of distributed generation (DG) has created the need for changing protection practices for electric utility distribution systems. An assessment of current practice and experiences is provided. This report is to make utility engineers aware of potential issues and present protection practices for systems with DG.

Background

Distributed resources have had significant impacts on electric utility power delivery systems. Greater impacts are expected on both the transmission and distribution systems as higher levels of DG penetration are introduced. Issues relative to DG integration in electric utility systems are provided in previously published EPRI Reports (TR-105589, 1000419, and 1024354). This report focuses on the results of a survey EPRI has conducted on distribution protection practices to accommodate DR. The report also includes descriptions of some of the interconnection problems experienced.

Objectives

In order to help utilities prepare to meet evolving challenges in distribution practices it is imperative to learn from the practices and experiences of the industry. Accordingly, a survey was conducted to gather information on these distribution protection practices.

Approach

The approach can be divided into three tasks. First, research was conducted to identify various issues and concerns that impact distribution protection from DG integration. This research—which consisted of a literature review [1-14], discussions with members, and peer discussions within EPRI — was used to form the survey questions. The second task was to conduct the survey. The third task was to follow-up the survey responses with phone interviews to discuss the topics of the survey and to clarify answers. The goal was to identify present protection practices and determine what lessons may be learned from the different experiences of implementing DG onto the system.

Results

The survey results found that DG interconnection protection practices vary significantly from utility to utility and even within a utility, depending on the unique characteristics of the electrical system. Despite different practices, the basic objectives of each utility's requirements and concerns are the same. For example, all planning and protection engineers have the same objectives: operate reliably and safely, operate without degrading electric service to nearby customers, and operate without compromising utility system integrity.

This report highlights the survey responses to existing protection practices and lessons learned.

Applications, Value, and Use

This document aims at assisting planning and protection engineers with lessons learned, practices for protection schemes, and present protection philosophies.

Keywords
Integration of Distributed Generation (DG)
Distribution Planning
Interconnection Practices
Distributed Resources
Distribution Protection
Protection Practices

ABSTRACT

Distribution protection has seen many changes in recent years with the integration of higher penetration of distributed generation (DG) and advanced control systems. In order to help utilities prepare to meet these evolving challenges it is imperative to learn from the practices and experiences of the industry. Accordingly, the Distribution Systems Research Program conducted a survey to gather information on distribution protection practices. The ultimate goal of the survey was to review existing protection practices and determine what lessons have been learned.

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KEY FINDINGS

Summary and Lessons Learned

This chapter provides some of the key finding concluded from the survey. Additional conclusions can be found in Chapter 3 with additional explanation.

Supervision of DG Protection

Regardless of who owns a DG, when it is placed into service in an electric utility system, it becomes a functioning part of the system. This requires the utility system to depend on the accuracy and reliability of the protective relaying at the DG interconnection point.

As discussed in the follow-up phone interviews, most utilities require some form of commissioning/witness testing before DG of certain type and size is allowed to connect to the system. In addition to, or in lieu of, testing, the one-line diagrams and test reports are submitted to the utility for approval. After this initial inspection/testing the protection system is very seldom inspected afterwards.

This gap in the inspection/testing processs needs to be addressed. In the follow-up phone interviews it was discovered that some DG owners had modified the initial voltage protection settings to allow higher power output. This has resulted in high voltages on the primary distribution system leading to customer complaints and damage to customers' loads.

System Overvoltages

By far, the protection issue of most concern is overvoltages, in particular, overvoltages occurring following an islanding event. Of those surveyed, 75% selected overvoltages and islanding as the biggest concerns. In most cases, the utility's protection goal is to prevent overvoltages rather than to protect against them.

Thirty percent of participants have experienced overvoltage issues and 27% were not sure. The known overvoltage events can be contributed to:

- DG feeding into a transmission system single-line-to-ground (SLG) fault after the transmission system protection isolated itself from the fault. (Figure 1-1)
- DG that was not effectively grounded feeding into an electrical power system after the effectively-grounded utility system becomes isolated; i.e. removing the electrical power system's connection to ground (islanding event).
- High-Penetration DG causing overvoltages. (Figure 1-2)

These overvoltages have resulted in surge arrester failures, electronic equipment problems/failures, activation of relaying, and complaints from the DG provider.

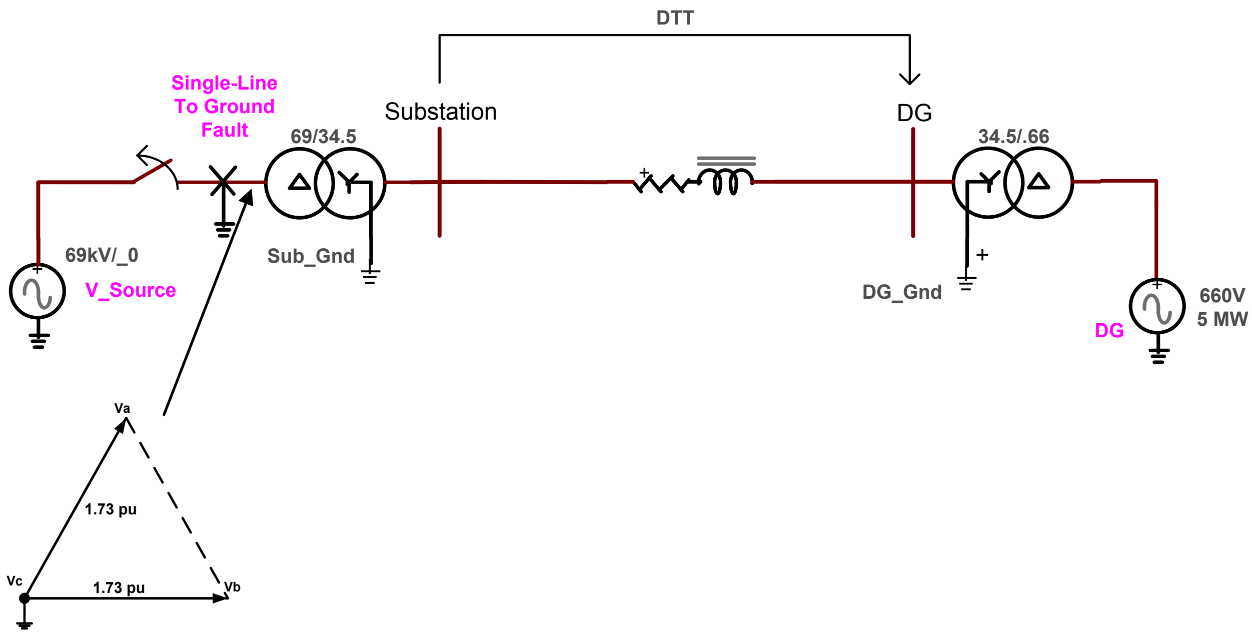

Figure 1-1
DG feeding into a transmission SLG Fault on the transmission system

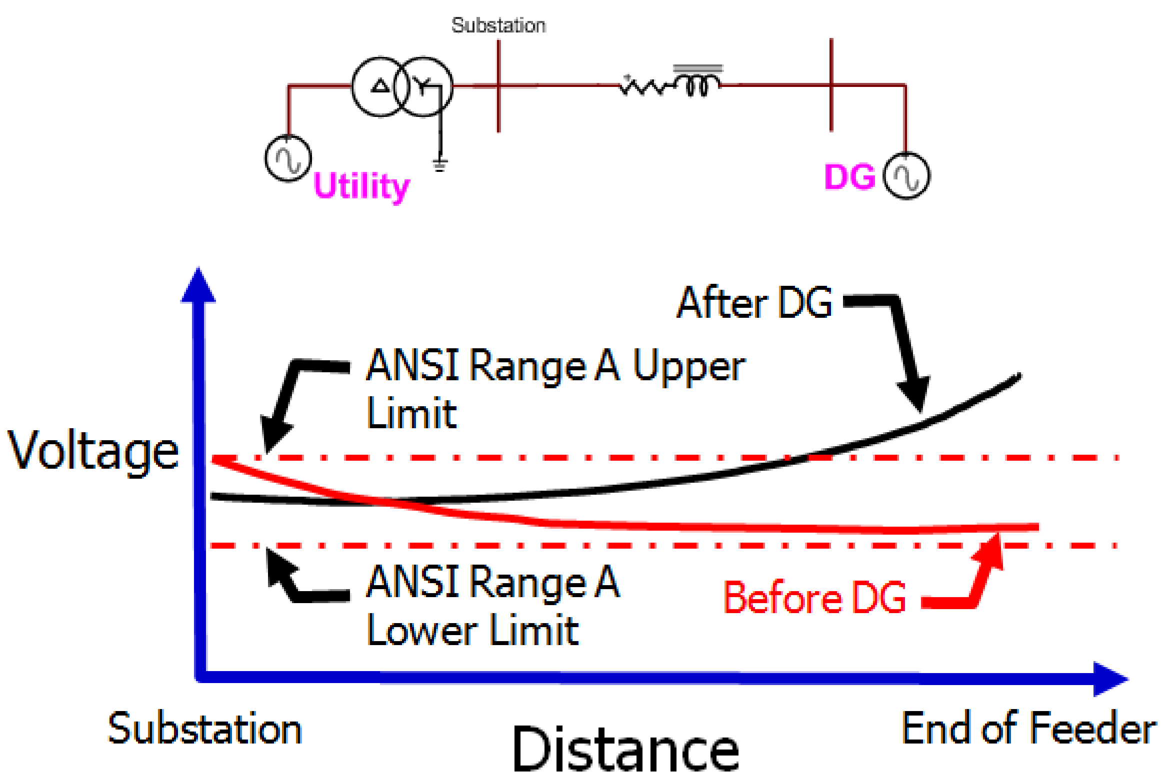

Figure 1-2
DG causing high feeder voltage when exporting large amounts of power relative to circuit impedance

Open-Phase Protection

Forty-three percent of respondents require detection against open-phase conditions. Of those who require protection against an open-phase condition, 33% require relaying in addition to simple overvoltage (59) relaying.

Based on the comments received and the follow-up phone interviews, the requirement to guard against an open-phase event on the utility distribution system is typically the responsibility of the customer. This is also the case for DG if it has been determined that it meets the requirements of IEEE Std 1547 and the DG is able to protect against an open-phase event. Two utilities found during DG commissioning tests that IEEE Std. 1547 was inadequate for protection against the open-phase conditions to which the DG could be subjected. These findings resulted in at least one of these utilities requiring an open-phase test to be conducted during DG commissioning.

Figure 1-3 illustrates a typical open-phase condition that can result from blown line fuses, damaged conductors, bad splices, etc. DG can be connected with any of a variety of transformer connections as depicted. Each connection can result in different behavior for the open-phase condition, requiring a different protection approach.

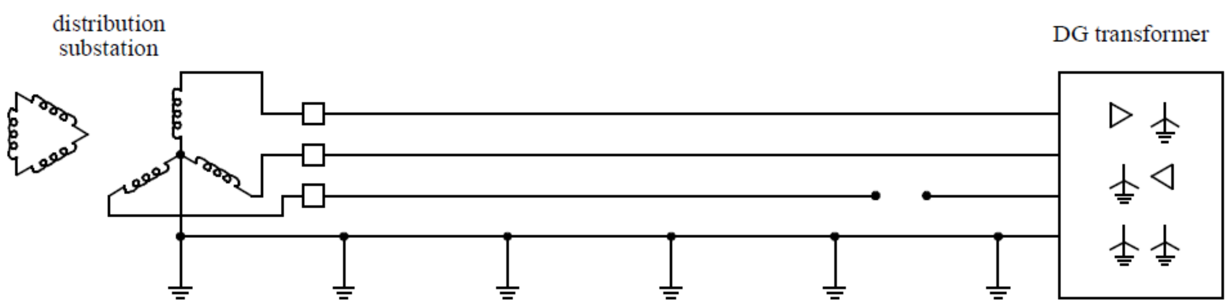

Figure 1-3
Open-Conductor condition with DG present

DG Infeed impact on Transmission Impedance Relay Settings

The impact of DG infeed on transmission impedance relay settings was raised as a concern in the follow-up phone interviews. Utilities with circuits containing higher penetrations of DG will screen for this issue and may require changes/additions to the substation protection.

Interconnection Transformer

The biggest requirement that went into selecting an interconnection transformer was the concern of system primary overvoltages. Opinions varied, with 43% recommending grounded wye – grounded wye (Yg-Yg) for the interface transformer for both inverter based and non-inverter based DG. See Figure 1-4 and Figure 1-5.

Most utilities that selected interface transformers with delta primaries had systems that were already designed to handle the potentially higher voltages associated with this type of connection. In some cases, if their standard transformer configuration for large 3-phase customers is Delta-Wye grounded (D-Yg) they may allow the D-Yg for DG interconnection to avoid ground fault coordination and fault locating issues. However, they may require the customer to install overvoltage relays that sense voltage on the primary. Some utilities indicated that early in the history of DG implementation on their systems, they allowed delta-connected DG systems on their system. However, after experiencing overvoltage events, grounding banks have been installed on some existing systems and they now require interconnection transformers to be effectively grounded on new DG installations.

Because of the concern of primary-side overvoltages, this led to varying requirements of what transformer type would be used to limit these overvoltages. The utilities that required some form of a grounded-wye/delta (Yg-D) transformer did so to ensure an effectively-grounded source that does not rely on the grounding impedance (or lack of grounding) of the generator itself.

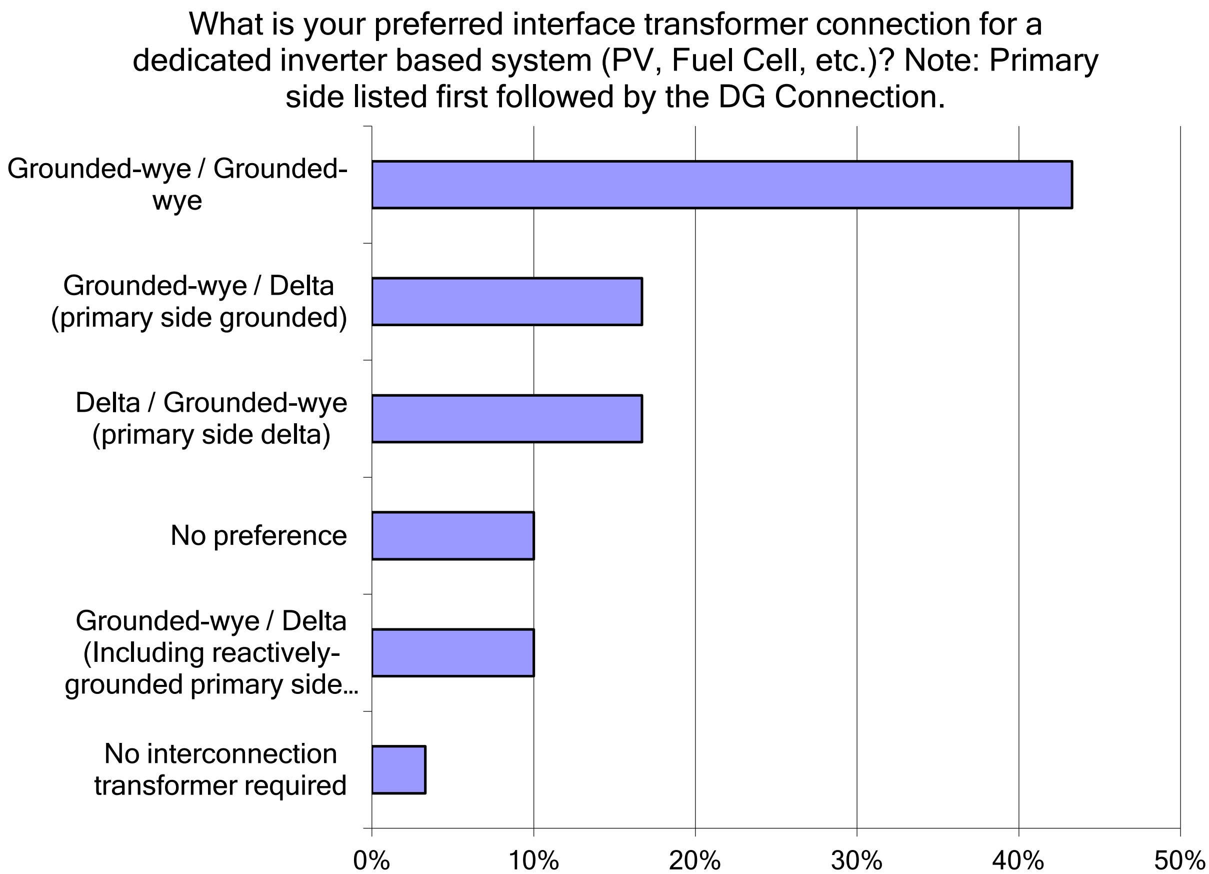

Figure 1-4
Preferred interface transformer connection for a dedicated inverter based system

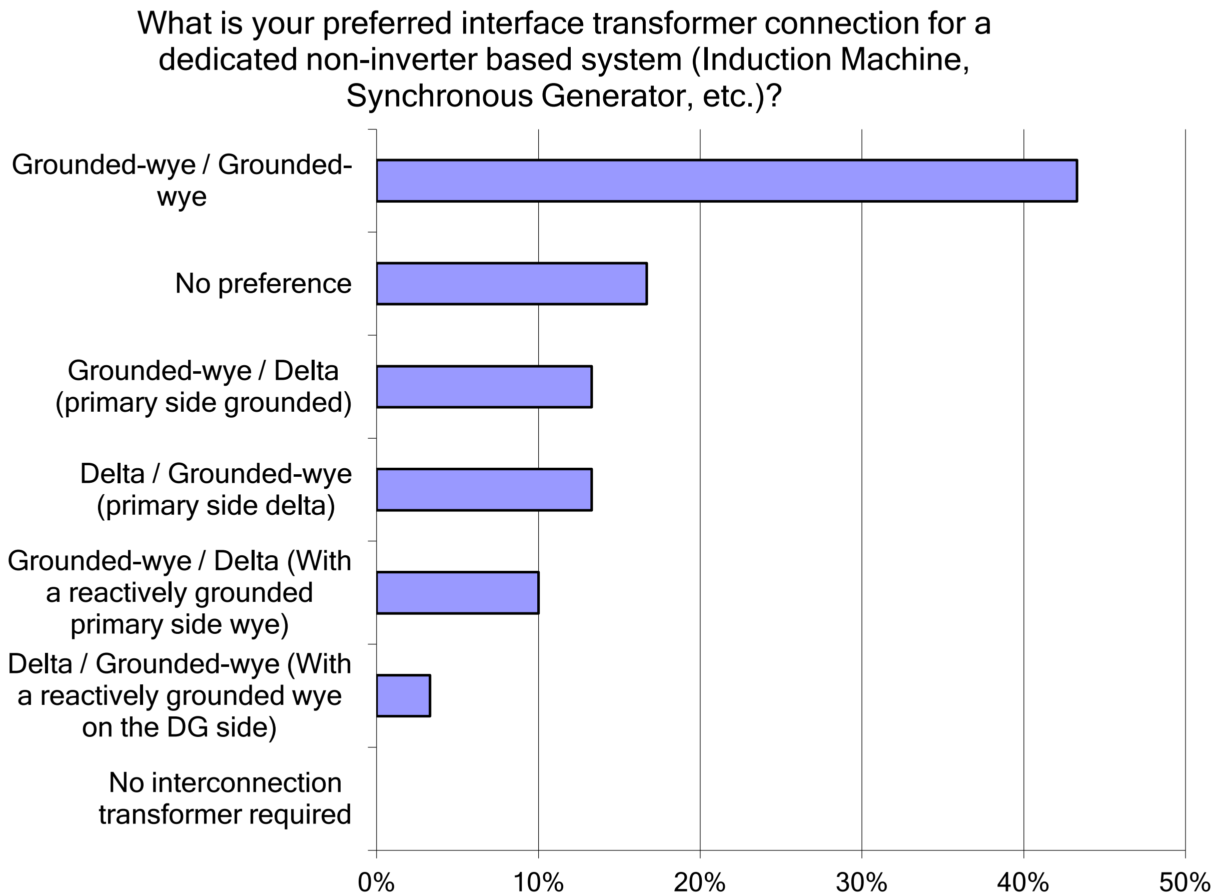

Figure 1-5
Preferred interface transformer connection for a dedicated non-inverter based system

Reclosing Practices

Over 57% of respondents have made changes to feeder reclosing practices, and 33% made changes to the substation reclosing practice to accommodate DG. As identified in the follow-up phone interviews, there may be more restrictions on reclosing operations for feeders with rotating-machine DG than for inverter-based DG. Some utilities still implement instantaneous reclosing on inverters. Even if an out-of-phase reclose does not damage the inverter, it could possibly result in the fault not clearing, transient overvoltages, or exposing motors and their mechanical loads to abnormal electromechanical torques. [10], [12]

Figure 1-6 illustrates a reclose into an inverter-based DG with 50 degrees of phase drift. Note the overvoltage and the abrupt change in voltage phase angle created by an out-of-phase reclosing. This out-of-phase reclosing becomes a concern in the case of inverter “run-on”, where the inverter continues to operate, and the amount of phase-angle drift experienced during this inverter “run-on” time.

