Distributed Generation Relaying Impacts on Power Quality

Technical Report

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REPORT SUMMARY

Proliferation of distributed generation technologies, which use an inverter controller to perform relaying functions, confronts utilities with additional challenges for interconnection. The objective of this report is to provide a technical assessment and guidelines to address those challenges and explore possible enhancements for a relaying scheme to minimize the power quality impacts of distributed generation technologies. Interconnection relays help protect the utility system from power quality problems caused by distributed generators. This report investigates relay technologies, gives the results of tests of inverter-based relay protection systems, and discusses the impacts of industry protection settings on power quality.

Background

For several technical, political, and economic reasons, distributed generation (DG) will play an increasing role in electric distribution systems. This report's predecessor (EPRI Report 1000405, *Power Quality Impacts of Distributed Generation,* December 2000) found that with existing DG technologies and interconnection methods, the impact of DG on power quality would be neutral at best. As DG becomes a significant portion of the distribution feeder load, it could have a negative impact. Relaying is an important line of defense against power quality problems caused by distributed generation. Traditional generator-interconnection schemes use utility-grade relays to perform necessary protection against islanding and other interconnection problems. New inverter based relaying technologies confront utilities with additional interconnection challenges. These new technologies include integrated generator-protection relays that package all of the functionality into one relay, inverter-based generators that use the inverter controller to perform relaying, and inverters that actively try to anti-island.

Objectives

To provide a technical assessment of the power quality impacts of relaying technologies on the interconnection of distributed generation; to provide information on existing relaying technologies and settings and explore how these technologies and settings can be improved.

Approach

First, the project team assessed how relaying impacts each one of the power quality categories identified in the *Power Quality Impacts of Distributed Generation* report. From there, the team evaluated the most important relay concerns and the most important power quality impacts. The team developed a field-testing protocol for inverter-based generators using the controller for relaying. Because field-testing is limited, the team expanded this effort and explored the concept of a portable DG tester and use of long-term monitoring as ways to test and verify the relaying performance. Finally, the project team tested an inverter-based DG with voltage sags and interruptions to evaluate the performance of controller-based relays.

Results

Integrated generator relays have external test ports that allow for testing in the field using signal injection. On the other hand, inverter-based relaying does not have provisions for external test ports for verifying the relay set points. The report's field-test protocol provides for limited testing approaches but does not completely test the interconnection protection. Using power-quality monitoring could help evaluate the performance of the generator's protective systems.

The impact of different existing and proposed interconnection standards was evaluated with regard to their power quality impact. Analysis of EPRI's Distribution Power Quality (DPQ) data found that without any time delay, generators can trip frequently, mainly due to voltage sags. Analysis showed that relays could incorporate additional functionality to protect against other power quality impacts of distributed generation such as flicker and harmonics. Finally, laboratory tests of an inverter-based DG and field-testing of parallel operation of multiple inverter-based DG identified some issues that can occur with inverter-based relays.

EPRI Perspective

By providing utilities with a clear understanding of the impacts of DG relaying on power quality, EPRI enables utilities to implement better interconnections with the DG of end-users. This report should help utilities perform better field testing of distributed generators and help identify other ways of verifying the integrity of DG interconnections. Data provided in the report should help utilities specify the appropriate settings for DG interconnections.

Keywords

Protection
Relaying
Anti-islanding
Field Testing
Power quality
Distributed generation
Harmonics

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1
POWER QUALITY ISSUES AND THE EFFECTS OF RELAYING

Relaying is an important line of defense against power quality problems caused by distributed generation. This report follows EPRI report 1000405, *Power Quality Impacts of Distributed Generation* (December 2000). This report focuses on relaying aspects related to power quality: the technologies, functionality, industry-standard settings, testing, and relay response to disturbances. This chapter begins with a summary of the power quality effects of distributed generation along with the effects of relaying; this chapter ends with a summary of the major topics in this report.

Effects of Relaying on Power Quality Issues Related to Distributed Generation

The following sections give a brief summary of each of the power quality issues impacted by distributed generation, along with a summary of how relaying affects these issues. The relaying effects are for *existing* relay technologies—chapter 6 addresses other ways that enhanced relays can be used to limit power quality problems caused by distributed generation.

Waveform Distortion

PQ impact: Possibility of harmonic resonance at light load due to the interaction of system reactance with the capacitor required for reactive support for induction generator.

Relay impact: none.

PQ impact: Harmonic current injected by static power converters can increase voltage distortion and possible resonance with utility power-factor-correction capacitors.

Relay impact: none.

PQ impact: High switching frequency of PWM static power converters can cause resonance (2 to 3 kHz) with cable-fed systems.

Relay impact: none.

PQ impact: Voltage distortion from rotating generators can cause resonance with utility power-factor-correction capacitors.

> *Relay impact: none.*

PQ impact: When disconnected from the grid and supporting a local load, the higher impedance of the DG source will increase the voltage distortion.

> *Relay impact: none.*

Voltage Unbalance

PQ impact: Existing unbalance of the feeder voltage can cause DG using rotating machines to trip on current unbalance and cause rotor heating due to the negative-sequence current.

> *Relay impact: The current-unbalance relaying trips the generator.*

PQ impact: Depending on the winding arrangement of the DG interconnection transformer, feeder current unbalance will be reflected in the interconnection transformer, causing transformer overload and possibly damage to the transformer if it does not have any overload protection grounded-wye/delta and grounded-wye/grounded-wye transformer (with the generator grounded).

> *Relay impact: Relaying may be used to detect excessive circulating current in grounded-wye/delta transformers.*

Steady-State and Long-Duration Voltage Regulation

PQ impact: DG located just downstream of a voltage regulator can interfere with the line-drop compensation in the regulator and cause low voltages downstream of the generator.

> *Relay impact: none (the undervoltage is not at the generator—it is at the end of the utility feeder).*

PQ impact: A DG can cause high voltages because of reverse power flow causing a voltage rise on the circuit.

> *Relay impact: Overvoltage relays should trip the generator if it is causing voltages above the ANSI limits.*

PQ impact: Improper coordination between a utility voltage regulator and a voltage-regulating DG can cause both regulators to “hunt.”

> *Relay impact: none.*

PQ impact: Properly applied DG can improve the voltage profile along a circuit because of the voltage boost caused by the injection of real power.

Relay impact: none.

PQ impact: Properly applied distributed generators can improve regulation if they are operated in a voltage-regulating mode (by varying reactive power).

Relay impact: none.

Voltage Fluctuations

PQ impact: Low RPM, low number of cylinders, or misfiring of reciprocating engines can cause voltage fluctuations.

Relay impact: none.

PQ impact: Cloud-caused irradiance changes could produce flicker on photovoltaic systems.

Relay impact: none.

PQ impact: Fluctuations in the wind speed, pitching/yaw error in blades, wind shear, or tower shading can produce flicker on wind turbine generators.

Relay impact: none.

Voltage Sags and Momentary Interruptions

PQ impact: Starting of induction generators directly from the line will cause a voltage drop similar to the starting of induction motors.

Relay impact: none.

PQ impact: DG will reduce the fault current contribution from the utility source and may increase the duration of the fault clearing and therefore increase the sag duration.

Relay impact: Minor— if the generator has relaying that detects utility faults, tripping the generator will remove the fault-current contribution.

PQ impact: Properly applied DG can provide voltage support and reduce the magnitude of voltage sags as seen by the load.

Relay impact: If the generator trips off as required by standards such as UL 1741 and IEEE 929, the voltage support will be removed.

PQ impact: Out-of-phase reclosing can damage the shaft of rotating machines. Utilities may have to increase their reclosing time to accommodate downstream DG, which results in an increased duration of momentary interruptions.

> *Relay impact: Quickly relaying generators in islanded situations will help make this less likely.*

PQ impact: The fault contribution of DG can cause nuisance operations of upstream breakers, reclosers, or sectionalizers. This will increase the number of momentary interruptions.

> *Relay impact: If the generator has relaying that detects utility faults, tripping the generator will remove the fault-current contribution.*

Transient and Temporary Overvoltages

PQ impact: Certain transformer connections for DG (wye/ungrounded wye, delta/wye, delta/delta, and wye/wye with an ungrounded generator) can cause voltage swells on healthy phases during line-to-ground faults during islanding.

> *Relay impact: Ground overvoltage relaying can be used to trip the generator for overvoltages caused by the neutral shift. Overvoltage relays on the utility primary connected phase-to-ground should also trip.*

PQ impact: Voltage swells and ferroresonant overvoltages can be caused during islanding because of resonances between the generator impedance and utility capacitors.

> *Relay impact: Overvoltage relays are the last line of defense against these overvoltages.*

PQ impact: Transient overvoltages can be caused by out-of-phase reclosing between the utility system and a DG island.

> *Relay impact: Anti-islanding relays (including over- and undervoltage, over- and under-frequency, and others) help remove an island before reclosing can occur.*

Summary of Important Relaying Issues

Of the power quality problems discussed in the previous section, some are more important than others. Overvoltages and islanding issues cause the most serious problems, and relaying is critical in helping to clear distributed generators that contribute to overvoltages and islanding issues.

Traditional Generator Interconnection Relaying

Generator interconnection relaying systems generally include over- and undervoltage relays and over- and under-frequency relays. Some applications require relays for synchronization, transfer trip, reverse power detection, and fault protection. Utilities prefer *utility-grade* relays (which are tested to IEEE standards and have test ports for field testing). Utility-grade relays are used almost universally on very large distributed generators. However, using utility-grade relays for smaller distributed generators (less than 10 kW) has been a major point of contention between utilities and non-utility generators.

Integrated generator relays integrate all generator interconnection functionality into one relay. The integrated relays are utility grade and have been tested to IEEE and IEC standards. They also have external test ports that allow for testing of the relaying system in the field using signal injection. For these reasons, utilities have been very positive towards their use.

Inverter-Based Relaying

Distributed generators based on inverters can do much of the interconnection relaying in the inverter controller. Utilities worry about inverter-based relays, mainly for the following reasons:

- Inverter-based relays are not utility-grade.
- Testing in the field is very difficult.

Inverter-based relays do have an advantage—inverters can actively perform anti-islanding relaying. The most promising *active* anti-islanding techniques are the Sandia voltage-shift and frequency-shift methods. These use positive feedback to make the voltage or frequency unstable if an island is being driven by generators with this form of anti-islanding. The unstable generator in an island pushes the voltage or frequency out of range, where standard voltage or frequency relays trip the generator.

Field Testing of Inverter-Based Relaying Systems

Field testing is a requirement to ensure the security of relaying systems. Inverter-based relays do not have test ports for a variety of technical and cost reasons. In Chapter 4, a case study of field testing shows several instances where an inverter-based relaying system did not perform as expected for undervoltages and for reverse power. The tests highlighted the difficulty of performing field tests and raised important questions about what counts as an island.

One way to test inverter-based relays is by set-point adjustment—as an example, test the overvoltage relay by lowering the overvoltage trip point until it trips (which should be at the present voltage). Set-point adjustment is dangerous because the trip thresholds may be left incorrectly set due to human error. Therefore, the set point should be adjusted only as a last resort.

A straw-man field-test protocol is introduced in this report. It outlines simple tests that can be done in the field on generators that do not have test ports. The field-test protocol consists mainly of a main test plus some optional tests.

Main test:

- **Generator disconnect test—**Disconnect the generator and check that the unit trips in the appropriate time frame.

Optional tests:

- **Generator disconnection with load**—Adjust the facility load to match the generation and trip the facility. This is only possible if the customer is willing and able to adjust its facility loads to approximately match the generation and to disconnect the facility.
- **Reverse-power test**—For cases where reverse power into the utility is not allowed, increase the generator power and decrease the facility load until the generator exports power to the utility and ensure that the generator trips within the required time.
- **Single-phase disconnect test**—Open one phase of a disconnecting switch to the facility and ensure that the generator trips within the required time. This test can be disrupted by transformer connections and backfeeding load, and there could be a variety of customer objections.

This field-test protocol will by no means guarantee that the tested generator relaying works properly. It does not adequately test the voltage thresholds or the frequency thresholds. It is very difficult to adequately test a generator with built-in relaying in cases where it is not possible to use secondary injections with standard relay test sets. The field-test protocol is a supplement to rigorous type testing in the laboratory that is capable of identifying gross malfunctions. In the future, more sophisticated mobile DG test sets may be developed that could adequately field test generators with built-in relaying.

Because of the field-test limitations, two additional approaches are identified:

1. Portable DG tester—Plugged in between the generator and the system, this device can fully test a powered generator for frequency deviations, voltage deviations, and possibly even anti-islanding.

2. Long-term monitoring to help verify proper DG and relay operation—Monitoring at the generator or at remote points helps verify proper operation by using normal system disturbances as checks on performance. Any utility-connected generator sees regular sags and momentary interruptions; the monitoring helps verify proper operation when they occur.

Implication of IEEE Standard Relay Set Points on Power Quality

The existing and developing industry-standard set points have deficiencies related to power quality. The main concerns are:

- The 110% trip limit on overvoltages allows generators to create voltage in excess of ANSI limits.
- The draft P1547 allows a relatively long time (0.16 seconds or 9.6 60-Hz cycles) for overvoltages above 120% to exist. IEEE 929 and UL 1741 both require the DG to cease injecting power within 2 cycles if an overvoltage greater than or equal to 138% is detected.

Also, the trip thresholds do not coordinate with the ITIC curve (formerly CBEMA curve), as shown in Figure 1-1.

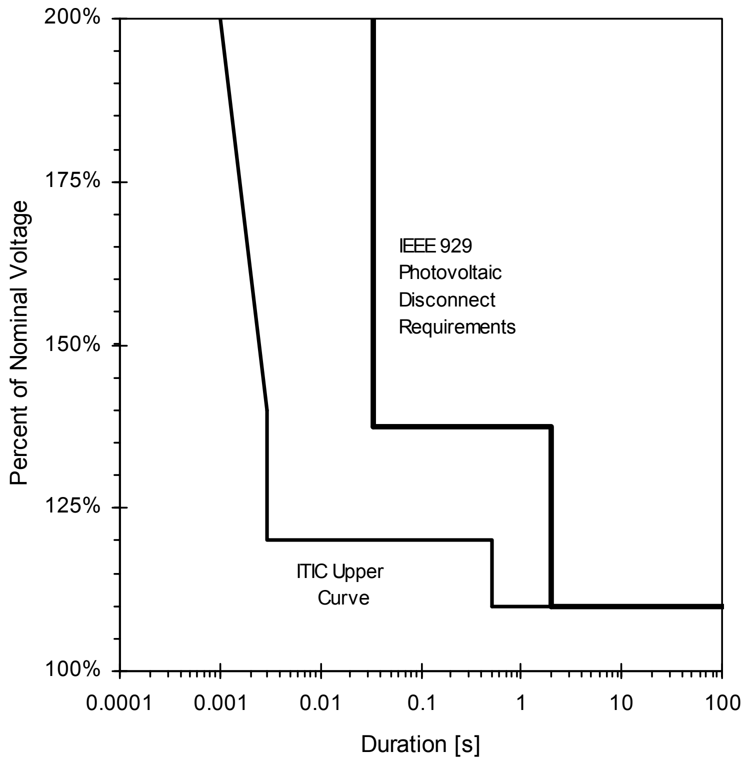

Figure 1-1
IEEE 929/UL 1741 Disconnect Requirements Compared Against the ITIC Curve

Based on these deficiencies, the project team recommends the thresholds given in Table 1-1.

Table 1-1
Recommended Trip Thresholds for DG Operations (the Bold Voltage Thresholds Indicate Where Changes are Different from IEEE P1547/D07 and D08)

Voltage Setting			Trip Time
	V	< 50%	0.16 s
50% ≤	V	< 88%	2 s
88% ≤	V	**≤ 106%**	Normal Operation
106% <	V	**< 110%**	180 s
110% <	V	< 120%	1 s
120% ≤	V		**0.1 s**

Note 1: Base voltages are the nominal voltages stated in ANSI C84.1.

Note 2: DR ≤ 30 kW Maximum Clearing Time. DR > 30 kW, Default Clearing Time or area electric power system (EPS) operator may specify different voltage settings or trip times to accommodate area EPS system requirements.

Power quality disturbances also impact generators because DG must trip for voltage excursions. An analysis of EPRI's Distribution Power Quality (DPQ) data showed the following:

- The number of generator trips at most sites is not particularly severe. Generators at most sites should have less than five trips per year when using the UL 1741/IEEE 929 or IEEE P1547 settings.
- Trips become excessive only if the DG undervoltage relaying is set at a very sensitive level.
- The generators are able to provide voltage support for many disturbances where the generator does not trip. Figure 1-2 shows that the occurrence of generator trips is much lower than the power quality disturbances that violate the ITIC curve.

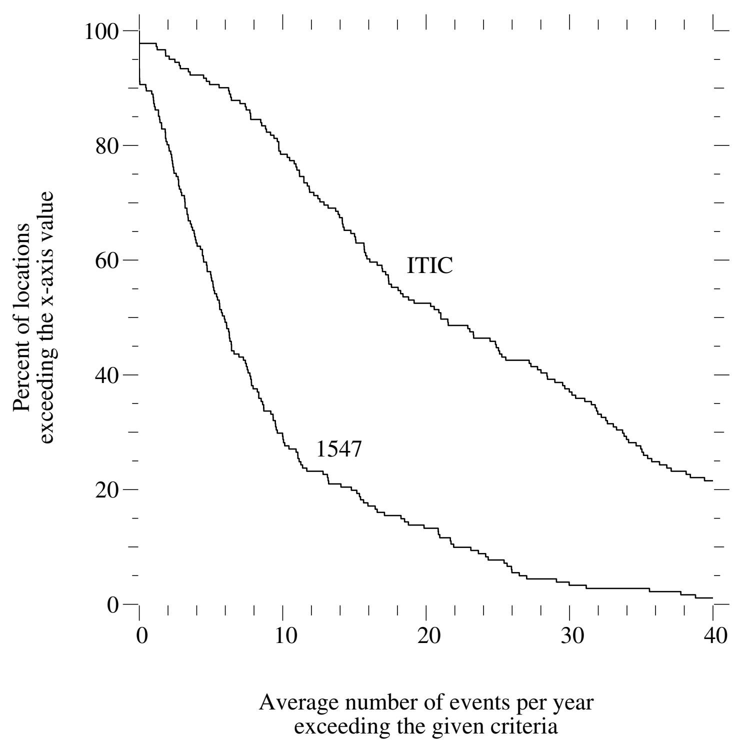

Figure 1-2
Comparison of the Number of Events Exceeding the 1547 Thresholds with Those Exceeding the ITIC Curve

Concepts for a 1547 Relay

The project team explored options for extending traditional relaying to include protecting the utility system against power quality problems caused by generators. The main ideas are taken from IEEE's draft 1547 guidelines (thus the name "1547 relay"):

- Flicker—Flickermeter functionality can be included in a relay. The relay should measure the current (and not just the voltage), so that it does not trip for voltage fluctuations caused by other fluctuating loads or generators.

- Harmonics—Detecting and relaying harmonic violations can be done in a relay. The relay should check the direction of harmonic power flow; the relay should not trip when the generator is absorbing harmonics. Note that the relay may miss resonances excited by the generator.
- Regulation—Over- and undervoltage relaying can be done in a relay; however, this relaying will miss many scenarios where the generator is not properly coordinated with utility-regulation equipment.
- Unbalance—Unbalance can be done in a relay.
- Overvoltage protection—Overvoltage relaying can be done with overvoltage detection connected phase-to-ground and ground overvoltage detection on ungrounded interconnections.
- Islanding/fault current issues—A 1547 relay can cover many of the standard islanding issues and can cover some of the fault-current issues. It would be difficult to design a relay that could handle every possible protection approach that would cover both islanding and fault current.

Tests of a 30-kW Inverter-Based Generator

EPRI PEAC Corporation performed many tests on a 30-kW inverter-based generator to evaluate the performance of its controller-based relaying system. Single-phase, two-phase, and three-phase sags and interruptions were applied.

The type and size of load, both supplied by the generator's protected load contactor and connected upstream of the generator, greatly affect the response of the inverter relaying to events. Some of the notable results of the tests are:

- This generator controller responds to phase-to-phase voltages, but not phase-to-ground voltages. It is desensitized to phase-to-ground voltage sags. To overcome this, undervoltage thresholds need to be changed to be more sensitive, or the voltage-sensing circuitry or software needs to be changed to detect phase-to-ground voltages.
- For single-phase interruptions, the unloaded generator tripped much more quickly than the loaded generator (either resistive or motor load). When unloaded, the generated voltage increased rapidly on the unloaded phase.
- Under matched load conditions, the generator was not able to trip quickly because the voltage stayed within relay bounds for some time. Figure 1-3 shows an example of two phases interrupted to the generator—it did not trip. After extending the interruption duration, the generator finally tripped after 1.3 seconds.

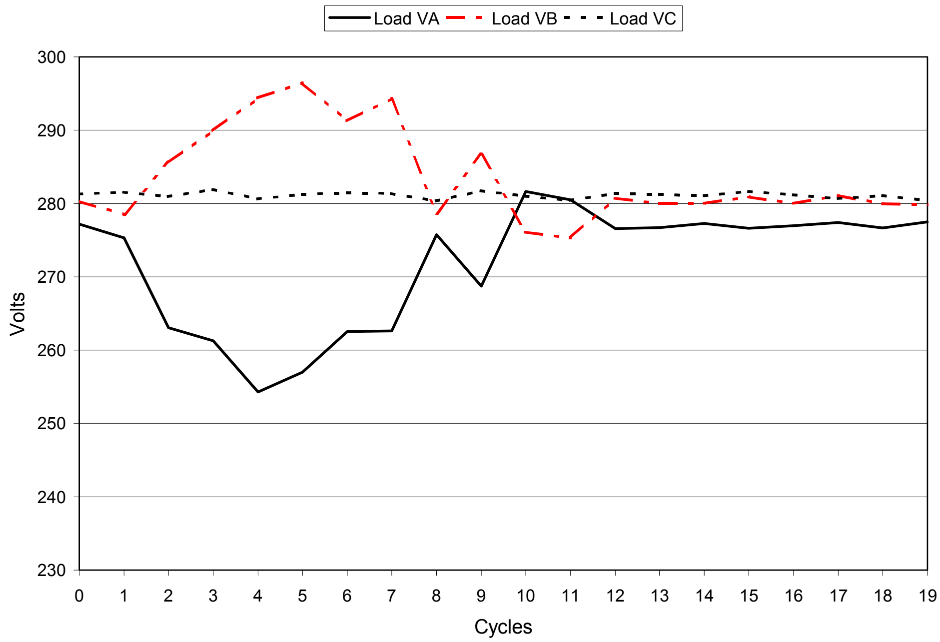

Figure 1-3
Voltages for a 10-Cycle Interruption on Phase A and B with Matched Load Connected to the Generator

2
TRADITIONAL RELAY PACKAGING AND FUNCTIONALITY

Background on Interconnection Issues

Interconnection provides several valuable operational elements to distributed power systems. The electric power system (EPS), by interconnecting a large number of power generators and consumers, enables a significant degree of load and source matching. This serves a valuable load-averaging or load-leveling function that is essential to economic operation of the electric power system. Several requirements related to safety, control, grounding, immunity, emissions, and protection usually define what needs to be included in the interconnection equipment package for the DG.

All generators that are connected to the power system, from the small net-metered units to large combined heat and power systems, must include certain interconnection devices and controls. Requirements related to safety, control, grounding, immunity, emissions, and protection usually define what needs to be included in the generator system interface equipment package. Figure 2-1 shows a simple conceptual drawing that defines the system components and frames the system connection points relative to interconnection of DG and the area EPS. In this report, “EPS” is intended to refer to the distribution feeder and the rest of the area electric power system.

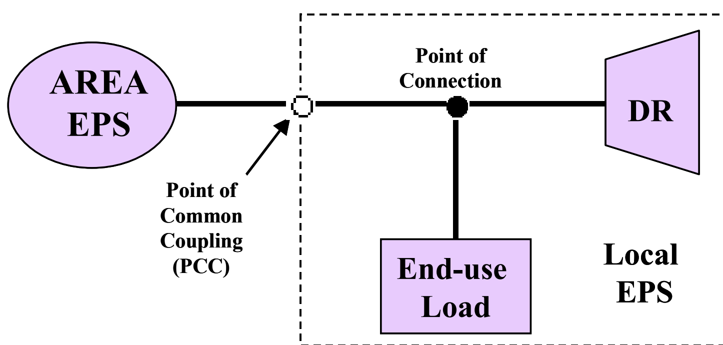

Figure 2-1
Interconnection Points between DG, End-Use Load, and the Area EPS

Depending on the type and design of the generator system, the interconnection equipment may be integrated into the DG equipment, provided as a separate package, or divided into several different installation components and packages. Current practices have not evolved into any uniform packaging. Interconnection requirements vary for different types of utility systems, such as radial compared to network. The requirements can also vary among different jurisdictions and regions around the country. In particular, the details of relay functions and settings can become complicated. This inconsistency has led to a variety of different implementations of interface equipment and packaging.

In larger installations, there are significant requirements for engineering, specification, and design of the interconnection and paralleling equipment. An example installation is shown in Figure 2-2 from a recent EEI study[1]. This figure is one of more than 20 illustrations showing different detailed requirements for interconnections depending on DG type and feeder configurations. The figure shows the level of complexity that is characteristic of many non-utility generator installations using rotating machines as the prime mover.

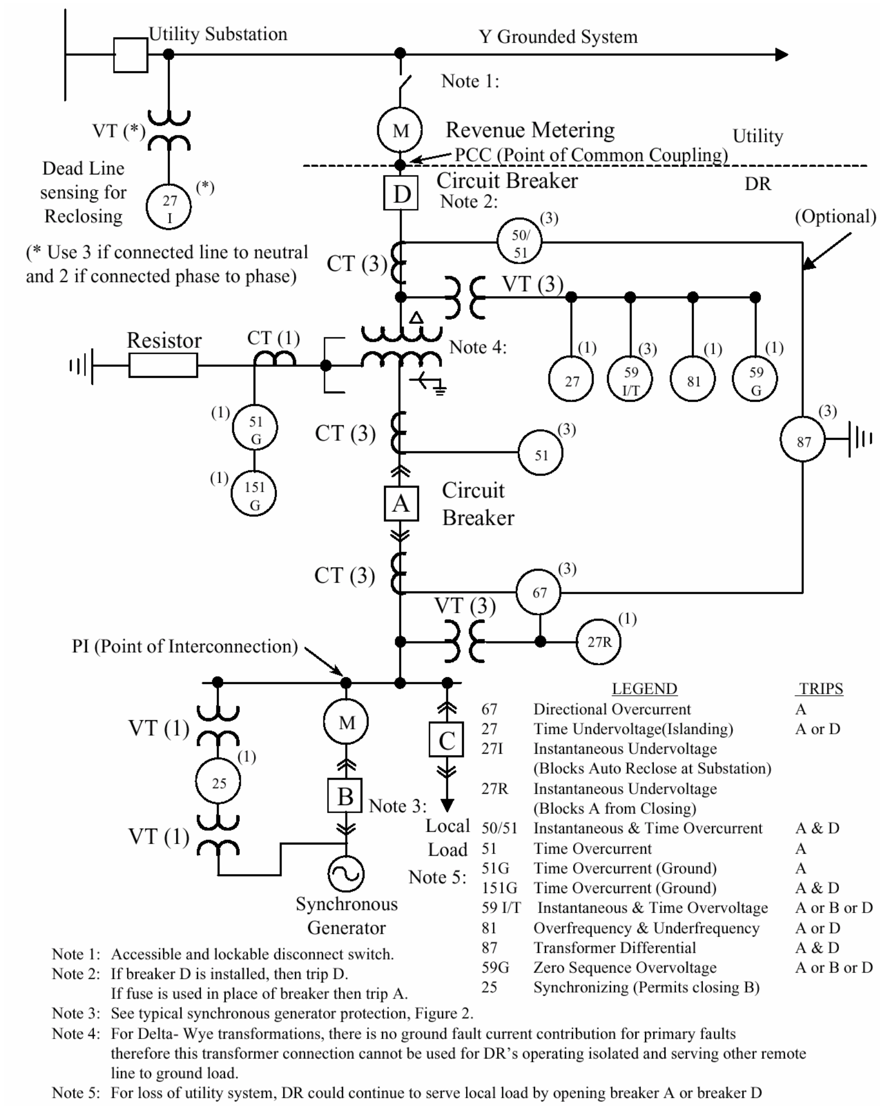

Figure 2-2
Synchronous Distributed Generator (1 to 5 MW) Connected to Primary EPS Voltage

[1] Edison Electric Institute Distributed Resources Task Force Interconnection Study by the Interconnection Working Group, Murray Davis, Detroit Edison Chair, June 2000.

Figure 2-2 defines only the protection typically desired for the electric power system. The relays are set up to protect the distribution feeder under normal and abnormal operating conditions of the power system. Protection of the generator from the EPS is not included. Another set or package of relays may include functions such as reverse power, negative sequence, loss of field, over-excitation, and internal short-circuit protections. The related voltage-sensing potential transformers (PTs) and current-sensing transformers (CTs) must also be installed. Figure 2-3, also from the EEI report, shows a typical synchronous generator protection package.

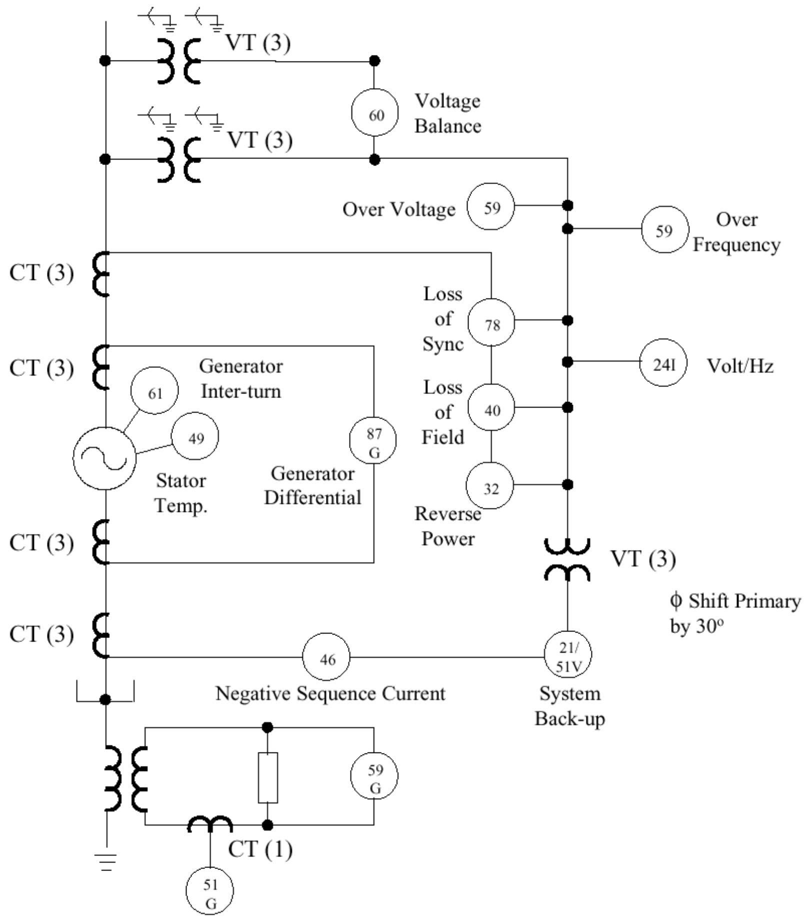

Figure 2-3
Typical Synchronous Generator Protection Package

With only small numbers of similar DG systems, lack of uniform requirements, and nonstandard configurations, the economies of production volume have not been realized in interconnection equipment. Consequently, the costs for interconnection of a small distributed generator can be relatively high, and costs for larger systems leave a lot of room for optimization and savings. This has led to a push for standardization and uniformity in DG interconnection equipment by DG manufacturers, regulators, and utilities.

Interconnection requirements stem from fundamental issues related to a compatible interface. These include safety, reliability, quality, and potentially damaging interactions. Some requirements come from the operator of the distribution system in fulfilling its obligation to protect the public power supply and to comply with the National Electrical Code (NEC). Other requirements are imposed by local codes and the NEC for premises wiring. State interconnection rules such as in Texas[2], New York[3], and California[4] require specific interconnection hardware and capabilities for DG. Also, some protection and control functions will be specified by the system owner to protect the investment or increase its functionality and value.

Five basic functions found in most interconnections are:

1. Electrical isolation via power transformer.
2. Controlled connection and disconnection (includes a load-break contactor and automatic paralleling control).
3. Visible and secure (lockable) disconnect.
4. Short-circuit protection (includes fault interruption rating).
5. Surge protection (required for relay and electronics).

Optional added-value interconnection equipment functions are:

- Remote communication capability (locally or with the EPS operator).
- Load transfer between local and utility sources.
- Power quality and event monitoring (voltage and current).

Typical EPS-DG Hardware Suppliers and Configurations

As has been discussed, there are a number of different possible implementations of EPS-DG interconnection equipment. Depending on the DG system type and design, the interconnection equipment may be integrated into the DG equipment, provided as a separate package, or divided into several different installation components and packages. Current practices have not evolved into any uniform packaging. Appendix B gives lists of contact information for manufacturers of relays, inverters, distributed generators, and support equipment.

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[2] Texas Public Utility Commission Requirements for Pre-Certification of Distributed Generation Equipment by a Nationally Recognized Testing Laboratory, Project No. 22318, Public Utility Commission of Texas, Austin, TX, September 2000.

[3] New York State Standardized Interconnection Requirements, Application Process, and Contract for New Distributed Generators: 300 kVA or less, Connected in Parallel with Radial Distribution Lines, NY State Dept. of Public Service, Albany NY, July 19, 1999.

[4] CEC Siting Committee Recommendation on DG Interconnection Rules, Rule 21, California Energy Commission, Sacramento, CA, May 2000.

Manufacturers of Protective and Control Relays

This is the most conventional and experienced source for the control of DG protection. The protective relay industry has supported the protection of transmission, distribution, and generation of electricity for many years. In the case of DG, the same relay approach is the most familiar and proven choice for utilities. The relays are the main controlling elements of interconnection. They are provided in discrete or integrated control packages and are integrated with switches, transformers, and disconnects in order to provide the complete set of interconnection functions.

For large DG systems connected at the transmission level, the relaying design for interconnection is likely integrated into and coordinated with the existing design of transmission protection. For large distribution-connected DG systems, protection relays are also designed on a case-by-case basis to address the specific feeder configurations. This includes the specific design criteria that most existing distribution protection is designed for (one-way power flow). In both of these cases, the interconnection protection is normally separated from the generator protection. Figure 2-4 shows a conceptual layout of standard relaying for interconnection. Note that other required disconnects, control contactors, and fault-interruption functions are not shown.

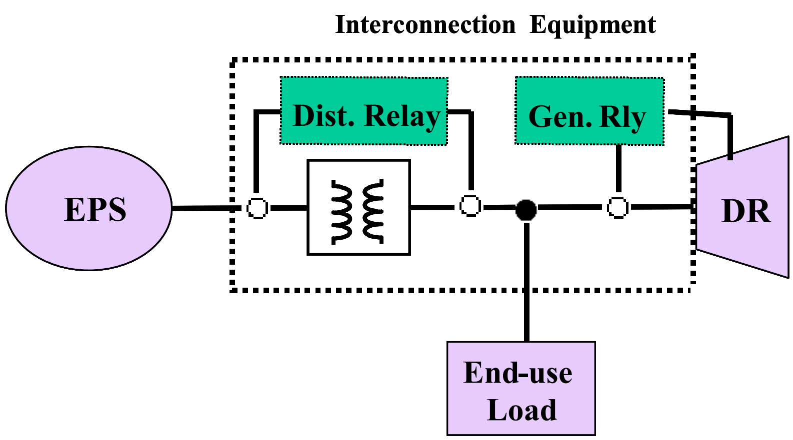

Figure 2-4
Conventional Independent Relaying Packages for Utility Feeder and Non-Utility Generators

The distribution-feeder relay package and the generator-protection relay package are provided by the traditional protective relay industry. For DG, this same relay industry has developed packages that integrate both the feeder and the generator protection in one package. Paralleling control and transfer from utility to generator source may also be offered in this integrated package shown by the block diagram in Figure 2-5. This can add functionality while simplifying installation and reducing the overall cost of interconnection.

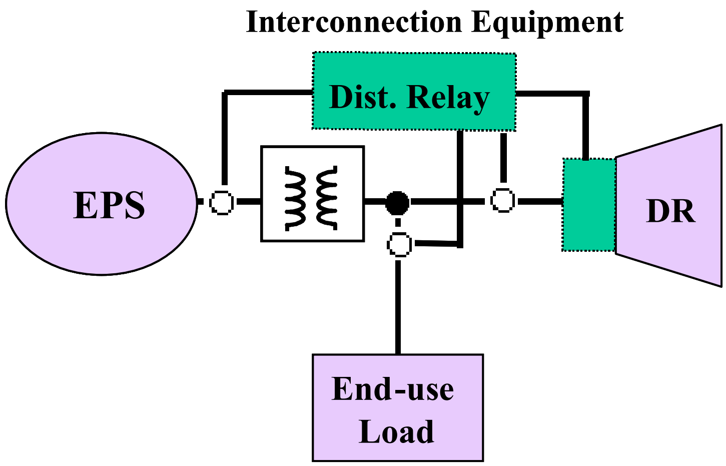

Figure 2-5
Integrated Distribution Feeder and Generator Protection in One Package

Manufacturers of Electronic Inverters

In the case of smaller distributed generators that are interconnected via an electronic inverter, the control capability of the inverter will play a role in making the connection. In this case, the customer-side protective functions can be completely addressed in the inverter. Figure 2-6 shows the conceptual idea of this arrangement. In some cases, the inverter manufacturer may use relaying designed and built by the protective relay industry. Depending on inverter size and design, a transformer may not be required between the generator inverter and the local facility power system. If the inverter connection can be made without a transformer and without additional synchronization and relaying protection, significant savings in the interconnection costs can be realized.

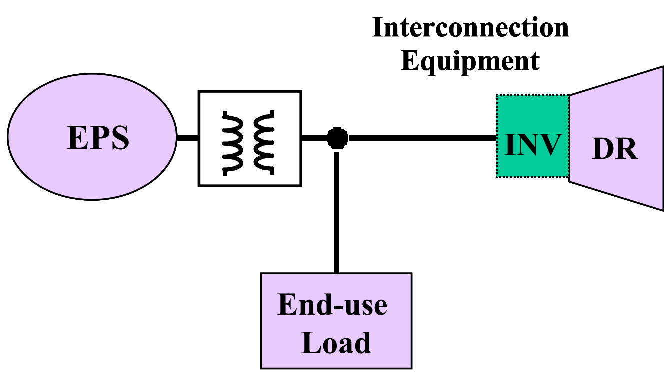

Figure 2-6
Interconnection Functions Provided by Electronic Inverter and Transformer

If the inverter-connected DG is large compared to the locally connected load, additional transformer isolation and additional relaying will likely be required. This system may look like Figure 2-7, where the protection is a hybrid between integrated inverter and separate conventional relaying. In this case, a step-up isolation transformer is likely to be required for both the load and the DG.

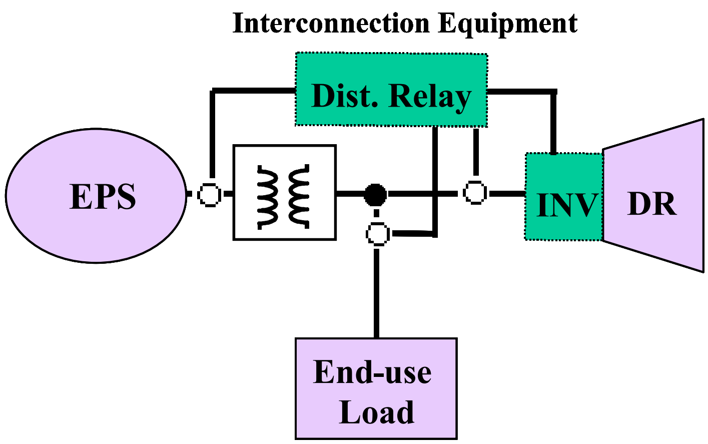

Figure 2-7
Protection for a Large DG Inverter May Require for both Built-In and Conventional Relay Functions

Traditional Relay-Protection Schemes

Utility-Grade Protective Relays

Many utilities require utility-grade relays for small installations, and essentially all require them for large installations. This raises the question, "What is a utility-grade relay?" The answer is that a utility-grade relay is one that a utility considers appropriate; however, there is no fixed definition for such a device. Some characteristics that utilities usually consider when specifying relays as utility-grade are:

- Meets or exceeds ANSI/IEEE standards (C37.90[5] and C39.90.1[6])
- High-quality components
- Very good accuracy and resolution of the pickup setting
- Extensive documentation covering application, testing, maintenance, and service

[5] ANSI/IEEE Std. 37.90-1994, Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

[6] ANSI/IEEE Std. 37.90.1-1994, Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems.

- Positive indication of what caused a trip (targets)
- High voltage-surge withstand
- Draw-out mounting
- Test plugs for in-place testing

Utility-grade relays are used almost universally on very large DR units. However, the utilization of utility-grade relays for smaller distributed generators (less than 10 kW) has been a major point of contention between utilities and non-utility generators. In the case of larger non-utility generators (100 kW and above), the relays are a few percent of the total system cost and make sense in light of the security issues and investments associated with larger generators. However, for small non-utility generators such as residential-scale photovoltaic systems of a few kilowatts, the requirement for utility-grade relays significantly increases the cost of such installations. Many utilities are acknowledging this and are no longer requiring such relays for smaller installations.

Islanding

Unintentional islanding is the most important concern when integrating distributed generators because it can create unsafe conditions. Islanding is a situation where a distributed generator and a portion of the utility system operate separately from the rest of the utility system. An example of islanding is a distribution feeder 10 km in length with a 500-kVA DG unit located 9 km out on the feeder. The feeder load over the last kilometer is also 500 kVA. If a switch just upstream of the generator is opened, sustained operation of the generator and the detached portion of the utility system may occur. Anti-islanding provisions need to be included in the interface package of the generator system. Even so, formation of an unintentional island of this nature may be possible and is very problematic for the utility company. The most important concerns are:

- Worker and public safety
- Damage to utility and customer equipment due to out-of-phase reclosure
- Voltage problems
- High overvoltages to utility equipment and customers caused by neutral shifts or ferroresonance

When islanding occurs, a portion of the system is separated from the main system, as shown in Figure 2-8. The system operator no longer controls the frequency or voltage in that section. Because most distributed generators are not set to regulate voltage on the feeder, it is unlikely that adequate voltage would be maintained at all points on the islanded section. Customers for whom the utility has total responsibility to deliver voltage of the proper range may be subjected to voltages and frequencies over which it has no control. Islanding may damage utility equipment and cause delays in service restoration. Once an island has been established, it will typically drift out of phase with the utility system voltage, and key switches and breakers may not be able to be reclosed until the island can first be de-energized. If the main system is closed into the island, the out-of-phase reclosure may damage the generator, customer loads, and utility switchgear, as well as being a significant power quality disturbance for customers upstream of the island. An island may also prevent the clearing of fault currents on the systems leading to reliability degradation and perhaps conductor burndowns.

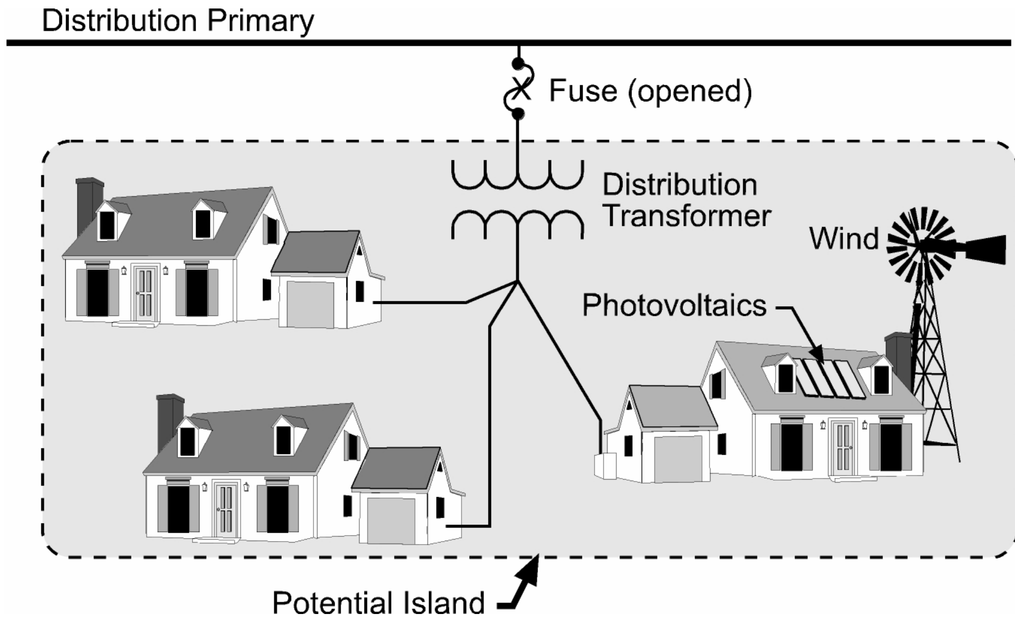

Figure 2-8
Unintended Island of Small Residential Group

Another important concern of islanding on the part of utilities is the danger it creates. Line crews working on a section of line that they believe is de-energized may unexpectedly encounter line voltage and could be electrocuted. The danger also extends to the general public in that there could be cases of downed conductors or other live wires on the ground within public reach that might have been de-energized by upstream utility switchgear had an island not developed. While it can be said that, in the absence of distributed generators, energized downed conductors are already a problem, the application of DG to these systems only increases the likelihood of this situation.

Islanding can occur with synchronous generators, induction generators, self-commutated inverters, and line-commutated inverters. The main criterion is that real-time power generation roughly matches the real-time power requirements of the system. Consequently, it is more likely to sustain an islanding when generators have built-in real and reactive power control. This is the case with synchronous generators and certain self-commutated inverters, while induction generators and line-commutated inverters require an external source of excitation and do not have reactive power control.

The worst-case overvoltage would occur with ungrounded high-side generator connections. When a single line-to-ground fault occurs on the distribution system and the substation breaker (or a recloser) opens, the system becomes a three-wire, ungrounded system driven by the ungrounded generator. The line-to-neutral voltage will attempt to rise to the line-to-line voltage ($\sqrt{3}$ = 1.73 times the line-to-neutral voltage).

The common way to prevent islanding is to use voltage and frequency relays on the DG unit, which are set to trip whenever the voltage or frequency migrates outside a selected window. This form of islanding protection is known as *passive* protection. It prevents islanding in most cases because when a section of the distribution system and generators separate from the rest of the system, the output of the generators will not match the power demand within the separated area. For synchronous or induction generators, this results in a change in voltage and frequency, causing the relays to trip in a very short time. Typically, the relays would be set to a rather tight frequency range of perhaps ±1 Hz or even ±0.5 Hz. Voltage would be a bit wider to allow for typical voltage-regulation excursions on the feeder (±5 to 10% would be typical).

Overvoltage and Undervoltage Relays

Over- and undervoltage relays are usually provided for DR interconnections and are an important line of defense against islanding. Typically, this consists of:

- Overvoltage time-delay relay (59T)—A pickup of 5 to 10% above nominal voltage is generally used. The time setting should be set above the normal clearing time of the feeder relays but less than the substation breaker reclosing time. One-half to one second is a reasonable setting.
- Instantaneous overvoltage element (59I)—An instantaneous overvoltage element is recommended (but not always used). A higher setting (such as 40% above nominal) may be needed to prevent excessive nuisance trips.
- Undervoltage time-delay relay (27T)—A pickup of 5 to 10% below nominal voltage is generally used. Similar time settings should be used as the overvoltage time-delay relay.
- Instantaneous undervoltage relay (27I)—As with the overvoltage instantaneous element, a loose setting is necessary to prevent nuisance trips (30% below nominal is reasonable).

The time-delay relays are time delays; they are not inverse-time relays. If the voltage on a 59T relay is above the magnitude setting for longer than the time setting, it will trip. If the voltage drops back below the magnitude setting, the timer will reset after the given reset time. Many generator-protection relays allow multiple pairs of magnitude and time-delay settings to achieve a stair-step voltage-time characteristic.

For overvoltages, it is best if the detecting potential transformers are on the primary side of the generator transformer (especially if the primary winding is ungrounded). For example, the neutral shift on an ungrounded island with a ground fault will not be detected on the secondary side of the transformer. To detect and trip on overvoltages, individual relays should be on each of the three phases (not just on an individual phase and not on an average of the three phases). The undervoltage relays will also provide backup for neutral-shift overvoltages by detecting the voltage sag on the phase with the line-to-ground fault.

Over-frequency and Under-frequency Relays

The over- and under-frequency relay (81U/O) is another line of defense against islanding. Trip thresholds of ±1% are common. Wide ranges of time delays are used for a 1% setting: 0.1

seconds to many seconds. Some utilities specify a wider range for the under-frequency setting to allow the generator to stay in for low-frequency events caused by system-wide disturbances. The low frequency indicates a need for generation, so it is helpful to have the distributed generation remain connected.

59G Ground Overvoltage Relay

Unbalanced overvoltages can be detected with a 59G relay with the connection shown in Figure 2-9. The relay operates based on the measurement of the sum of the three line-to-neutral voltages obtained from the grounded-wye broken-delta PT arrangement. Ground overvoltage detection is especially needed for ungrounded connections to clear overvoltages caused by line-to-ground faults during islanding. These cannot be detected on the generator side of the transformer.

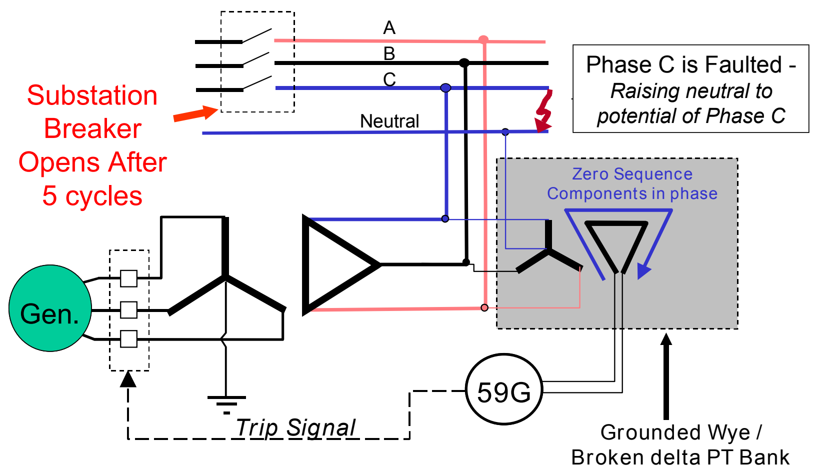

Figure 2-9
Ground-Fault Overvoltage-Detection Scheme (59G)

Synchronization

Synchronizing relays (function 25) are another functional requirement that is necessary to meet several different operating criteria. Controlled connection is obviously needed to synchronize and parallel with the utility system. It is needed to reconnect after a protective trip, usually with some time delay once normal utility voltage conditions are restored. Synchronization is important for protection of generators as well as protecting the utility system and other customers against transient overvoltages.

Only one breaker should be used for synchronization; usually, this is the breaker closest to the generator. If the DG can be started by itself without the utility, all breakers upstream of the "synchronizing breaker" must have a voltage relay to block closing of the breaker if there is voltage on the generator side of the breaker. This is to prevent an operator from closing the breaker after starting the generator.

Another related function that the generator controller must perform is controlled reconnection. The delay upon reconnection should be coordinated with utility reclosing practices. A delay on the order of five minutes is typical.

Other Functionality

Other functionality may be needed for interconnection:

- Transfer trip—For large generators, a trip signal from upstream utility breakers and reclosers is needed to ensure that the generator trips off line whenever the utility source is disconnected. This becomes the primary anti-islanding protection.
- Reverse power relays—For distributed generator applications where power is not to be exported to the utility, reverse power relays will help prevent islanding situations.
- Fault protection—instantaneous overcurrent (50), time overcurrent (51), and ground overcurrent (51G)—The generator should be disconnected for cases where the generator is feeding utility faults and the utility is feeding faults downstream of the point of common coupling.

Integrated Generator Relay Packages

Integrated generator relay packages are available from several manufacturers. These provide all of the interconnection functions needed (and possibly all of the generator protection functions as well).

Companies like Beckwith Electric have been developing integrated relay products specifically for the distributed generation market since the PURPA legislation of 1978 (for example, the “PRIDE” relay that was sold in the 1980s). Products such as the M-3420, featured in Beckwith’s September 2000 newsletter, the Alstom MiCOM P341, Basler’s feeder relay BE1-951 and machine relay GPS-100, the Cooper 150-23, and Schweitzer 300G are targeting the dispersed generations and the independent power producer (IPP) market, and they sell for $2000 to $5000.

The integrated relays are “utility grade” and have been tested to IEEE and IEC standards. They also have external test ports that allow for testing of the relaying system in the field using signal injection. For these reasons, utilities have been very positive towards their use.

3
INVERTER-BASED RELAYING

Present Trends for Relaying Inverters

There are interconnection and operating options that affect how distributed energy sources that use inverters to interface with the AC system must or can be relayed. Some of the options are stated as questions below; the answer given for each question indicates the present trend:

- Is the connection through a dedicated transformer required? No.
- Can either a line-commutated or a self-commutated bridge be used? Yes.
- Are voltage-source or current-source inverters used? Most are current-source.
- Will the inverter have to stop supplying power if it is part of an island that becomes separated from the utility grid? Yes.
- If it is disconnected, under what conditions may it reclose? Minutes after the island rejoins the utility network.
- Can it (or must it) vary its reactive power output to help control voltage? No.
- Can it (or must it) vary its active power output to help control system frequency? No.
- Are both single-phase and three-phase sources allowed? Yes.
- Is power flow into the utility allowed? Yes.
- Is distributed generation normally connected through a radial feeder? Yes.

FERC rules, state regulations, industry standards, and utility regulations provide direction on some of these issues, but there is no consistent policy in most cases, and even the existing policy may have to be revisited if large amounts of the load in a particular area will be served by distributed generation.

This section deals only with relaying applied at the inverter to protect other equipment and individuals. Other protection such as reverse-power relays and ground-fault protection may be needed at the utility interface or at other locations. Of course, distributed sources may also have additional device specific protections to limit internal damage for certain faults.

A consensus has not yet developed on how distributed generation should be relayed. The Underwriters Laboratories Subject 1741-1999 (UL 1741[7]) provides a test procedure to verify that distributed generation shall "cease to export power" under certain conditions. It does not, however, specify whether this is to be achieved by design, by control action, or by use of particular types of protective equipment. A consensus on relaying is perhaps closer to developing for small (<500 kW) photovoltaic systems than for most other types of distributed generation. Photovoltaic converters are normally connected to the AC system using current-source converters, so a similar strategy can probably be applied for other types of distributed generation that use current-source converters. Larger systems may require additional protection or perhaps use an entirely different control and protection philosophy. To satisfy the UL-1741 requirements, which have also been adopted by the IEEE 929 standard[8] for photovoltaic systems, the following types of protection will probably be applied at a current-source inverter used for distributed generation:

- Over-frequency
- Under-frequency
- Overvoltage
- Undervoltage
- Active anti-islanding

A voltage-source inverter would probably be connected to the AC system by a dedicated transformer. It might have the following relays:

- Over-frequency
- Under-frequency
- Overvoltage on the system side of the transformer
- Undervoltage on the system side of the transformer
- Overcurrent possibly with voltage restraint
- Active anti-islanding

Relays that sense the rate of change in frequency, residual DC current, or excessive harmonic distortion in the voltage waveform may also be used in some cases.

Distributed generation creates protection problems that are not present when there are no energy sources connected to the distribution system. Perhaps the most important issue is the need to disconnect the distributed generation if it is attached to a portion of the utility network that has become separated from utility-controlled generation. This is done to protect utility personal while they work on the isolated part of the network, to let the current through any short circuits

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[7] UL 1741, Inverters, Converters, and Controllers for Use in Independent Power Systems, Underwriters Laboratories, Inc., January 17, 2001.

[8] IEEE 929, Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

on the island extinguish naturally, to facilitate reclosing, to avoid damaging equipment, to limit the utility's responsibility for an electrical environment that it can no longer control, and to simplify the restoration of the system.

Some distributed energy sources are equipped with built-in protective devices that perform some of the functions indicated above. The settings for built-in protection are sometimes fixed and sometimes adjustable, and tamper-proof settings may or may not be provided when the settings are adjustable. The present trend is to provide fixed settings for small (<10 kW) distributed sources and adjustable tamper-proof settings for larger sources. Circuitry may or may not be provided for testing the protective functions, and test points may or may not be set up to be conveniently available to utility personnel. Some utilities require protection with separate utility-grade relays, which are "known quantities." These relays can be adjusted, tested, and maintained using standard procedures and are perceived to be more robust than equipment-based protection.

Different types of protection may be needed if some of the trends that are indicated above change. It would theoretically be possible to operate an island disconnected from the utility generation if it has enough distributed generation to cover the load. This would improve the reliability of the islanded system but complicate the operation, control, maintenance, and restoration for the overall system. If enough distributed generation is installed, it may no longer be possible to rely on the utility generation to control frequency and regulate voltage. It may therefore be necessary to require the distributed generation to participate in the voltage regulation and frequency regulation. This would also favor self-commutating converters that are operated as controlled voltage sources, thus providing new sources of fault current in the distribution system. Meshed distribution grids instead of radial feeders might then also be desirable. This would completely change the protective strategy used for distribution systems; it might then be similar to the strategy used for transmission systems.

Concerns with Inverter-Based Relaying

Utilities worry about inverter-based relays, mainly for the following reasons:

- Inverter-based relays are not utility-grade.
- Software changes to the controller may interfere with the performance of the relaying.
- Testing in the field is very difficult (see chapter 4).

Utility-grade relays meet several industry-standard tests, including:

- IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus, ANSI/IEEE Std C37.90-1989.
- IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers, IEEE Std C37.90.2-1995.
- IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems, ANSI/IEEE Std C37.90.1-1989.
- IEEE standard seismic testing of relays, ANSI/IEEE Std C37.98-1987
- IEC 255-5 Isolation Testing for Electrical Relays (Part 5). 1977:

- IEC 255-6: 1988 Electrical Relays, Part 6: Measuring Relays and Protection Equipment, High Frequency Disturbance Tests (Type Test).
- IEC 801-4: 1988 Electromagnetic Compatibility for Industrial-Process Measurement and Control Equipment, Part 4: Electrical Fast Transient/Burst Requirements, Severity Level 4 (4 kV on Power Supply, 2 kV on Inputs and Outputs) (Type Test).
- IEC 801-2: 1991 Electromagnetic Compatibility for Industrial-Process Measurement and Control Equipment, Part 2: Electrical Discharge Requirements (Type Test).
- IEC 255-5: 1977 Electrical Relays, Part 5: Insulation Tests for Electrical Relays.
- IEC 68-2-30: 1980 Basic Environmental Testing Procedures
- IEC 255-21-1: 1988 Electrical Relays, Part 21: Vibration, Shock, Bump and Seismic Tests on Measuring Relays and Protection Equipment, Section One - Vibration Tests (Sinusoidal), Class 1 (Type Test).
- IEC 255-21-2: 1988 Electrical Relays, Part 21: Vibration, Shock, Bump and Seismic Tests on Measuring Relays and Protection Equipment, Section Two - Shock and Bump Tests, Class 1 (Type Test).
- IEC 255-21-3: 1993 Electrical Relays, Part 21: Vibration, Shock, Bump, and Seismic Tests on Measuring Relays and Protection Equipment, Section Three - Seismic Tests, Class 2 (Type Test).

Many modern relays also offer many functions that help verify proper operation.

- Internal diagnostic tests.
- Display of the operation of each protective function.
- Automated output contact testing.

Utilities fear that inverter-based relays will not be as robust as utility-grade relays. Stability is also a concern—software upgrades may compromise protection.

Advanced Anti-Islanding Protection

Anti-islanding protection for each distributed energy source must be designed so it can recognize when it is isolated from utility generation sources and automatically cease its own energy production. Both active and passive methods are used to detect system separation. The passive methods measure electrical quantities such as voltage magnitude, harmonic content, or frequency and trip the distributed generation if any one or more of these quantities are too high or low or are changing too rapidly. The IEEE 929 standard for photovoltaic systems indicates that passive methods should in the vast majority of cases be able to remove the distributed generation in 10 cycles or less. However, there is a limited range of network conditions for which passive methods may not work. The IEEE 929 standard allows 2 seconds to remove the distributed generation for these conditions. For these conditions, active methods of detection will probably be necessary. Active methods perturb the normal system operation and use the measured response to detect islanding. This section discusses some of the active methods that have been proposed or are in use.