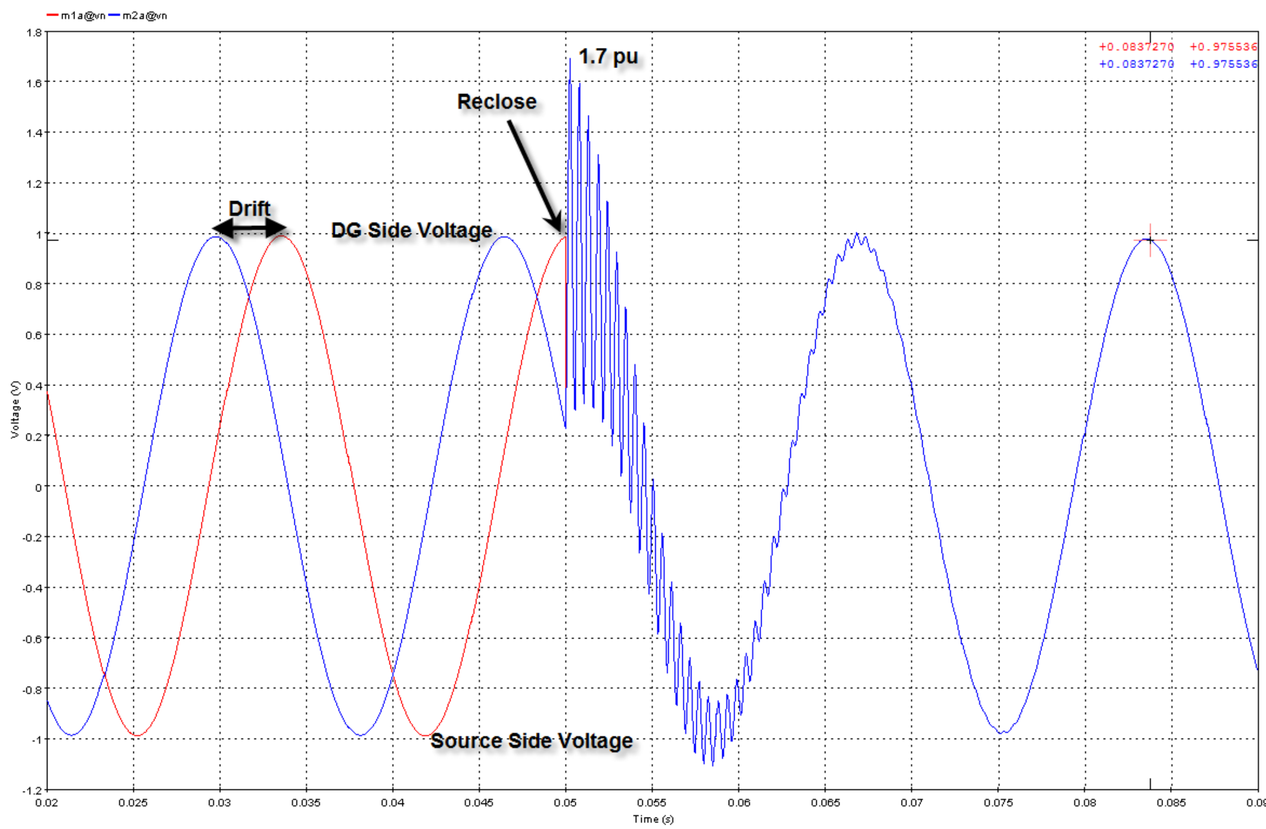

Figure 1-6
Reclose action into an unintentional island with 50 degrees of drift

Impacts on Existing Protection and Operating Procedures

Fifty-six percent of respondents indicated that changes/limitations have been put in place for their existing substation manual switching procedures due to DG. Some of these changes were safety related due to the concern of active generation existing on the feeder resulting in a voltage hazard after the circuit is opened. A number of procedure changes were related to the fact that the coordination of feeder relaying was of concern when scenarios existed that had not been studied; and therefore, proper coordination with existing protection had not been determined. In addition, if some DG require a Direct Transfer Trip (DTT) signal, it would also limit which substation breaker can serve feeders with DG.

2
SURVEY RESPONSES

Survey Questions

Survey questions were compiled based on a literature review [1-14], discussions with members, and peer discussions within EPRI.

The survey results are provided below along with comments. The comment numbers were kept consistent throughout the questions, e.g. “Commenter #1” in one response is the same “Commenter #1” in another response. This was done because some referred back to their previous comments. Minimal grammatical and clarification were performed on some comments, and some comments were altered to protect the identity of the utility.

Question 1) Information on survey responder.

The survey conducted consisted of 32 questions. There were a total of 30 respondents to the survey. This consisted of approximately 70% of those asked to participate in the survey.

Question 2) Please indicate which of the following existing protection practices have been impacted by adding Distributed Generation (DG)

This question was aimed at seeing what existing protection practices have been impacted on their respective systems. Responders were allowed to select multiple answers.

Table 2-1
Existing protection practices that have been impacted by adding DG

	Response Percent	Response Count
Coordination of feeder relaying	66.7%	20
Feeder reclosing practices	56.7%	17
Substation manual switching procedures	56.7%	17
Settings of existing phase relays	46.7%	14
Substation reclosing practices	33.3%	10
No effects	10.0%	3
Not applicable	6.7%	2

Comments

Commenter #1) Some Distribution connected DG's (ex. 4-5MW PV systems) require supervised reclosing of the substation feeder breaker. After a breaker operation, reclosing timer will be paused in the event voltage is still detected on the load side of the feeder breaker until voltage goes away. Coordination and settings of feeder relays need to account for fault current contribution/change due to the presence of DG.

Commenter #2) Larger, non-inverter based DG need to be isolated via visible break for dead line clearance.

Commenter #4) We have only isolated installations of DG, generally with small impacts on the networks to which they are connected. Auto-reclose is affected in some applications, depending on the islanding characteristics of the generator technology. Similarly, synch and system checks are sometimes used before closing.

Commenter #11) Have delayed automatic reclosing and installed voltage check schemes that prevent reclosing when DG is on line.

Commenter #12) Had to create several new switching procedures for operations when dealing with DG. DG/Customer requirements typically add more complexity to the design of the overall protection system.

Commenter #17) The substation and feeder reclosing practices are impacted at our territory due to the fact that the reclosing time interval is set at minimum 10 seconds, and as prescribed by IEEE 1547 all DGs must cease to energize the system in the intentional and faulted island within 2 seconds. Hence, the feeder and substation relays can reclose safely. Since we require all DGs to provide effectively grounded source to mitigate the voltage issue once the feeder recloser opens to clear the fault, all reclosers upstream of the Point of Common Coupling are desensitized. The relay coordination review addresses the required setting changes to maintain the proper coordination. Substation switching is impacted because the DG might have severe adverse impact on back up buses/feeders.

Commenter #19) Primarily we had to occasionally delay our first reclosing which sometimes tends to be close to instantaneous. We would evaluate coordination with the feeder but so far we did not have to change settings

Commenter #20) Direct transfer trip has been added in some cases.

Commenter #21) T-reclosing practices for subs tapped between breaker stations.

Commenter #23) For large customer generation we modified reclosing on the circuits feeding the customer. No effect for typical DG as of today

Commenter #25) Delay reclosing to 5 seconds.

Commenter #26) Impact on the issues checked above occurs very seldom and only for larger distributed generation.

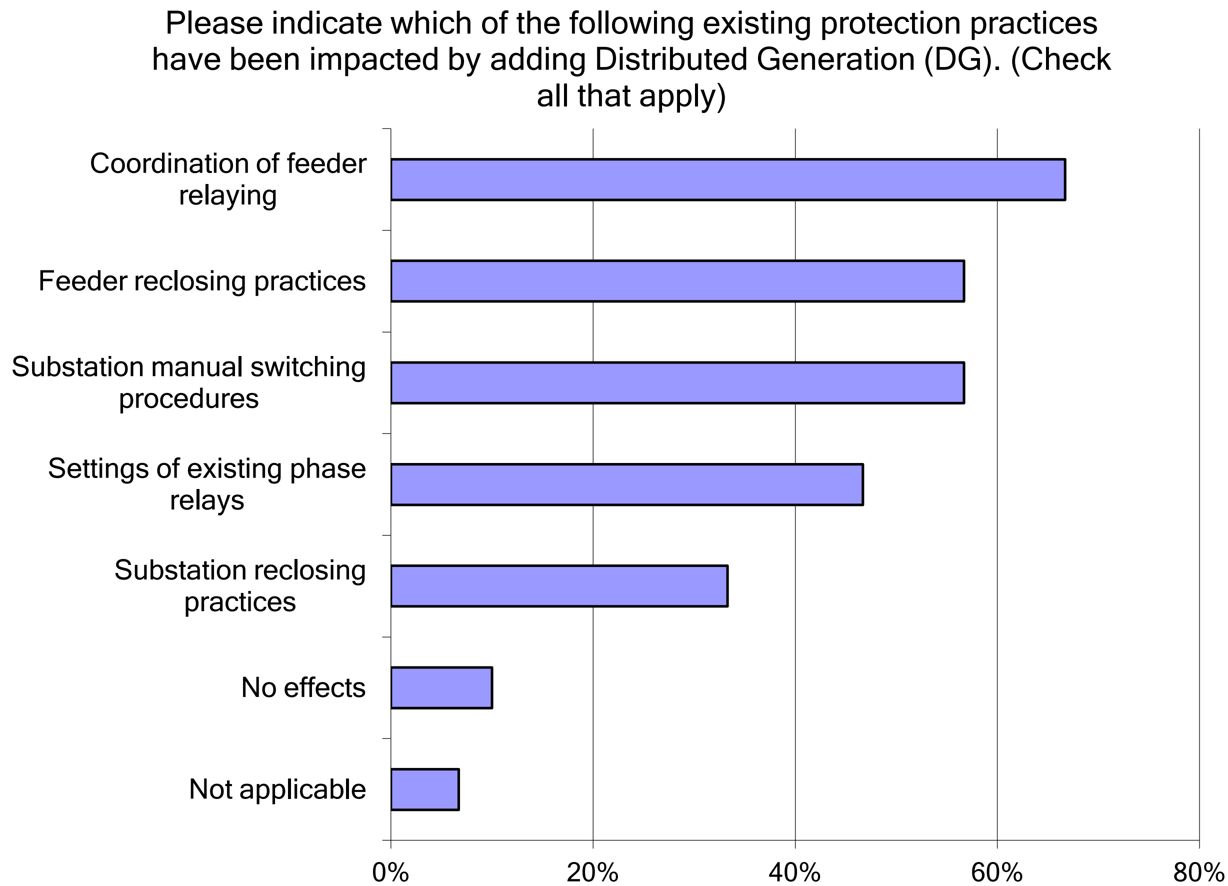

Figure 2-1
Existing protection practices that have been impacted by adding DG

Question 3) Please indicate if any of following have been added to your existing distribution system protection practices to accommodate Distributed Generation (DG)

The intent of this question was to see which of the following choices have been added to their existing protection practices. Responders were allowed to select multiple answers.

Table 2-2
Protection practices added to your existing distribution system to accommodate DG

	Response Percent	Response Count
Transfer trip capabilities	67.9%	19
Directional phase overcurrent relays	39.3%	11
Directional ground overcurrent relays	35.7%	10
Supervisory control to the feeder	32.1%	9
No Additions	14.3%	4
Adaptive relaying	7.1%	2
Not applicable	7.1%	2
Distance relaying	3.6%	1

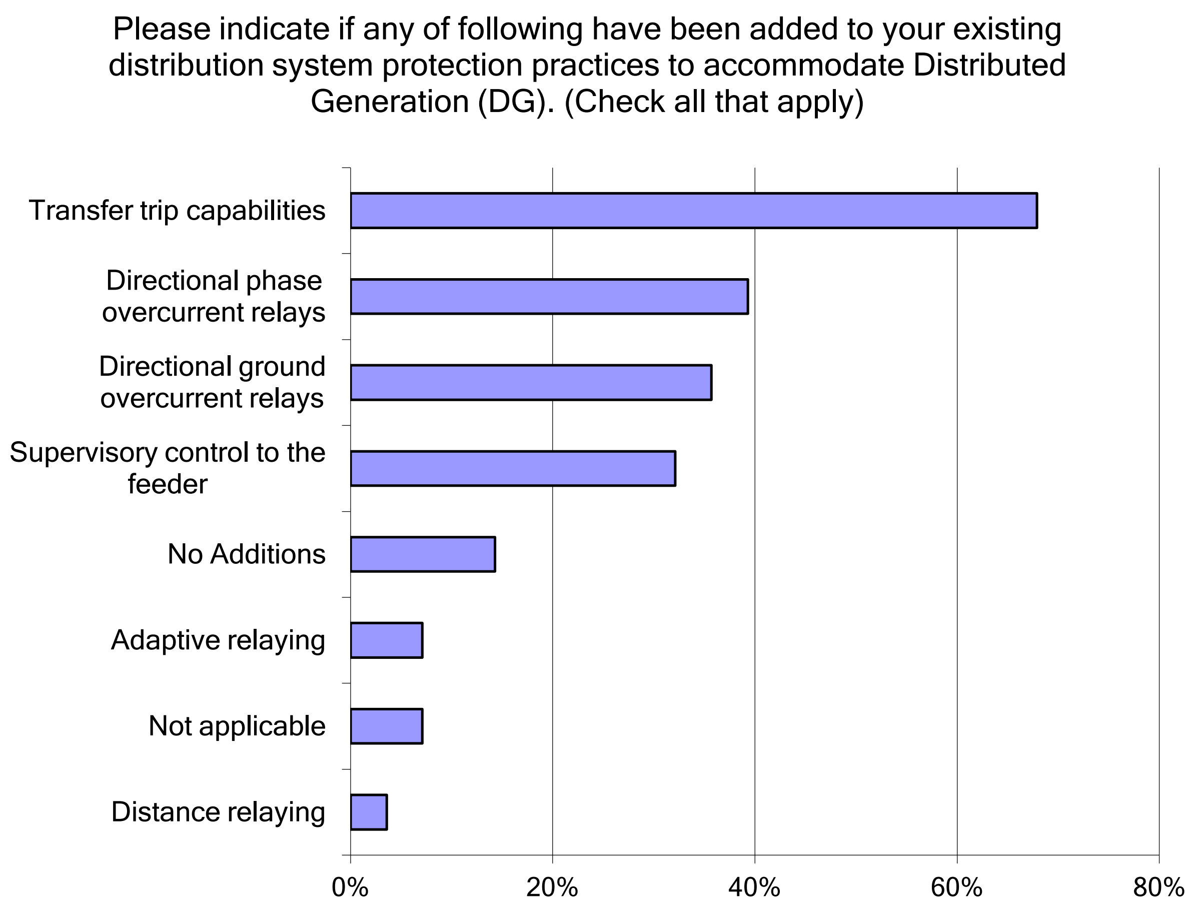

Figure 2-2
Protection practices added to your existing distribution system to accommodate DG

Comments

Commenter #1) Direct Transfer Trip was added to a feeder breaker relay and two site reclosers that connected about 14MW of rotating based DG (landfill methane burner). Directional ground and phase overcurrent settings were added to a site recloser interconnecting a large (3-4MW) rotating based DG. DG site was about 7 circuit miles from the substation and was experiencing too many trips and lockouts due to faults on the feeder.

Commenter #4) These features (except for Distance protection) are already available in the standard protection schemes. We have had a few cases where transfer trip capabilities were used. We have an option to apply HV-level schemes for MV networks if needed, although I am not aware of this being required as a result of DG.

Commenter #6) Added feeder voltage block close in some applications-

Commenter #12) We have required transfer trip for several customers. This is a safety concern especially for generation that is capable of islanding.

Commenter #19) We modify relaying including adding transfer trip when the system conditions require it. We also occasionally add dead line sensing.

Commenter #21) Addtion of voltage supervision of reclosing at sub and mid-line reclosers

Commenter #26) Transfer trip only added in a few applications with large Distributed Generation, this is typically not the case.

Commenter #27) Included Remove Automatic Reclosers due to the need to change substation relay settings. Also modify existing non-directional relay schemes with load encroachment type protection scheme

Question 4) What is your biggest protection concern with the interconnection of DG to your distribution system?

The intent of this question was to see what the biggest concern was about DG implementation, with the understanding that multiple concerns exist. Respondents were allowed to select only one answer.

Table 2-3
Biggest protection concern with the interconnection of DG

	Response Percent	Response Count
Islanding	50.0%	14
Sustained Overvoltages	25.0%	7
Separation/Disconnection from the distribution system during storm events	14.3%	4
Exceeding the interrupt ratings of existing equipment	7.1%	2
Impact to Ground Fault Current Coordination	3.6%	1
Impact to Phase Fault Current Coordination	0.0%	0

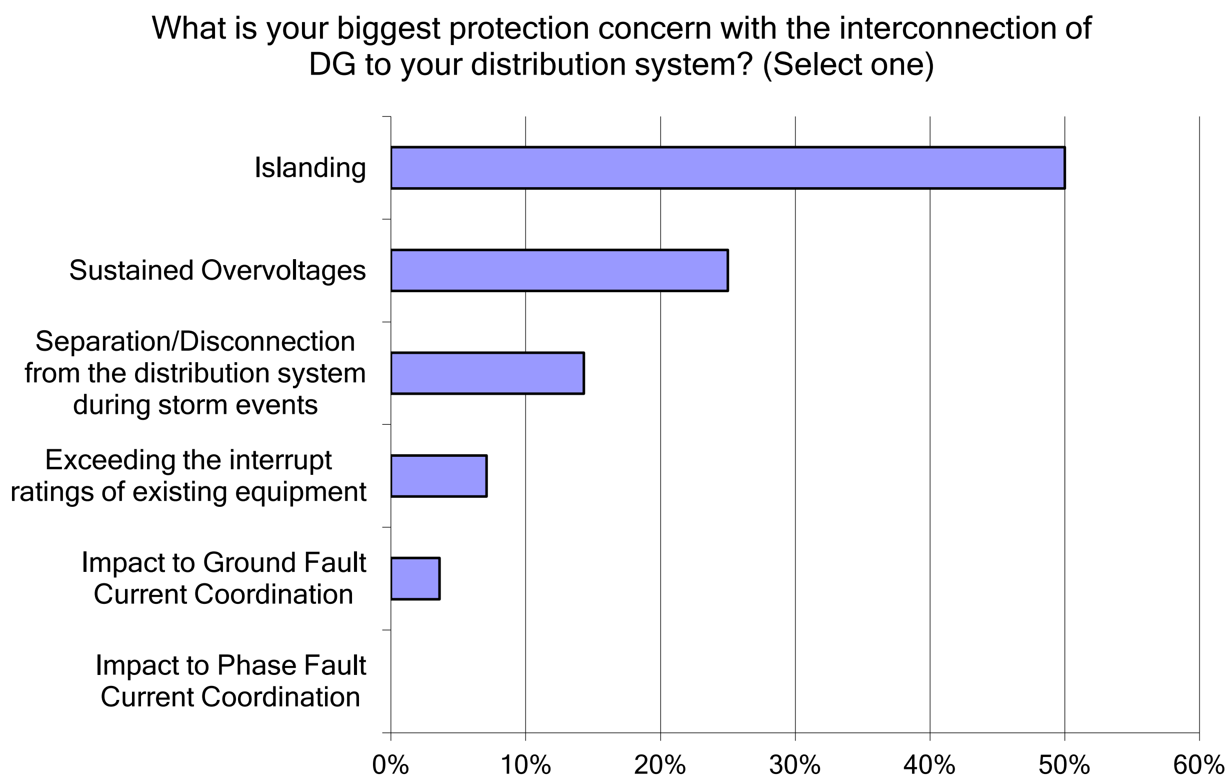

Figure 2-3
Biggest protection concern with the interconnection of DG

Comments

Commenter #1) If we have to select one it will be the protection system losing sensitivity/reach and not tripping for a fault on the feeder. Impact to ground and phase currrent coordination. Islanding is as equally important, big safety concern.

Commenter #7) It is impossible to choose one. They are all of concern depending upon the characteristics of the DG and the characteristics of the distribution circuit

Commenter #8) Protecting the DG from system events

Commenter #12) For synchronous machines that parallel we are quickly approaching the maximum interrupting ratings of our equipment at a few locations.

Commenter #15) Usually sustained overvoltages are caused by DGs bypassing 59 settings and disabiling voltage control on long feeders.

Commenter #18) Sustained Overvoltages is also a concern but does not include the safety issues.

Commenter #23) Safety Issues

Commenter #24) I have selected Islanding. However, all of the above individually could qualify for the biggest concern, because it is subjective and depends upon the type, location, and size of generation as well as on the type of the distribution system (1 phase/3phase, 3phase - 3 Wire, 3phase - 4 Wire, voltage class 44, 27.6, 25, 13.8, 8.32kV etc)

Commenter #25) Both Islanding and Sustained Overvoltages

Commenter #29) If DG facility does not properly separate, the islanding of limited portions of the Utility system could allow anything from mild PQ events to damage by overvoltage through zero-sequence open circuits.

Question 5) What communications technologies, if any, has been added to your system to communicate between the feeder relaying and interconnected DG?

This question wanted to survey the different communication technologies that are being used on DG.

Table 2-4
Communications technologies that have been added to your system to communicate between the feeder relaying and interconnected DG

	Response Percent	Response Count
Fiber Optic	50.0%	15
Radio	43.3%	13
Telephone	33.3%	10
None added	26.7%	8
Spread Spectrum Communications	20.0%	6
Power Line Carrier	3.3%	1
Two-Way Pagers	0.0%	0
Not applicable	0.0%	0

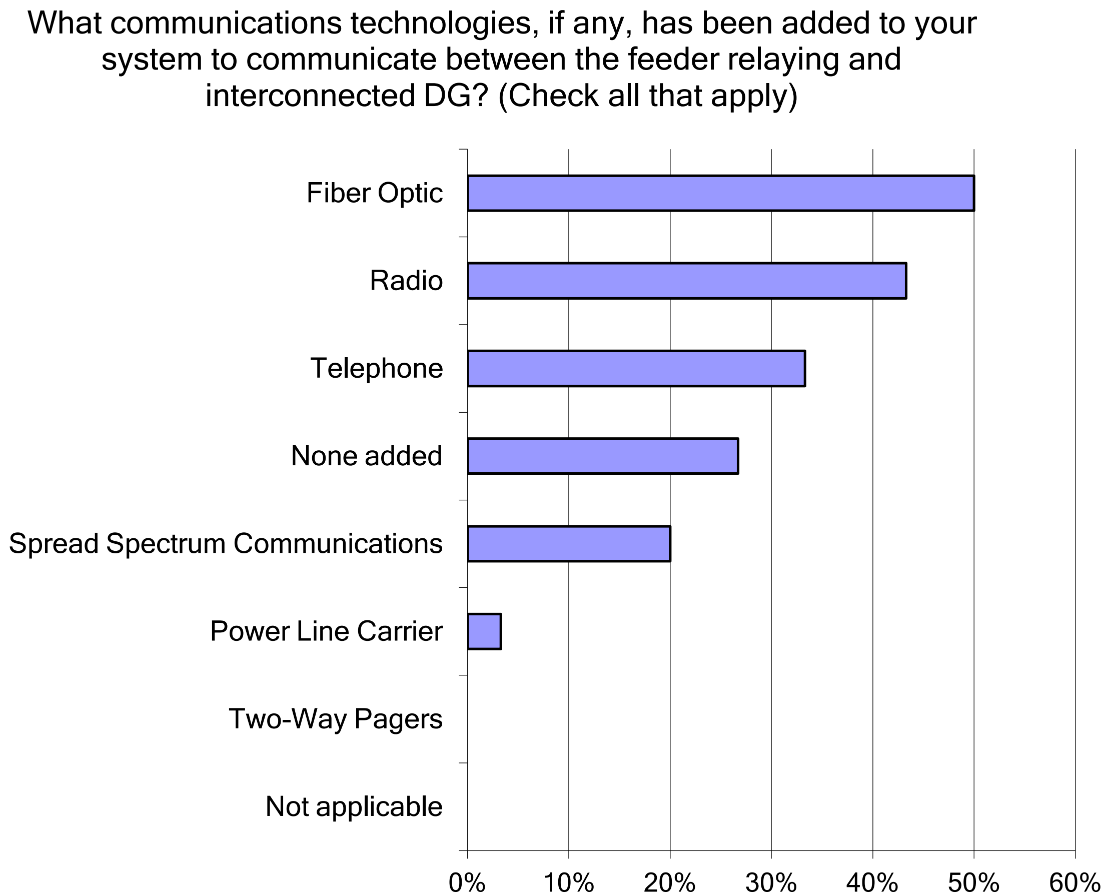

Figure 2-4
Communications technologies that have been added to your system to communicate between the feeder relaying and interconnected DG

Comments

Commenter #1) Fiber Optic cable was added to connect feeder breaker relay and two DG site reclosers. See the our comment in Question #3 for more details.

Commenter #3) Not that these are new to our system but we have had to add communications at certain locations

Commenter #12) Telephone and Fiber are the most typical means of communications we are however currently investigating radio as a possible alternative.

Commenter #15) DG communications only used for SCADA/Metering.

Commenter #17) Where Direct Transfer Trip (DTT) is required, telephone line or Radio can be used to shut down the generation during island. If needed, DTT is only installed on the feeder breaker at the substation. The Dispatch center shuts down the generators through RTU or any DNP3 compliant communication device, if feeder switching is necessary. All generators 1MW and above require remote monitoring and control.

Commenter #26) Radio when transfer trip is needed which per our comment in question 3, does not occur very often.

Commenter #27) We have utilized the Internet with RTU systems to provide telemetry data for small generator projects.

Question 6) If communications were added to the DG installation for functions such as Direct Transfer Trip what caused this requirement?

This question was a follow-up to the previous question to understand what resulted in the requirement to add communications. The responders were allowed to choose more than one reason.

Table 2-5
Reasons for adding communications to the DG installation

	Response Percent	Response Count
Islanding Concerns	91.7%	22
Generation Size	58.3%	14
Impact to existing coordination	16.7%	4
Provisions for microgrid	4.2%	1
Provisions for possible future growth	0.0%	0

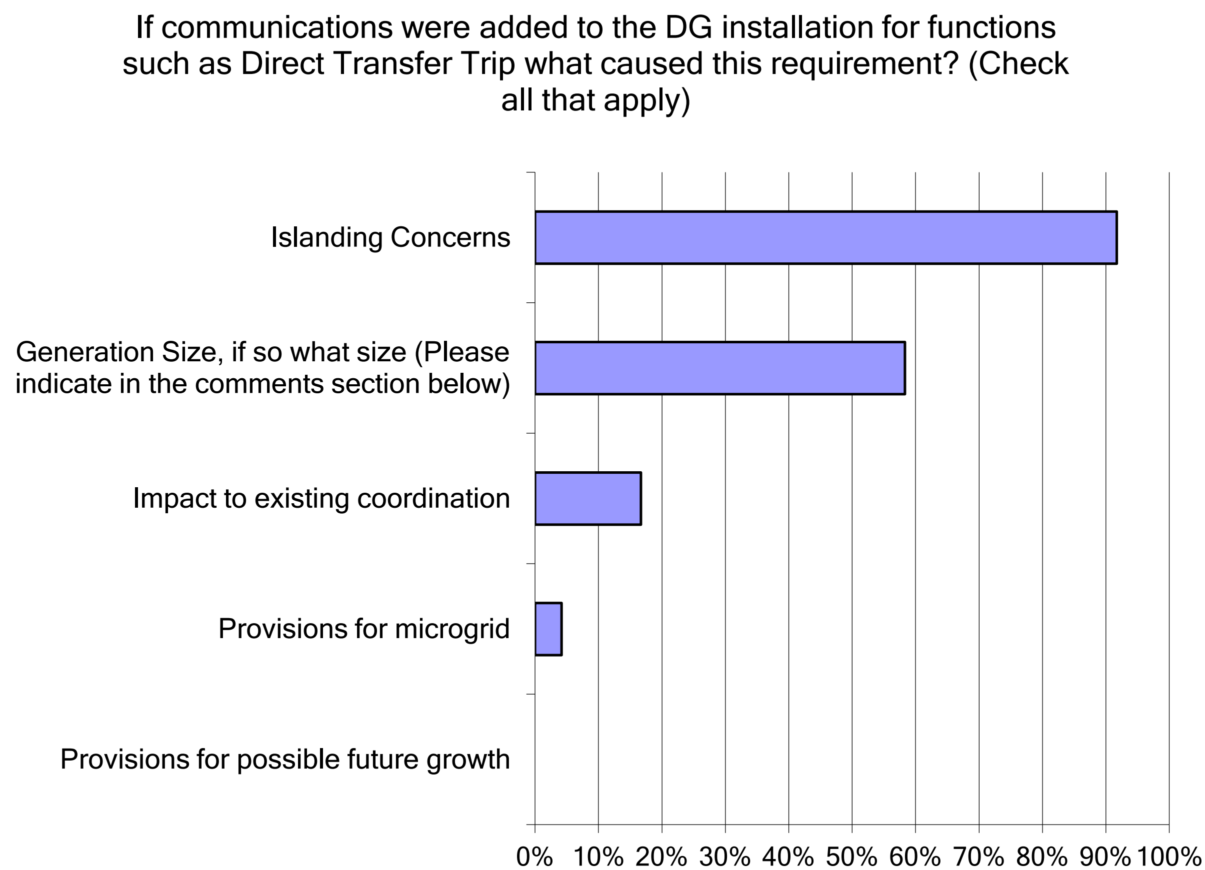

Figure 2-5
Reasons for adding communications to the DG installation

Comments

Commenter #1) See question #3 above for details. DG size was about 14MW on a 12kV distribution feeder. DG could backfeed transmission system. During the DG feeder breaker operation, we wanted to make sure DG immediately trips. Also added supervised reclosing at the feeder breaker.

Commenter #2) approx 2MW exporting

Commenter #3) Any generation over 2MW requires SCADA. Circuits approaching saturation may require SCADA at a lessor amount.

Commenter #5) Depending on location and load

Commenter #15) Potential to use communications for voltage dispatch and VVO.

Commenter #17) In some cases, the generator might sustain the island for longer than 2 seconds, which is the threshold to require Transfer Trip.

Commenter #19) We usually look at the size of the generator vs. the minimum load of the island. If there is a 3:1 ratio of load vs generation then we waive the transfer trip requirement. We still install over and under voltage, over and under frequency relaying.

Commenter #21) Added for generation that is large relative to feeder capacity especially if DG are rotating machines, such as 5-10 MW for urban 15 kV class feeder.

Commenter #24) DTT required whenever Generation is greater than 50% of the minimum load of feeder/feeder section

Commenter #25) When generation can meet or exceed minimum feeder loading we are concerned about islanding, as over/under frequency and over/under voltage relaying may not work.

Commenter #26) When generation size is close to or exceeds minimum feeder loading.

Commenter #27) N/A

Commenter #28) 100 kW and above

Question 7) What is your preferred interface transformer connection for a dedicated inverter based system (PV, Fuel Cell, etc.)? Note: Primary side listed first followed by the DG Connection.

This question was attempting to understand the preferred transformer connection for interfacing with inverter based systems.

Table 2-6
Preferred interface transformer connection for a dedicated inverter based system

	Response Percent	Response Count
Grounded-wye/Grounded-wye	43.3%	13
Grounded-wye/Delta (primary side grounded)	16.7%	5
Delta/Grounded-wye (primary side delta)	16.7%	5
No preference	10.0%	3
Grounded-wye/Delta (Including reactively-grounded primary side neutral)	10.0%	3
No interconnection transformer required	3.3%	1

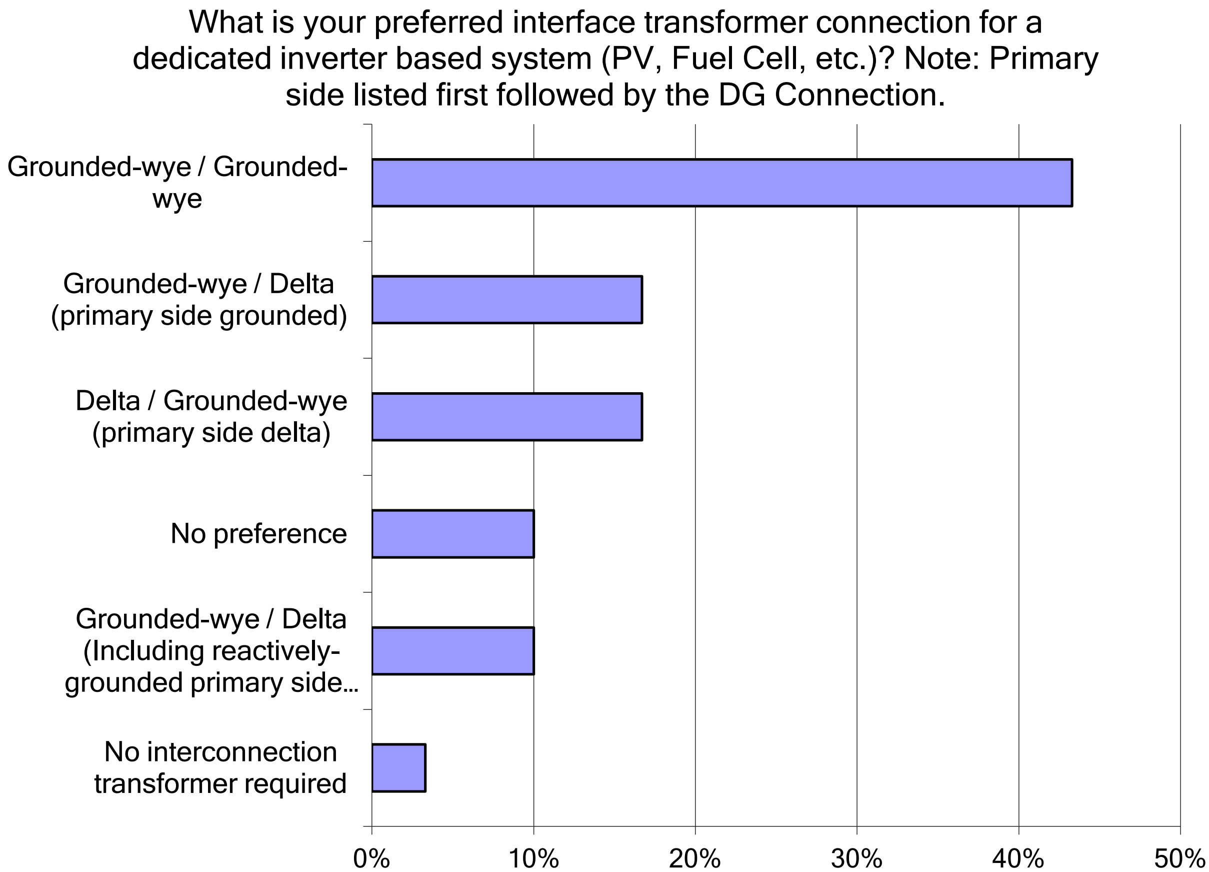

Figure 2-6
Preferred interface transformer connection for a dedicated inverter based system

Comments

Commenter #1) Grounded-wye/Grounded-wye; our system is a 4 wire GRDY system, all equipment is rated L-G. We don't allow a DELTA customer/secondary connection for inverter based systems.

Commenter #4) Delta/Grounded-wye (primary side delta); we use a low-impedance resistive earthing on our MV networks. We prefer that they be earthed at the source only. We do have provision for DG's to provide a switched or high-impedance earth on the MV network if this is required for intentional islanded operation of the plant (islanded operation on our network is not permitted).

Commenter #5) Delta/Grounded-wye (primary side delta); with ground detection scheme

Commenter #12) Grounded-wye/Delta (Including reactively-grounded primary side neutral); it is preferred to have a grounded source with respect to the utility system for the DG especially if the DG is larger than the local load at the DG location. May require the DG to provide test reports showing how quickly the DG reacts to faults and to determine it is capable of producing and overvoltage for a single line to ground fault.

Commenter #15) Grounded-wye/Delta (primary side grounded); for smaller inverters (< 1 MW) there is no preference. We have very few inverters > 1 MW. Current practice follows requirements for Synchronous and Induction machines and has not

Commenter #17) Grounded-wye/Grounded-wye; if the PV is connected to an effectively grounded feeder, the interconnection transformer configuration must be: 1) Yg/Yg with an effectively grounded inverter, or 2) Primary Yg/Secondary Delta (Neutral grounding reactor might be added to the primary neutral winding to limit the fault current contribution to 3X PV max rating), or 3) If the PV is not effectively grounded, Yg/Yg with a grounding bank on the secondary (Neutral grounding reactor might be added to the primary neutral winding to limit the fault current contribution to 3X PV max rating)

Commenter #18) Grounded-wye/Delta (primary side grounded); this is the distribution system preference. Since most of our DG is on the distribution system, this is what is used. We would investigate other connections if the customer requested it.