Pilot Signal

A high-frequency pilot signal would be injected into the transmission network at major power-system generation centers. A protective relay would then trip the distributed generation if it cannot detect the pilot signal. This is straightforward, but has several potential problems:

- All of the distributed generation in the whole network would trip if the pilot signal is lost for some reason
- The pilot signal might interfere with other relaying or communications
- The high-frequency pilot signal would attenuate much faster than the fundamental frequency
- Pilot signals from different generation sites might interact or cancel
- The high-frequency pilot signal in the rest of the system might be inductively or capacitively coupled to an electrical island and prevent tripping

Active or Reactive Power Perturbation

The distributed generation may vary its active or reactive power output, or a large shunt capacitor or reactor might be energized or disconnected to perturb the system. If the generation is islanded, the voltage magnitude or frequency will presumably shift enough to trigger the voltage or frequency relays and trip the unit.

Some potential problems with these methods are:

- If there is too much distributed generation on the island, a distributed generator acting independently will not be able to change the voltage or frequency enough to trigger the relays
- Other units with similar protection acting independently may interfere
- To remove the generation promptly, the perturbation would have to be nearly continuous

Apparent Impedance Measurement

The distributed generation varies its active or reactive power output to perturb the system, and the change in voltage due to the perturbation in current is used to find the apparent impedance seen by the distributed source. An increase in the apparent impedance that exceeds a threshold is then used as a signal to trip the unit.

Some potential problems with this method are:

- If there is too much distributed generation on the island, a distributed generator acting independently will not be able to change the voltage or frequency enough to significantly change the voltage
- Other units with similar protection acting independently may interfere
- To remove the generation promptly, the perturbation would have to be nearly continuous

This method is standard in Germany, and excessive nuisance trips occur for generators on weak distribution circuits

Remote Switching From the Utility Control Center

A communication link could be provided to each distributed generator from the control center. The distributed generation could then be tripped if the control center determines that it is islanded. This also has several potential problems:

- Individual communication links could be expensive
- The control center may not have sufficient information to detect all islanded conditions
- The communication link may not be reliable

Sandia National Laboratories Active Anti-Islanding Methods

Sandia National Laboratories[9] has proposed two active anti-islanding techniques that were originally developed for photovoltaic systems but are applicable for all distributed generation using current-source inverters:

- The Sandia Frequency Shift, SFS, technique
- The Sandia Voltage Shift, SVS, technique

Both techniques use a controller with a positive feedback to create an unstable situation when the source is isolated. The SFS technique applies positive feedback to the electrical frequency control, and the SVS technique applies positive feedback to the voltage magnitude control. When the source is connected to an external system that employs normal voltage and frequency control, the external system will stabilize the frequency and voltage, so the SFS and SVS controls have little effect. However, when one or more sources employing the SFS/SVS controllers become isolated, the frequency/voltage will drift up or down, and the sources will be tripped by relays that sense that the frequency/voltage is out of bounds. A major advantage of the Sandia techniques is that the anti-islanding responses of all the SVS-controlled sources in an island are inherently coordinated, so they do not interfere with each other. These techniques cannot be used for distributed sources that are not bridge-connected.

The Sandia Voltage Shift, SVS, Technique

One of the advantages claimed for distributed generation is that by supplying power locally, it will be possible to avoid upgrading the distribution system. For the SVS technique to work properly, there must be a significant difference between the apparent resistance seen by the distributed source when the island is attached to the rest of the network and the apparent resistance seen without the interconnection. This would normally be the case with the present distribution-system feeders. This, however, may not always be the case if a large proportion of

[9] Stevens, J, et al, Development and Testing of an Approach to Anti-Islanding In Utility-Interconnected Photovoltaic Systems, SAND98-1684, Sandia National Laboratories, 1999.

the power used by a feeder is supplied locally (see Appendix A for a controls analysis of the SVS technique). As more load and distributed generation is added to a feeder, it will become increasingly more difficult to find a suitable gain for an SVS voltage controller unless the interconnection is strengthened. The apparent resistance seen by a distributed source may vary significantly with the day-to-day loading of the feeder and system outages. The minimum gain for the SVS controller will be inversely proportional to the lowest possible apparent resistance without the utility interconnection. This will probably be the resistance at peak load. The maximum transient gain of the SVS voltage regulator will be inversely proportional to the highest possible apparent resistance while connected to the rest of the network.

A fast-acting voltage-control device in the island will effectively disable the SVS anti-islanding detection. For the SVS anti-islanding to work well, only slow-acting voltage controllers can be used in the portion of the network that might be islanded. A Sandia report[10] recommends that if inverters with SVS protection use power-factor tracking, the tracking should have a response time no faster than 20 seconds. Fortunately, fast-acting, locally connected voltage controllers are not normally needed on distribution feeders because they can rely on external voltage support through strong interconnections. But, this may not be the case if a large proportion of the power used by a feeder is supplied locally by distributed generation to avoid upgrading the feeder. Local voltage support will then need to be at least fast enough to follow rapid load changes.

Rotating sources connected to the island will reduce the voltage variation even if their excitation is fixed. This will tend to desensitize the anti-islanding detection applied to other distributed generation. Tests at Sandia Laboratories and Ascension Technology[11] do, however, indicate that the SVS and SFS protection functions properly with induction motor loads connected to the island.

With some forms of distributed generation such as solar and wind, the current output is varied quite rapidly in response to the uncontrolled power output of the energy source. If the current output varies too rapidly, it will interfere with the operation of the SVS. Therefore, it may be necessary to provide additional energy storage so that the current output does not have to follow the energy-source output quickly.

The Sandia Frequency Shift, SFS, Technique

The SFS frequency controller will increase the frequency of the current-source if the system frequency is already high and decrease the frequency of the current-source if the system frequency is low. Because of the gain in the SFS controller, a 0.5-hertz deviation in system frequency will produce approximately a 3.5-hertz change in the current-sources frequency. The firing of the bridge controller is also controlled to keep the current in step with the voltage. The current output starts when the oscillating voltage becomes positive. If the controller has raised the frequency of the current source, it will complete a half cycle before the next voltage

[10] Stevens, J., et al, Development and Testing of an Approach to Anti-Islanding In Utility-Interconnected Photovoltaic Systems, SAND98-1684, Sandia National Laboratories, 1999.

[11] Stevens, J., et al, Development and Testing of an Approach to Anti-Islanding In Utility-Interconnected Photovoltaic Systems, SAND98-1684, Sandia National Laboratories, 1999.

crossover. However, the next half cycle of current will not be triggered until the voltage becomes negative, so the current will be held at zero for approximately 10 degrees if the source-current frequency is elevated by 3.5 hertz. Similarly, the negative half cycle of current will finish before the next voltage crossover, and the current will be zero in the interim, as shown in Figure 3-1.

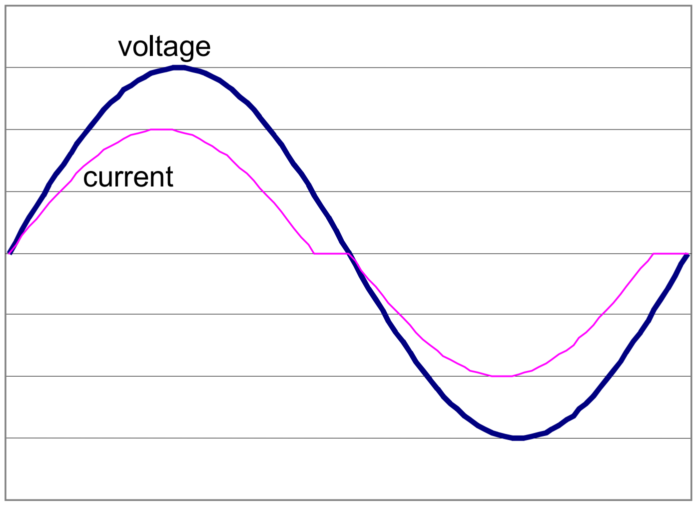


Figure 3-1
SFS Current Waveform for High Frequencies

If the controller has lowered the frequency of the current-source, the current will not have completed its first half cycle when the voltage again changes polarity. The bridge pulse width modulation will truncate the positive current and start the negative half cycle. This half cycle will also not be completed when the voltage again changes polarity and will be truncated, as shown in Figure 3-2.

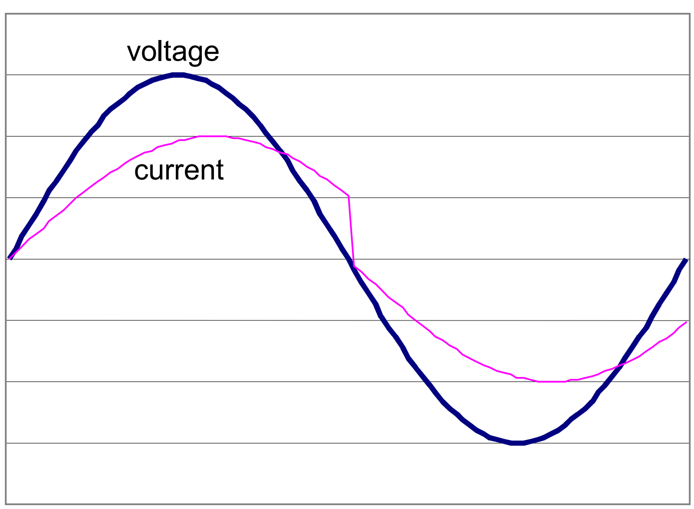


Figure 3-2
SFS Current Waveform for Low Frequencies

For both positive and negative system frequency deviations, the current waveform will therefore not be sinusoidal and will include harmonics. If there is a large amount of distributed generation with SFS anti-islanding protection, these harmonics may become objectionable.

When a distribution feeder is closely tied to the transmission network, the waveform of the distribution system voltage will be largely determined by the network voltage; so the voltage crossovers, which trigger a distributed generation current-source, will be synchronized to the utility. However, if the connection becomes weak, the current-source may significantly affect the timing of the voltage crossovers, so the current-source will determine the system frequency. If the connection is open, the voltage and frequency will be determined by the current-source unless there are other sources in the island that do not have the SFS anti-islanding protection. The SFS anti-islanding protection is sufficiently complex, so it is not obvious how strong the interconnection has to be to prevent inappropriate operation or how many sources (if any) without SFS protection can be on the island before the SFS scheme fails to function. However, tests at Sandia Laboratories and Ascension Technology do indicate that the SVS and SFS protections function properly with induction motors connected to the island.

Anti-Islanding Protection for Voltage-Source Converters

The Sandia SFS anti-islanding techniques were designed for use with photovoltaic systems, which normally use current-source inverters. There does not appear to be a workable approach similar to the SFS technique based upon voltage-source converters. A voltage-source converter on the island may in fact keep the SFS systems that are applied to other distributed generators from operating properly.

However, an approach similar to the SVS technique might work for distributed generation that uses voltage-source inverters. For this approach to work, the voltage-source would have to be connected to the distribution system through a transformer or series reactor, and the magnitude of the transformer leakage reactance or the magnitude of the reactor impedance would have to be small compared to the driving-point impedance of the system when it is connected to the AC system.

Testing Anti-Islanding Protection

The Underwriters Laboratories Subject 1741-1999 (UL 1741) and the IEEE 929 standards provide the following test procedure to verify anti-islanding protection for inverters. Sandia Laboratories originally suggested the test procedure, but it is intended to be applicable to all types of active anti-islanding protection, not just the Sandia techniques, which were originally developed for photovoltaic systems. This test verifies that an anti-islanding device will disconnect a source when it is called upon. It does not, however, verify that the device will not disconnect the source inappropriately when it is still tied to the utility network. To avoid false operation, it may be necessary to tune it for use in a particular electrical environment. The impedance of the interconnected network as seen from the distributed source could be particularly important. The IEEE 929 standard recommends that this procedure be used for certified design testing that would probably be done by the manufacturer. Tests should probably also be performed to verify that the device will not operate inappropriately in various electrical environments and to suggest tuning parameters for a range of possible system impedances.

This test is not designed to show the performance of the anti-islanding protection when there are rotating sources in the island or multiple distributed energy sources protected either by the same type of anti-islanding device or different anti-islanding devices.

The following is a brief summary of the test recommended by UL 1741 and IEEE 929. The test is repeated at several levels of inverter load. For each level of load, the test starts with the inverter attached to both the utility and a parallel RLC circuit (see Figure 3-3).

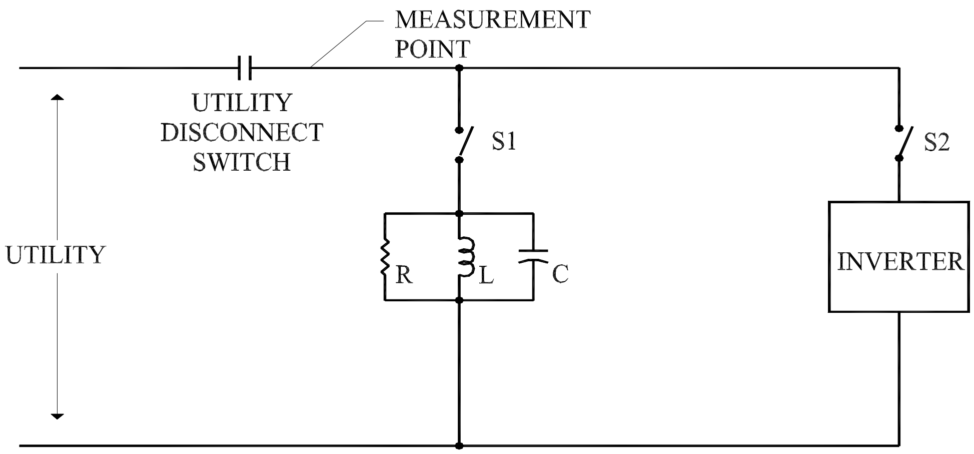


Figure 3-3
UL 1741/IEEE 929 Anti-Islanding Test Circuit

When the test is done for a bridge that is designed to be operated at unity power factor, the RLC circuit is selected to have the following properties:

- To draw enough active power to balance the output of the inverter
- To be resonant at the fundamental frequency (60 or 50 hertz)
- To have a quality factor of 2.5

The quality factor, Q, for a parallel RLC circuit is given by

$$Q=R*SQRT(C/L)$$

The resonant frequency, f, in hertz for a parallel RLC circuit is given by

$$f=1/(2*\pi*SQRT(LC))$$

where

R is the resistance in ohms,

C is the capacitance in farads, and

L is the inductance in henries.

To test with an inverter that is generating reactive power, the capacitance is reduced to balance the inverter's reactive power output.

To perform the test, the utility is disconnected, leaving the parallel RLC circuit connected to the inverter. The inverter's protection must trip the inverter in less than 2 seconds for the test to be successful.

The UL/IEEE test adequately tests one unit in an island, but additional concerns are:

- The test does not show the performance of multiple inverter-based generators in parallel (with the same type of anti-islanding or with different types of anti-islanding)
- The test does not show the performance of anti-islanding with rotating generators or motors in the island

4
FIELD-TESTING ISSUES

Background

Maintaining the safety of personnel and ensuring proper operation of the distribution grid are of paramount importance to utilities. The addition of small-scale distributed generation technologies in the distribution system poses a challenge to distribution engineers. In order to provide a uniform technical guide, IEEE is currently (October 2001) working on P1547 Draft 08 *Standard for Distributed Resources Interconnected with Electric Power Systems,* which will provide a uniform standard for interconnection of distributed resources with electric power systems. It provides set points for different parameters, such as over- and undervoltage, over- and under-frequency, and islanding, and defines how quickly the generator should respond during a utility disturbance to ensure safety and proper operation of the distribution grid. It also requires commissioning testing to ensure that the protection set points have been set properly by manufacturers, that there has been no degradation of the equipment software or hardware performance during shipment, and that over a period of time, the protection set points have not drifted from the original setting.

The primary concern is with generators interfaced through an inverter, where relaying is done by the inverter controller. An integrated relay/controller is more economical for distributed generation (DG) manufacturers but makes adequate testing more difficult. This chapter illustrates a case study showing the importance of field testing for anti-islanding and reverse power flow for a packaged set of parallel-connected generators, discusses ways in which testing can be done on inverter-based relays, and presents a protocol for field testing such relays. Because field testing is limited in how well it can verify the relaying protection of a distributed generator, additional methods of testing are also discussed, including monitoring and the development of more advanced DG testing equipment.

Traditional Utility Relay Testing

Source injection is the standard method used by utilities to test utility and customer-owned relay systems. A relay test set creates a calibrated signal that is injected in place of the “real” signal. This is normally at the inputs to the relay, which may be on the secondary of the PT or CT. The relay itself can be tested—in this case, the actuating contact of the relay is bypassed. On many relays, the power and trip circuits can be disconnected and testing done in place. Test plugs are usually available to facilitate testing. In addition to just testing the relay alone, the entire protection scheme downstream of the injected signal can be tested. Online, operational testing will ensure that the relay and the protective device operate properly.

Utility crews are well-trained and experienced in testing relays with test sets. Packaged generator relays have test points, and source injection can be used to test the standard generator protection functionality, including over- and undervoltage, over- and under-frequency, and other protections such as over-excitation protection.

Ways to Test Inverter-Based Relays

It is difficult to test inverter-based DG relays because the relaying is tightly coupled with the unit. Adequate testing requires the DG unit to be tested as a whole under normal operations. In the laboratory, the following tests can be done to verify relaying operation:

- Frequency variations to test over- and under-frequency operation.
- Voltage variations to test over- and undervoltage operation.
- Matched load/generation under islanded conditions to test anti-islanding relaying.
- Reverse power tests to verify the performance of reverse-power relays (if the DG site is to be operated as a one-way power flow only).

Such testing requires specialized equipment capable of varying voltage and frequency to a generator operating under load. Load banks are needed to be able to recreate islanded situations. Because of such complexity, all of these types of tests must be done in a laboratory setting. Field testing of inverter-based generators is generally limited to various disconnect tests and set-point adjustment.

Tests by Set-Point Adjustment

One way to evaluate the performance of inverter-based relaying systems is with set-point adjustment. For example, if the under-frequency relay is normally set at 59.9 Hz, the set point could be increased (for example, in steps of 0.1 Hz) until DG trips. Because the actual line frequency is 60 Hz, the DG should trip when the set point hits 60 Hz. Some inverter controllers may have features that prevent set-point adjustments because of the following reasons:

- Set points cannot be changed when the unit is operating.
- Wide variations that are in most cases improbable values for relay thresholds (such as an over-frequency threshold of 59 Hz) may not be allowed.

Set-point adjustment tests the ability of the relaying logic to trip the protective device if a relaying threshold is crossed. It can also give some feedback on how accurate the relay-sensing circuitry is. Consider the example of an undervoltage relay being checked, and the system frequency is exactly 60 Hz. If the generator trips off when the set point is set to 59.8 Hz, the frequency-relay system is over-measuring, has built-in conservatism, or the frequency-measuring system is very noisy. If it does not trip until the set point is changed to 60.2 Hz (this is a sign of problems), then the frequency sensing is under-measuring or has other defects.

Set-point adjustment should be done with caution. The testing itself can possibly compromise the security of the relays. If the relay set points are not returned to their proper values, the relay system could be left with overly sensitive relays, with desensitized relays, or, the worst possible case, without any relaying.

Steps can be taken that limit the risk of set-point adjustment:

- Develop a standardized protocol for each type of DG that is to be tested.
- Only have utility personnel do the testing (not the DG owner/maintainer).
- Document the thresholds of the DG relay trip and the testing procedure in a book attached to the DG controller interface.
- Once the testing is complete, include one or more final checks on the relay set points (possibly signed off by two people).
- Spot checks could be done just to check relay test points (this might be a good idea even if set-point adjustment is not used to reduce the chances that the set points get changed for other reasons such as customer changes, changes caused by customer firmware upgrades, or controller resets that may change relay settings).
- Train crews on the testing protocol and enforce proper procedures.

Even with a rigorous protocol, the probability of introducing errors is thought to be too high. Set-point adjustment could be used more effectively if it is done at commissioning or when problems are suspected.

Inverter-controllers could have modifications that would help facilitate set-point adjustment:

- Warnings issued by the controller interface of improbable set point values (such as an under-frequency trip threshold of 60.1 Hz).
- Timed return to fallback set points—A controller could have two sets of set points: *primary* set points and *fallback* set points. The primary set points would be the operational set points. These could be changed during the set-point adjustment testing. The fallback set points would automatically overwrite the primary set points periodically (for example, every half hour). The fallback set points would be the desired operational set points. The fallback set points would be configured so that improbable values are not allowed.

These options are hypothetical and do not eliminate the possibility of error.

Why Inverter-Based Generators Don't Have Test Ports

Because it is so difficult to adequately test inverter-based generators, one may wonder why they do not have external test ports. There are several reasons for this. Some are based on economics and some are based on how entwined the inverter controller is with the actual DG unit. A typical inverter controller is shown in Figure 4-1. This particular controller provides the following functionalities:

- Relaying (undervoltage, overvoltage, under-frequency, over-frequency, and rate of change of frequency, reverse power flow, and fault current).

- Control and firing of the self-commutated inverter
- Regulation of the fuel supply to the turbo-generator and combustion management
- Internal communication with auxiliaries
- External communication with the user and other equipment

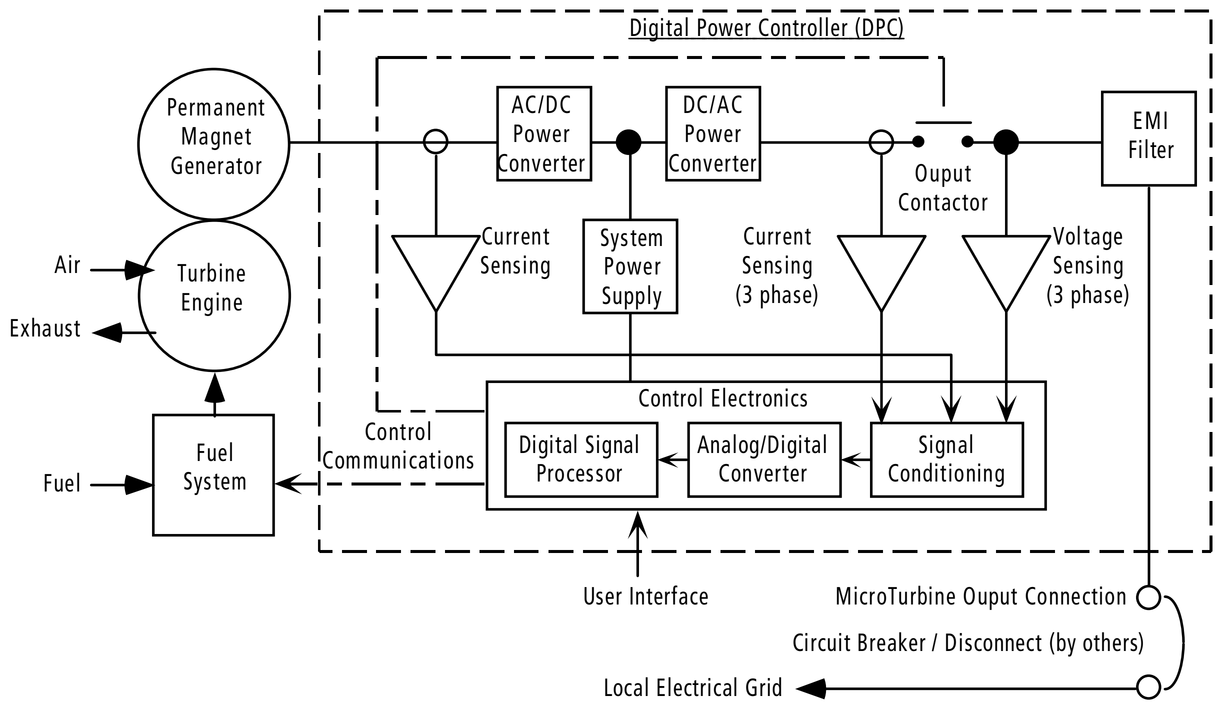


Figure 4-1
Block Diagram of a Capstone Microturbine Controller[12]

Separation of the relaying component from the other controller functionalities is difficult to do because the voltage and current sensing is used for other control aspects. For example, if the voltage-sensing circuitry is switched to an alternate source, the controller will think that the voltage is still the actual voltage to the power converter. If the "test-port" voltage is different from the actual voltage, the results could be disastrous. The inverter power electronics may fire at exactly the wrong time and create high transients that could damage the inverter and cause voltage spikes to nearby equipment.

To have entirely separate relaying functionality, dual voltage-sensing circuitry would be needed (and possibly dual current sensing as well, depending on the needed relaying capability). This would require redundant signal conditioning and A/D converters, which would increase the cost of the controller.

[12] Capstone, Inc., "Protective Relay Functions," July 2000. Available at http://www.capstoneturbine.com/technology/whitePapers/ProtectiveRelay.pdf as of July 2000.

If test ports are provided on inverter-based relays, there could still be some questions on the degree of separation. With an external relay, it is obvious that with external relay test points, the injected signal is actually testing the system. For an example, with an external voltage test port, does an injected signal really test the relay system? The controller may treat the test-port signal differently than it treats the actual signal. Without physical separation, that is not obvious. Detailed documentation and laboratory testing can overcome these concerns.

Need for Testing Inverter-Based DG: Parallel Connected DG Case Study

Field tests of a combined set of three parallel inverter-based DG units at a commercial facility have highlighted the need for field testing of not just a single unit but a parallel combination of units (especially for anti-islanding and reverse power flow). Figure 4-2 shows a diagram of the facility. Three types of tests were performed:

1. A three-phase disconnect test with the facility load matched to the generator output
2. Single-phase disconnect tests
3. Reverse power test

More details of each test are given in the following sections.

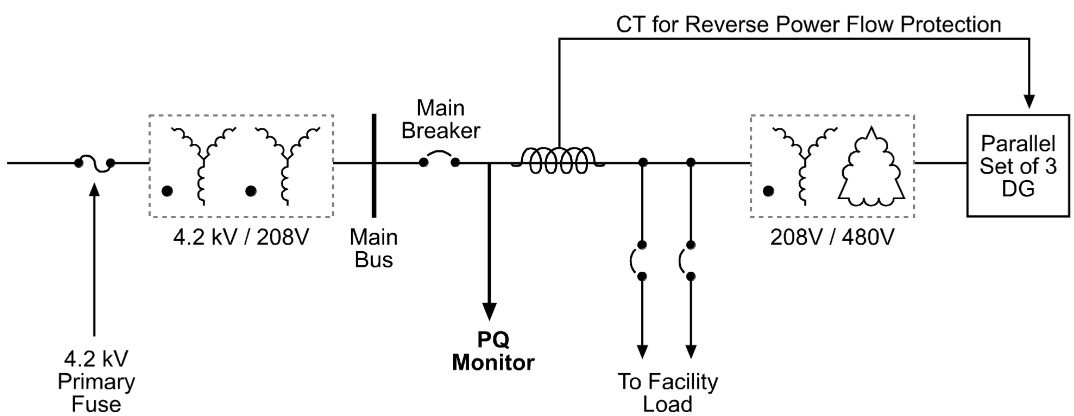


Figure 4-2
Schematic of Parallel Set of Inverter Based DG Installation

Open Disconnect Test

The generator's output was matched to the load as closely as possible. Then the main breaker was opened to test the anti-islanding protection feature of the DG. The generator tripped properly after thirteen cycles. The voltages and currents from this project are shown in Figure 4-3.

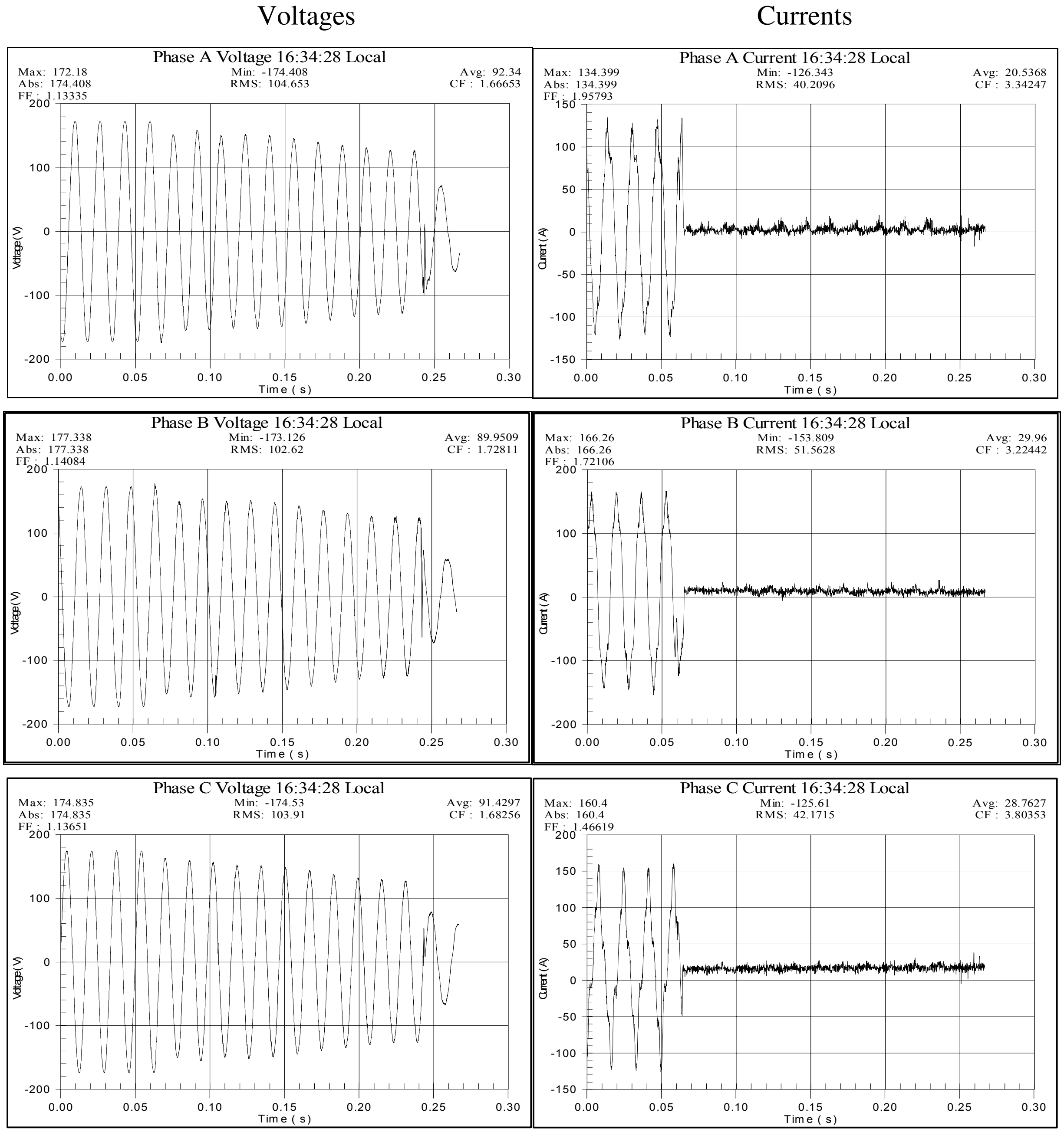


Figure 4-3
Voltages and Currents from a Load-Matching Three-Phase Disconnect Test Where the DG Successfully Tripped

Single-Phase Isolation Test

This test was similar to the three-phase disconnect test, but only one phase was disconnected (and it was done on the primary side). The generator's output was matched to the load as closely as possible. Then the phase-C cutout was opened on the 4.2-kV primary. The DG did not trip, and the test was ended by opening the main breaker after five minutes.