Commenter #21) Grounded-wye/Grounded-wye is company standard for 4 wire systems. Delta-wye for three wire systems. NR-Wye-delta for large faculties (usually customer owned)

Commenter #24) Grounded-wye/Delta (Including reactively-grounded primary side neutral); I this one assuming it is Wye-neutral reactively grounded (utility side)/delta (DG side) interface transformer on 3phase 4wire distribution where 3phase ganged tripping is practiced. However, the preference of interface transformer depends upon the type of the distribution feeder and tripping practiced (1phase tripping or 3phase ganged tripping).

Commenter #25) Delta/Grounded-wye (primary side delta); our standard transformer configuration for large 3-phase loads is Delta-Grounded-wye. We use this transformer configuration to avoid ground fault coordination and fault locating problems. However, this configuration may cause overvoltage problems for back-fed ground faults. In some cases we require customer to install overvoltage relays on the high-side. For small customers single phase-ground transformers are used.

Commenter #27) No preference; If we are installing the transformer, then we will install our standard D/Y-grounded transformer.

Commenter #29) Grounded-wye/Grounded-wye; Assuming inverter bank is solidly grounded wye. If generator is ungrounded or impedance grounded, prefer a GWye/Delta connection.

Question 8) What is your preferred interface transformer connection for a dedicated non-inverter based system (Induction Machine, Synchronous Generator, etc.)?

This question was attempting to understand the preferred transformer connection for interfacing with rotating based systems.

Table 2-7
Preferred interface transformer connection for a dedicated non-inverter based system

	Response Percent	Response Count
Grounded-wye/Grounded-wye	43.3%	13
No preference	16.7%	5
Grounded-wye/Delta (primary side grounded)	13.3%	4
Delta/Grounded-wye (primary side delta)	13.3%	4
Grounded-wye/Delta (With a reactively grounded primary side wye)	10.0%	3
Delta/Grounded-wye (With a reactively grounded wye on the DG side)	3.3%	1
No interconnection transformer required	0.0%	0

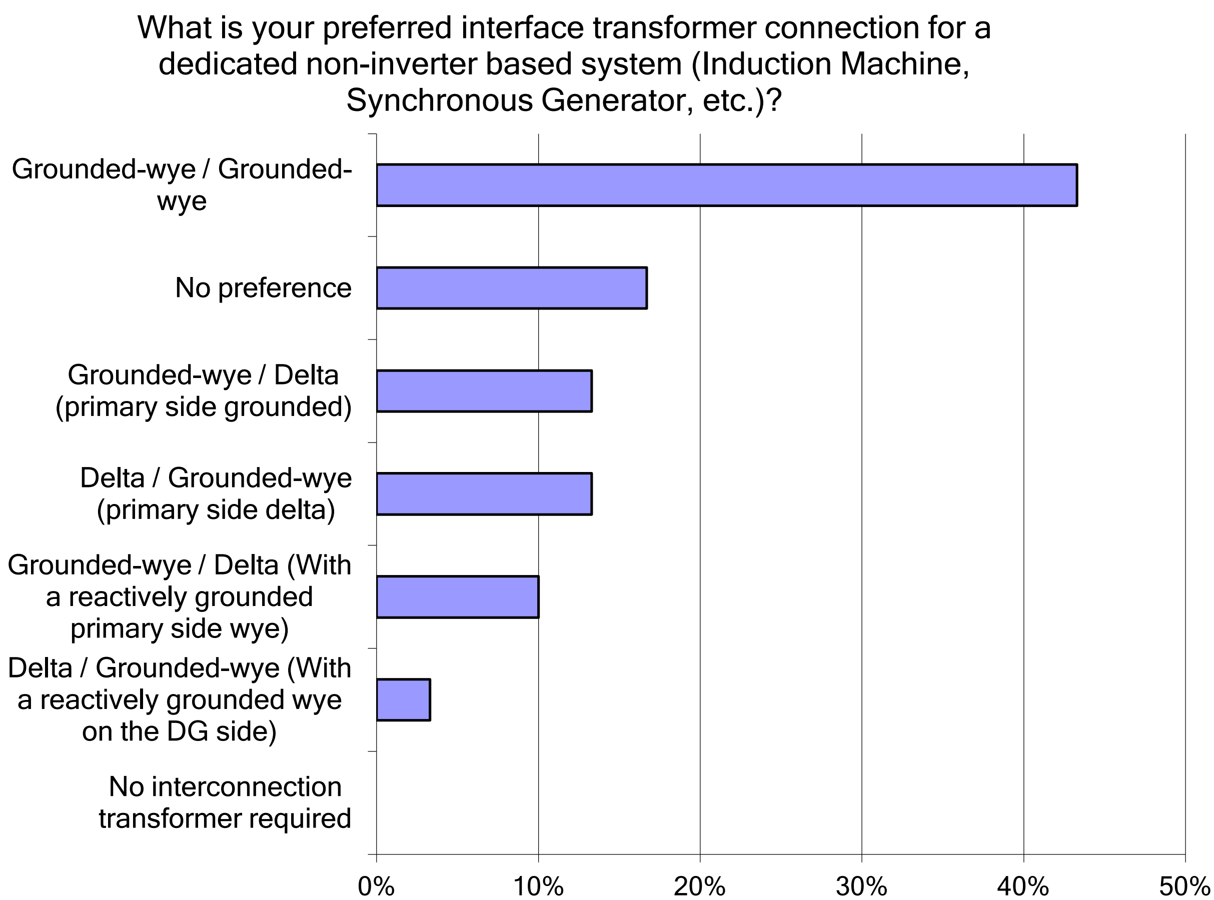

Figure 2-7
Preferred interface transformer connection for a dedicated non-inverter based system

Comments

Commenter #1) Grounded-wye/Grounded-wye; our system is a 4 wire GRDY system, all equipment is rated L-G. However, we don't specify customer side connection. Many rotating based DG's have a 3 wire DELTA connection on their end.

Commenter #4) Delta/Grounded-wye (primary side delta); as previous comment in question #7 above.

Commenter #5) Delta/Grounded-wye (primary side delta); with ground detection scheme

Commenter #9) Grounded-wye/Delta (primary side grounded); Generator needs to be Delta

Commenter #12) Grounded-wye/Delta (With a reactively grounded primary side wye); a grounded source must be provided by the DG with respect to the utility system. This is required for all synchronous interconnections that wish to parallel for greater than 100ms. Grounding reactor must be sized to not adversely affect existing ground relaying and to not cause overvoltages that would exceed the ratings of utility equipment.

Commenter #17) Grounded-wye/Grounded-wye; if the non-inverter based generator is connected to an effectively grounded feeder, the interconnection transformer configuration must be: 1) Yg/Yg with an effectively grounded source, or 2) Primary Yg/Secondary Delta (Neutral grounding reactor might be added to the primary neutral winding to limit the fault current contribution to 3X PV max rating), or 3) If the generator is not effectively grounded, Yg/Yg with a grounding bank on the secondary (Neutral grounding reactor might be added to the primary neutral winding to limit the fault current contribution to 3X PV max rating)

Commenter #18) Grounded-wye/Delta (primary side grounded); this is the distribution system preference. Since most of our DG is on the distribution system, this is what is used. We would investigate other connections if the customer requested it.

Commenter #21) Grounded-wye/Grounded-wye; see previous comment in question #7 above

Commenter #24) Delta/Grounded-wye (With a reactively grounded wye on the DG side); comments are same as Question # 7

Commenter #25) Delta/Grounded-wye (primary side delta); our standard transformer configuration for large 3-phase loads is Delta-Grounded-wye. We use this transformer configuration to avoid ground fault coordination and fault locating problems. However, this configuration may cause overvoltage problems for back-fed ground faults. In some cases we require customer to install overvoltage relays on the high-side. For small customers single phase-ground transformers are used.

Commenter #27) No preference if we are installing the transformer, then we will install our standard D/Y-grounded transformer

Commenter #29) Grounded-wye/Grounded-wye; assuming generator is solidly grounded wye. If generator is ungrounded or impedance grounded, prefer a GWye/Delta connection.

Question 9) When specifying an interconnection transformer, what is your biggest concern?

The purpose of this question was to understand what went into the requirement for which interface transformer was selected.

Table 2-8
Biggest concern in specifying an interconnection transformer

	Response Percent	Response Count
System primary overvoltages	62.1%	18
Impact on ground fault current coordination	20.7%	6
Protecting the DG equipment from system ground faults, harmonics, unbalance, etc.	10.3%	3
Impact on phase fault current coordination	6.9%	2

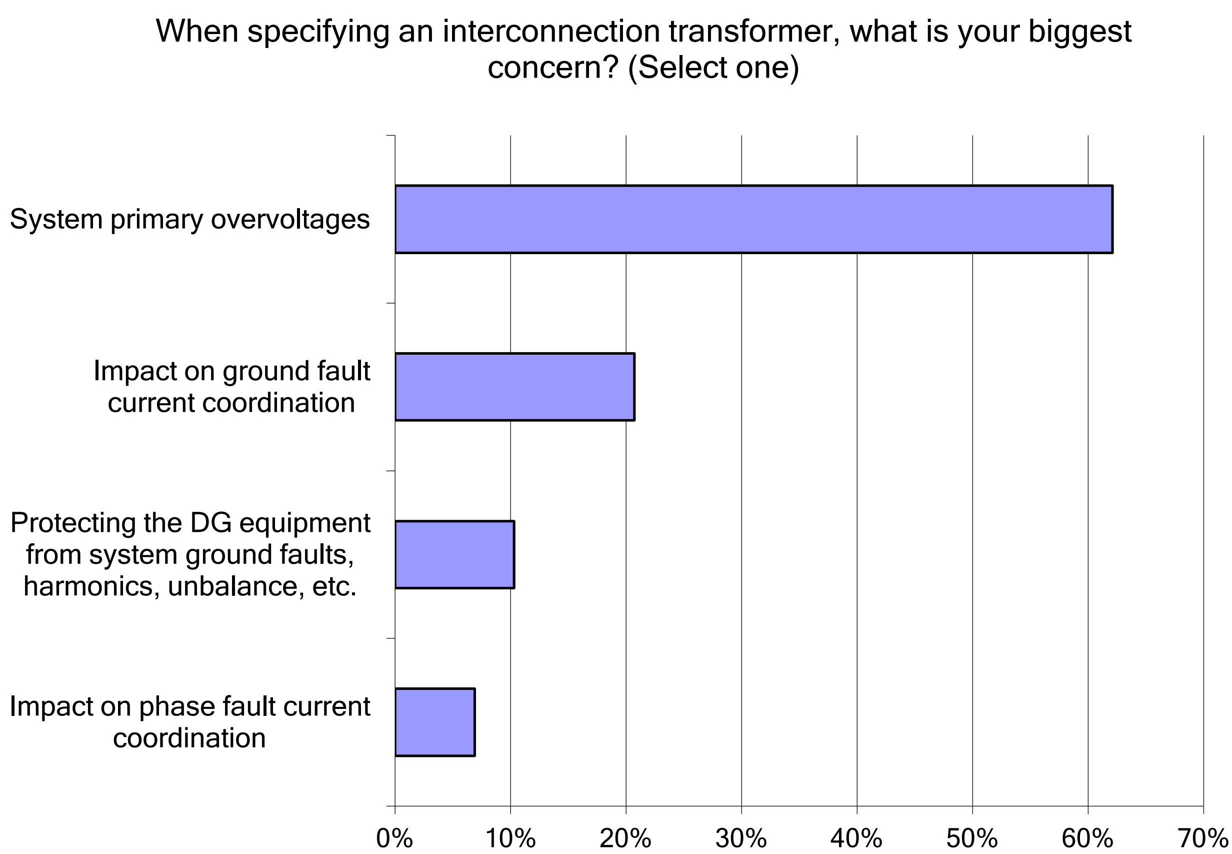

Figure 2-8
Biggest concern in specifying an interconnection transformer

Comments

Commenter #1) Potential Overvoltage on L-G rated equipment is a concern as well as islanding with a 3 wire utility side connected DG, therefore connection has not been allowed. Also, we want to be able to see and trip for ground faults on the DG side and also the DG to trip for some faults on the feeder.

Commenter #5) Protecting the system from Harmonic Injection

Commenter #7) Distribution system reference neutral being carried through to the DG so the DG reference is the same as the distribution system to which the DG connects

Commenter #12) Especially for synchronous machines.

Commenter #17) Once the feeder recloser is opened due to a L-G fault, an ungrounded generator on the islanded section of the feeder might create L-L voltages on the un-faulted phases if the islanded load is not large.

Commenter #21) Applies to 4 wire feeders. Restraint of TOV during islanding and ground faults are of high priority.

Commenter #24) I have selected first (System primary overvoltages) assuming connection on 3phase 4wire multigrounded distribution feeder. However, for 3phase 3wire distribution feeder where there are no 1phase laods (phase to neutral) connected the overvoltage is not the biggest concern, instead the ground fault current coordination is an issue.

Commenter #25) Both overvoltages which can damage our lightning arresters; and islanding, which can damage other customer equipment due to low or high voltage and off-frequency operation.

Question 10) Do you require at least one side of the interconnection transformer to be a delta winding?

Another question to better understand the requirement for the DG interface transformer.

Table 2-9
At least one side of the interconnection transformer is required to be a delta winding

	Response Percent	Response Count
No	60.0%	18
Depends on installation	23.3%	7
Yes	16.7%	5
Does not apply	0.0%	0

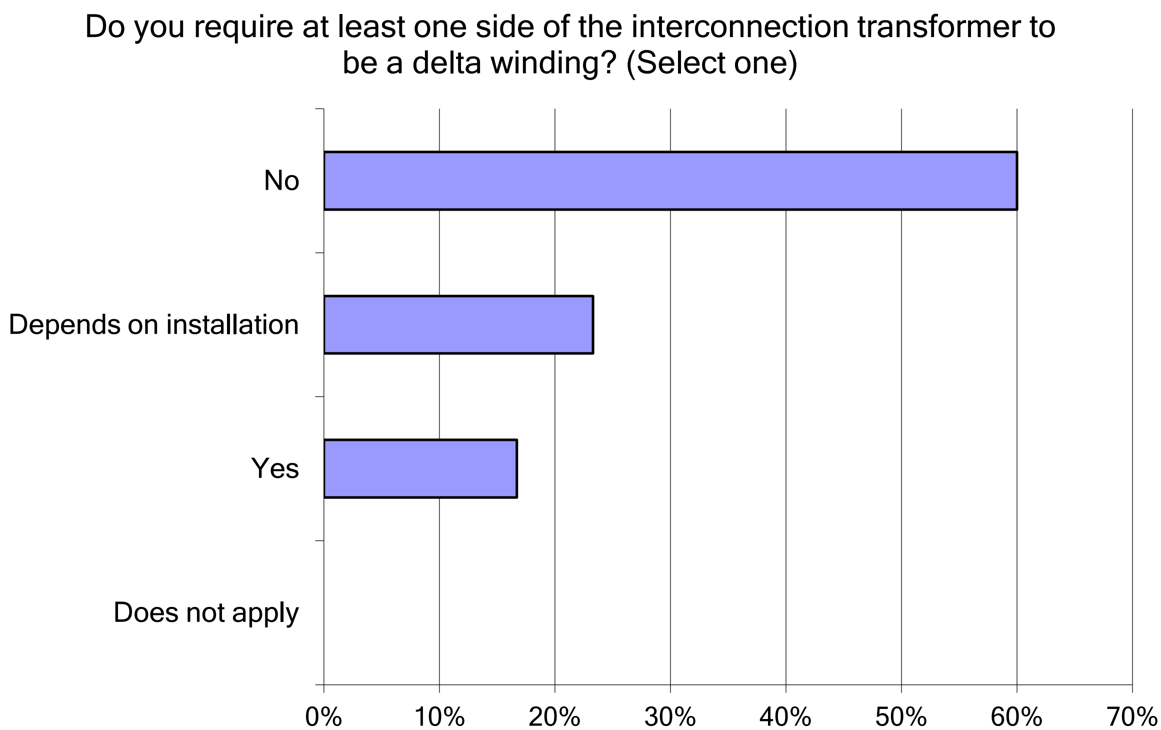

Figure 2-9
At least one side of the interconnection transformer is required to be a delta winding

Question 11) Have you ever required a grounding transformer for mitigating primary Transient Overvoltages (TOV)?

This question is to survey the use of grounding transformers to mitigate transient overvoltages.

Table 2-10
Required a grounding transformer for mitigating primary Transient Overvoltages

	Response Percent	Response Count
Yes	53.3%	16
No	43.3%	13
Does not apply	3.3%	1

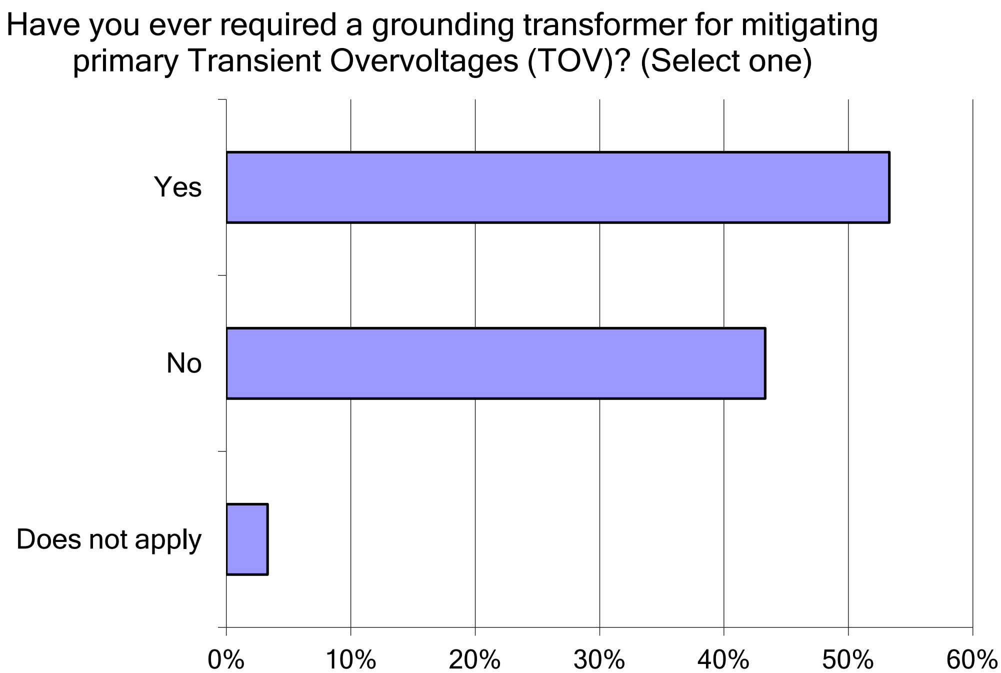

Figure 2-10
Required a grounding transformer for mitigating primary Transient Overvoltages

Comments

Commenter #1) We require the DG utility side connection to be a solid GRDY connection.

Commenter #4) Early DG applications in the 1990's had this requirement. There were frequent failures of the transformers due to circulating zero sequence currents. The latest approach is to use neutral voltage displacement or other protection types to trip the DG in the event of infeed to an unearthed network.

Commenter #9) I think we did once... but it is rare

Commenter #15) Grounding transformer have only been required for facilities with existing HV Delta winding.

Commenter #17) If the source is not effectively grounded, the generator can connect to our effectively grounded feeder through a Yg/Yg transformer and a grounding transformer on the secondary.

Commenter #21) Applied to all three phase rotating machines and inverters over 100 kW. Machine grounding and inverter transformer grounding accepted instead of GB.

Commenter #26) When a grounded Wye interconnection transformer is not used to connect the DG to our system

Commenter #27) This is our standard installation for 4-wire system and for synchronous and Induction generation projects.

Question 12) Have you experienced any ferroresonance problems associated with DG interconnection transformers?

This question is to survey the experience of ferroresonance with DG transformers.

Table 2-11
Experienced any ferroresonance problems associated with DG interconnection transformers

	Response Percent	Response Count
No	66.7%	20
Not Sure	30.0%	9
Yes	3.3%	1

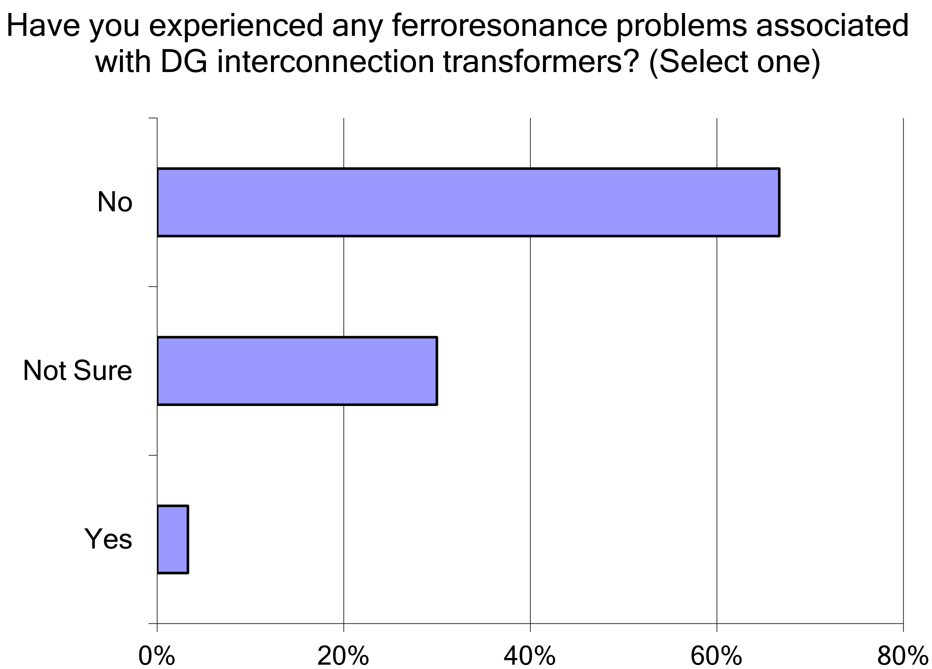

Figure 2-11
Experienced any ferroresonance problems associated with DG interconnection transformers

Comments

Commenter #1) Not that we are aware of

Commenter #9) Not that we are aware of

Commenter #12) We typically try to mitigate the potential for ferroresonance before it becomes an issue. Either by replacing a Delta - Wye Transformer with a Wye-Wye (Less prone) or adding a 3 phase switching device as the disconnecting means for the transformer.

Commenter #27) No event has been correlated back to the DG facility.

Commenter #28) Could be what's happening at some high saturation DG areas. Still investigating

Commenter #29) Have heard no reports

Question 13) If you have experienced any ferroresonance problems, what were the impacts?

This question was to determine what the impact of a ferroresonance condition on the system has been.

Table 2-12
Impact of ferroresonance condition

	Response Percent	Response Count
Resulted in relaying to activate due to overvoltages or excessive current	12.5%	1
Transformer Failure	12.5%	1
Surge Arrester Failures	12.5%	1

Question 14) Do you require the DG developer to add relaying to detect ferroresonance and to isolate its interconnection transformer from the primary?

This question is to survey whether or not ferroresonance is protected against with interconnection of DG transformers.

Table 2-13
Added relaying to detect ferroresonance

	Response Percent	Response Count
No	76.7%	23
Yes	16.7%	5
Depends	6.7%	2

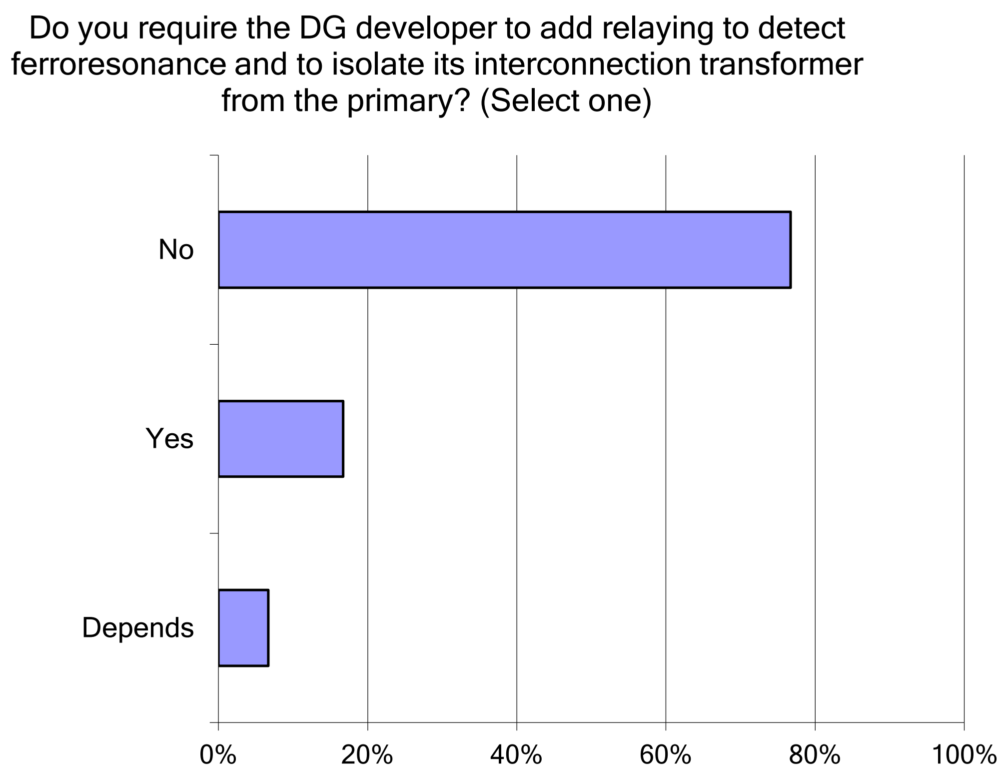

Figure 2-12
Added relaying to detect ferroresonance

Question 15) If "Yes" to question 14 above, please indicate what type below.

This question is to survey what protection is used to protect against ferroresonance conditions.

Table 2-14
Type of relaying to detect ferroresonance

	Response Percent	Response Count
Does not apply	62.5%	10
59I (Instantaneous Overvoltage)	18.8%	3
59 (Standard Overvoltage)	18.8%	3

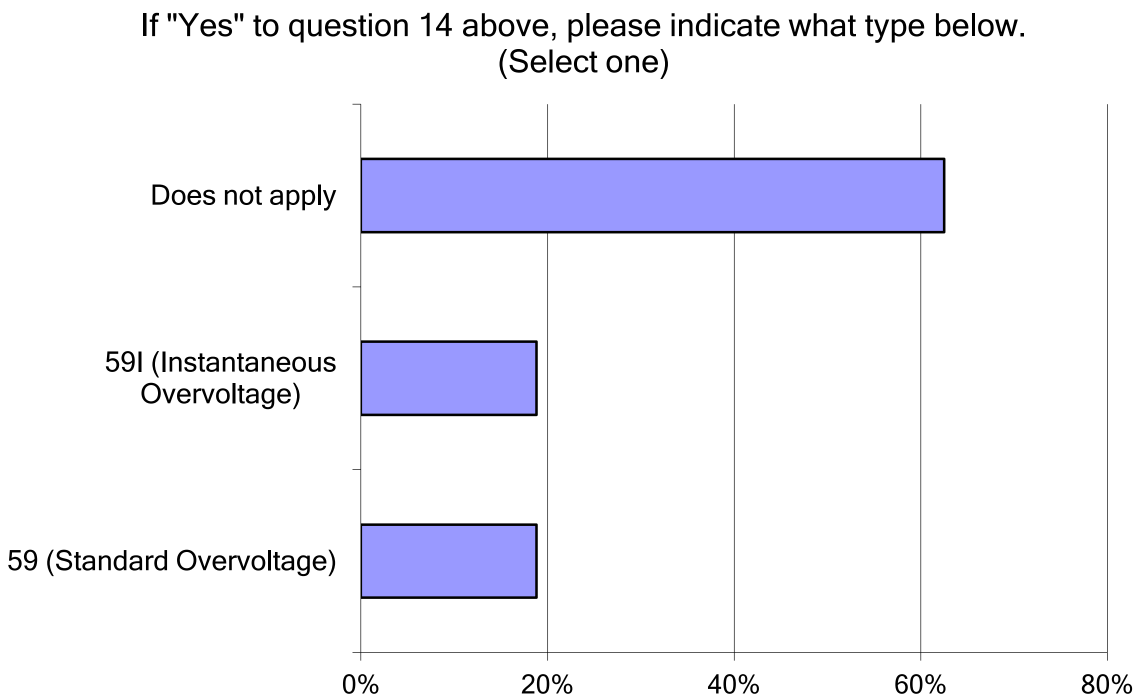

Figure 2-13
Type of relaying to detect ferroresonance

Question 16) Do you require the interconnection transformer to be isolated/disconnected on the primary voltage side?

This question is to survey whether or not the disconnection point for DG is on the primary side or secondary side of the transformer. DG installers sometimes prefer to isolate on the secondary side to reduce cost.

Table 2-15
Require the interconnection transformer to be isolated/disconnected on the primary voltage side

	Response Percent	Response Count
Sometimes	34.5%	10
No	31.0%	9
Yes	27.6%	8
Does not apply	6.9%	2

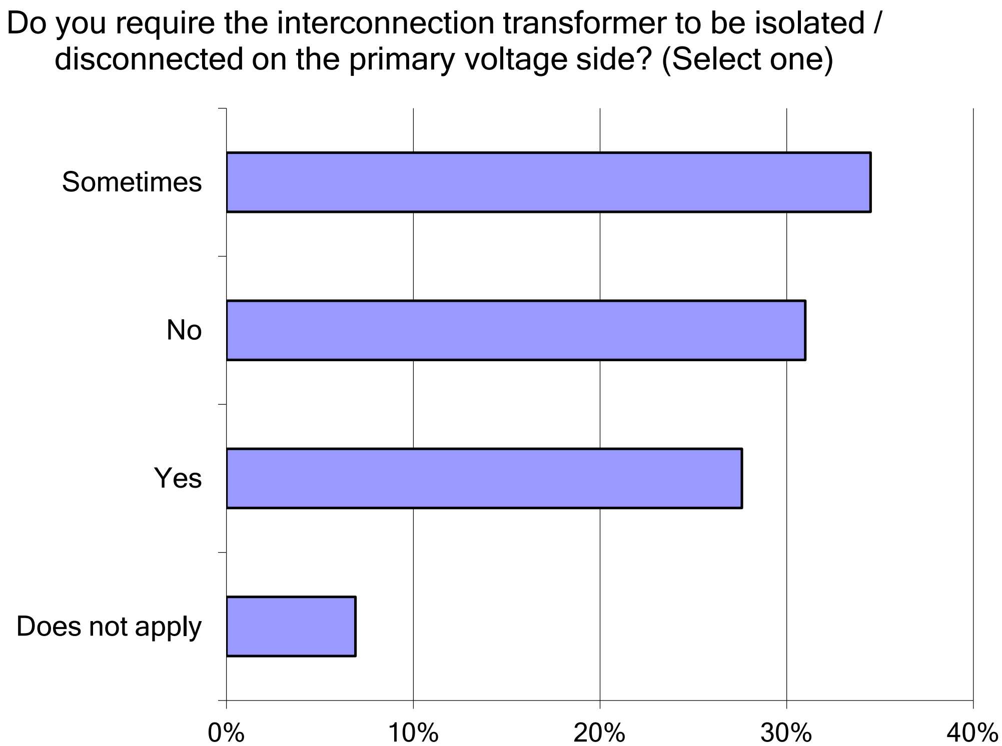

Figure 2-14
Require the interconnection transformer to be isolated/disconnected on the primary voltage side

Question 17) Have you ever experienced any sustained primary overvoltages associated with DG interconnections?

This question is to survey the experience of overvoltages associated with DG interconnections.

Table 2-16
Experienced sustained primary overvoltages associated with DG interconnections

	Response Percent	Response Count
No	43.3%	13
Yes	30.0%	9
Don’t know	26.7%	8

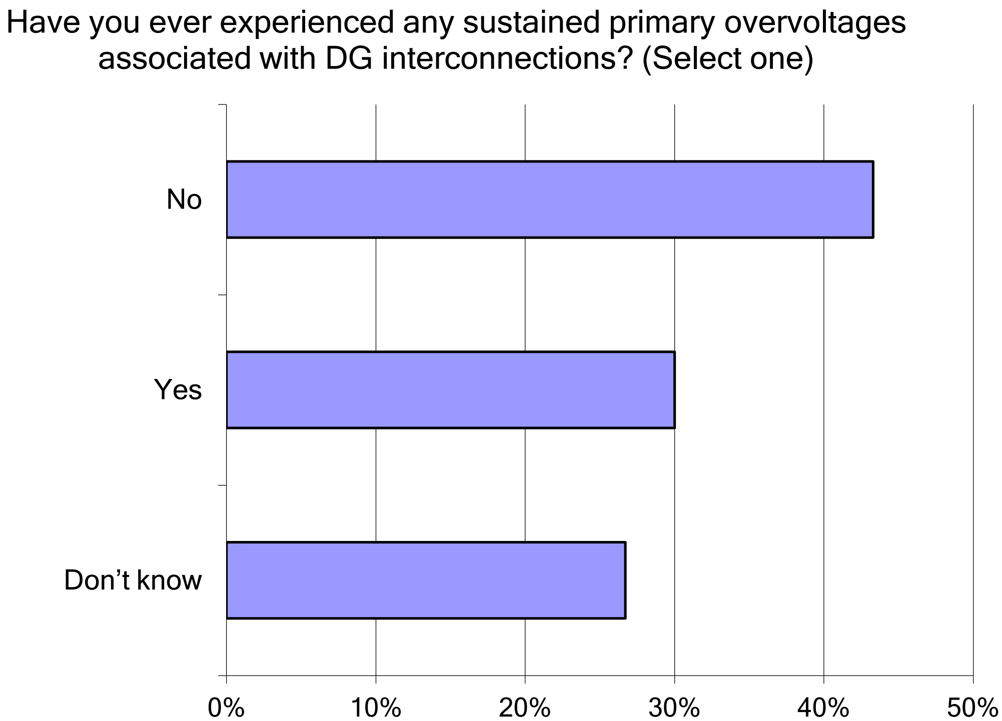

Figure 2-15
Experienced sustained primary overvoltages associated with DG interconnections

Comments

Commenter #2) On inverter based systems

Commenter #15) Voltage usually does not get too high. Issue has been DG disables voltage control and 59 relays and operates at a high voltage at POI. Caused by high impedance of long rural feeders.

Commenter #21) Corrected with leading power factor control

Commenter #27) We see those overvoltages in the study process and mitigate those conditions prior to allowing the project to interconnect to the system.

Commenter #29) Only under 1ph Fault conditions. Never during steady state operation.

Question 18) If "Yes" to question 17 above, what was impacted, if anything?

This question was to determine what the impact of an overvoltage condition has been on the system.

Table 2-17
Impact of an overvoltage condition

	Response Percent	Response Count
No Damage	54.5%	6
Surge Arrester Failures	27.3%	3
Resulted in relaying activation due to overvoltages or excessive current	9.1%	1
Load Failures	9.1%	1
Transformer Failure	0.0%	0

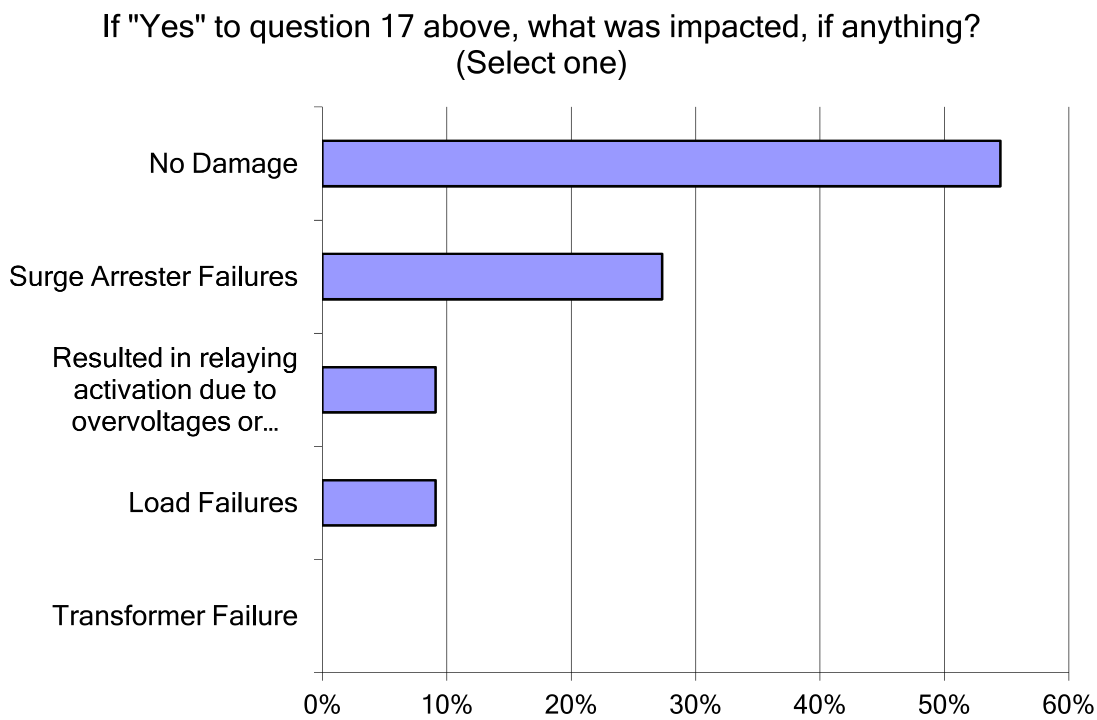

Figure 2-16
Impact of an overvoltage condition

Comments

Commenter #1) Surge arresters and permissive voltage transformer on customer side of recloser failed. Interconnection reloser tripped, but the OV condition lasted until DG system shutdown, failing equipment on the DG side of the recloser.

Commenter #6) High voltage to customers

Commenter #13) Customer voltage - inverter trip outs

Commenter #15) Also complaints from other customers of electronic equipment problems/failures

Commenter #24) Although I have selected first (no damage), the failures of surge arresters have been observed many times but never accounted for overvoltages specifically. As my understanding besides aging and tracking the fundamental frequency overvolages are the main reason for their failure.

Commenter #29) But have seen arrester failures during 1ph fault conditions

Question 19) Have you experienced any sympathetic tripping of breakers on unfaulted feeders that were supplied from the same bus as a faulted feeder?