The DG did not trip because the voltages were within normal range (see Figure 4-4). The voltages were held within normal by the wye-delta transformer (and possibly by other loads in the facility). The generator connection itself contributed to the balancing of voltages and the backfeed to the opened phase. It may not have been the only contribution—three-phase motors can also provide backfeed in these situations.

It is difficult to design a relaying function that would avoid this situation with the provided transformer connection. The wye-delta transformer acts to balance the phases and keeps the voltages within normal ranges. A ground overcurrent relay (51G) on the wye side of the wye-delta transformer could have detected this situation because the wye-delta transformer would have provided a large amount of ground current (to feed the facility load on the opened phase). The Edison Electric Institute (EEI) guideline[13] for interconnections recommends using the 51G ground overcurrent relay on inverter-based DG interconnections with a wye-delta transformer in this size range (see Figure 4-5).

The usual transformer interconnection requiring scrutiny is at the interface between the utility and the customer. This application highlights that it is also important to analyze how the DG is connected to the customer's system. The application of the wye-delta transformer for the interconnection between the customer wiring and the DG is effectively the same as having a wye-delta connection for the facility because the main transformer is a wye-wye connection. This means that the DG is a grounding source; there could be concerns with circulating current in the delta winding of the transformer, and the connection is more likely to backfeed as happened during these tests.

[13] EEI Interconnection Working Group, M. Davis, chair, "Edison Electric Institute Distributed Resources Task Force Interconnection Study," June 2000. Available at: http://www.eei.org/edg/dist/state_reg/EEI_DRTF_Interconnection_Study.pdf as of June 2000.

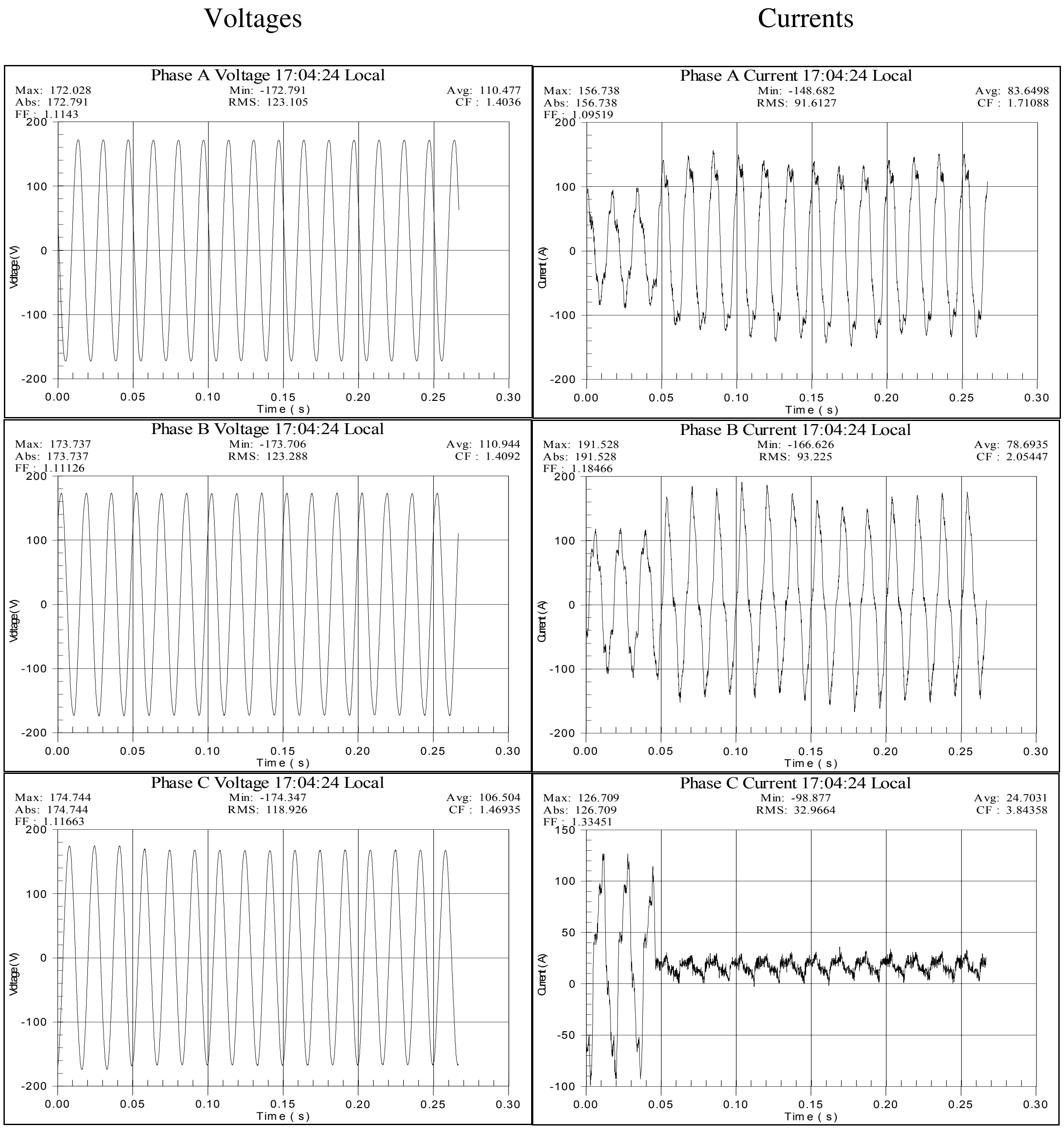
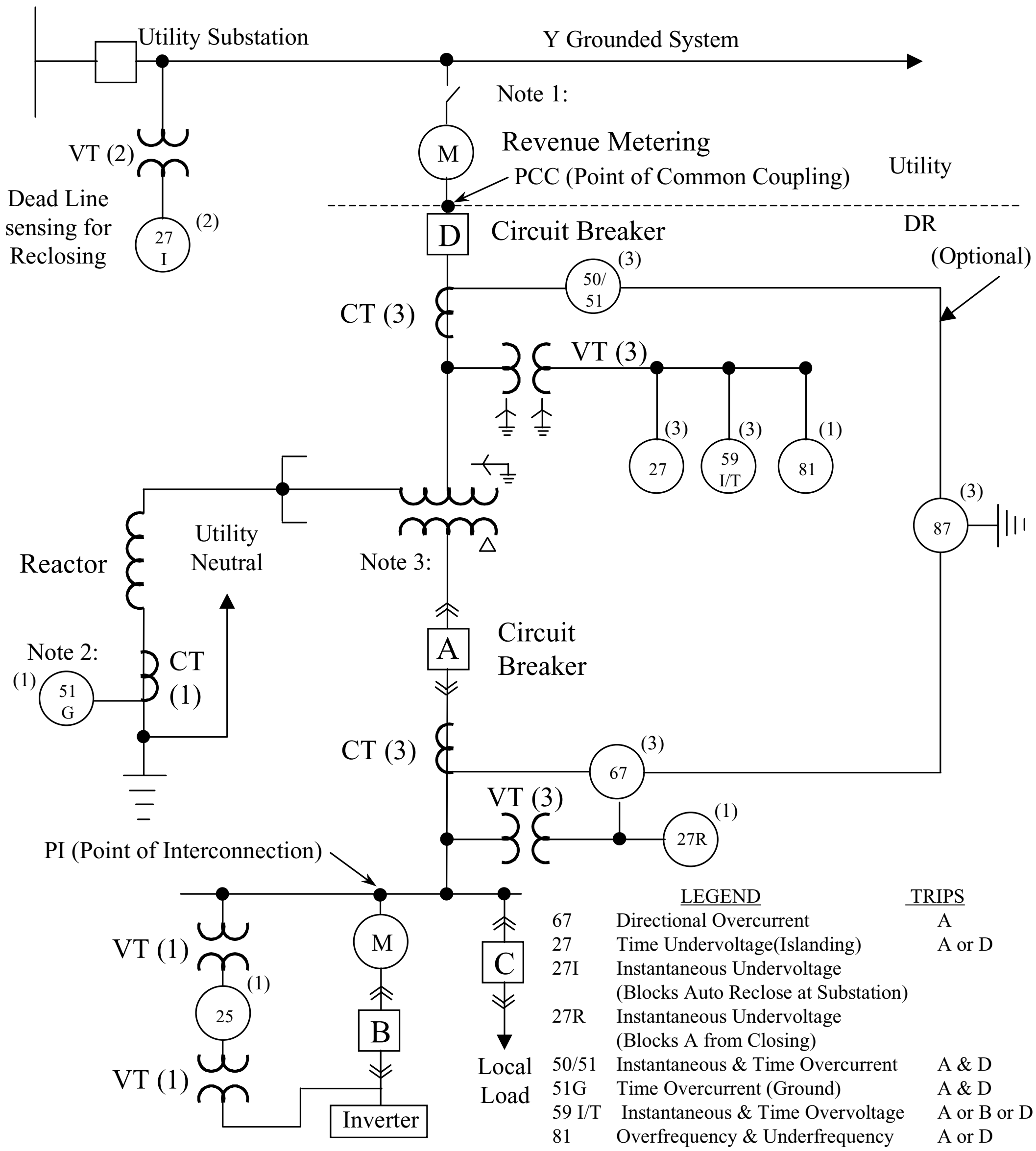


Figure 4-4
Voltages and Currents from a Single-Phase Disconnect Test on a DG



LEGEND		TRIPS
67	Directional Overcurrent	A
27	Time Undervoltage(Islanding)	A or D
27I	Instantaneous Undervoltage (Blocks Auto Reclose at Substation)	
27R	Instantaneous Undervoltage (Blocks A from Closing)	
50/51	Instantaneous & Time Overcurrent	A & D
51G	Time Overcurrent (Ground)	A & D
59 I/T	Instantaneous & Time Overvoltage	A or B or D
81	Overfrequency & Underfrequency	A or D
87	Transformer Differential	A & D
25	Synchronizing (Permits closing B)	

Note 1: Accessible and lockable disconnect switch.
Note 2: Reduces Zero Sequence current flow to distribution line faults.
Note 3: DR's using Wye-Delta transformations can run isolated and serve other remote loads. However, the size of the reactor could limit the amount of load served remotely.
Note 4: For loss of utility system, DR could continue to serve local load by opening breaker A or breaker D

Figure 4-5
EEI Recommended Interconnection for a Small Three-Phase Inverter (<100 kVA) and a Grounded Wye-Delta Transformer

Two-Phase Disconnect Test

Following the single-phase isolation test, another test was performed in which two phases were disconnected. Again, the load was matched with the generation. In this test, the generator tripped but not until after approximately ten seconds. The utility power system only supplied one phase, so the inverter-based generator and the wye-delta transformer supplied the other phases. The voltages at the opening of the second cutout and at the point at which the generator tripped are shown in Figure 4-6. The voltages on the opened phases decayed during the course of the test until the DG unit finally tripped. The voltages during the test are summarized in Table 4-1.

During the test, the voltages declined until the generator finally tripped. The generator did not meet the tripping thresholds in IEEE 929 and UL 1741, which should have caused it to trip within 2 seconds. Information provided by the manufacturer indicated that the generator would have tripped properly with an updated version of the software that was to be available shortly. The existing software would only trip when all three phases were below a given threshold. This is a good illustration of the need to pay attention to software changes. One of the big fears of using inverter-controller-based relaying is that its software will be upgraded periodically. Each upgrade is a potential introduction of an anomaly in the relaying system that must be tested.

Table 4-1 highlights another important consideration—whether line-to-ground voltages, line-to-line voltages, or both should be used for disconnect tests. Usually, line-to-ground voltages tend to be more sensitive. IEEE 929 does not mention whether the voltages should be measured line-to-ground or line-to-line. UL 1741 specifies line-to-ground voltages.

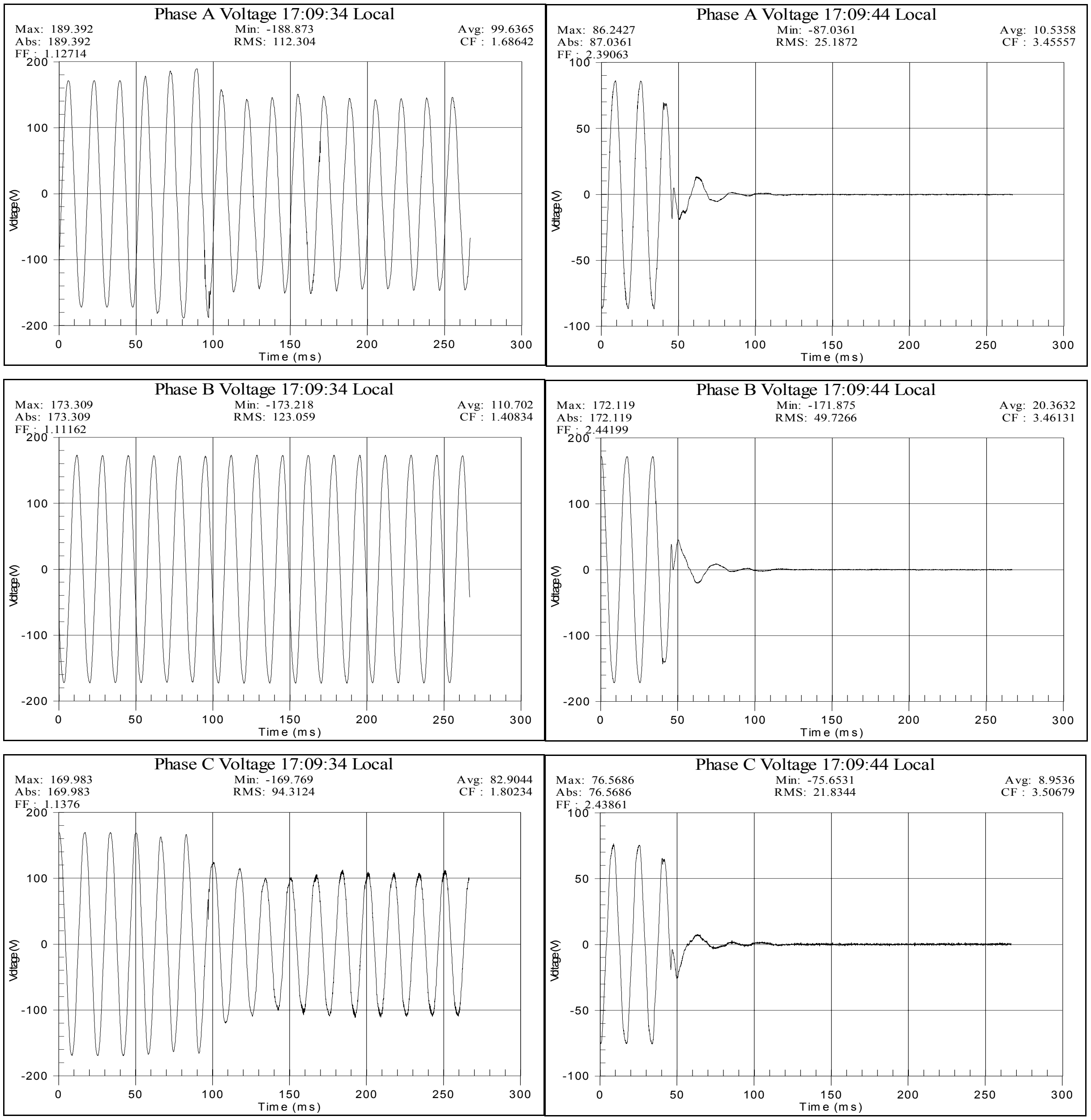


Figure 4-6
Voltages and Currents from a Load-Matching Two-Phase Disconnect Test (the DG Tripped After About 10 Seconds)

Table 4-1
Voltages During the Two-Phase Disconnect Test (Phases A and C Disconnected on the Utility Primary)

Voltages (Percent of Nominal)					
Line-to-Ground			Line-to-Line		
Phase	At start	At trip	Phase	At start	At trip
A	**85%**	**51%**	AB	92%	**76%**
B	100%	100%	BC	**83%**	**74%**
C	**65%**	**45%**	CA	**75%**	**48%**

Note 1: Voltages highlighted in bold should have caused the unit to trip in 2 seconds per IEEE 929/UL 1741.
Note 2: Voltages highlighted with shading should have caused the unit to trip in 6 cycles (0.1 seconds) per IEEE 929/UL 1741.

Reverse Power Test

The final test involved a test of the reverse-power relaying scheme that was implemented on the generator. A reverse-power relay was required because this was to be a one-way DG application (real power should only flow into the facility). The generator should have tripped whenever there was power flowing into the utility.

During the test, the generator power output was increased until it was providing about 5 kW into the utility system. Figure 4-7 shows the power and current during the test period. The generators did not trip off line, so the test was ended.

There are two main theories as to why this unit may not have tripped:

1. The unit may have been confused by var flows. While the unit was exporting 5 kW of real power, it was absorbing a significant amount of reactive power (about 10 kvar) from the utility grid.

2. Another possibility is that the protection systems were confused by the wye-delta transformer arrangement. The current was measured on the delta side, but the voltage was measured on the wye side. If the phasing was not taken into account in the power calculations, this may have caused the failure to trip.

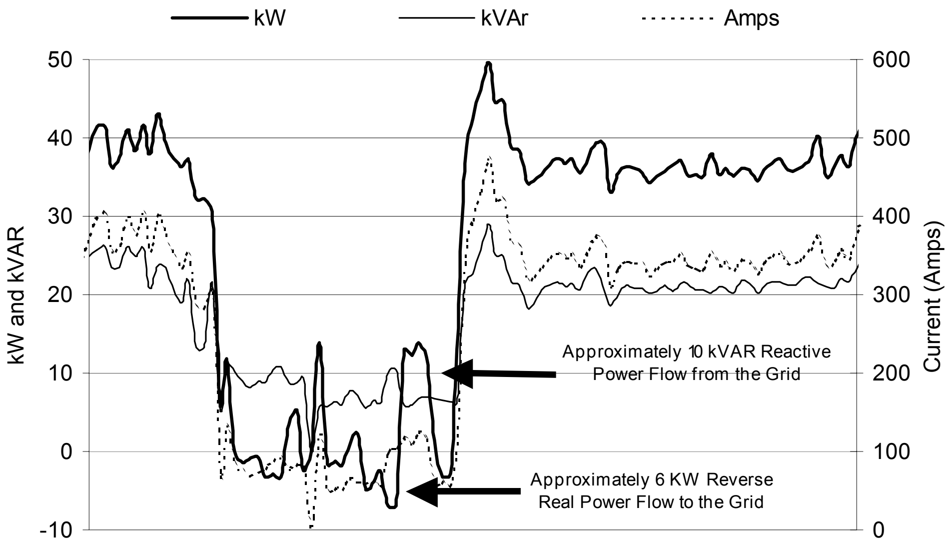


Figure 4-7
Power and Current during a Reverse-Power Test

Conclusions of the Test Case

These tests demonstrated the reasons for doing field testing. The field tests revealed that the system did not have all of the protective features that the utility expected. This is the sort of information that should be revealed in a commissioning test. This case study raises some serious questions that need to be addressed within the industry:

- How should software changes be handled (especially given the fact that it can be difficult to test in the field)?
- What is the definition of an island? Does the loss of one or two phases constitute an island? During islanding, the utility should want the DG to separate because single phasing creates backfeed situations and increases the chance that ferroresonance could create overvoltages.
- How should anti-islanding be implemented on a three-phase inverter (the IEEE 929 active anti-islanding was primarily developed and tested for single-phase systems)?

Straw-Man Field-Test Protocol

This test protocol is for inverter-based relays with internal relaying logic. For DG installations with external relays with standard test ports, standard tests can be done on the relay settings using secondary injections. The field-test protocol consists mainly of one main test plus some optional tests:

Main test:

- **Generator disconnect test**—Disconnect the generator and check that the unit trips in the appropriate time frame.

Optional tests:

- **Generator disconnection with load**—Adjust the facility load to match the generation and trip the facility. This is only possible if the customer is willing and able to adjust its facility loads to approximately match the generation and to disconnect the facility.
- **Reverse-power test**—For cases where reverse power into the utility is not allowed, increase the generator power and decrease the facility load until the generator exports power to the utility and ensure that the generator trips within the required time.
- **Single-phase disconnect test**—Open one phase of a disconnecting switch to the facility and ensure that the generator trips within the required time. This test can be disrupted by transformer connections and backfeeding load, and there could be a variety of customer objections.

This field-test protocol will by no means guarantee that the tested generator relaying works properly. It does not adequately test the voltage thresholds or the frequency thresholds. It is very difficult to adequately test a generator with built-in relaying where it is not possible to use secondary injections with standard relay test sets. Therefore, the project team mainly view the field-test protocol as a supplement to rigorous testing in the laboratory—the protocol is only capable of identifying gross malfunctions. In the future, more sophisticated mobile DG test sets may be developed that could adequately field-test generators with built-in relaying.

Generator Disconnect Test

1. Isolate the DR at the electrically closest disconnecting switch upstream of the generator.
2. Monitor the voltage on the generator side of the disconnecting switch.
3. Verify that the generator trips within the proper time frame.
4. Reclose the disconnecting switch.
5. Verify that the generator does not re-engage until the proper delay time has passed.

Repeat the test two more times.

Testing Intervals

A new system test should be performed whenever any interconnection system hardware or software is changed. This includes any adjustments of field programmable trip thresholds. Even if the functionality of the software change should not affect the significant protective functions, a test should be performed.

Periodic tests are also prudent to help ensure reliable operation of the protective equipment. The testing interval should be mutually determined by the utility and the DG operator. A one or two-year interval is appropriate for many applications, and it is not prudent to go beyond four years between tests. The DG operator should keep a log of test results and/or test reports.

Special Situations

A system that depends upon a battery for trip power should be checked and logged once per month for proper voltage. Once every four years, the battery must be either replaced or a discharge test performed.

Optional Extended Tests

The extended tests are for special situations. They may not be applicable in all cases. It is not expected that they would be done on a regular basis (possibly only at commissioning).

Generator Disconnection with Load (If Possible)

1. Match the facility load as close as possible with the generator load.
2. Trip the facility breaker or other disconnecting switch.
3. Monitor the voltage on the generator side of the breaker.
4. Verify that the generator trips within the proper time frame.
5. Reclose the breaker.
6. Verify that the generator does not re-engage until the proper delay time has passed.
7. Repeat the test two more times.

Note that some customers will not agree to adjust their facility loads or to disconnect the facility during a disconnect test (both cause disruptions in facility operation). This may limit tests to weekends or other facility down times.

Reverse-Power Test (If Required and If Possible)

1. Increase the generator power and decrease the facility load until the generator exports power to the utility.
2. Monitor the power flow into the utility with a suitable monitoring device.
3. Verify that the generator is offline within the proper time frame once the threshold for reverse power has been exceeded.
4. Verify that the generator remains offline for the appropriate delay.
5. When the generator comes back online, verify that it is not exporting power.
6. Repeat the test two more times.

Note that some customers will not agree to remove enough load to cause the generator to export power (especially when the generator is small relative to the facility load).

Single-Phase Disconnect Test (If Possible)

1. Open one phase of a disconnecting switch to the facility.
2. Monitor the voltage on the generator side of the switch.
3. Verify that the generator trips within the proper time frame.
4. Verify that the phase-to-neutral voltage goes below 50% of nominal when the disconnect switch is opened. If it does not, then the generator, other loads within the facility, or transformer connections are backfeeding voltage to the opened phase. If this is the case, skip this test.
5. Reclose the switch.
6. Verify that the unit does not re-engage until the proper delay time has passed.
7. Repeat the test on the other two phases.

Notes:

- Many facilities may not have convenient single-phase disconnect switches.
- This test may not work at facilities where loads or transformers backfeed. If the backfeed were enough to keep the generator voltages within the normal operating range, the generator would not be expected to trip.
- The primary fuse can be used as the disconnect switch, but the transformer type must be considered. A grounded-wye, grounded-wye transformer should be okay. A delta grounded-wye transformer will introduce some odd voltages. Two of the phases will drop to half value—this is still a useful test of the generator because it should trip under these circumstances. Utilities will not want to use the primary fuse for routine DG testing.
- If the test may subject customer motors to single-phasing, the customer will likely object.

Inadequacies of the Field-Test Protocol

There are several inadequacies of the field-test protocol. These inadequacies are pirmaly because the there is no adequate testing apparatus that can test a generator as a whole. Some of these inadequacies are:

- **No overvoltage test**—Overvoltage relaying is very important because it provides an important safeguard to help prevent overvoltages that could cause local failures of nearby equipment (the customer's, an adjacent customer's, or the utility's equipment) and is a safety issue.

- **No frequency test—**The frequency test is an important anti-islanding protection, and it is virtually impossible to test this relaying feature in the field without sophisticated equipment.
- **No test of voltage sags—**Voltage sags cannot be generated easily.
- **No active anti-islanding test—**The anti-islanding test in IEEE 929 requires a specific circuit to match the load, which would be almost impossible to realistically include in a field test.

In addition, many of the optional tests that could provide extra information about the performance of the relaying system may not be allowed by the customer, or physical circumstances may prevent them. Set-point adjustment could be used to partially test some of these factors (such as frequency).

Portable DG Tester

A portable DG tester could solve many of the concerns with field testing. Field testing is an important step in accepting DG into the distribution system, but existing methods are inadequate. One way to solve this would be to require external, utility-grade relays at *all* DG applications. Then, field testing could be done with standard relay test sets using secondary injections. This most likely would be an expensive proposition for the DG manufacturers and customers. An alternative is to develop a portable tester that is capable of testing smaller-scale inverter-based DG systems.

Such a tester could be designed to connect to the generator in standalone mode or, more likely, would be inserted in series between the facility electrical system and the generator. The tester could be able to test over- and undervoltages, over- and under-frequencies, and do load matching to test anti-islanding response. A sophisticated version could even be devised to replicate the IEEE 929 active anti-islanding test, where the DG drives a tuned circuit in an islanded operation.

A portable DG test system could help solve the problem of field testing inverter-based DG systems and help DG acceptance. The only concerns may be related to overvoltage tests. It would have to be worked out with manufacturers how severe of an overvoltage test is reasonable (to avoid having the test possibly damage the generator).

Long-Term Monitoring to Help Verify Proper DG and Relay Operations

Because existing field-testing capabilities are quite limited, longer-term monitoring is another way to better test the performance of the relay system of an inverter-based distributed generator. Most DG sites will experience regular voltage sags and momentary interruptions. These disturbances can help determine if a DG relaying system is not performing as expected. The minimal monitoring approach may be to use existing monitoring, specifically:

- Substation SCADA system that monitors breaker operations (and possibly line recloser operations)
- DG monitoring record of when the DG tripped offline and for what reason

If these two sets of information are available, correlations between substation breaker operations and DG trip operations could be done. The distributed generator should always trip for an operation of the substation breaker. Any breaker operations without a DG trip should be investigated. There is some chance that a short-duration interruption (for example, 0.5 seconds for an immediate reclose) would not necessarily trip the generator. Such a case could occur if an island forms where the generation is nearly matched to the load. The frequency and voltage may not drift that much during the short interruption. If active anti-islanding is used, IEEE 929 still allows 2 seconds for the generator to trip. Actual waveform monitoring would help sort this out. If this approach is used, it is helpful if the SCADA system and the DG recording system can synchronize their clocks to a time standard to help with the correlations.

A more sophisticated approach would involve using actual power quality recorders. This would provide much more detail and would help identify other problems with the DG application, including power quality disturbances created by the generator. Monitoring at the generator might be used to reveal the following:

- Determine if the generator trips properly during voltage and frequency excursions that violate the relay settings (from causes such as interruptions, sags, swells, long-duration over- or undervoltages, or frequency deviations during islanding).
- Measure the change in voltage caused by the generator during startup and shutdown.
- Determine if the DG could be causing voltage fluctuations or harmonics.
- Record changes in generator output that could be a sign of interaction with a utility voltage regulator or capacitor bank.

Some suggestions for distributed generator monitoring are:

- Record both voltage and current, and for three-phase installations, record all three phases plus the ground current.
- If possible, record output contacts of the DG controller that may indicate the operational status of the unit.
- Synchronize the monitoring clocks to a GPS time reference to help correlate with other monitoring data or event records. If this is not feasible, establish a protocol of regularly setting the recorder clocks (and logging the errors to be able to adjust for drift) to keep them close to a time standard.
- Record trend data (for example, one-minute maximum, minimum, and average values) as well as triggered data (sags, swells, and so on).

Other monitoring systems and locations can provide more information that could be used for correlations or checks on the performance of a distributed generator. Substation SCADA records can be used to correlate with data recorded at DG sites. Other monitoring locations may be appropriate for revealing other problems (see Figure 4-8). Feeder-level monitoring is especially appropriate for feeders with high penetration of DG. Locally, the options are to monitor right at the generator or at the service entrance.