This question is to survey the experience of sympathetic tripping of breakers.

Table 2-18
Have experienced sympathetic tripping of breakers on unfaulted feeders

	Response Percent	Response Count
No	83.3%	25
Yes	16.7%	5

Question 20) If you have experienced any sympathetic trips of breakers, which relays operated causing this condition?

This question is to survey the relay that activated to cause the sympathetic tripping event.

Table 2-19
Relays that operated during a sympathetic tripping event

	Response Percent	Response Count
Unknown	70.0%	7
Ground instantaneous overcurrent relay	20.0%	2
Phase instantaneous overcurrent relay	10.0%	1
Phase time overcurrent relay	0.0%	0

Question 21) If you have experienced any sympathetic trips of breakers, which do you believe to be the cause?

This question is to survey the cause of sympathetic tripping of breakers.

Table 2-20
Cause of a sympathetic tripping event

	Response Percent	Response Count
Ground source transformer connection on load or DG	17.6%	3
DG Fault current contribution	5.9%	1
AC motor load inrush	5.9%	1
Incorrect relay settings	5.9%	1

Question 22) What protection do you have in place to guard against sympathetic substation breaker trips, if any?

This question is to survey what protection has been put in place to guard against sympathetic tripping of breakers.

Table 2-21
Protection in place to guard against sympathetic substation breaker trips

	Response Percent	Response Count
None	48.1%	13
Timed coordination	33.3%	9
Directional ground overcurrent relays	7.4%	2
Directional phase overcurrent relays	3.7%	1
Distance Relaying	3.7%	1
Adaptive Relaying	3.7%	1
Directional Comparison blocking scheme (DCB)	0.0%	0
Differential Relaying	0.0%	0

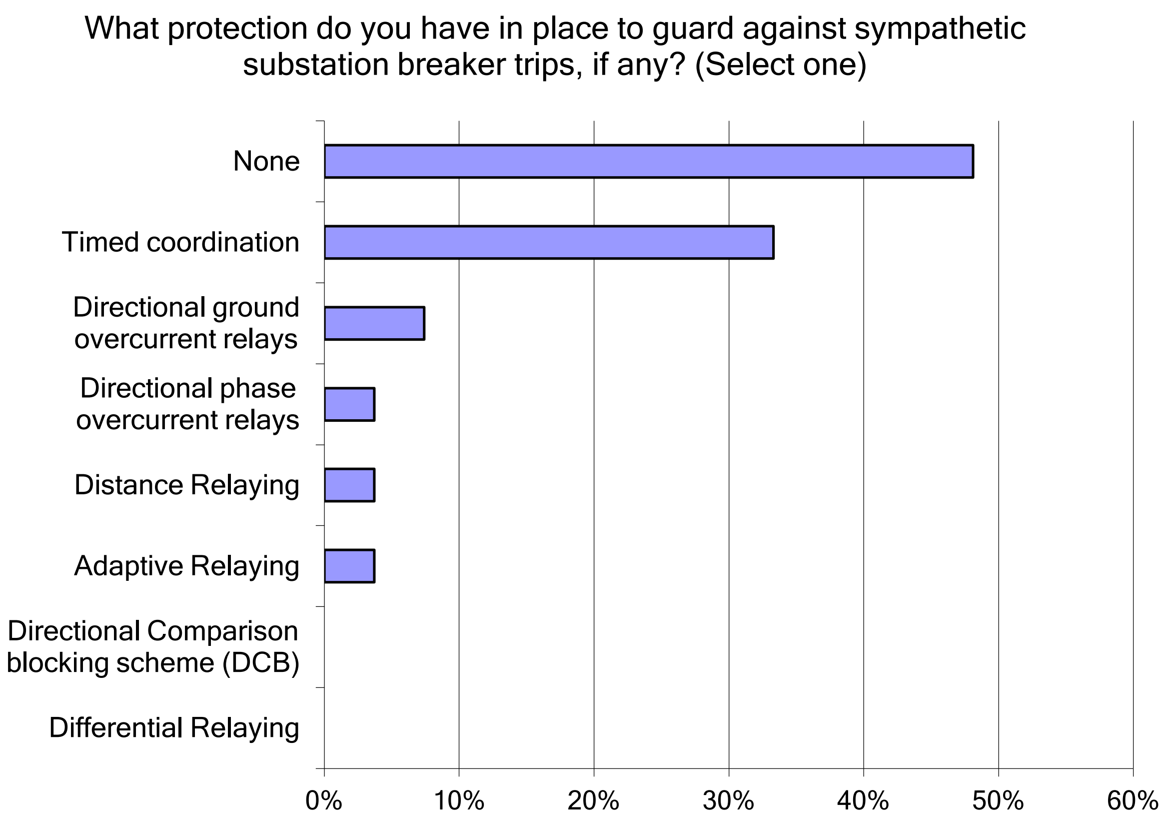

Figure 2-17
Protection in place to guard against sympathetic substation breaker trips

Comments

Commenter #1) Time coordination between feeder breaker relays and feeder reclosers

Commenter #3) We use multi function relays and activate both directional ground and directional phase functions

Commenter #4) Avoidance of multiple earths. Application of directional earth fault and Sensitive Earth Fault where this is not feasible.

Commenter #5) Programmed relay to delay ground TOC during severe voltage

Commenter #18) Directional relays are also used.

Commenter #20) Require DG to install neutral reactor to the interconnection transformer. This reactor size is studied during the design process.

Commenter #21) The listed alternatives would be considered if the situation presented itself. To date, no situations have been encountered that were vulnerable to this.

Commenter #24) I have selected " distance relaying" because it is our latest feeder protection standard, but we have used both directional phase overcurrent and direction ground overcurrent relays in past

Commenter #27) None - We try to resolve these issues via appropriate coordination studies.

Question 23) Have you experienced any trips due to magnetizing inrush events?

This question is to survey the experience of magnetizing inrush.

Table 2-22
Experienced trips due to magnetizing inrush events

	Response Percent	Response Count
No	53.3%	16
Yes	33.3%	10
Don’t know	13.3%	4

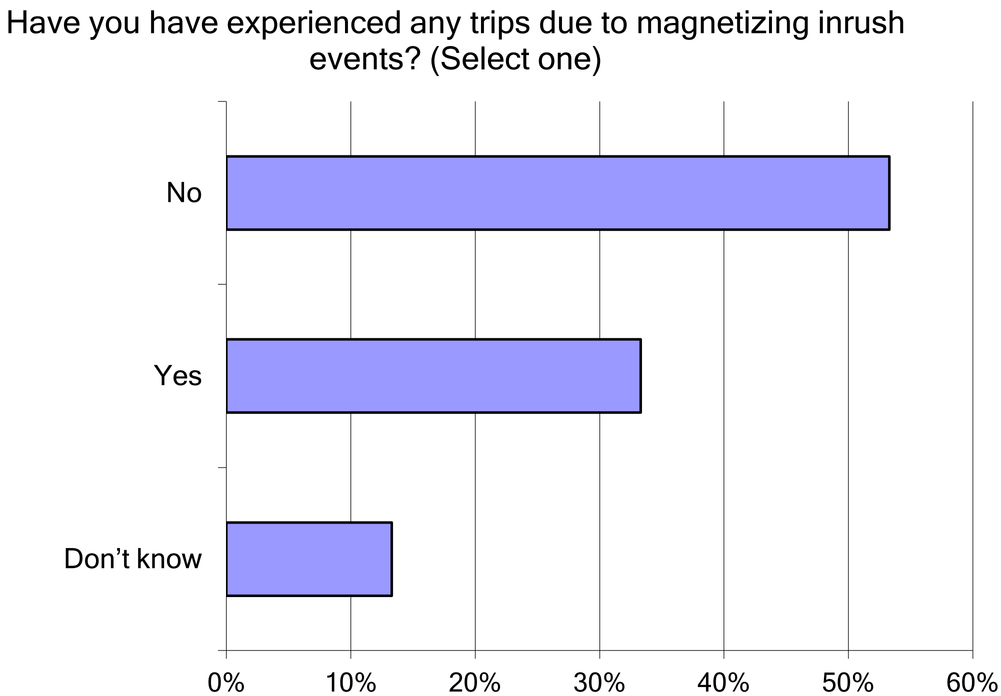

Figure 2-18
Experienced trips due to magnetizing inrush events

Question 24) If you have experienced any trips due to magnetizing inrush events which do you believe to be the cause?

This question is to survey the cause of magnetizing inrush.

Table 2-23
Cause of magnetizing inrush events

	Response Percent	Response Count
Load Transformer inrush	41.7%	5
DG interconnection transformer inrush	25.0%	3
Unknown	16.7%	2
AC motor starting inrush	8.3%	1
Incorrect relay settings	8.3%	1

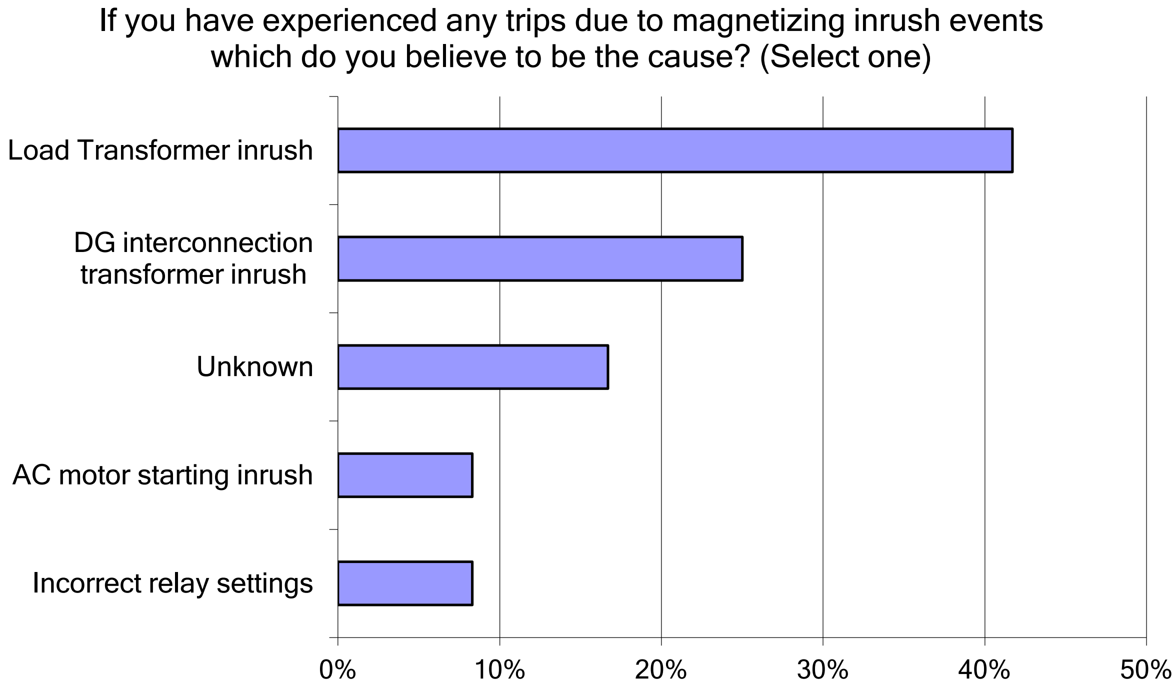

Figure 2-19
Cause of magnetizing inrush events

Question 25) Do you require harmonic relaying of monitoring at the DG site to isolate it in order to protect your system from harmonics produced by DG?

This question is to survey use of power quality protection at DG site.

Table 2-24
Require harmonic relaying of monitoring at the DG site

	Response Percent	Response Count
No	73.3%	22
Depends	16.7%	5
Yes	10.0%	3

Comments

Commenter #1) We require the DG customer to comply with IEEE 1547 and UL 1741.

Commenter #5) rely on certification to minimize harmonic injection

Commenter #7) We have no DG installations that produce harmonics at a level of concern.

Commenter #16) The utility meters we require for such installations are able to record harmonic components and can be interrogated to evaluate the need for isolation.

Commenter #17) All generators are required to maintain the Total Harmonic Distortion (THD) below 5%.

Commenter #18) Size of both the DG and system dictate this.

Commenter #21) Most have been certified inverters. Main sources have not been DG.

Commenter #23) Refer to standard

Commenter #26) Only if suspect or identified as an issue which is rare.

Question 26) Do you require any additional relaying protection at the DG installation to protect against open-phase conditions? (Open-phase conditions occur on utility distribution systems due to blown fuses, damaged conductors, bad splices, etc. This involves the failed conductor with either a high impedance ground fault or no connection to ground.)

This question is to survey use of protection specifically for open-phase events.

Table 2-25
Require additional relaying protection at the DG installation to protect against open-phase conditions

	Response Percent	Response Count
Yes	43.3%	13
No	40.0%	12
Maybe	16.7%	5

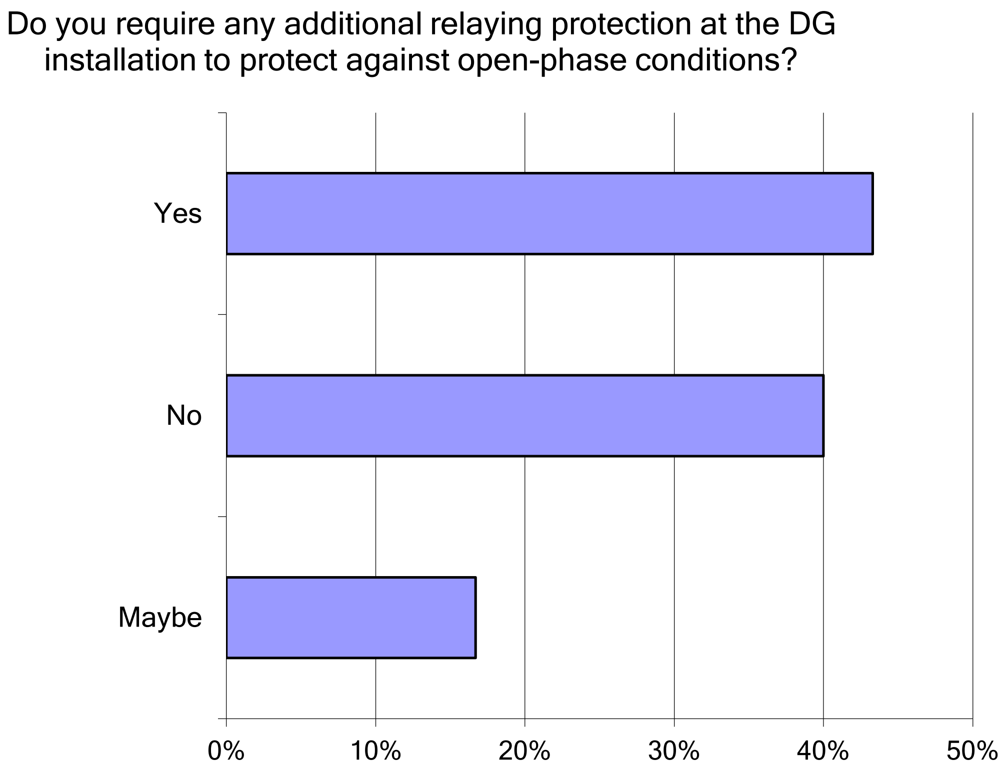

Figure 2-20
Require additional relaying protection at the DG installation to protect against open-phase conditions

Comments

Commenter #1) We require the DG customer to comply with IEEE 1547 and UL 1741. Inverter based systems have to be 1741 listed and comply with anti-islanding.

Commenter #3) The protections must meet IEEE 1547 islanding 1547.1 Section 5.9 Open Phase testing.

Commenter #4) The onus is on the DG or customer to protect himself from such conditions. This is a disclaimer in our connection agreements.

Commenter #5) require fuse replacement w/3 phase device at high side of bank for >1 Min

Commenter #7) DG Customer must sense for loss of voltage

Commenter #12) Depends on the type of interconnection.

Commenter #16) The DG customer is responsible for detecting and protecting against single phasing or open-phase conditions.

Commenter #18) The inverter or DG system protection is required to sense this.

Commenter #19) If we determine the condition exists due to the type of interconnection transformer connection and the generator relaying we may require zero sequence overvoltage protection

Commenter #21) Protection of customer generation and loads from the utility system is the customer's responsibility. We only address protection of our customers from the DG.

Commenter #23) We expect DG to isolate if one phase is lost

Commenter #25) Our tariffs state the customer is responsible for their own single-phasing protection.

Commenter #26) It is our customer's responsibility to protect their equipment against open phase conditions. We do not specify how this is done.

Commenter #28) overvoltage relaying

Commenter #29) Customer must isolate for any interruption in utility connectivity.

Question 27) If "Yes" to question 26 above, what type of protection? (Select one)

This question is to survey what protection is used in protecting against open-phase events.

Table 2-26
Protection for open-phase conditions

	Response Percent	Response Count
Overvoltage Relaying	66.7%	8
Negative Voltage Sequence Relaying	25.0%	3
Negative Current Sequence Relaying	8.3%	1

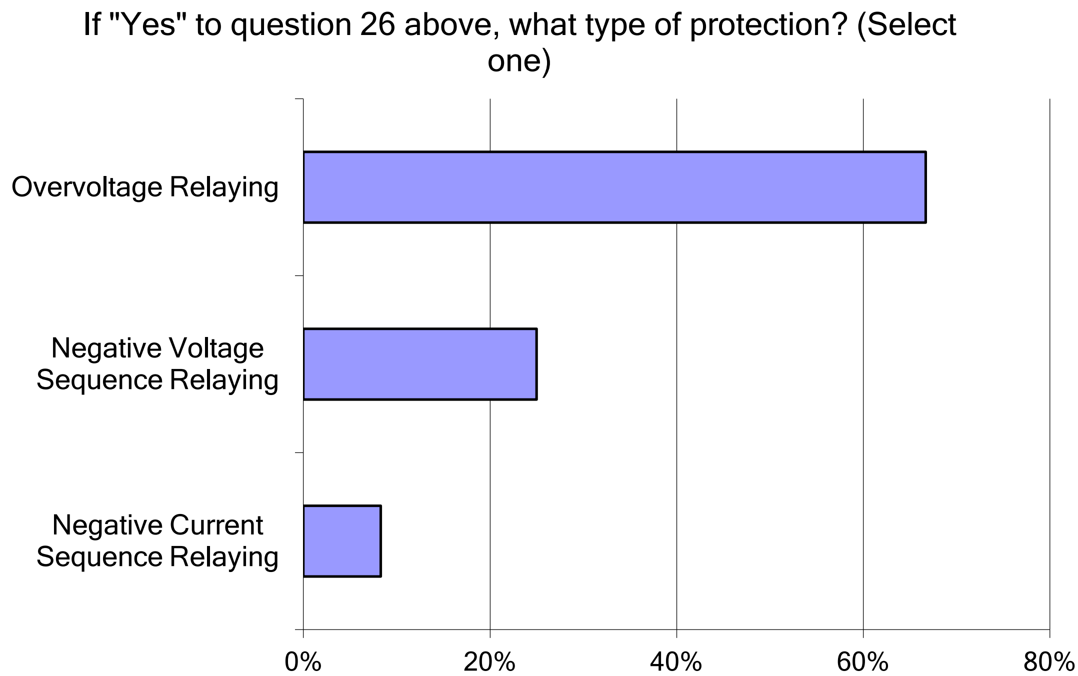

Figure 2-21
Protection for open-phase conditions

Question 28) How is anti-islanding being addressed?

This question is to survey what protection approaches are used in protecting against anti-islanding events. The respondents were allowed to choose multiple protection approaches.

Table 2-27
Protection for anti-islanding

	Response Percent	Response Count
Under/Over Voltage	83.3%	25
Under/Over Frequency	83.3%	25
Depend on inverter Controls	66.7%	20
Transfer Trip	63.3%	19
Reverse Power Protection as backup	50.0%	15
Minimum to Maximum Generation Limits placed on DG penetration	40.0%	12
Rate of Change of Frequency (ROCOF)	20.0%	6

How is anti-islanding being addressed? (Check all that apply)

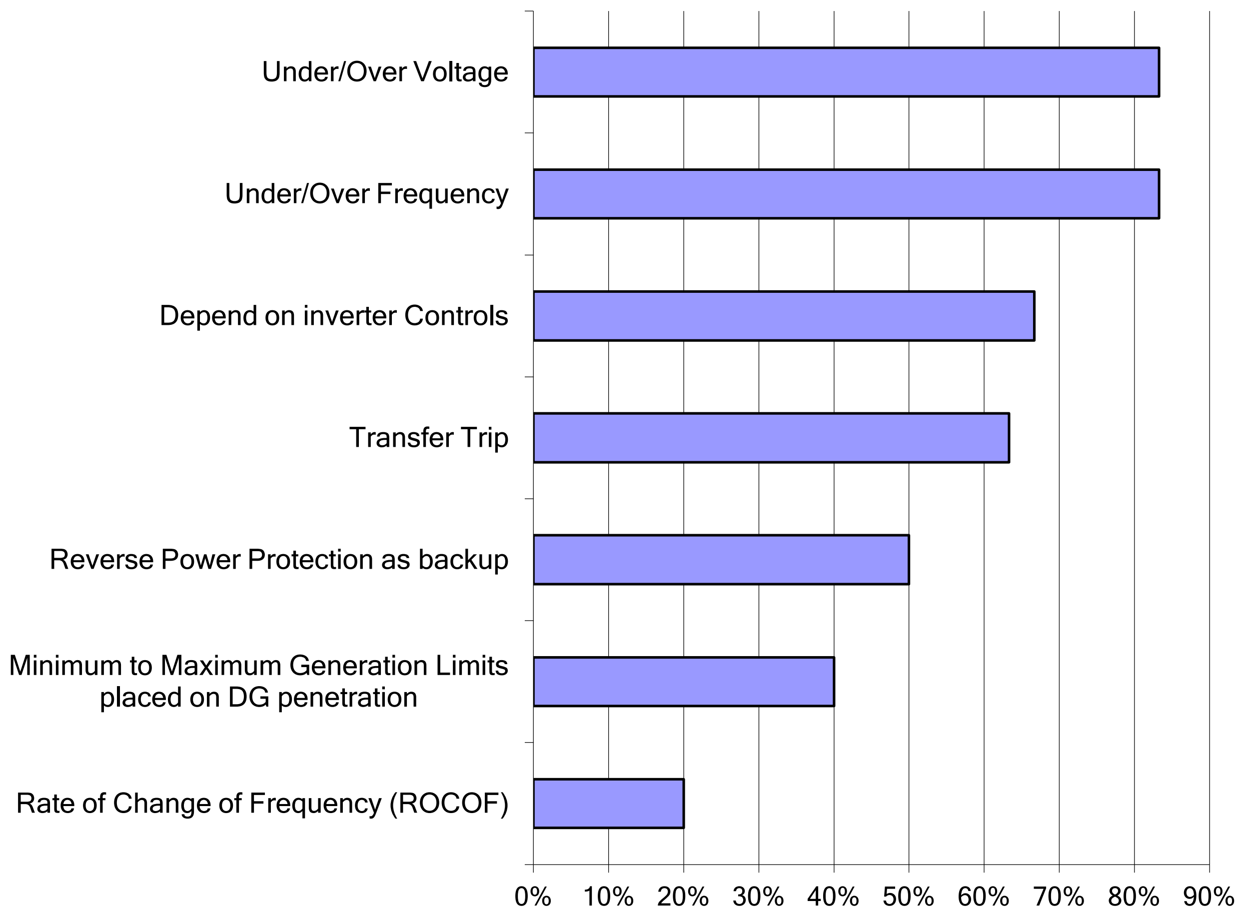

Figure 2-22
Protection for anti-islanding

Comments

Commenter #1) Inverter based systems have to comply with IEEE 1547/UL 1741 anti-islanding requirements. Rotating based systems have to comply with IEEE 1547. Interface recloser complies with IEEE 1547 voltage protection requirements. Reverse power relay is required for momentary parallel of DG.

Commenter #4) ROCOF is very difficult to apply, so we do not encourage its application.

Commenter #12) Underpower protection is preferred to reverse power as it is inherently more reliable. Other than that we use a combination of all of the above to ensure reliable anti-islanding.

Commenter #16) All apply and have been used, depending on the installation circumstances.

Commenter #18) Only Maximum Limits are placed on DG penetration.

Commenter #21) We also use voltage supervision of reclosing to protect against reclosing caused TOV hazards.

Commenter #25) For traditional generation we use O/U frequency, O/U voltage. We use reverse power when not selling back into our. For small solar/wind inverter installations we rely on the protection provided by the inverter per UL1741.

Commenter #26) Always require 27, 59, 81 O/U; other types of protection or considerations are on a case by case basis depending on size of DG, Type of DG, how it is connected, and feeder characteristics.

Commenter #27) UL certification for inverter based generation.

Question 29) How is the issue of the loss of protection sensitivity with the addition of DG transformer presently being addressed? This is the possibility that the addition of a distributed generator to the feeder leads to a reduction in the available fault current contribution from the system.

The purpose of this question is to determine what adjustments, if any, are made to accommodate DG connections.

Table 2-28
Dealing with the loss of protection sensitivity with the addition of DG

	Response Percent	Response Count
Adjust the existing relay settings	31.0%	9
Limit the DG penetration levels on the feeder	24.1%	7
Does not apply	20.7%	6
Direct Transfer Trip signal	13.8%	4
Distance Relaying	6.9%	2
Contractual Provisions to require the DG interconnection to be altered if more DG is added to the system	3.4%	1
Require an interconnection transformer to mitigate this factor	0.0%	0
Adaptive Relaying	0.0%	0

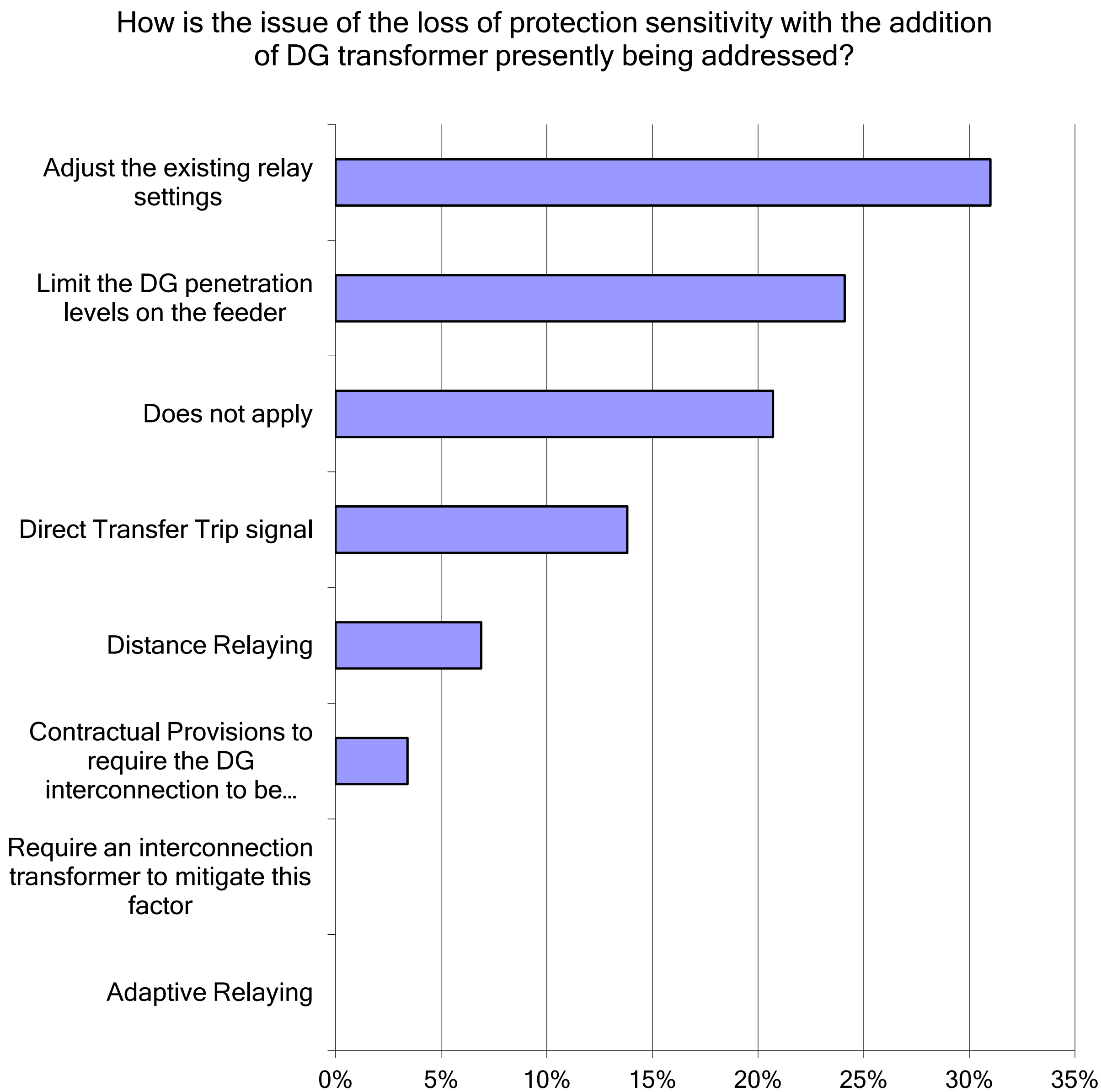

Figure 2-23
Dealing with the loss of protection sensitivity with the addition of DG

Comments

Commenter #1) On one case DTT was also added.

Commenter #4) We have low levels of DG penetration. Studied per application.

Commenter #7) Even though you ask for (Select one) this is determined on a case by case basis and there is more than one correct answer for system as large and varied as our distribution system and the DGs connected therein.

Commenter #12) typically we limit DG penetration levels however we also may require an interconnection transformer for certain DG if it is shown that they will lead to desensitization of utility relaying.

Commenter #13) Not currently part of our integration analysis.

Commenter #20) Require DG to have a properly sized neutral reactor.

Commenter #21) The primary approach has been to add additional protective devices to ensure adequate reach.

Commenter #25) When needed we would install relays with load encroachment logic

Commenter #26) Normally DG does not significantly impact protection sensitivity (its fault contribution is typically much lower that the system's available fault contribution at the point of interconnection).

Commenter #29) This is not currently considered as a risk.

Question 30) Are you making any provisions in DG installations to accommodate future DG installations that may be added on the same feeder/substation

The purpose of this question is to determine what provisions, if any, are being put in place to deal with future DG.

Table 2-29
Making provisions in DG installations to accommodate future DG installations

	Response Percent	Response Count
No	80.0%	24
Maybe	16.7%	5
Yes	3.3%	1

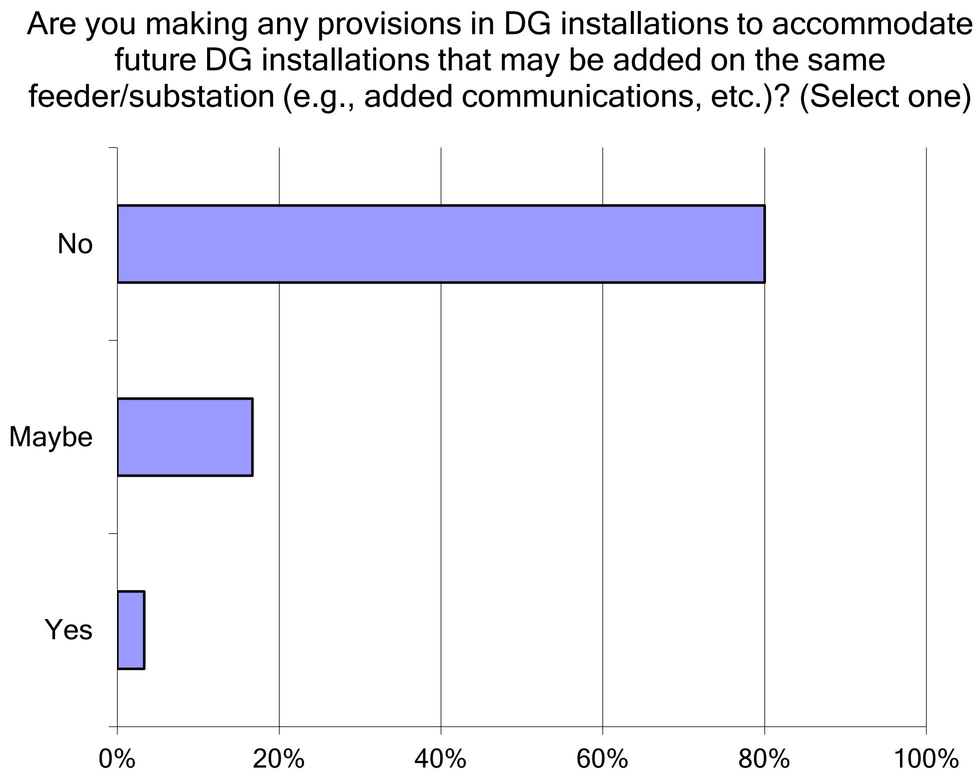

Figure 2-24
Making provisions in DG installations to accommodate future DG installations

Comments

Commenter #1) Our planning folks look at the feeder capabilities along with current DG installations, DG proposals and potential future load growth of the feeder.

Commenter #3) Circuits approaching DG saturation limits may be required to install SCADA & reduce generation as required.

Commenter #7) Customer pays for DG impact to the distribution system. Upgrades are made as necessary when DG applications result in actual DG connection.

Commenter #12) The cost for additional upgrades shall be paid for by the interconnecting generator.

Commenter #15) Not intentionally, but some requirements do help.

Commenter #21) Interconnections are approved only if there is a margin left in the design to cover circuit reconfigurations, etc. This allows modest margins for additional DG.

Commenter #25) Other than isolated large generator installations we have not yet reached a point of excessive small generator installations.

Commenter #28) depends how you look at it. Voltage regulation and capacitance is being added to address DG issues and are 'oversized' to accommodate future DG.

Commenter #29) Any costs to incorporate future DG Interconnections will be borne by that customer.

Question 31) Are you making any provisions in DG installations to accommodate microgrids (e.g., added communications or var support)?

The purpose of this question is to determine what provisions, if any, are being put in place to deal with microgrids.

Table 2-30
Making provisions in DG installations to accommodate microgrids

	Response Percent	Response Count
No	83.3%	25
Yes	13.3%	4
Maybe	3.3%	1

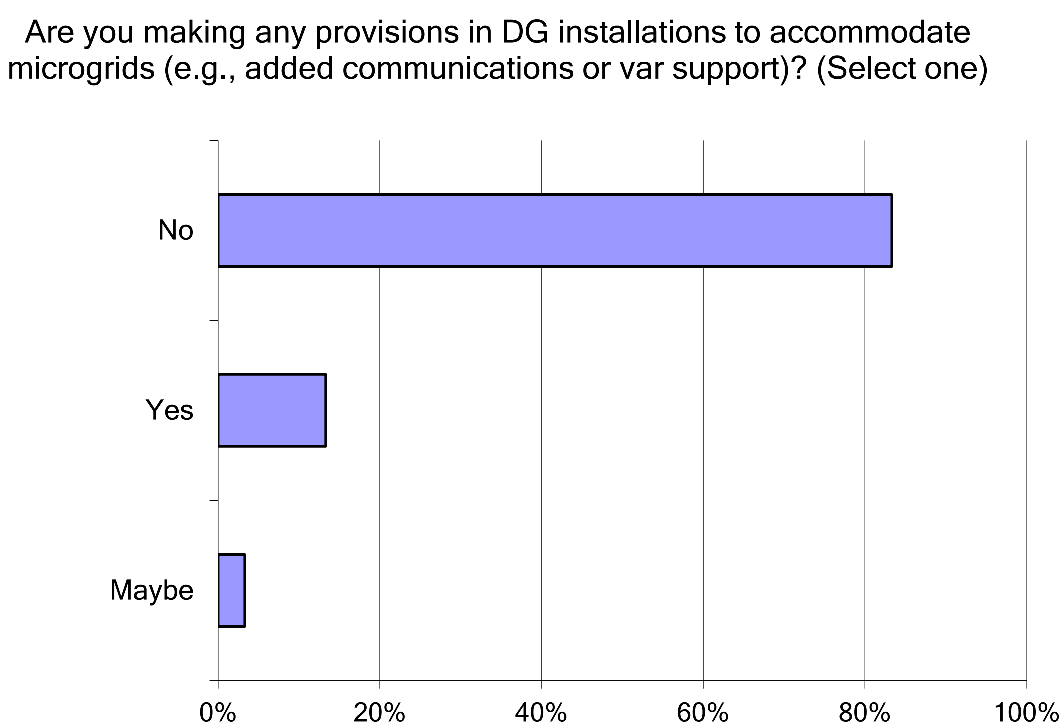

Figure 2-25
Making provisions in DG installations to accommodate microgrids

Commenter #1) However, depending on circuit impact and DG/circuit performance, VAR support might be required from the DG.

Commenter #5) (Facility) - Microgrid design is up to the developer

Commenter #7) If a DG is installed in a microgrid (I am assuming you mean a smartgrid communication area where the distribution system is capable of self directed reconfiguration based on utility source loss) the impact study incorporates all reconfigurations and the DG impact upon each.

Commenter #15) Working on incorporating DG into our VVO scheme to minimize VAR losses and regulate voltage. DGs typically operates in voltage control. This will add communications requirements.

Commenter #17) Our utility and EPRI are implementing the VAR support technology in a pilot project to enhance the system reliability, We and EPRI are studying the feasibility of a battery storage installation to accommodate the Micro-Grid.

Question 32) What would be the approximate threshold (if any) in which the following issues become a concern from a planning perspective.

The intent of this question is to determine issues that are of most concern to planners. A value of one (1) indicates no concern, while a value of five (5) indicates very concerned. Values in between one and five indicate increasing concern.