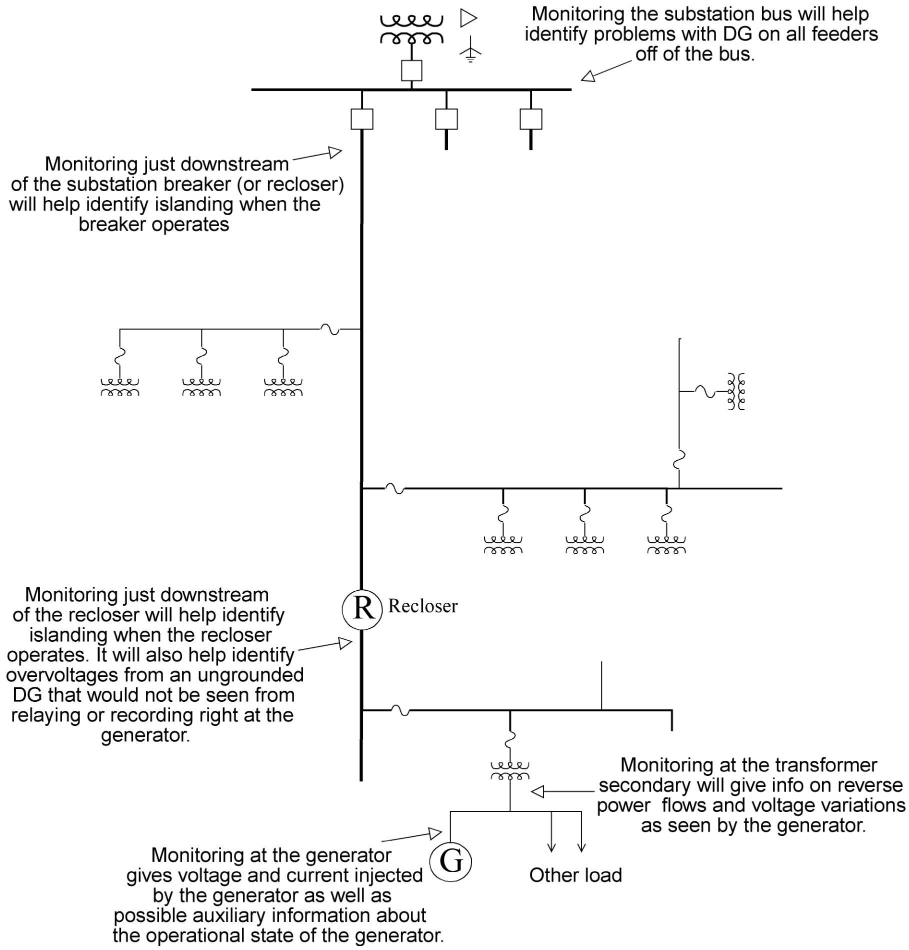


Figure 4-8
Monitoring Locations That Could Help Verify Proper DG Operation

A drawback to monitoring is that it requires expert manpower to operate. It takes considerable work to install the monitoring, setup the downloading, and (most significantly) to analyze the data. In the future, pseudo-intelligent software may be able to help highlight or par down and summarize the data to help reduce the effort required to use monitoring data to verify DG operation.

Sometimes power quality recorders are used in "stealth" mode: They are installed and largely forgotten until there are customer or utility problems. This should not be done with monitoring of DG systems. The main purpose of monitoring is to use power system disturbances as tests of the DG relaying. The data must be checked periodically to ensure that the generator trips off appropriately. Many relay malfunctions may be benign until just the right island is formed or just the right resonance is created, but benign failures are a signal that something may need to be corrected.

5
IMPLICATION OF IEEE STANDARD RELAY SET POINTS ON POWER QUALITY

Industry Standard Set Points

IEEE 929/UL 1741 Set Points

Recent industry standards for DG interconnection have specified standard trip thresholds. This is an effort between manufacturers and utilities to ease the complications of interconnection. IEEE 929, *Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*, took the lead in adopting standardized trip thresholds in 2000. The 929 recommendations are targeted at "small" systems rated at 10 kW or less. In 2001, these same trip thresholds were adopted into UL 1741, *Inverters, Converters, and Controllers for Use in Independent Power Systems.* UL 1741 applies to *all* inverter-based DG, which would cover other technologies including microturbines, fuel cells, and other inverter-based systems. The voltage-trip thresholds in 929 and 1741 are shown in Table 5-1.

Table 5-1
Standard Trip Thresholds for DG Operations per the IEEE 929[14] and UL 1741[15]

Voltage Setting		Trip Time	
Volts (120-V Nominal)	Percent	Cycles	Seconds
V < 60	V < 50%	6 cycles	0.1 s
60 ≤ V < 106	50% ≤ V < 88%	120 cycles	2 s
106 ≤ V ≤ 132	88% ≤ V ≤ 110%	Normal Operation	Normal Operation
132 < V < 165	110% < V < 138%	120 cycles	2 s
165 ≤ V	138% ≤ V	2 cycles	0.033 s

[14] IEEE Std. 929-2000, Recommended Practice for Utility Interface of Photovoltaic (PV) Systems.

[15] UL 1741, Inverters, Converters, and Controllers for Use in Independent Power Systems, Underwriters Laboratories, Inc., January 17, 2001.

Some of the “fine print” for these standard limits is as follows:

- Voltage measurement location:
  - IEEE 929 specifies the voltage measurements at the PCC.
    - UL 1741 specifies a test for an inverter-based DG. No mention is made of the exact measurement location, but it implies measurement at the DG.
- Measurement phasing:
    - IEEE 929 does not specify how the voltage is to be measured (phase-to-phase or phase-to-ground). IEEE 929 was primarily written for small photovoltaic interconnections, which are generally connected single-phase.
    - UL 1741 specifies line-to-ground voltages for three-phase connections, and the DG should cease exporting when any of the three voltages exceeds the limits in Table 5-1.
- Adjustability:
    - IEEE 929 specifies that the set points should be fixed for small systems (< 10 kW).
    - Adjustable set points are optional in UL 1741.

Another important item is that even though this document refers to the set points as “trip” settings, the UL and IEEE standards do not specify that a protective device must open and separate the generator. The actual 929 requirement is: “A PV system should sense utility conditions and cease to energize the utility line,” and the UL requirement is: “…a utility-interactive inverter initially exporting power within its normal operating range shall cease to export power,” and “A utility-interactive 3-phase inverter shall cease to export power on all 3 phases.”

IEEE Draft 1547 Set Points

The IEEE Working Group on Distributed Resources and Electric Power Systems Interconnection is developing an IEEE standard on interconnection of distributed generation. This document will likely supplant IEEE 929 and UL 1741 as the main governing document covering interconnection of distributed generation. The draft versions of the report give trip thresholds that are close to the IEEE 929 and UL 1741 standards, as shown in Table 5-2. Draft 7 of the document did not pass the IEEE balloting procedure. Draft 8 has been updated based on balloting comments. Both contain the same set of trip thresholds.

Table 5-2
Standard Trip Thresholds for DG Operations per Draft 7 (Which Was Negative-Balloted) and Draft 8 of IEEE 1547[16]

Voltage Setting			Trip Time
	V	< 50%	0.16 s
50% ≤	V	< 88%	2 s
110% <	V	< 120%	1 s
120% ≤	V		0.16 s

Base voltages are the nominal voltages stated in ANSI C84.1.
DR ≤ 30 kW Maximum Clearing Time. DR > 30 kW, Default Clearing Time or area EPS operator may specify different voltage settings or trip times to accommodate area EPS system requirements.

P1547 draft 7 specifies that the voltages should be detected on each line-to-ground voltage or on each phase-to-phase voltage. This was modified in draft 8 to be: "The protection functions of the interconnection system shall detect the effective (RMS) or fundamental frequency value of the voltage (all voltages are considered to be balanced voltages)." This modification is probably even more controversial than the draft 7 version, so it will probably undergo further revision.

Voltages are required to be measured at the point of common coupling (PCC). Measurement is allowed at the point where the generator is connected if:

- The total local generation connected at that PCC is less than 30 kW.
- The interconnection equipment is certified to pass a non-islanding test.
- The DR is less than 50% of the minimum local demand, and the export of real or reactive power is not permitted.

Commentary on Set Points

The main concerns with the standard overvoltage trip thresholds are:

- The 110% trip limit on overvoltages allows generators to create voltage in excess of ANSI limits.
- The draft P1547 allows a relatively long time (0.16 seconds or 60-Hz 9.6 cycles) for overvoltages above 120% to exist. IEEE 929 and UL 1741 both require the DG to cease injecting power within 2 cycles if the relay detects an overvoltage greater than or equal to 138%.

[16] IEEE P1547, Draft Standard for Interconnecting Distributed Resources with Electric Power Systems, Draft 7, Feb. 9, 2001, and Draft 8, Aug. 29, 2001.

Sometimes, DG units will unnecessarily trip offline due to short-term excursions of voltage that are slightly outside the steady-state operating limits defined by ANSI C84.1. Temporary high voltages on the distribution system can occur for a variety of reasons, including the loss of a single large load or block of loads when a fuse, switch, or breaker interrupts power flow. Also, the switching of a large power-factor-correction capacitor can result in a sudden increase in voltage. These events frequently lead to mild overvoltages up to about 10% above nominal that persist until utility voltage-regulation equipment can respond to correct the situation. Utility voltage regulators usually employ time delays of anywhere from 10 to 90 seconds. Short-term mild overvoltages of this nature are not a threat to loads, but they will cause nuisance trips of DG that strictly use the ANSI C84.1 limits as the acceptable operating window and trip offline very fast for anything outside the range.

To prevent nuisance DG trips, the IEEE 929 PV standard and various utility DG interface requirements have employed voltage trip settings that allow DG to continue operating indefinitely even when the voltage is slightly outside of the ANSI limits. For example, IEEE 929 allows PV inverters to operate at up to 132 volts (+10% above nominal) before they are required to trip. These settings are also included in UL 1741. Draft standard IEEE P1547-D7, which is still in development, also allows for a +10% limit. The upper ANSI range B limit is 127 volts (6% higher than nominal), so both IEEE 929 and IEEE P1547-D7 allow the DG to function considerably higher than the ANSI range B limit.

The upper thresholds can also be compared to industry-standard power quality benchmarks. The most prominent is the ITIC curve[17] (also referred to as the new CBEMA curve), which was developed to represent the ride-through capability of computers. Figure 5-1 shows that the IEEE 929/UL 1741 thresholds are less strict than the ITIC curve—DG-caused overvoltages will not necessarily trip the DG before the ITIC sensitivity curve is violated.

[17] *ITI (CBEMA) Curve Application Note*, Information Technology Industry Council (ITIC), available at http://www.itic.org as of 10/1/01.

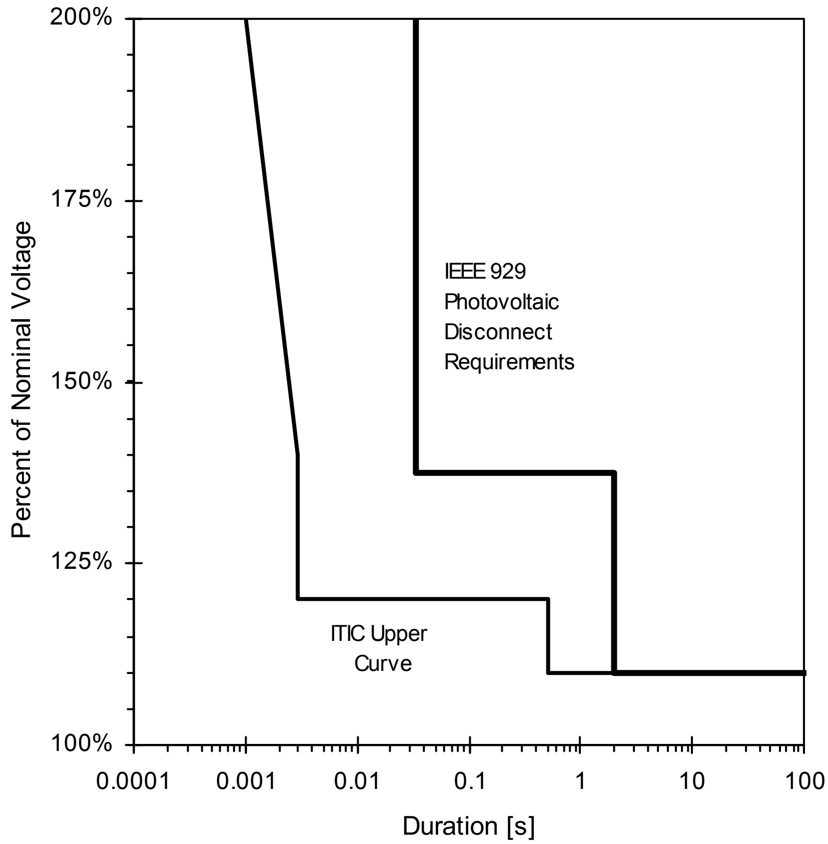


Figure 5-1
IEEE 929/UL 1741 Disconnect Requirements Compared Against the ITCI Curve

On the undervoltage/sag side, the trip thresholds are not as important because distributed generation should not contribute to voltage sags. In fact, distributed generation should provide support during voltage sags. However, it is worthwhile exploring the effects of the undervoltage thresholds. Figure 5-2 shows the ITIC curve compared to the IEEE 929/UL 1741 disconnect thresholds. The other major standard for voltage sags, the SEMI curve[18], is also shown. Many events below the ITIC/SEMI curves do not cause generators to trip, which is actually beneficial because generators provide voltage support during sags. This report will explore support during voltage sags in more detail by looking at the EPRI DPQ data.

[18] SEMI F47-0200, *Specification for Semiconductor Processing Equipment Voltage Sag Immunity,* Semiconductor Equipment and Materials International, Sept. 1999.

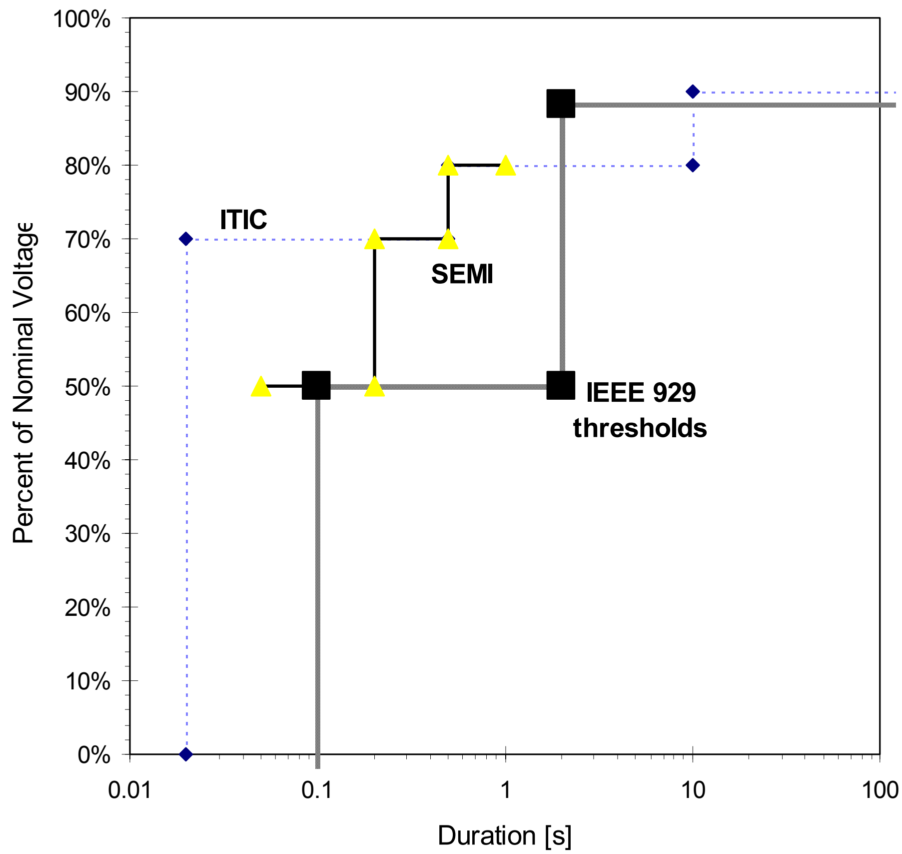


Figure 5-2
IEEE 929/UL 1741 Disconnect Requirements Compared Against the SEMI Curve and the Lower Part of the ITIC Curve

Line-to-Line versus Line-to-Ground Voltages

Another one of the questions about relaying set points is whether to use line-to-line voltages, line-to-ground voltages, or both. Generally, line-to-ground voltages are more sensitive, so they should be used, but it is not always straightforward. Figure 5-3 shows the line-to-line and line-to-ground voltages on a connection with an overvoltage on phase A of 150% on the primary. If a grounded-wye, grounded-wye transformer is used, the line-to-ground voltages on the secondary are most sensitive. If a delta, grounded-wye transformer is used, the line-to-line voltages on the secondary are slightly more sensitive (although, overall the ability to sense primary line-to-ground overvoltages is reduced by the delta-wye connection). A grounded-wye, delta connection has line-to-ground voltages more sensitive to the overvoltage (again, the ability to sense primary line-to-ground overvoltages is reduced because of the transformer connection). The voltages shown assume that the DG does not change the voltage on the primary or secondary, when in reality, the DG will normally be changing the voltage on the secondary and maybe even the primary.

One important point is that all three voltages must be measured (whether they are line-to-line or line-to-ground voltages). If voltages are assumed balanced and only one of the three voltages is used, sustained overvoltages could occur on the unmonitored phases.

Another more likely example is shown in Figure 5-4, where a neutral shift has occurred on the distribution system to a line-to-ground fault. Phase A has a voltage sag, and phases B and C have voltage swells due to the neutral shift. This is a more severe neutral shift than is usual on a 4-wire multi-grounded distribution circuit; it could represent an island being driven by distributed generators.

As in the previous example, the grounded-wye, grounded-wye transformer connection allows the most sensitivity on the secondary side with the line-to-ground voltages. Neither the delta, grounded-wye nor the grounded-wye, delta connection is very sensitive to this primary-level disturbance. Again, this example assumes that the DG is not significantly changing the voltages.

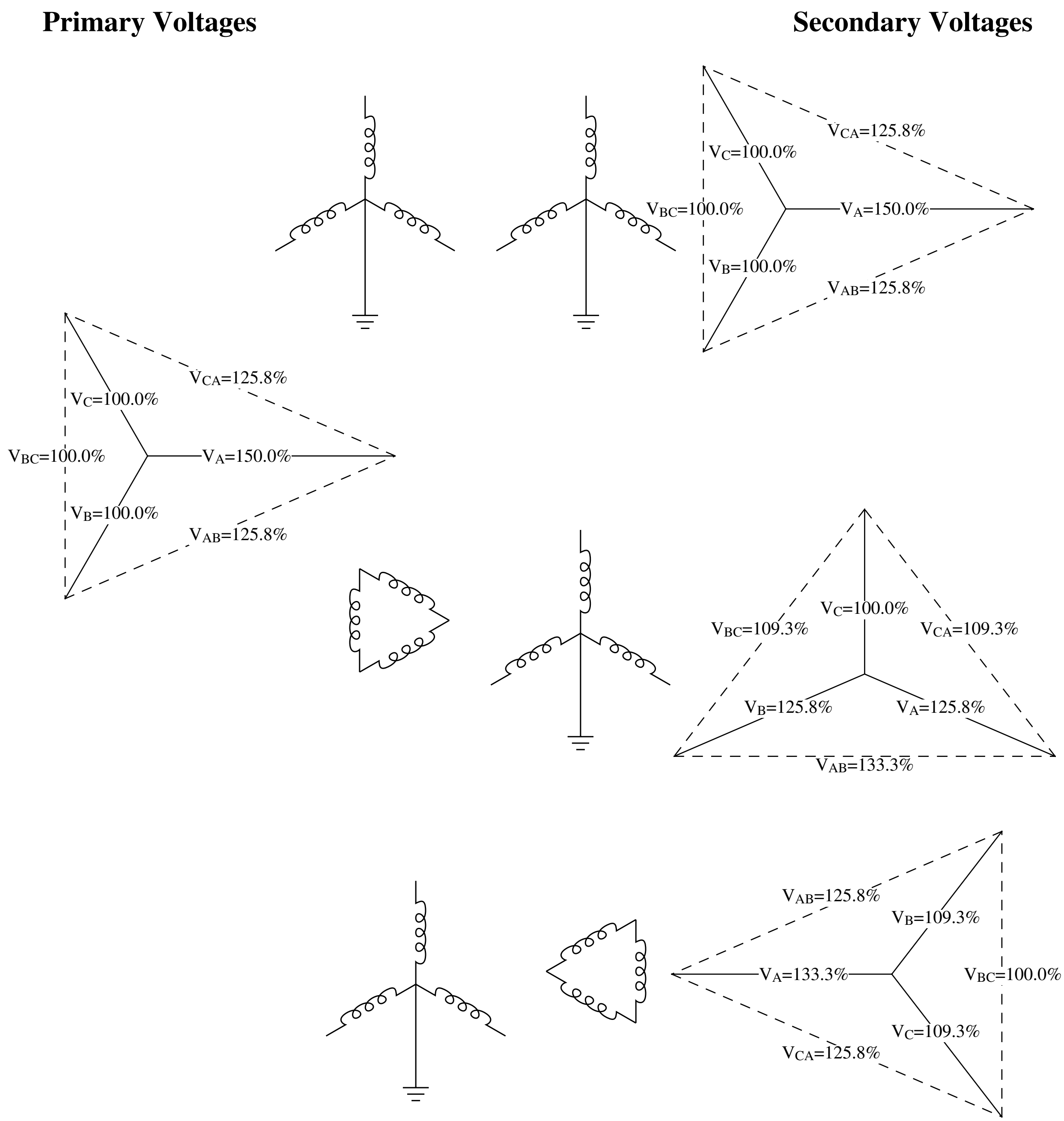


Figure 5-3
Line-to-Line and Line-to-Ground Voltages on the Primary and Secondary of Several Transformer Connections for an Overvoltage of 150% on Primary Phase A

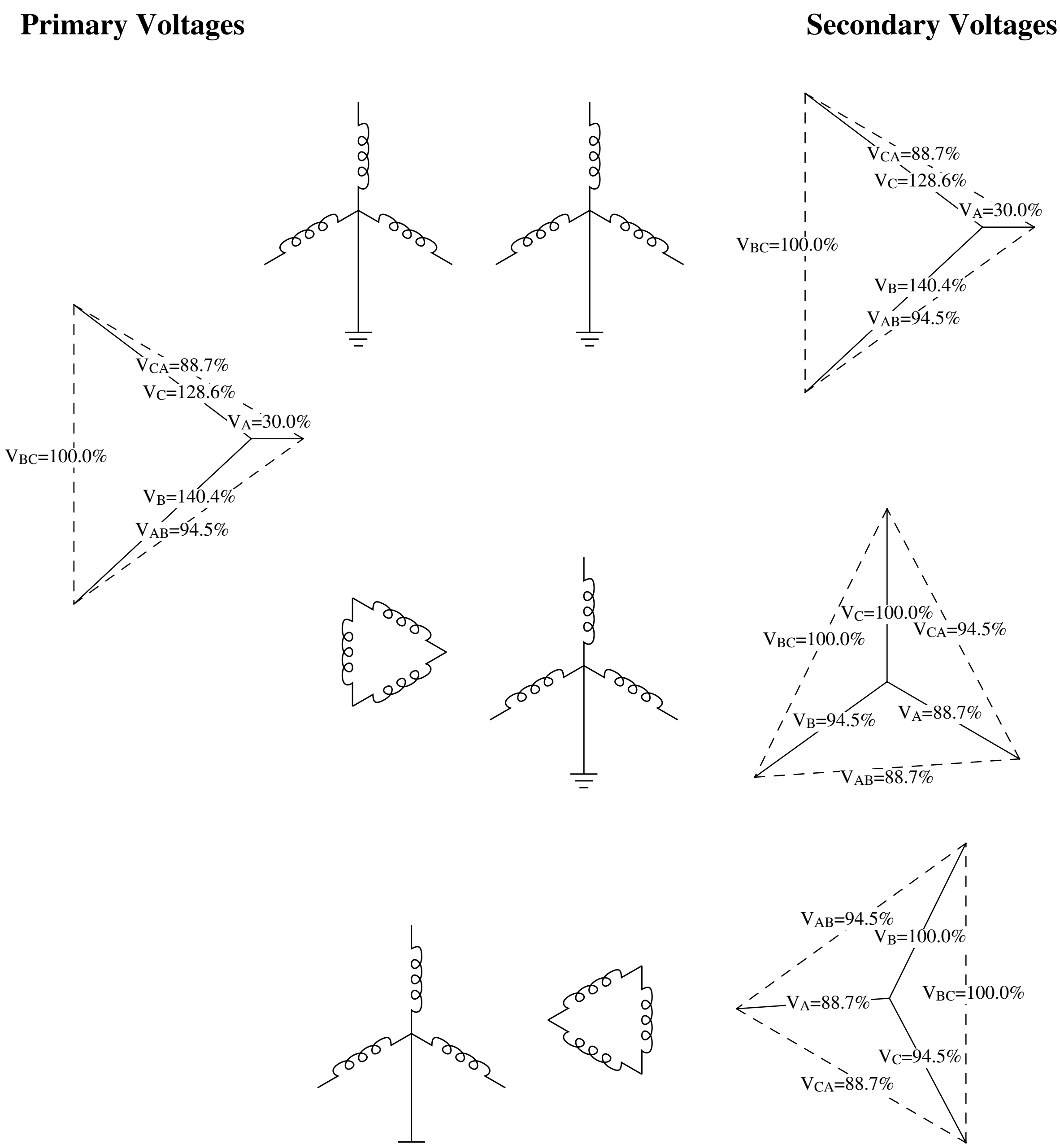


Figure 5-4
Line-to-Line and Line-to-Ground Voltages on the Primary and Secondary of Several Transformer Connections for an Overvoltage Due to a Neutral Shift for a Fault on Primary Phase A

Measurement Location

The point where the voltage is measured can play a large role in determining the sensitivity of the relays. The three main locations that can be monitored are:

1. Generator interconnection point

2. Secondary of the customer transformer

3. Primary of the customer transformer (the distribution system primary)

These measurement locations are shown in Figure 5-5. The distribution primary is usually the most sensitive location for measuring distribution-system overvoltages and undervoltages that could signal primary islanding.[19] Therefore, the primary is the best place to measure, especially for larger distributed generators. It is generally acceptable to measure medium-sized and small DG on the secondary of the transformer, and for very small generators, the voltage may be measured at the generator terminals.

The IEEE P1547 document refers to the point of common coupling (PCC) as the preferred generator interconnection point. Care must be taken when referring to the PCC because it is an arbitrary point that can change depending on the customer. The PCC for smaller distribution customers is generally on the secondary of a distribution transformer owned by the utility. Usually, for larger distribution customers, the PCC is on the primary, but it may be on the secondary depending on whether the customer is metered on the primary or secondary. A 5-MW generator should have relaying on the primary even if it happens to be metered on the secondary of the transformer.

Transformer connections can play a larger role in distorting the voltages and making relaying harder, as shown in the examples in the previous section. If there is a transformer between the utility transformer and the generator interconnection point (as depicted in Figure 5-5), this can further distorting the voltages.

Overall, the best place for relay monitoring is on the primary using line-to-ground voltages. Smaller DG applications (< 1 MW) may use other measuring applications, but the transformer connections should be considered to make sure that effective relay sensitivity is obtained.

[19] Secondary islands are also a concern if they are shared by multiple customers. This can be a small residential island or a larger secondary network island.

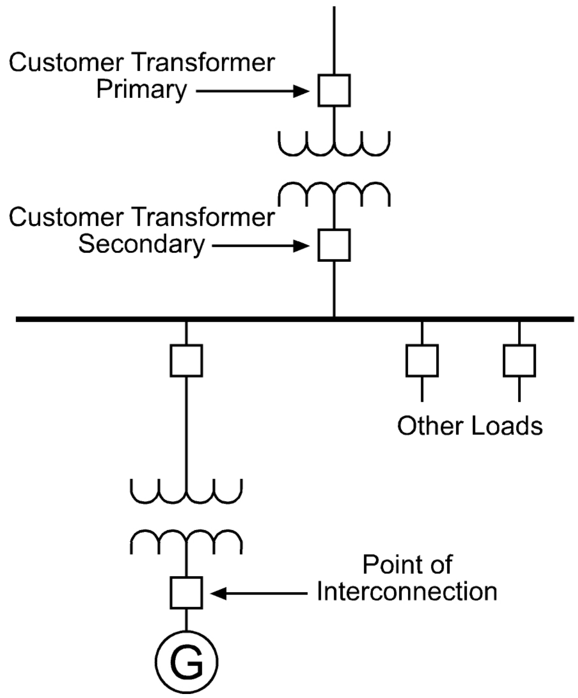


Figure 5-5
DG Measurement Locations

Recommended Set Points

The IEEE 929/UL 1741 approach, using less strict settings, certainly will reduce the incidence of nuisance trips; however, it also creates the potential for sustained high voltage above ANSI range B limits because of DG power injection. In some cases, this could be a threat to loads and power-system equipment, potentially causing damage and perhaps even posing safety issues. It is recommended that the industry consider an alternative approach that provides suitable protection against sustained overvoltage but will still allow DG to ride through mild overvoltages without nuisance trips. This approach essentially means that DG should have an acceptable continuous operating window that is consistent with ANSI C84.1 and should use a long time delay for mild overvoltages.

Table 5-3 shows recommended voltage trip settings for DG that should offer good protection against nuisance trips and sustained overvoltages. This table essentially follows the settings in the IEEE 929/UL 1741/IEEE P1547-D7 standards, but it includes an extra row of settings for voltages ranging from 106% to 110% of nominal with a time delay of 180 seconds. It also allows a continuous (no trip) operating range of only 88% to 106% that is a bit narrower than the current draft standard.

The table also includes an adjustment to the upper overvoltage setting to require a faster trip time for overvoltages. This is an effort to reduce the chance of damaging overvoltages by reducing the duration. While it is not reasonable to expect a two-cycle response for many types of protection systems as per IEEE 929, a 0.1-second response is readily available with a breaker and an instantaneous relay.

Table 5-3
Recommended Trip Thresholds for DG Operations (the Bold Voltage Thresholds Indicate Where Changes are Different From IEEE P1547/D07 and D08)

Voltage Setting			Trip Time
	V	< 50%	0.16 s
50% ≤	V	< 88%	2 s
88% ≤	V	**≤ 106%**	Normal Operation
106% <	V	**< 110%**	180 s
110% <	V	< 120%	1 s
120% ≤	V		**0.1 s**

Base voltages are the nominal voltages stated in ANSI C84.1.
DR ≤30 kW Maximum Clearing Time. DR > 30 kW, Default Clearing Time or area EPS operator may specify different voltage settings or trip times to accommodate area EPS system requirements.

Overvoltage Example Case Study

An instructive example of an overvoltage and the DG nuisance trip response to it recently occurred at a Reliant Energy distribution system.[20] In this case, a 5-MW combustion turbine was operating in parallel with the utility system at an industrial load that is supplied by a 12-kV distribution circuit. The DG unit is located 3 miles from the substation. The DG trip settings were in accordance with Texas PUC Rule 25.212, where the first trip threshold is 126 volts with a 30-second time delay, and the second trip threshold is 132 volts with a 10-cycle time delay. Shortly after the DG was cut-in, the generator tripped offline due to overvoltage.

To assist the DG customer in determining the cause for these over voltage trips, the DG was allowed to change the overvoltage set point to 132 volts (+10%). Power quality monitoring equipment was installed at the service entrance to monitor feeder voltage, real power, and reactive power output of the facility. Figure 5-6 shows the real and reactive power during a snapshot of generator operation (which includes the generator plus the load within the facility). When the generator is on, it forces the voltage at the service entrance up. Data from the power quality recorders shows that as the generator exports power, the feeder voltage magnitude changes as a function of generator output. The voltage on the feeder varies from 124 to 130 V (on a 120-V base). The voltage reached a peak of 130 V (108.6%) and regularly exceeded the 126-V ANSI C84.1 upper threshold.

The case study shows that the preferred and technically better approach is using the settings recommended in Table 5-3. These provide good mitigation of false trips due to temporary

[20] R. Comfort, M. Gonzalez, A. Mansoor, P. Barker, T. Short, and A. Sundaram, “Power Quality Impact of Distributed Generation: Effect on Steady State Voltage Regulation,” PQA Conference, 2001.

overvoltages up to a few minutes duration but will protect against a sustained overvoltage outside the ANSI C84.1 standard.

Questions arise as to what would have happened if this unit were allowed to operate with the IEEE 929/IEEE P1547/UL 1741 settings instead of the more strict Texas PUC Rule 25.212 set points. It would create a situation where the feeder is subjected to a sustained overvoltage beyond the ANSI C84.1 range. This could possibly damage customer equipment or utility equipment.

The example also highlights the importance of coordination with utility voltage-regulation equipment. As shown in Figure 5-6, the voltage does not always stay high. The substation LTC responds to the overvoltage and brings the voltage back within proper range.

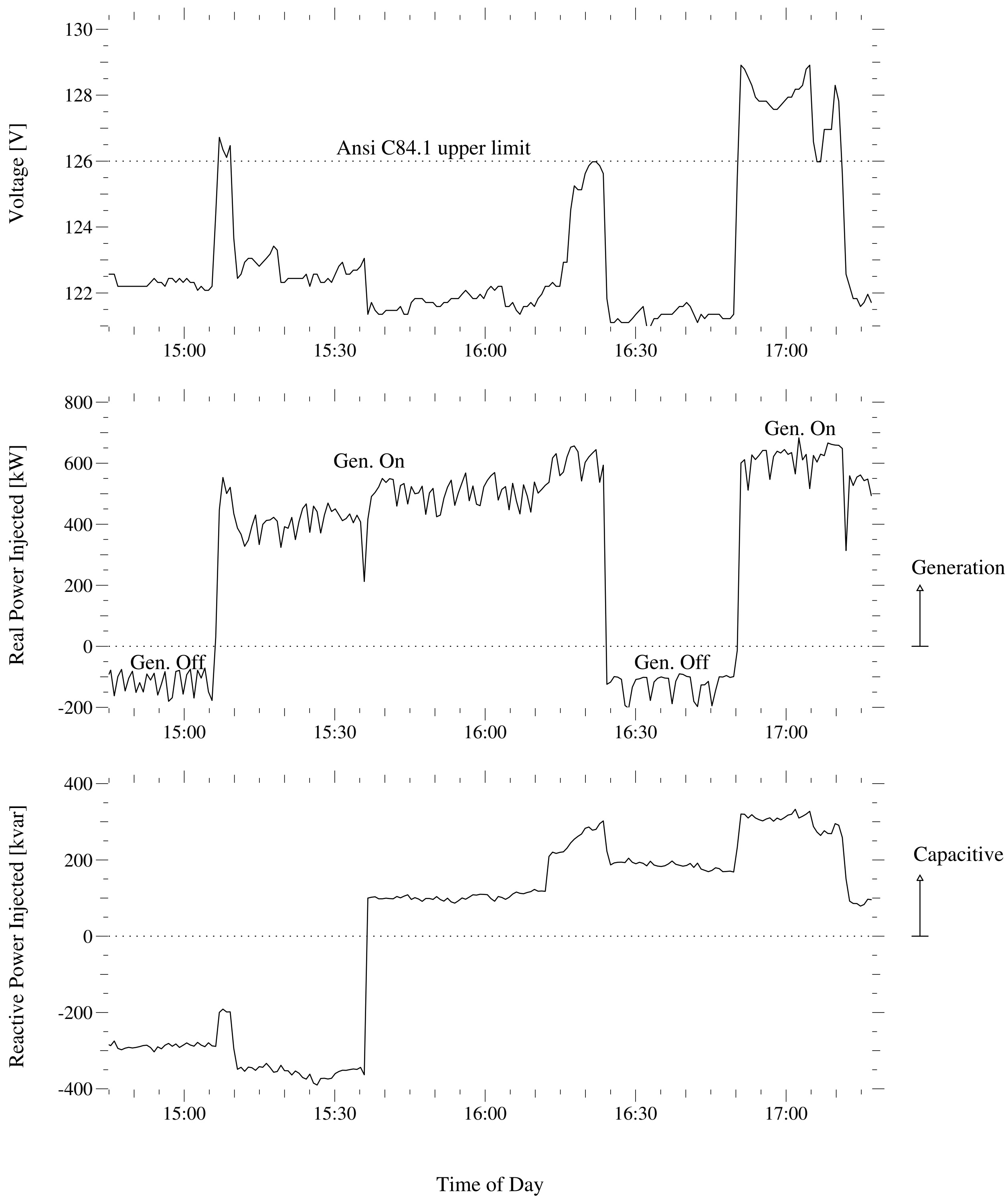


Figure 5-6
Voltage and Real and Reactive Power on Phase A of a 5-MW Generator

Nuisance Trip Rates Based on DPQ Results

Some questions remain about the impact of system power-quality events on the generator relay set points and how they interact with the system:

- How often will generators trip due to power quality events such as sags and momentary interruptions?
- How will the relay set points impact the voltage-support power quality feature of distributed generators? Will the DG-tripping mean the loss of voltage-support during system faults?

The EPRI Distribution Power Quality Project provided a statistically valid sample to assess voltage sags in the U.S. electrical distribution system. As electric utilities became more interested in benchmarking power quality levels, many distribution companies began installing power quality monitoring equipment to collect data for their individual systems. In 1989, EPRI began an extensive assessment of the quality of service provided on distribution systems across the United States. This effort, known as the EPRI Distribution Power Quality (DPQ) Project, was completed in 1995, and the results were made available to EPRI-member utilities in 1996. The project report, *An Assessment of Distribution System Power Quality* (RP 3098-1)[21], summarizes the power quality data recorded on 24 utility systems from across the country. Measurement data was collected from 276 locations on 100 distribution system feeders over a 27-month period, resulting in a measurement database of over 30 gigabytes of power quality data.

The DPQ data provides a very good benchmark for voltage sags that can be used to analyze the impacts of sags on distributed generators. Figure 5-7 shows the number or voltage sags that would cause generators to trip with either the IEEE 929/UL 1741 or the IEEE 1547/D07 thresholds. The DPQ recorded both substation and feeder data. The data shown is from feeder sites only because these are most representative of customer locations where DG would be located. Substation DG sites would have even fewer “sag” trips than the feeder site data shown.

[21] EPRI TR-106294-V2, An Assessment of Distribution System Power Quality; Volume 2: Statistical Summary Report, May 1996.

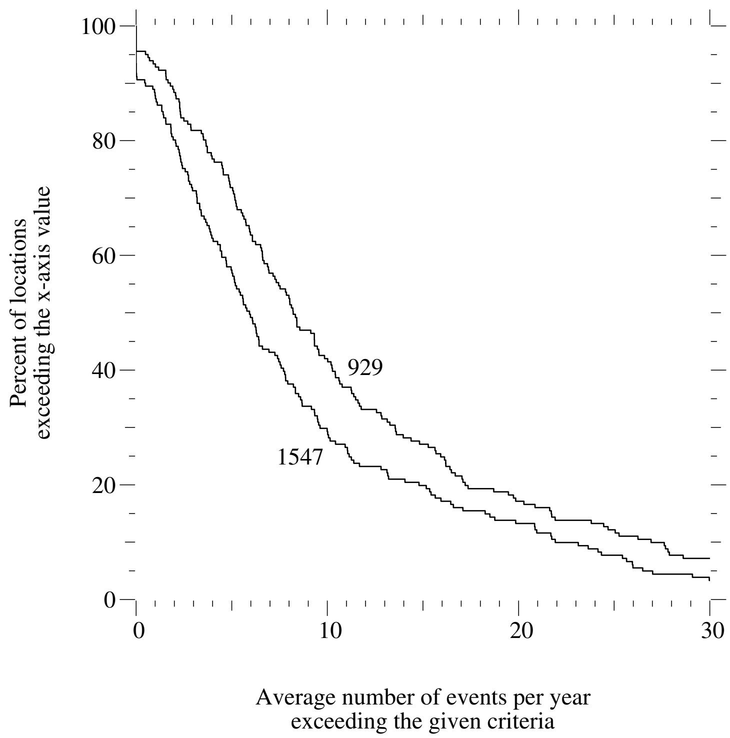


Figure 5-7
Number of Events per Year Exceeding the IEEE 929/UL 1741 and IEEE 1547/D07 Voltage Thresholds

The number of generator trips at most sites is not particularly severe. Most sites will have less than 10 trips on average per year. A small number of sites may have a large number of trips (over 30 per year). In most cases with generators having automatic restarting capability, this level of dropouts should not be a burden to DG operators.

The industry standard thresholds specify a maximum clearing time. They do not specify a minimum detection time. For example, the P1547/D07 thresholds have a 50% undervoltage clearing time of 0.16 seconds (about 10 cycles). Depending on the operation of the protective device, the detection may need to be done much quicker. For a five-cycle breaker, the detection would have to be done in five cycles to meet the ten-cycle standard. It would probably be done even faster in order to have some built-in margin.

Figure 5-8 shows that if a manufacturer trips faster (to be sure to meet the clearing times), there will be more generator trips (but still not to excessive levels). It is recommended that manufacturers use reasonable relaying and clearing times to avoid excessive nuisance trips (which also means that the DG can provide voltage support for a longer duration during the event). If the manufacturers trip very quickly, nuisance trips become very high (see Figure 5-9).

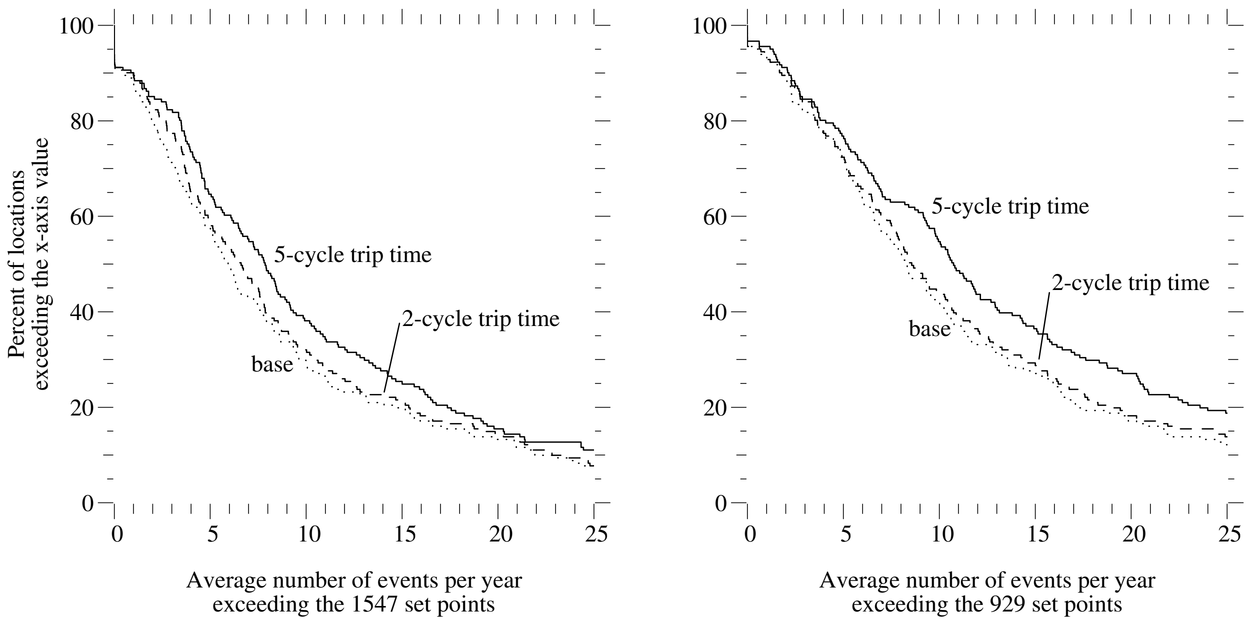


Figure 5-8
Effect of the Time It Takes for a Protective Device to Operate on the Events per Year Exceeding the IEEE 929/UL 1741 and IEEE P1547/D07 Voltage Thresholds—The Total Event Time Is the Device Trip Time (2 or 5 Cycles) Added to the Voltage Sag Duration

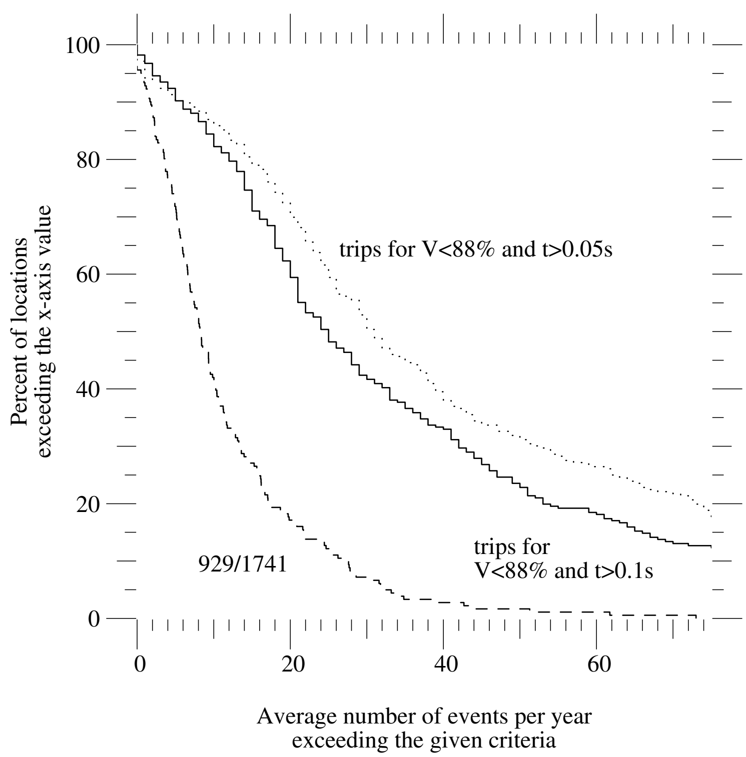


Figure 5-9
Comparison of Very Fast Trip Times (0.1 and 0.05 seconds) to the IEEE 929/UL 1741 Voltage/Time Thresholds

Most of the events that cause generator trips are voltage sags. Undervoltages and voltage sags are much more common than overvoltages, as shown in Figure 5-10, which gives a breakdown by type of event.

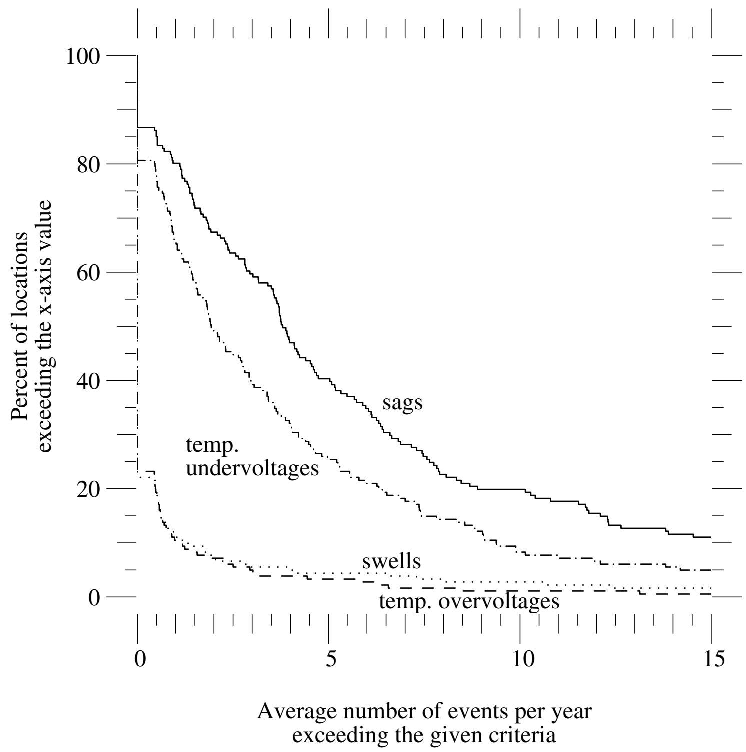


Figure 5-10
Distributions by Types of Events That Would Cause Operations with the IEEE 929/UL 1741 Voltage Thresholds

Voltage Support

Facility generation will provide support during voltage sags. Figure 5-11 shows an example of a fault on an adjacent feeder fault. During the sag, the generator will feed the fault. By providing this current, the generator will help hold up the voltage at the facility (and to some degree all customers downstream of the generator).

Figure 5-12 shows the number of sags that trip a generator per the IEEE P1547/D07 thresholds along with the number of sags that exceed the ITIC curve. The number of voltage sags outside the ITIC curve is much larger than the number of 1547 trips, so a distributed generator can provide voltage support during most voltage sags.

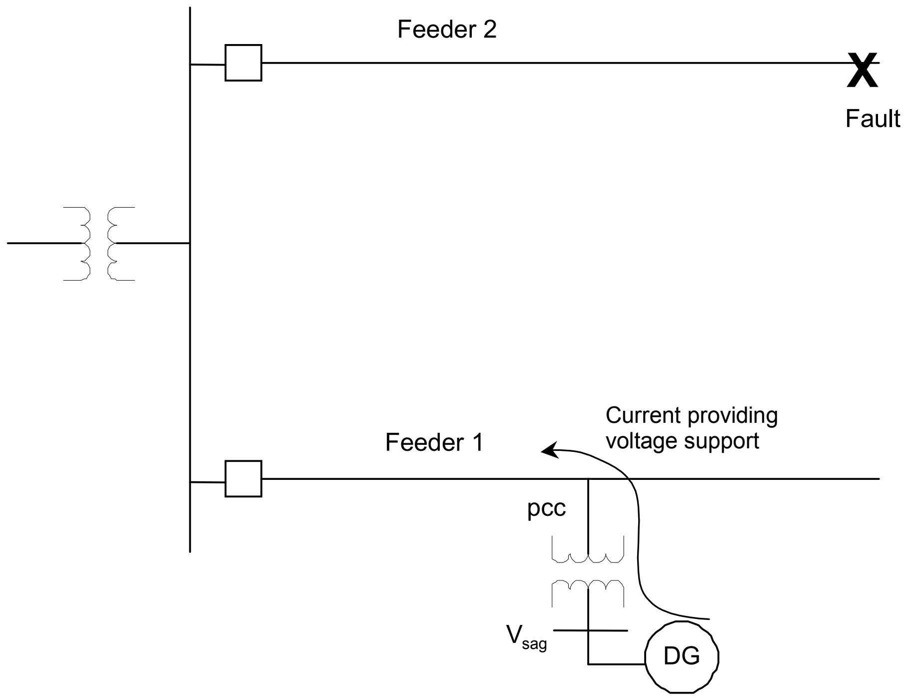


Figure 5-11
DG Providing Voltage Support During a Fault on an Adjacent Feeder

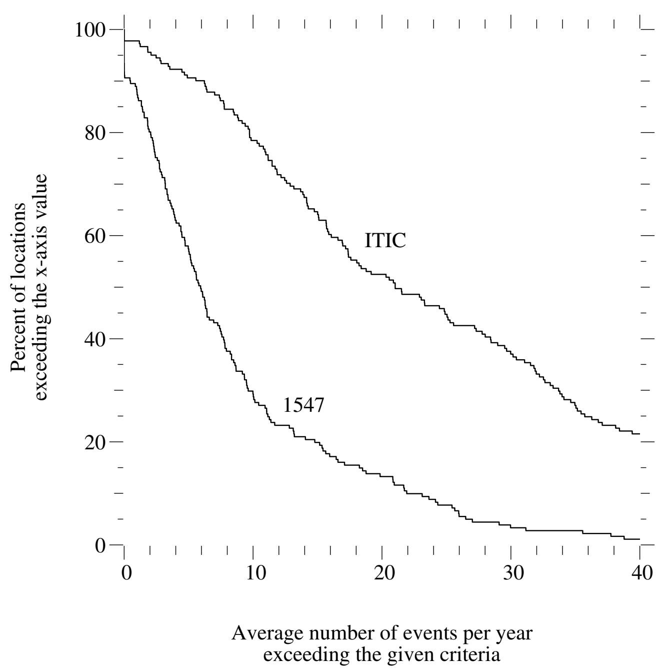


Figure 5-12
Comparison of the Number of Events Exceeding the 1547 Thresholds with Those Exceeding the ITIC Curve

6
CONCEPTS FOR A "1547 RELAY"

Overview

Can relay functionality be extended to include additional relay functionality? Can features be added to clear the generator when the generator is creating power quality disturbances (such as voltage fluctuations)? Is it best to alarm for power-quality disturbances or to trip the generator? These are some of the questions that are explored in this chapter, which investigates the possibilities of a "1547 relay"—a relay that can detect violations of interconnection rules. This chapter explores several power quality and interconnection issues as to how relays could be programmed to remove the generator when it is creating problems.

This chapter uses several quotes from IEEE P1547 draft 7 pertaining to different subject areas. Possible ways to implement the ideas in a relay are discussed. The IEEE P1547 document[22] is not yet a standard, but the existing document highlights several interconnection issues where an enhanced relay may be able to provide more protection.

Flicker

IEEE P1547/D07: "*The DR shall not create objectionable flicker for other customers on the Area EPS.*"

Flickermeter capability can be implemented in a relay. If voltage fluctuations exceed a certain amount, the relay trips the generator. In another variation, the relay sends an alarm signal to the utility. Flicker is not an emergency, so an alarm signal is most appropriate.

Two concerns about a flicker relay are:

- How to differentiate between flicker caused by the generator and flicker caused by other sources.
- How to identify the level of flicker at nearby customers—of most concern is the flicker to nearby utility customers. If the flicker is due to the generator, the flicker will be less severe at an adjacent customer than at the generator terminals.

Flicker discrimination could be implemented by also measuring current. Current will help determine whether the source of the flicker is the generator. Generation provides support for

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[22] IEEE P1547, Draft Standard for Interconnecting Distributed Resources with Electric Power Systems, Draft 7, Feb. 9, 2001, and Draft 8, Aug. 29, 2001.

flicker from other flicker sources, so generators need not trip for flicker unless the generator is the cause of the flicker.

One way to discriminate is to multiply the current by the source impedance and subtract this from the average voltage or nominal voltage. This *derived* voltage feeds into the flickermeter for excessive flicker detection. The impedance from the generator back to the utility source (the short-circuit impedance without the generator connected) would be entered by the user, or, with more sophistication, the generator controller could calculate it based on local measurements.

To relay or alarm based on the voltage at a location other than the measuring point (which is usually the PCC or generator terminals), a multiplier to the flickermeter output can be used. The European-originated flickermeter outputs the *short-term flicker level* units of P_{st}. This can be treated like a voltage, and impedance dividers can be used to determine the voltage at other locations on the circuit.

Consider the flicker generator in Figure 6-1, fed from point P by a feeder line issuing from point A. Z_{AP} is the impedance of the line, and Z_A is the short-circuit impedance at point A, resulting in the following relation:

$$P_{st}(A) = P_{st}(P) \times \frac{|Z_A|}{|Z_A + Z_{AP}|}$$

The multiplier for the flickermeter is then $\frac{|Z_A|}{|Z_A + Z_{AP}|}$, which can handle most needs to alarm or relay based on remote measurement locations. In many DG applications, Z_{AP} is the DG interconnection transformer impedance, and Z_A is the utility impedance back to the source.

If something other than the European flickermeter approach is used, the same multiplier can be used by applying the multiplier to ΔV instead of to P_{st}.

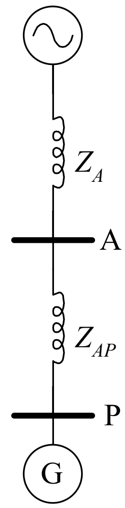


Figure 6-1
Disturbance Source P Supplied By A Radial from The Station A

What is the timeframe for tripping or alarming? Because flicker is mainly an annoyance problem, only flicker that is ongoing should be flagged to avoid needless alarms to the generator operator and to the utility. The time delay should be many hours, and the reset time should be even longer to catch problems caused by a few significant events during a day (people tolerate an isolated voltage change but start complaining when it happens a few times per day). If the European flickermeter approach is used, two outputs are available: P_{st} (short-term) and P_{lt} (long-term). The short-term flicker level covers ten minutes. The long-term flicker level is based on N=12 successive P_{st} values using:

$$P_{lt} = \sqrt[3]{\frac{\sum_{i=1}^{N} P_{st,i}}{N}}$$

P_{lt} is more appropriate for flicker relaying because of the longer time frame (or both could be used, with tighter limits on P_{lt}).

Harmonics

UL 1741, IEEE 929, IEEE P1547/D07, and IEEE 519[23] all have the same harmonic limits on current, which are shown in Table 6-1.

[23] IEEE Standard 519-1992, Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.

Table 6-1
IEEE P1547/D07 Table 2 Maximum Harmonic Current Distortion in Percent of Current

IEEE P1547/D07 Table 2 Maximum Harmonic Current Distortion in Percent of Current (I) [(a)]						
Individual Harmonic Order (Odd Harmonics) [(b)]	<11	11≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	TDD
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0
(a) I = the greater of the Local EPS maximum load current integrated demand (15 or 30 min) without the DR unit, or the DR unit rated current capacity (transformed to the PCC when a transformer exists between the DR unit and the PCC). **(b)** Even harmonics are limited to 25% of the odd harmonic limits above.						

A relay should differentiate between harmonics caused by the generator and harmonics absorbed by the generator. Existing UL and IEEE standards do not distinguish between the two cases. Rotating generators as well as inverter-based generators can be low impedances to harmonics, so they help the utility system soak up harmonics. (It is commonly believed that inverter-based generators cannot absorb harmonics, but a constant-voltage, PWM converter can effectively absorb low-order harmonics.) Rotating generators may have a harmonic impedance of as low as 10 to 20% of their rating (and below 5% for zero-sequence harmonics such as the third). Also, each harmonic may be different—a generator could absorb the fifth and seventh, but generate the third.

The angle between the harmonic-current vector and the harmonic-voltage vector determines the direction of the harmonic flow. Harmonic power flows follow the same rules as 50- or 60-Hz power flow—if the 3rd-harmonic voltage and 3rd-harmonic current are in phase, 3rd-harmonic power is flowing out of the generator (assuming that the CT is wired so that real power out of the generator gives currents in phase with voltages). Therefore, a harmonic relay should only trip or alarm if the generator is injecting the offending harmonic.

Harmonic detection at the generator could miss harmonic problems elsewhere on the system; the generator can pump a resonating circuit (see Figure 6-2). If the generator harmonic currents are within limits, there is no way to detect problems due to harmonic resonances elsewhere on the system. Measuring current at the point of common coupling helps detect any resonances caused by capacitors within the facility, but little can be done (short of external monitoring) to detect utility-side resonances.

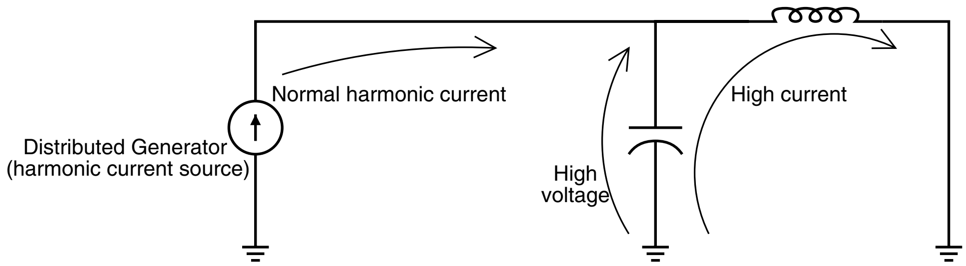


Figure 6-2
Harmonic Resonance Driven by a Generator

Relaying time frame is a question. Heating causes most harmonic problems, so a fast trip is not necessary because of the time constants involved. Some problems related to interactions with other sensitive equipment (for example, harmonics cause a UPS to switch to its battery) are helped by faster harmonic relaying. The limits above are for times longer than one hour according to 519 (the limits can be exceeded by 50% for shorter intervals). For most cases, a long time delay is needed on a "harmonics relay," on the order of one hour.

Regulation

IEEE P1547/D07: *"DR shall not degrade the voltage provided to the customers of the Area EPS to service voltages outside the limits of ANSI C84.1, Range A."*

Over- or undervoltages at the generator point of interconnection or at the point of common coupling can be detected and relayed using standard over- and undervoltage relays. This has been previously discussed in detail in this report. Of most importance are generators injecting real power, causing overvoltages. Problems caused by distributed generators interacting with utility voltage regulation are much harder to diagnose, including:

- If just downstream of a regulator, a generator may cause low voltage at the far end of the circuit.
- A generator causing reverse power flow on a regulator with bi-directional controls causes the regulator to ratchet all the way to the top or bottom of its range. (Local relaying should detect this in many cases because it could cause a high under- or overvoltage.).
- Interactions with a switched capacitor bank or regulator—real or reactive power variations of a generator—can cause excessive device switching, which is difficult to identify locally.