Table 2-31
Issues of concern from a planning perspective

	1 = no concern				5= very concerned	
Answer Options	**1**	**2**	**3**	**4**	**5**	**Response Count**
Impacts of having a DG source on your system that is not effectively grounded.	1	6	4	5	14	30
Fault current rise through protection elements by encroaching on the interrupt ratings of existing devices – This includes fault current from upstream and downstream sources.	1	14	6	2	7	30
Breaker reduction of reach – This is the reduction in sensitivity of the feeder breaker.	2	6	10	6	6	30
Breaker/fuse coordination – This is the change in amps that would affect the time current curve coordination.	1	7	9	8	5	30
Sympathetic breaker tripping – This is the current that may potentially trip the relay at the feeder relay due to an upstream fault.	3	11	6	6	4	30
Accommodating additional DG onto the system where DG already exists.	2	6	9	8	4	29
Accommodating a possible microgrid system.	6	8	9	2	3	28

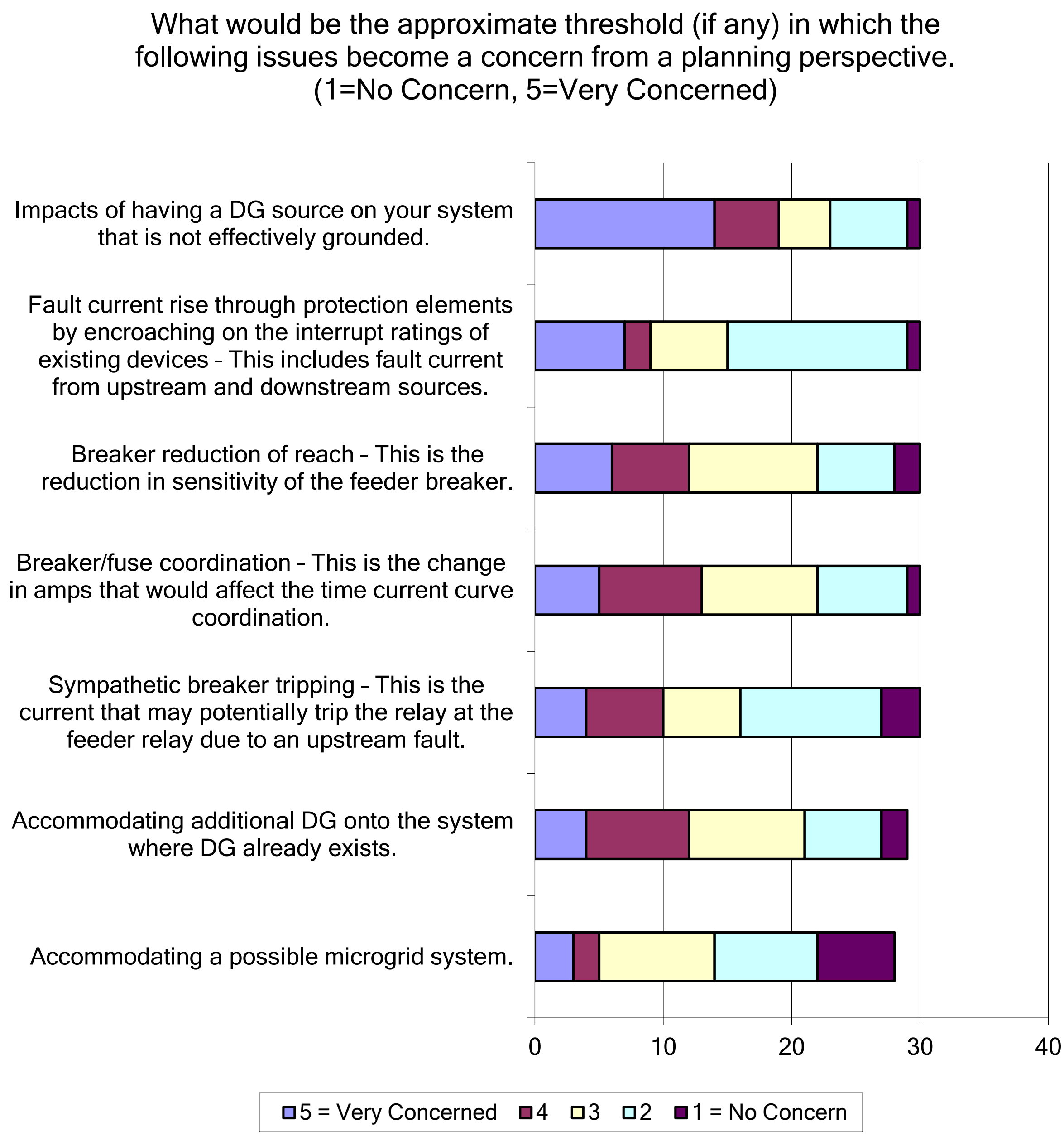

Figure 2-26
Issues of concern from a planning perspective

3
CONCLUSIONS AND FUTURE WORK

The protection issue of most concern is the impact of having a DG source on the system that is not effectively grounded. The concern is for overvoltage issues that can occur during an islanding event. Over 90% said that islanding concerns are the reason for requiring the addition of features such as Direct Transfer Trip (DTT) and other types of communications and control to the DG installation.

The majority of respondents stated that overvoltages on the primary distribution system are the biggest concern when it comes to specifying an interconnection transformer. However, system requirements were not consistent across the industry when it came to selecting an interface transformer, with 43% recommending a grounded wye – grounded wye (Yg-Yg) for the interface transformer for both inverter-based and non-inverter-based DG.

Most utilities that selected interface transformers with delta primaries had systems that were already designed to handle higher voltages associated with this type of connection (i.e. delta systems or impedance-grounded wye-connected systems). In some cases, if the standard transformer configuration is already delta- wye grounded (D-Yg) for large 3-phase customers, they may allow D-Yg connections for DG This is to avoid ground fault coordination and fault locating issues. However, they may require the customer to install overvoltage relays that sense voltage on the primary side of the interconnection transformer. Some utilities indicated that early in DG implementation they allowed delta connected DG systems onto their system; However, after experiencing overvoltage events, grounding banks have been installed on some existing systems and they now require interconnection transformers to be effectively grounded on new DG installations. The survey results indicate that 53% required a grounding transformer for mitigating overvoltages. This result may be skewed because some respondents considered a Yg-Yg interconnection transformer as a “grounding transformer”.

The utilities that required some form of a grounded-wye/delta (Yg-D)transformer did so to avoid impact of the DG’s impedance/status on the system’s zero-sequence network. That is, with a grounding type transformer Yg-D, with or without a grounding reactor) the zero-sequence impedance of the DG interconnection is relatively independent of the DG source itself i.e. the generator. For example, in Figure 3-1(b) the Yg-D isolates the DG generator’s impedance in the zero-sequence impedance.

To illustrate this, a simple direct-quadrature-zero (dq0) controlled inverter model was developed. This same inverter model is connected to a Yg-Yg transformer and also to a Yg-D transformer. A single-line-to-ground (SLG) fault is applied on the medium voltage (primary) side and the utility-side breaker opens leaving the inverter islanded with a SLG fault applied to the output of its interconnection transformer. As can be seen in the Figure 3-2, the Yg-Yg transformer interconnection reaches approximately 1.6-pu voltage then drops down to 1.3 pu until the inverter shuts off. For the Yg-D transformer the voltage stays below 1.0 pu. This reaction of the inverter is highly dependent on its controls and its relative size to the system. This is an area where additional research is needed to determine the large and small signal response of inverters to this type of event to determine best practices for inverter integration.

One thing to keep in mind is that the Yg-D configuration acts as a ground source and can increase the ground fault current and decrease the sensitivity of the ground fault detection at the substation. Figure 3-1 shows the sequence networks for the SLG fault condition to illustrate the increased ground fault contribution from this transformer configuration. When Figure 3-1(a) is compared to Figure 3-1(b), it can be seen that the zero-sequence current is divided between the utility and DG connection. This increases the overall ground fault contribution but reduces the ground fault current “seen” at the substation [13]. Eighty percent of those respondents who experienced sympathetic trips did so because of the ground fault contribution of the DG interconnection. Because of this issue, 10% of the respondents require the use of a neutral grounding reactor in the wye winding with this type of connection.

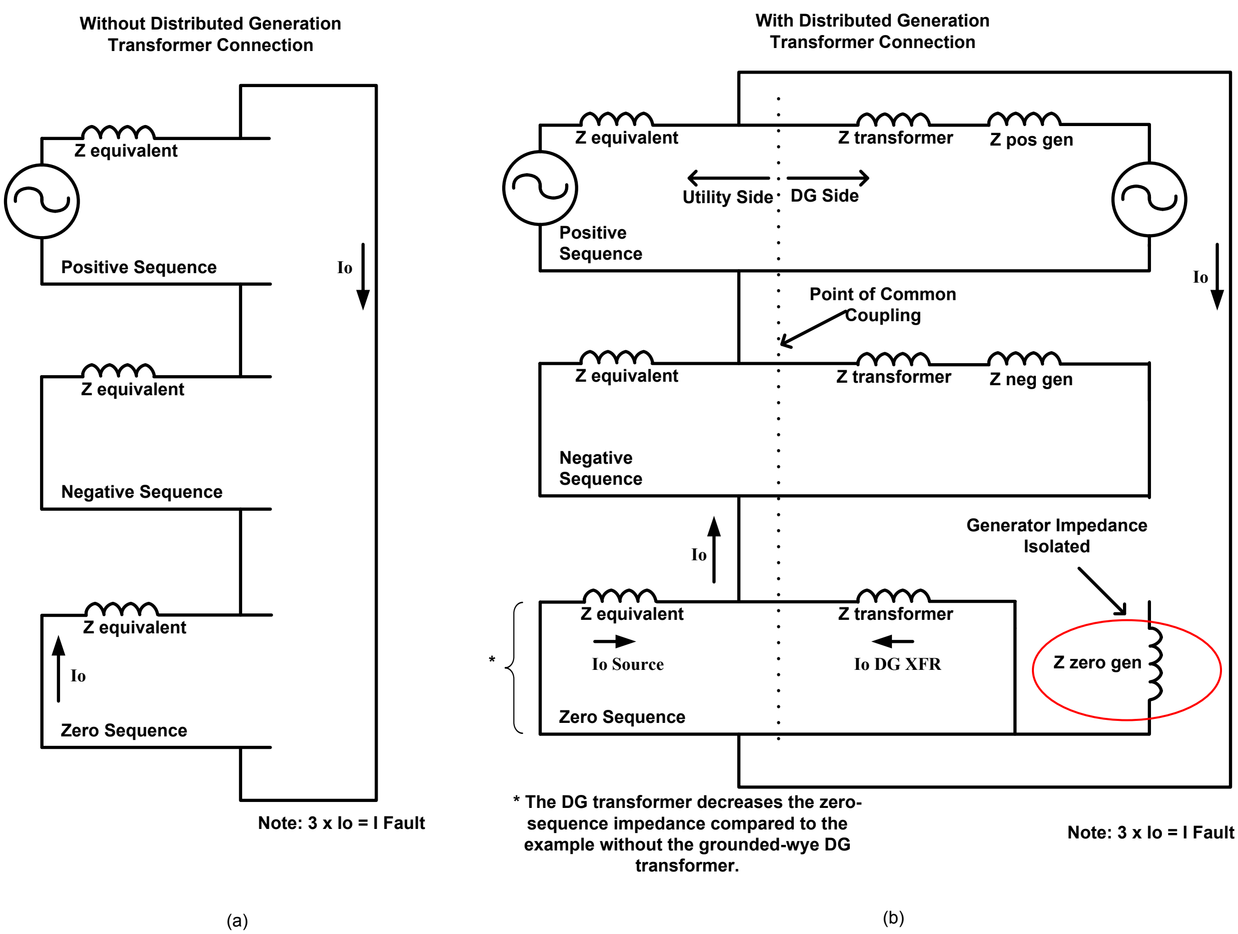

Figure 3-1
(a) Sequence Diagram for SLG Fault in system without any Ground Wye/Delta Transformer Connection (b) Sequence Diagram for SLG Fault with Grounded-Wye/Delta Transformer Connected

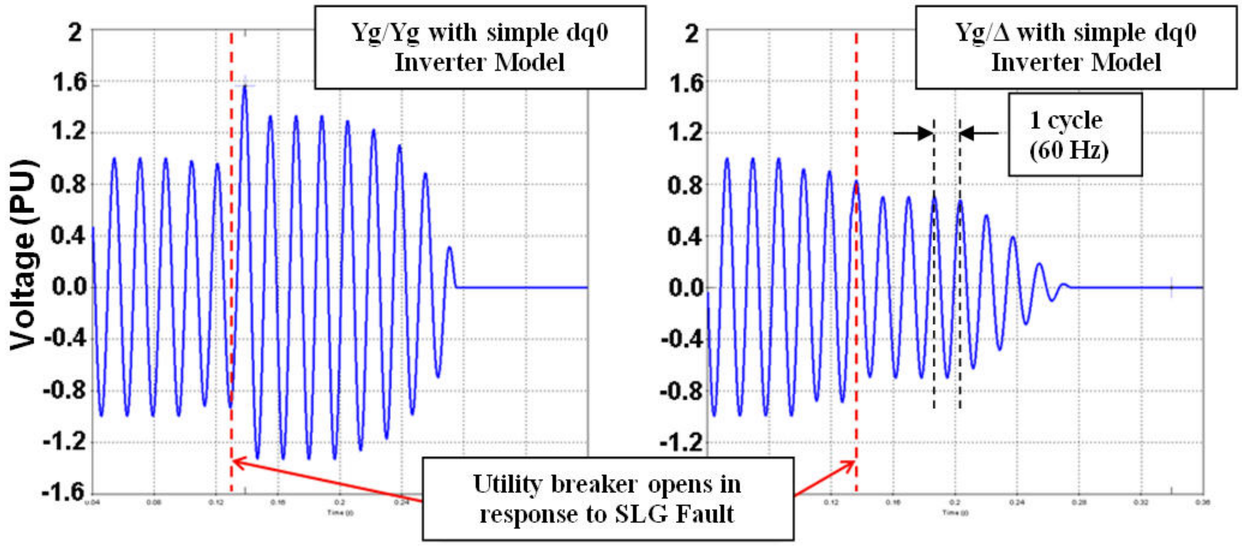

Figure 3-2
SLG Fault with the utility side breaker opening (islanding) for a simple dq0 inverter model

As discovered in the follow-up phone conversations, some utilities are taking precautions against overvoltages caused by inverters being isolated from utility. It is not uncommon for DG to suddenly trip offline due to various grid-related conditions. It has been observed in the lab that when an inverter system is disconnected from the grid and left connected to only a very small amount of local load, sudden overvoltages can occur. This is often referred to in the industry as the Load Rejection Overvoltage (LRO). An LRO of up to 225% of rated voltage for as long as 3 cycles has been reported by Southern California Edison (SCE) and discussed in references [5] and [6]. Because of this at least one utility has incorporated a grid disconnection test into their commissioning test.

Open-conductor conditions, which are discussed in Chapter 1, is an issue that some utilities require to be studied for DG interconnection and at least one utility requires an open-phase test to be conducted during DG commissioning. It is the opinion of most survey respondents that open-phase detection is the responsibility of the customer. Some utilities have determined that if DG meets the requirements of IEEE Std 1547 [11] then it is able to protect against an open-phase event. There were two utilities that made the assumption that the requirements IEEE Std 1547 protected them against an open-phase event until commissioning tests were conducted which included the interconnection transformer that proved otherwise. This event resulted in at least one of these utilities requiring an open-phase test to be conducted during DG commissioning.

As evident in the survey and the comments received, harmonic currents are considered a nonissue if the generator meets the IEEE Std 1547. It is typically a safe assumption if the DG satisfies the IEEE Std 1547 harmonic requirements, it would not cause the system to exceed the limits set forth in IEEE Std 519 harmonic standards. However, even if the DG passes the IEEE Std. 1547 requirements, it could still possibly cause harmonic problems on a system that has resonances at frequencies emitted by the inverter. Also note that an inverter may meet the harmonic requirements of IEEE Std. 1547at full loading, but it may exceed the harmonic distortion limits if the inverter is operating less than full load. No such cases were reported in the survey, but EPRI has been involved in studies where this was the case [1].

One respondent had a ferroresonance issue associated with a DG interconnection transformer that resulted in the failure of the transformer and surge arresters. Some respondents analyze the interconnection before commissioning to ensure it is not susceptible to ferroresonance or precautions are taken to make it less susceptible. The three critical parameters in determining an interconnection's susceptibility to ferroresonance include:

1. The transformer's primary connection is a critical parameter in the analysis of ferroresonance. Delta and ungrounded-wye winding connections are highly susceptible to ferroresonance. Other winding connections are less susceptible to ferroresonance, and some winding connections will prevent ferroresonance under all conditions [15].

2. There must be sufficient capacitance between the transformer and the open conductor(s) location to cause ferroresonance.

3. The losses in the circuit and the resistive load on the transformer must be low (little or no damping).

These conditions may be met at a variety of ways. The low resistive load requirement is often met on Distributed Generation (DG) installations when there may be times when there is no load on the transformer or only a few small loads. EPRI has seen increasing ferroresonance issues on DG installations, due primarily to the fact that the DG transformer is not-loaded or is lightly loaded when an open-phase condition occurs [14]. One method to protect the DG transformer from ferroresonance is to use an instantaneous overvoltage (59I) relay on the primary voltage to detect the event and trigger the disconnection of the transformer to prevent damage. Eighteen percent of respondents require a 59I (instantaneous overvoltage) at the DG installation to protect against a ferroresonance condition.

Multiple protection methods are used for anti-islanding protection as listed in Table 3-1. The requirement to comply with IEEE Std 1547 or subsequently UL1741, especially for smaller inverters, is seen as sufficient to protect the inverter and the local electric system from islanding events. No utilities that were interviewed actually use Rate of Change of Frequency (ROCOF) for islanding detection although 20% of respondents recognized it as an option for protection.

Table 3-1
Protection for anti-islanding

	Response Percent	Response Count
Under/Over Voltage	83.3%	25
Under/Over Frequency	83.3%	25
Depend on inverter Controls	66.7%	20
Transfer Trip	63.3%	19
Reverse Power Protection as backup	50.0%	15
Minimum to Maximum Generation Limits placed on DG penetration	40.0%	12
Rate of Change of Frequency (ROCOF)	20.0%	6

Ten percent of the respondents have experienced trips due to the magnetizing inrush of DG transformers. This may become a bigger issue as more DG is brought on-line without any staggered starts or protection relay restraint to prevent this event.

The biggest impact that DG has had on existing protection practices is on the coordination of feeder relaying. 56% of respondents indicated that changes/limitations have been put in place for their existing substation manual switching procedures due to DG. Some of these changes were safety-related due to the concern of active generation existing on the feeder resulting in a voltage hazard after the circuit is opened. A number of procedure changes were related to the fact that the coordination of feeder relaying was of concern when scenarios existed that had not been studied and, therefore, had not been properly coordinated with existing protection. In addition, if some DG units require a Direct Transfer Trip (DTT) signal, the utility would also limit which substation breaker can serve that feeder with DG. This is a growing concern due to the fact that transfer trip capabilities have been added to accommodate DG for 68% of the respondents.

One solution for some of these reconfiguration issues may be to add some adaptive relaying to alter the protection settings as configurations change. Most modern integrated relay packages already have communication interfaces and software to allow for adaptive relaying [18]. Two respondents of this survey have added adaptive relaying to their system to accommodate DG. Only one respondent has added distance relaying to their circuit. The use of distance relays for distribution protection to solve some of the DG integration problems is a possible area for further research.

The security and the protection of the DG interconnection protection must be addressed due to the finding that some DG operators override the initial voltage protection settings to allow for higher penetration of DG. These unauthorized changes resulted in high voltages on the primary feeder, leading to customer complaints and damage to customers' loads. This gap in security also enables updates to firmware in digital relays to occur without follow-up testing.

Based on the survey results, 80% of the respondents are not making any provisions for future DG interconnections and 83% of the respondents are not making any provisions for future microgrids. For most, if future changes are required, it is part of the installation cost for the customer requesting to interconnect. This may decrease the tolerable penetration levels of DG and may make more complex integration systems difficult to implement in the future.

4
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