Remote monitoring may identify these scenarios, but relaying with local signals cannot.

Unbalance

Generators often have voltage or current unbalance relays to protect the generator. A 1547 relay could easily perform this function; its main purpose is to protect the generator.

Overvoltage Protection

IEEE P1547/D07: *"For DR interconnections, directly or through a transformer[24], to Area EPS primary feeders of multi-grounded or uni-grounded four-wire construction, or to tap lines of such systems, the maximum unfaulted phase (line-to-ground) voltages on the Area EPS primary feeder, during single line-to-ground fault conditions with the Area EPS source disconnected, shall not exceed those voltages that would occur during the fault with the same Area EPS source connected and no DR generation."*

This statement is almost impossible to meet in many realistic DG applications. Even with a grounding transformer, some customers could see higher voltages during islanding once the utility disconnects. Of most concern, ungrounded generator connections can raise the line-to-ground voltage to phase-to-phase voltage (173%), which cannot be detected on the generator side of the transformer. A ground overvoltage relay (59G, see page 2-11) will detect the overvoltage, and the 1547 relay could perform this feature.

If the interconnection is grounded, standard overvoltage relays will detect the overvoltage *if* the relays measure line-to-ground voltages (relays miss the overvoltage with line-to-line measurements). In addition, the standard overvoltage relays safeguard against resonant or ferroresonant overvoltages driven by a distributed generator.

Islanding/Fault Current Issues

IEEE P1547/D07: *"With a stiffness ratio of 10 or less, the DR unit shall be equipped with current-based protection [25] and current-based or voltage-based ground fault protection suitable for the detection of Area EPS faults."*

A 1547 relay could incorporate this feature with suitable current or voltage inputs.

IEEE P1547/D07: *"The ground-fault current contribution ($3I_0$) of the DR, including the effect of any transformers between the DR and the primary feeder, shall not be greater than 100% of the fault current contribution of the DR to a three-phase fault at the same primary feeder fault location."*

Grounded interconnections hold down overvoltages but create ground sources that feed utility ground faults. P1547 addresses the fault-contribution side of the tradeoff by limiting the ground-fault current to the three-phase fault current. A ground overcurrent relay can detect excessive ground current. The relay pickup should be set to the value calculated for the three-phase fault current for a fault on the primary side of the interconnection transformer, which can be calculated as follows:

---

[24] In many existing 4-wire multi-grounded distribution circuits, the existing transformer for commercial and industrial facilities is a Y-Y-connected transformer. In these cases, consideration has to be given to the grounding of the generator if the secondary service is a 4-wire service.

[25] For example, voltage-restrained overcurrent relays or voltage-controlled overcurrent relays or distance relays are typically used for this purpose.

$$I = \frac{V_{LL} / \sqrt{3}}{X_t + X_g}$$

where,

V_{LL} is the line-to-line voltage on the primary or secondary (depending on where the CTs are connected)

X_t is the interconnection transformer impedance in ohms $= \frac{(kV_{LL})^2}{MVA_{tran}} X_{\%}$

X_g is the generator impedance in ohms, for a synchronous machine, use $\frac{(kV_{LL})^2}{MVA_{gen}} X_d''$

Limiting the ground-fault current to the three-phase fault value limits the type of transformer connection. A grounding transformer cannot be used without a large neutral reactor. Any rotating generator connected through a grounded-wye, grounded-wye transformer must have a grounding reactor or resistor to limit fault current.

IEEE P1547/D07: *"For an unintentional island in which the DR and a portion of the Area EPS remain energized through the PCC, the DR shall cease to energize the Area EPS within ten seconds of the formation of an island."*

Under- and overvoltage relays and under- and over-frequency relays form the main defense against islanding. These relays may not operate if the load happens to match the generation in the island. Active anti-islanding protection helps protect inverter-based generators (see chapter 3). A 1547 relay can include active anti-islanding if it has an output that can control the firing of the converter. Auxiliary communication ports can be added to a 1547 relay if transfer trip or other communication schemes are needed.

Summary

The following summarizes the capabilities that are possible with a 1547 relay:

- Flicker: Flickermeter functionality can be included in a relay. The relay should measure the current (and not just the voltage), so that it does not trip for flicker caused by other fluctuating loads or generators.
- Harmonics: Detecting and relaying harmonic violations can be done in a relay. The relay should check the direction of harmonic power flow; the relay should not trip when the generator is absorbing harmonics. The relay may miss resonances excited by the generator.
- Regulation: Over- and undervoltage relaying can be done in a relay; however, this relaying will miss many scenarios where the generator is not properly coordinated with utility regulation equipment.

- Unbalance: Unbalance can be done in a relay.
- Overvoltage Protection: Overvoltage relaying can be done with overvoltage detection connected phase-to-ground and ground overvoltage detection on ungrounded interconnections.
- Islanding/Fault Current Issues: A 1547 relay can cover many of the standard islanding issues and can cover some of the fault-current issues. It would be difficult to design a relay that could handle every possible protection approach that would cover both islanding and fault current.

7

SAG AND INTERRUPTION TESTS OF AN INVERTER-BASED GENERATOR

Introduction

A 30-kW inverter-based generator was tested to evaluate the performance of its controller-based relay system. Response was benchmarked by programming the IEEE P1547 undervoltage requirements when the generator was operated in a grid-dependent mode. These tests were designed to characterize the response of the generator to variations in the electrical parameters of the grid, such as voltage sags that might be encountered during a utility fault.

Single-phase, two-phase, and three-phase sag testing of the generator was performed with and without a large induction motor in the circuit. The test setup is shown in Figure 7-1. Voltage sags were created using EPRI PEAC's 100-A voltage sag generator. Single-phase, two-phase, and three-phase interruption testing of the generator was also performed. These outages were created by opening contactors or using the sag generator to switch to an open circuit.

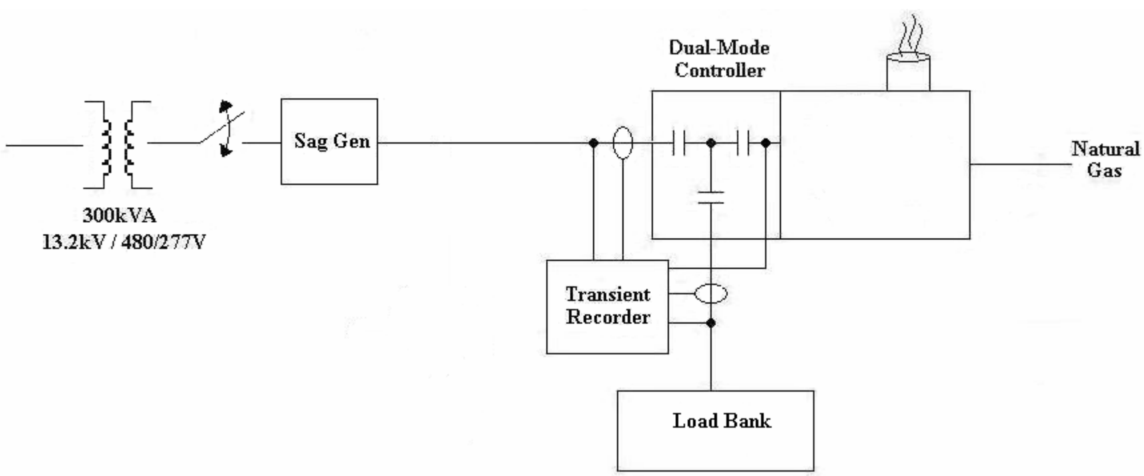


Figure 7-1
Voltage-Sag Test Setup

Electronically switching from nominal to reduced-voltage taps on transformers created the voltage sags. The sag generator is computer-controlled with a programmable sag duration of ¼ to 180 cycles (in ¼-cycle increments). The tapped transformers were connected in a wye configuration, and the sags were created on a phase-to-neutral basis. Each phase-to-neutral voltage is controlled independently. By disconnecting the transformer for an associated phase, it is possible to simulate an outage on that phase with the sag generator.

During all of the tests, the undervoltage relay settings were set according to the IEEE P1547 draft 7 (see Table 7-1).

Table 7-1
The Generator's Grid-Connect Undervoltage Relay Settings

IEEE P1547 Draft 7			Undervoltage Relay Settings	
Voltage (%)	Time (Cycles)	Time (Seconds)	Voltage (Volts with a 480-V Nominal)	Time (Seconds)
50% ≤ V < 88%	120	2.0	424V	2.0
V < 50%	10	0.167	240V	0.17

Single-Phase Testing with an Induction Motor

Figure 7-2, Figure 7-3, and Figure 7-4 show some of the pre-sag and sag data for the voltage and current of the utility source and the 15-kW load (see Figure 7-1 for voltage and current monitoring points). It is interesting to note the increase in the source currents on Phases B and C with the significant decrease in current on Phase A. The increase in current on the phases that were not sagged was most likely caused by the 100-HP induction motor. When the duration of the voltage sag reached 120 cycles, the generator tripped. Figure 7-5, Figure 7-6, and Figure 7-7 show the end of the sag and the recovery of the system.

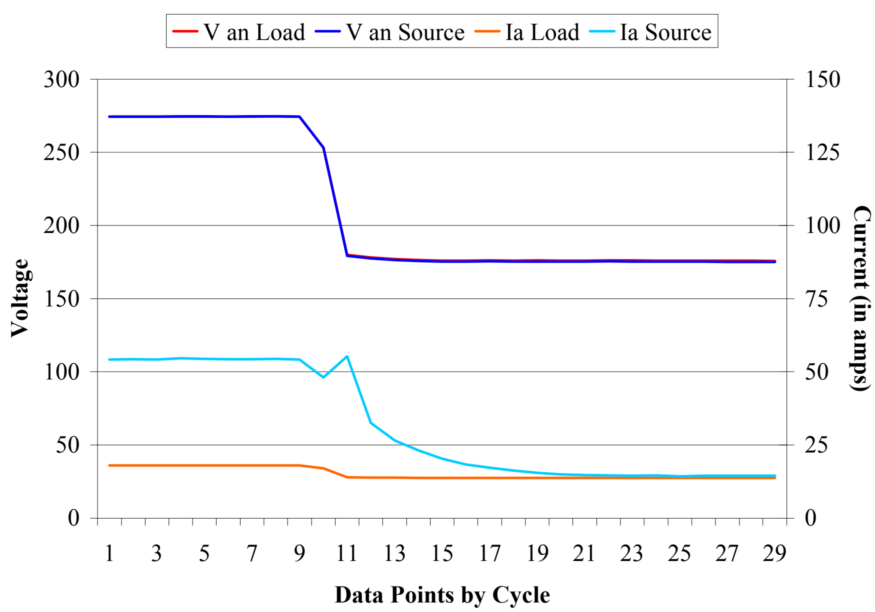


Figure 7-2
Single-Phase Sag Tests on Phase A – RMS Voltage and Current (Van and Ia)
Van = 60%, Vbn = 100%, Vcn = 100%, Duration = 120 Cycles (2 Seconds)

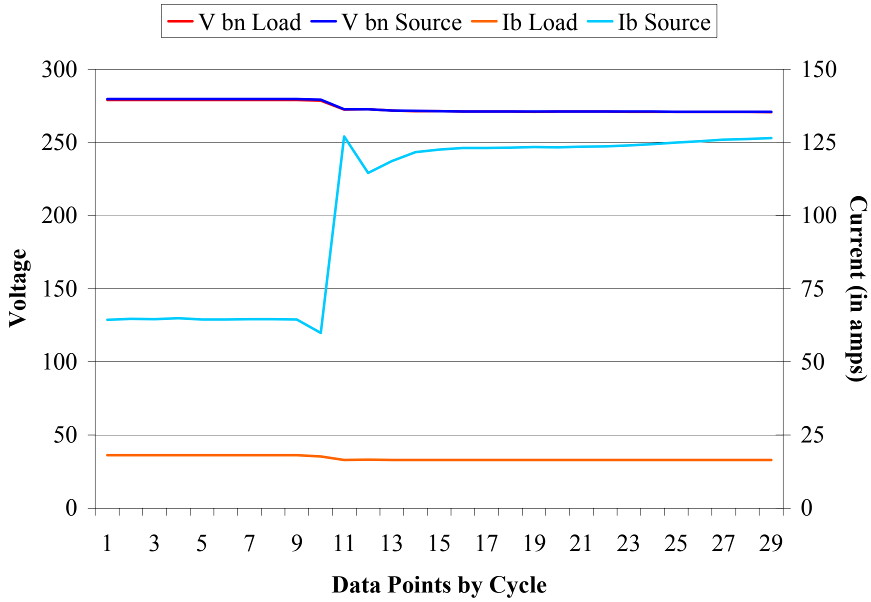


Figure 7-3
Single-Phase Sag Tests on Phase A – RMS Voltage and Current (Vbn and Ib)
Van = 60%, Vbn = 100%, Vcn = 100%, Duration = 120 Cycles (2 Seconds)

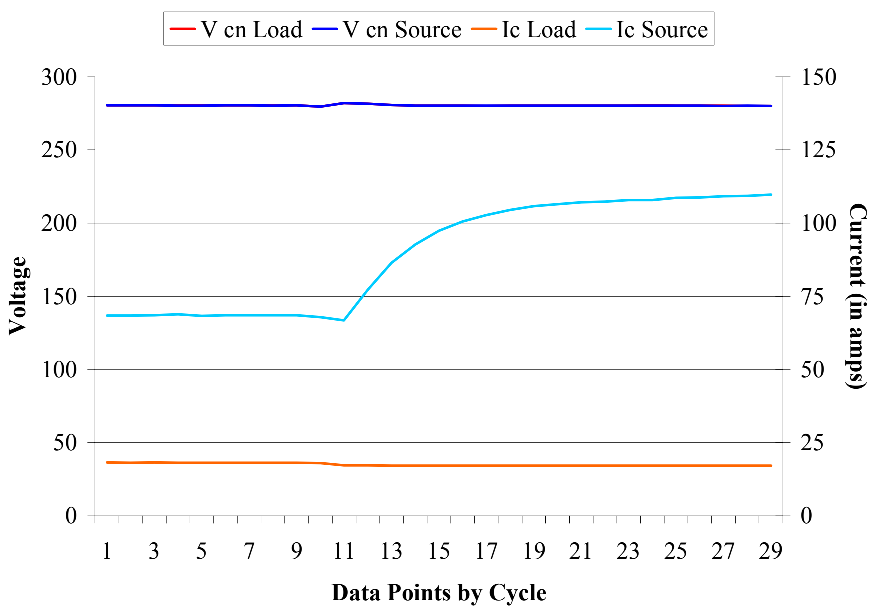


Figure 7-4
Single-Phase Sag Tests on Phase A – RMS Voltage and Current (Vcn and Ic)
Van = 60%, Vbn = 100%, Vcn = 100%, Duration = 120 Cycles (2 Seconds)

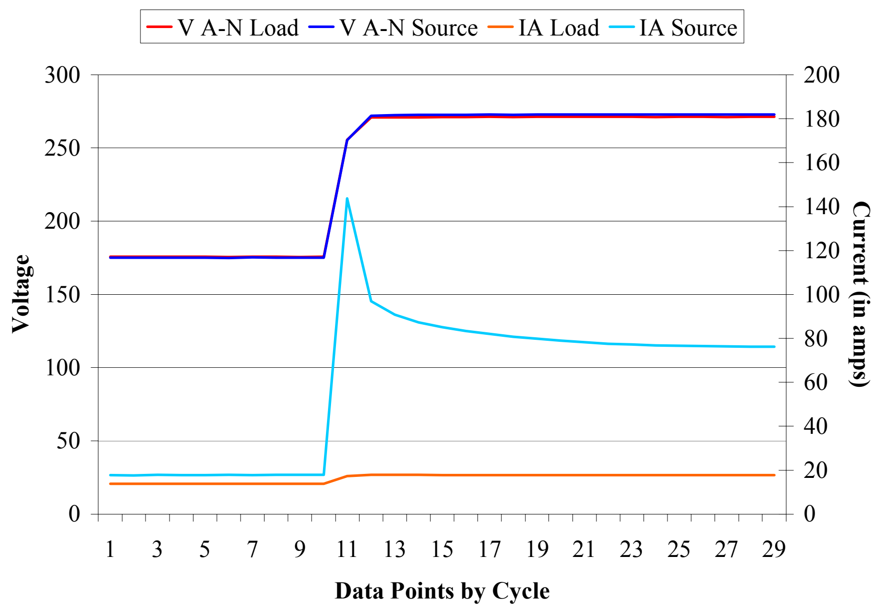


Figure 7-5
Single-Phase Sag Tests on Phase A – RMS Voltage and Current (Van and Ia)
Van = 60%, Vbn = 100%, Vcn = 100%, Duration = 120 Cycles (2 Seconds)

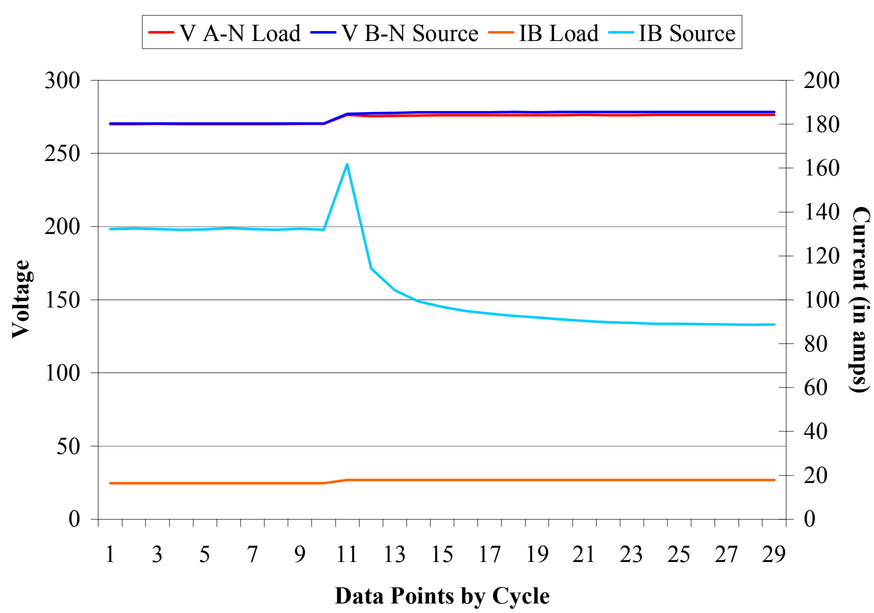


Figure 7-6
Single-Phase Sag Tests on Phase A – RMS Voltage and Current (Vbn and Ib)
Van = 60%, Vbn = 100%, Vcn = 100%, Duration = 120 Cycles (2 Seconds)

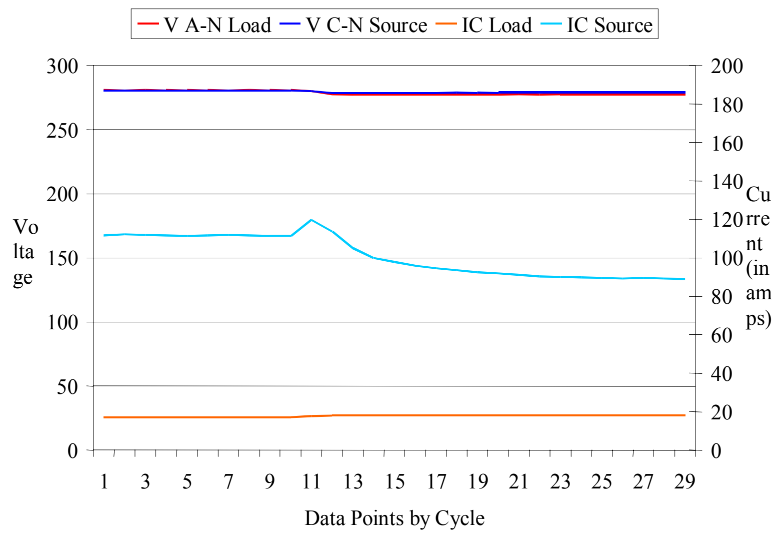


Figure 7-7
Single-Phase Sag Tests on Phase A – RMS Voltage and Current (Vcn and Ic)
Van = 60%, Vbn = 100%, Vcn = 100%, Duration = 120 Cycles (2 Seconds)

Although the generator tripped during this test, the results show that the 15-kW load connected directly to the generator itself did not experience any interruption in power. In many industrial and commercial situations, this is an important performance response. Any loss of power to a critical load is likely to cause it to shut down, even if the interruption lasts for only a few cycles. Approximately four minutes after the sag ended, the generator restarted, reconnected to the power grid, and resumed generating 15 kW. Figure 7-8 shows the volt-time sensitivity curve for the sag tests of Phase A of the generator.

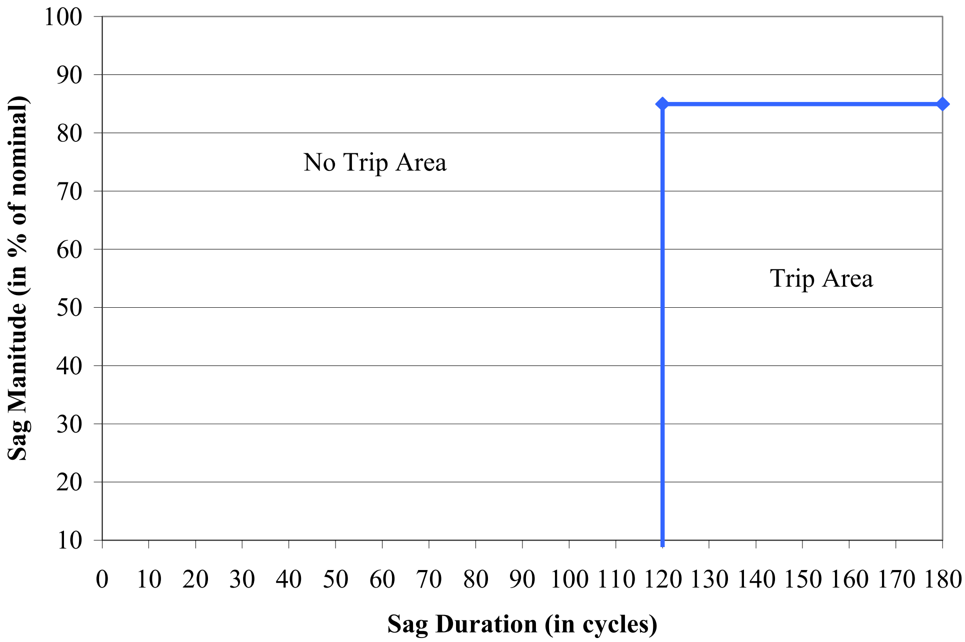


Figure 7-8
Voltage Sag Susceptibility Curve – Phase-A-to-Neutral Sags (for the Test Setup Shown in Figure 7-1)

At first glance it would appear as though the generator's undervoltage protection was not functioning as programmed (see Table 7-1). This is due to the fact that the generator controller only monitors the phase-to-phase voltages. In these tests, voltage sags were created on a phase-to-neutral basis. The resulting phase-to-phase voltages were not below the undervoltage trip points.

The next test involved running a 100-HP three-phase induction motor, as shown in Figure 7-1, while interrupting a single phase of the 480-V power upstream of the motor using a contactor. This test was performed to see if the back EMF from the induction motor would affect the generator's response to outages. The motor was unloaded for the first test. Figure 7-9 and Figure 7-10 show the results of a 180-cycle outage. The data-acquisition system only captured the first 120 cycles of the test. The outage begins near the 70th cycle. The generator did not detect an outage and continued to run during the entire outage.

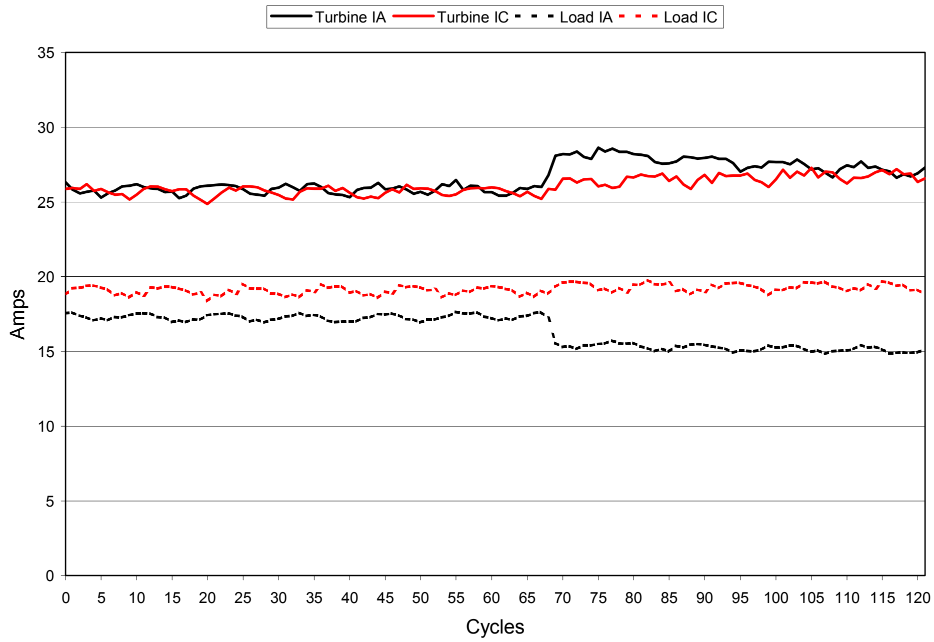


Figure 7-9
Currents for an Interruption on Phase A with an Unloaded Induction Motor in the Circuit

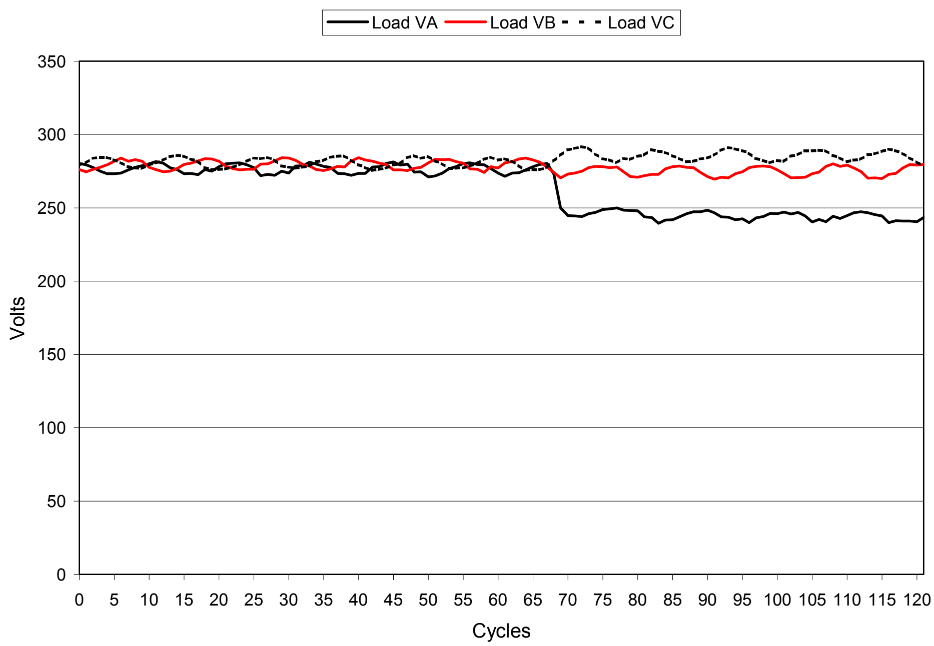


Figure 7-10
Voltages for an Interruption on Phase A with an Unloaded Induction Motor in the Circuit

The test was repeated with the motor approximately 1/3 loaded. Figure 7-11 and Figure 7-12 show the results of this test. Again, the data acquisition was only able to capture 120 cycles of data with the event occurring at approximately the 60th cycle. The generator tripped after 120 cycles of outage. The trip was due to the undervoltage relay setting. The generator did not detect the single-phase outage. However, the resulting voltage sag on phase A was enough to trip the generator.

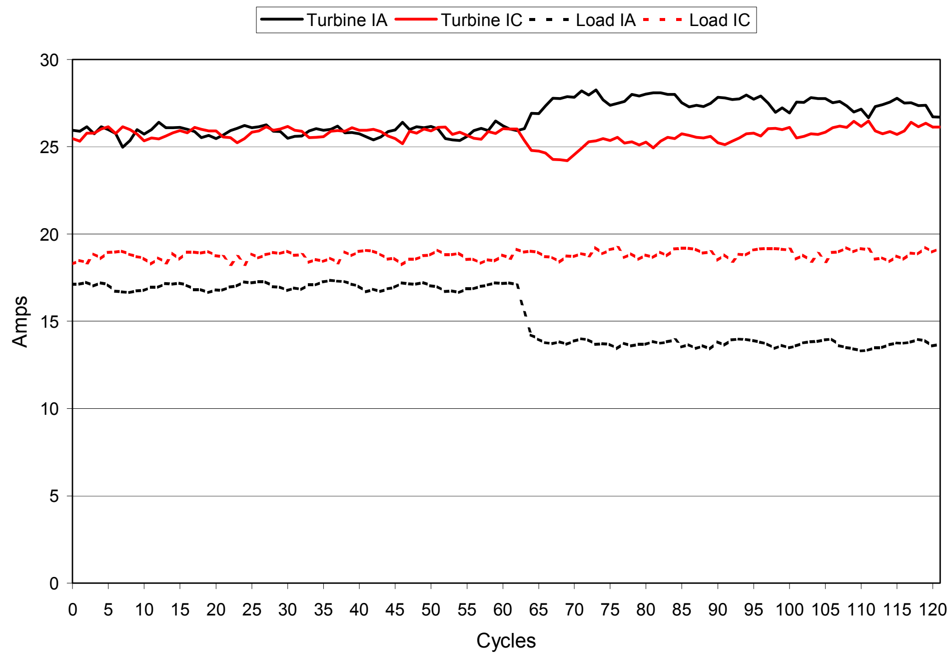


Figure 7-11
Currents for an Interruption on Phase A with a Partially Loaded Induction Motor on the Same Circuit

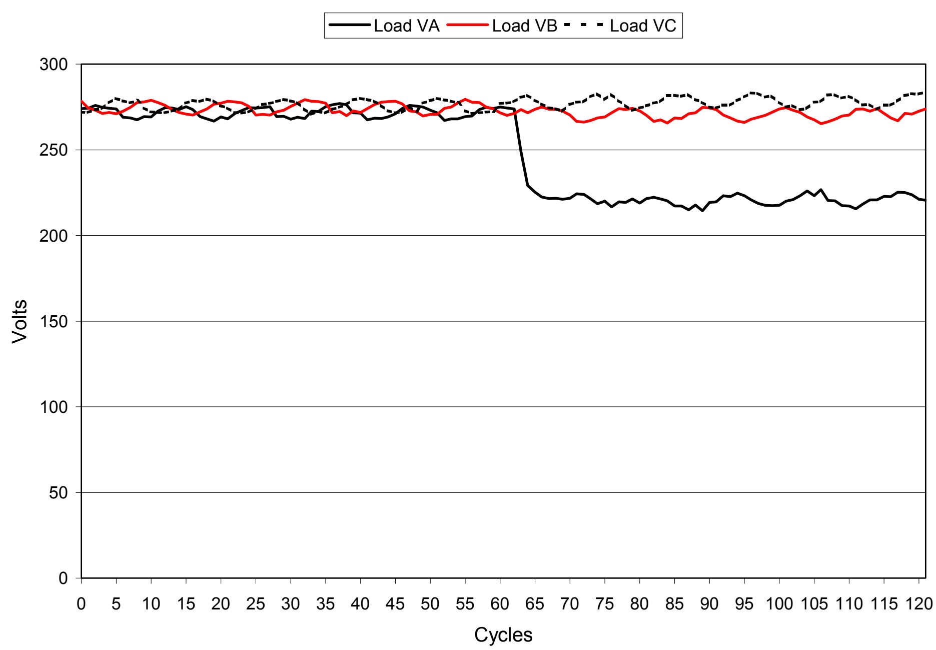


Figure 7-12
Voltages for an Interruption on Phase A with a Partially Loaded Induction Motor on the Same Circuit

Single and Multi-Phase Interruption Testing without an Induction Motor

The next series of tests were performed without the induction motor in the circuit. The test setup is shown in Figure 7-13. The sag generator was used to switch one or more phases to an open condition. All tests were performed with the generator in grid-connected mode. The goal of the testing was to determine the response of the generator to single- and multi-phase outages. The load used in these tests was a three-phase, wye-connected linear load bank. The load bank was connected to the protected load contactor of the generator. The amount of load was switched between three load settings: 0 kW, 7.5 kW, and 15 kW. The output of the generator was adjusted to the following set points: 7.5 kW, 15 kW, or 30 kW. These settings were adjusted to test situations in which the output of the generator was less than, was matched to, or was greater than the connected load. This was done to determine if load size affected the response of the generator to interruptions.

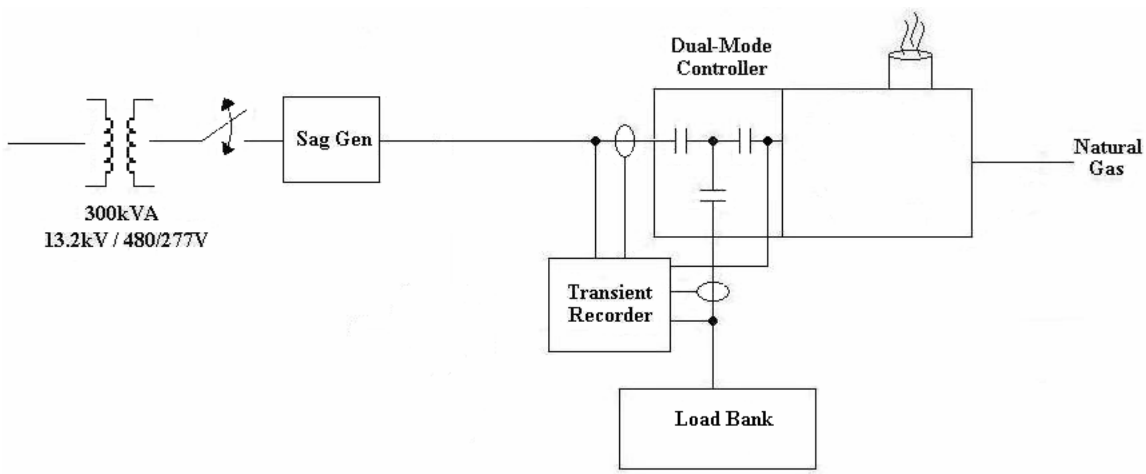


Figure 7-13
Sag and Outage Test Setup without an Induction Motor

The data in Figure 7-14 through Figure 7-19 show the results of 10-cycle interruptions on phase A of the 480-V source with various load and power output configurations, as show in Table 7-2.

Table 7-2
Load Size and Generator Power Outputs during Interruption Testing on Phase A

Duration of Interruption (Cycles)	Load Size (kW)	Turbine Output (kW)
10	0	30
10	15	15
10	15	7.5

In the first test, the generator output was set to 30 kW, and the load size was set to 0 kW. As shown in Figure 7-14 and Figure 7-15, the generator tripped offline within 3 cycles. The generator tripped on a fast inverter overvoltage condition. With no other load connected downstream of the open point, the output voltage of the generator inverter increased quickly after phase A opened.

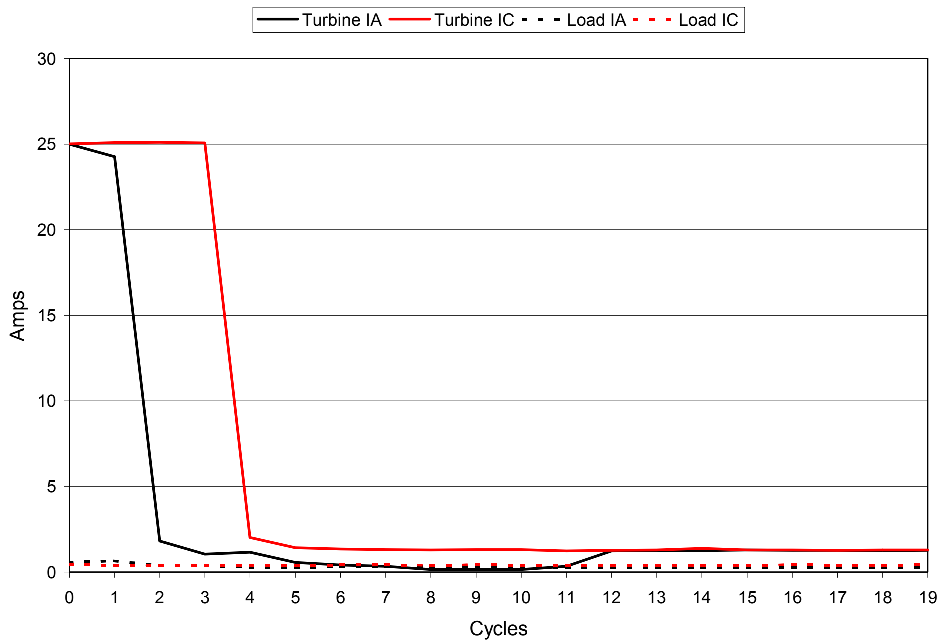


Figure 7-14
Currents for a 10-Cycle Interruption on Phase A with No Load Connected to the Generator

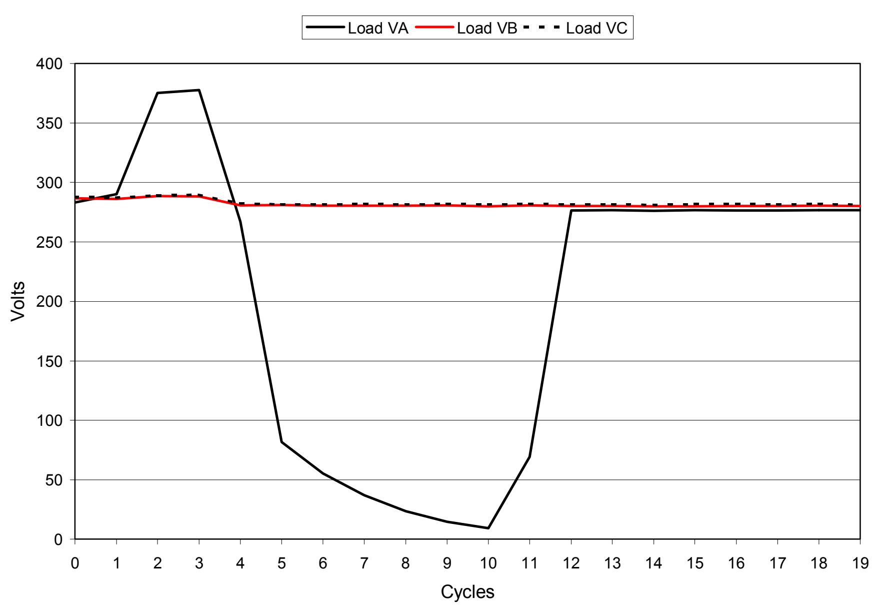


Figure 7-15
Voltages for a 10-Cycle Interruption on Phase A with No Load Connected to the Generator

The next test involved setting the generator output to 15 kW and the load bank to 15 kW. This created a condition in which the entire output of the generator was being consumed by the load bank. As shown in Figure 7-16 and Figure 7-17, the generator did not trip offline. The output of the generator was consumed by the load; therefore, the voltage and current excursions were relatively minor. The test was repeated with a duration of 120 cycles with the same results. It was then repeated by manually opening a contactor on phase A and timing the response of the generator. The generator tripped at approximately 24 seconds.

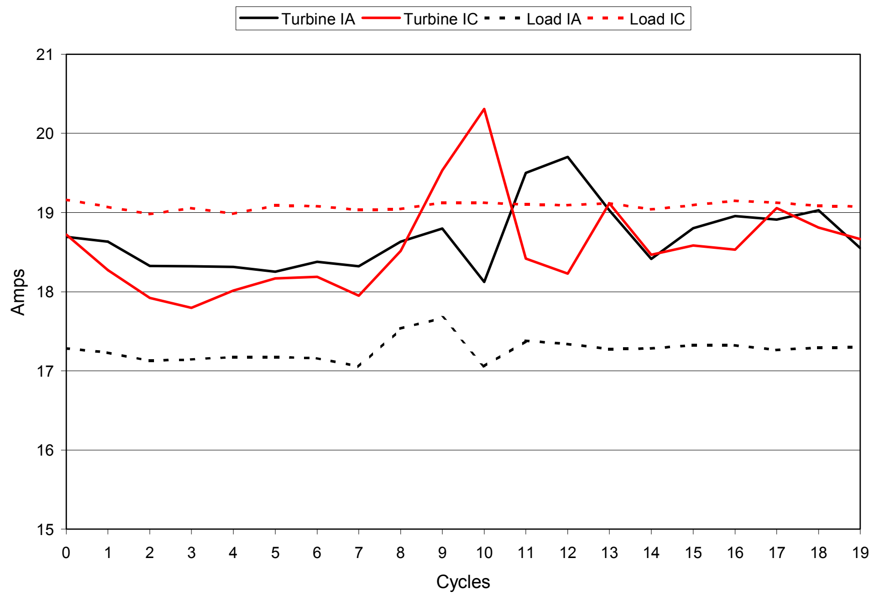


Figure 7-16
Currents for a 10-Cycle Interruption on Phase A with Matched Load Connected to the Generator

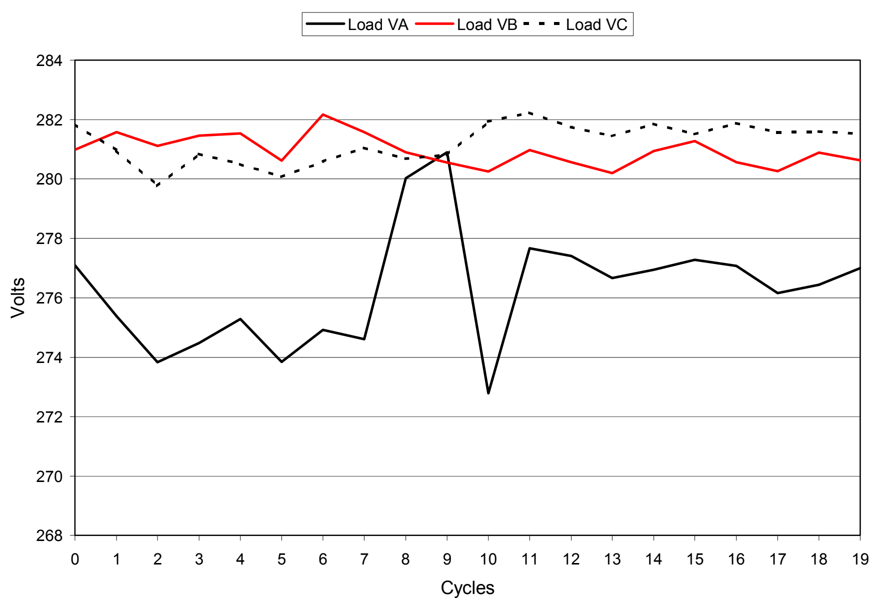


Figure 7-17
Voltages for a 10-Cycle Interruption on Phase A with Matched Load Connected to the Generator

The next test involved setting the generator output to 7.5 kW with the load bank set to 15 kW. Thus, the generator was supplying half of the load. As shown in Figure 7-18 and Figure 7-19, the generator did not trip offline during the 10-cycle outage. The test was repeated with a duration of 120 cycles. As shown in Figure 7-20, the generator tripped after approximately 80 cycles.

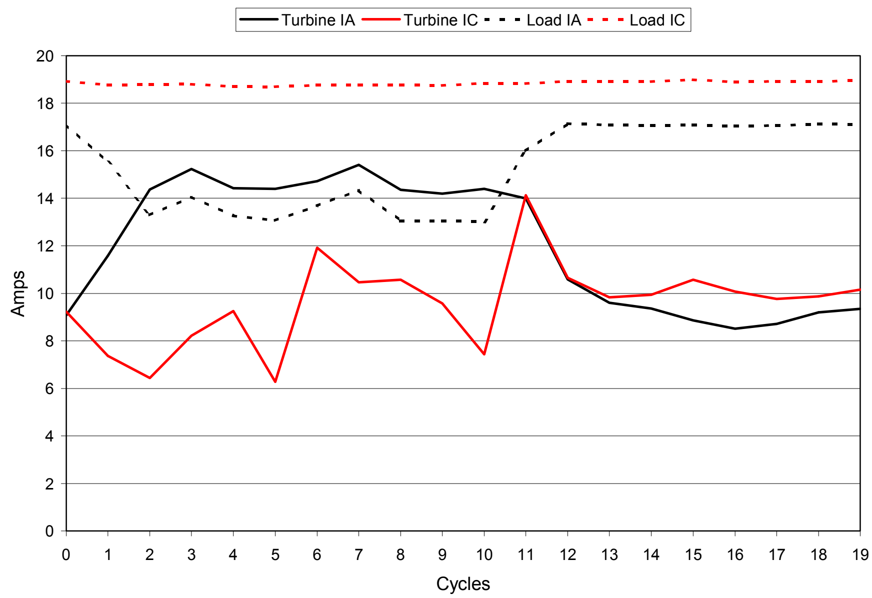


Figure 7-18
Currents for a 10-Cycle Interruption on Phase A with Connected Load Greater than Generator Output

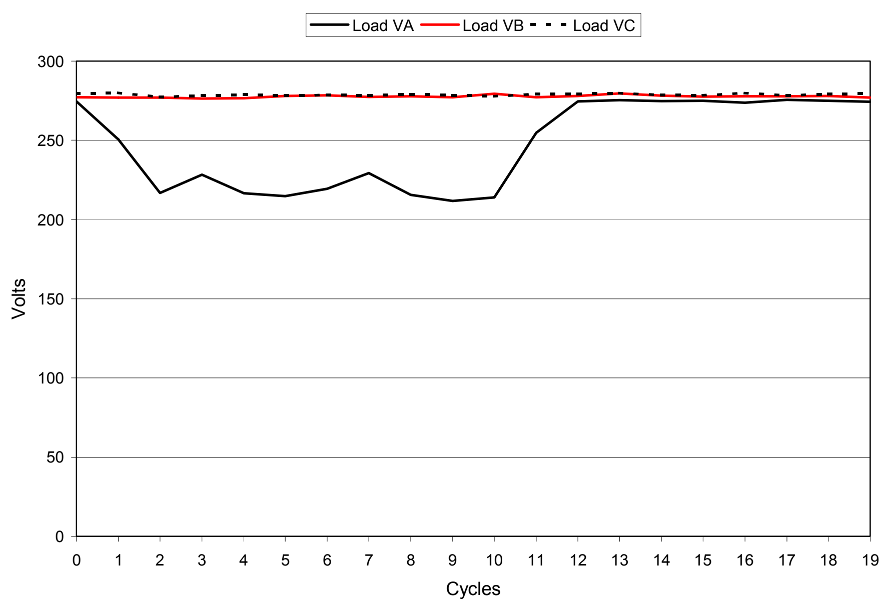


Figure 7-19
Voltages for a 10-Cycle Interruption on Phase A with Connected Load Greater than Generator Output

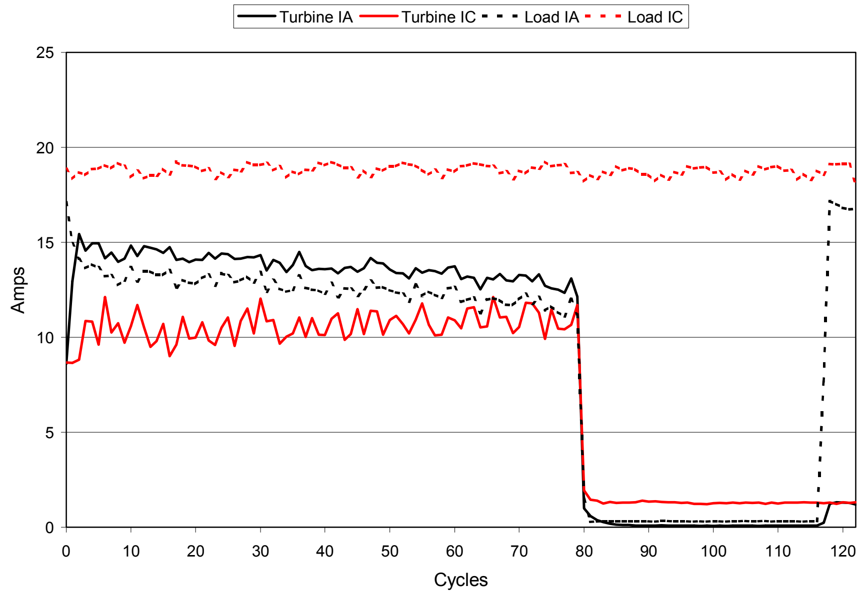


Figure 7-20
Currents for a 120-Cycle Interruption on Phase A with Connected Load Greater than Generator Output

The final test was to set the generator output to 15 kW and the load bank to 15 kW. Both phase A and phase B of the 480-V supply were then interrupted for 10 cycles. As shown in Figure 7-21 and Figure 7-22, the generator did not detect the outage and continued to serve the load. The test was repeated with a duration of 120 cycles. The results are shown in Figure 7-23. The generator tripped after approximately 80 cycles.

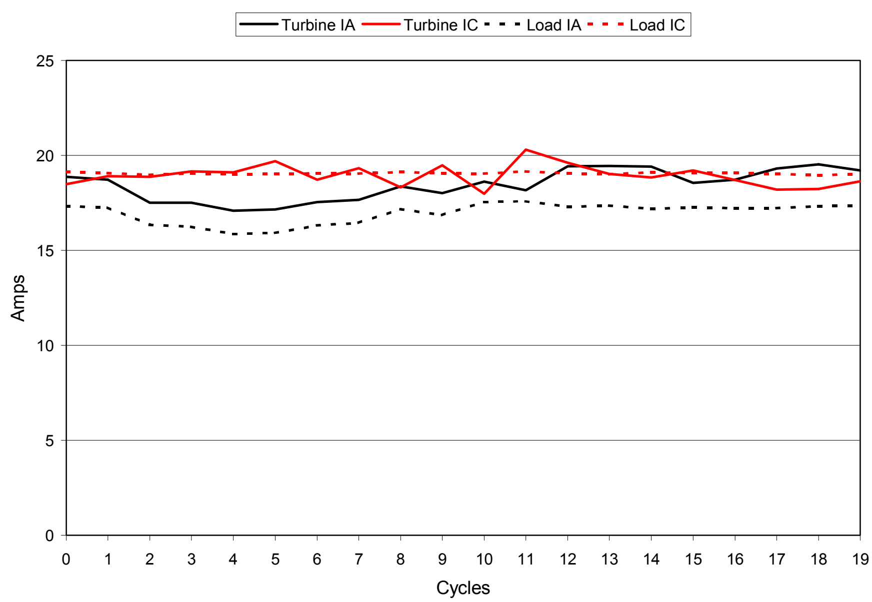


Figure 7-21
Currents for a 10-Cycle Interruption on Phase A and B with Matched Load Connected to the Generator

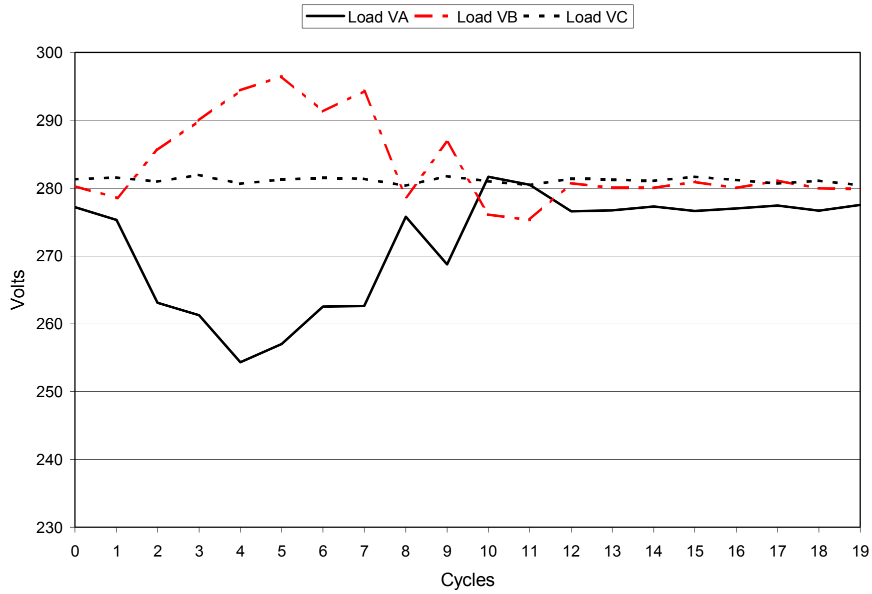


Figure 7-22
Voltages for a 10-Cycle Interruption on Phase A and B with Matched Load Connected to the Generator

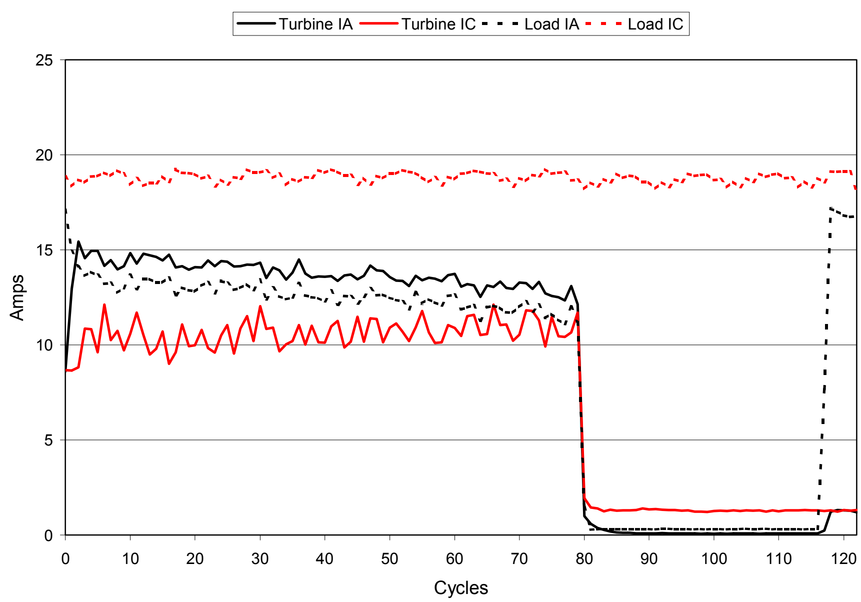


Figure 7-23
Currents for a 120-Cycle Interruption on Phase A and B with Matched Load Connected to the Generator

Conclusions

The response of the generator to various single and multi-phase voltage variations was tested. It was discovered that the type and size of load, both supplied by the generator's protected load contactor and connected upstream of the generator, can greatly affect the response of the inverter relaying to events.

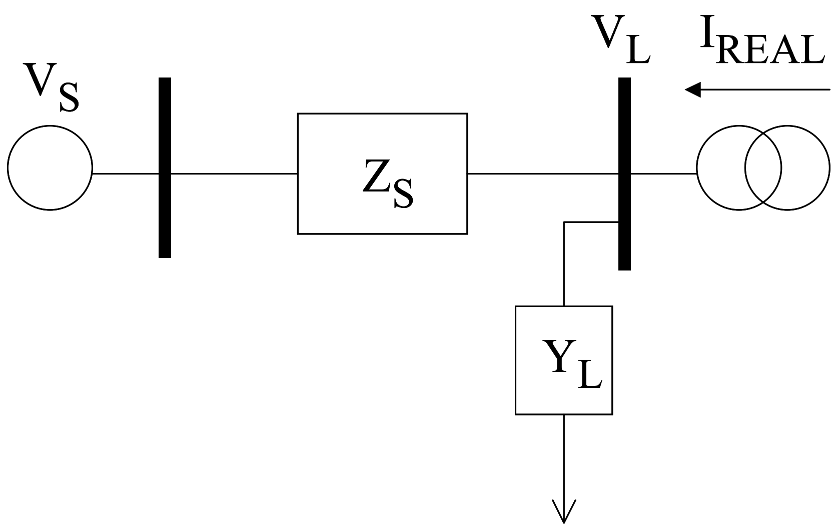
Some of the notable results of the tests are:

- This generator responds to phase-to-phase voltages, not phase-to-ground voltages. It is desensitized to phase-to-ground voltage sags. To overcome this, undervoltage thresholds need to be changed to be more sensitive, or the voltage-sensing circuitry or software needs to be changed to detect phase-to-ground voltages.
- For single-phase interruptions, an unloaded generator trips much more quickly than a loaded generator (either resistive or motor load). When unloaded, the generator generated significant voltage increases on the unloaded phase.
- Under matched-load conditions, the generator was not able to trip quickly because the voltage stayed within relay bounds for some time.

A

SANDIA VOLTAGE SHIFT (SVS) ANTI-ISLANDING CONTROL ANALYSIS

Figure A-1 shows an equivalent circuit that may be used to represent a current-source inverter attached to an AC system. As is often the case, the current source is assumed to inject current that is in phase with the voltage.



Where:

$Y_L = 1/(R_L + j\,X_L)$ is the admittance of the load
$Z_S = R_S + jX_S$ is the source impedance
V_S = is the Thevenin voltage of the source
V_L is the voltage at the current-source inverter and load
I_{REAL} is the current injected by the current-source, which is in phase with voltage

Figure A-1
Equivalent Circuit

Because the current is in phase with voltage, the change in the voltage magnitude due to a small change in current is given by the following equation:

$$\Delta V_L = R * \Delta I_{REAL}$$

Where R is the real part of the driving point impedance seen from the distributed source.

If the inverter is not connected to the network,

$$R = REAL\ (1/Y_L) = R_L \tag{A-1}$$

If the inverter is connected to the network,

$$R = REAL\ (Z_S/(Y_L * Z_S + 1)\ ) \tag{A-2}$$

Or

$$R = (R_S^2 * R_L + R_L^2 * R_S + R_L * X_S^2 + R_S * X_L^2) / ((R_S + R_L)^2 + (X_S + X_L)^2) \tag{A-3}$$

If the load is purely resistive ($X_L = 0.0$) and the source impedance is only reactive ($R_S = 0.0$), this becomes:

$$R \approx X_S^2 * R_L / (R_L^2 + X_S^2) \tag{A-4}$$

If $Z_L > X_S$ and they both have similar X/R ratios,

$$R \approx R_S \tag{A-5}$$

The Sandia SVS technique uses a voltage controller with a positive feedback to vary the magnitude of the inverter AC current. The error in the measured value of voltage is found by subtracting the actual value of voltage from a measured value. The magnitude of the current injected into the AC system by the inverter is incremented by an amount that is proportional to this error signal. The current flowing through the AC network impedance will in turn change the voltage. Figure A-2 shows the control block diagram for the process.

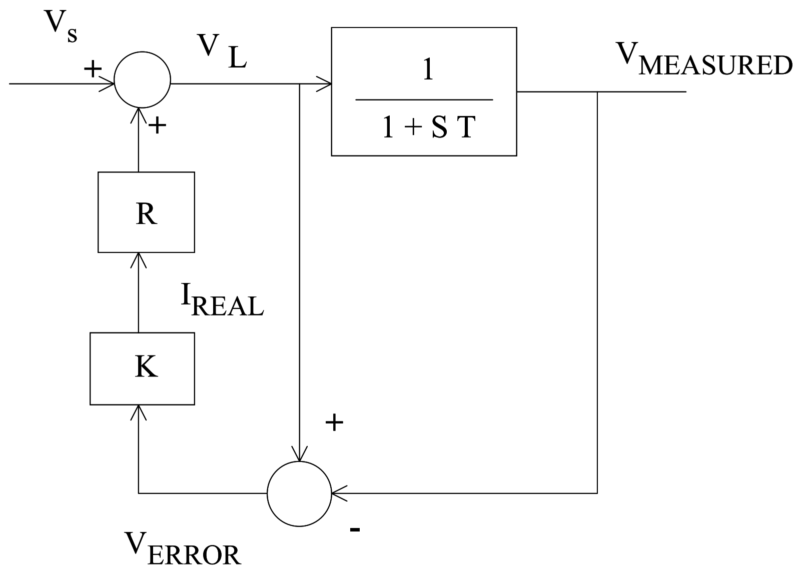


Figure A-2
SVS Voltage Controller and AC System Response

The arithmetic loops in Figure A-2 can be simplified:

$$V_L = V_S + (V_L - V_{MEASURED}) * R * K$$

$$V_L * (1 - R*K) = V_S - R*K * V_{MEASURED}$$

$$V_L = (V_S - R*K * V_{MEASURED}) / (1 - R*K)$$

Figure A-3 shows the block diagram with this simplification.

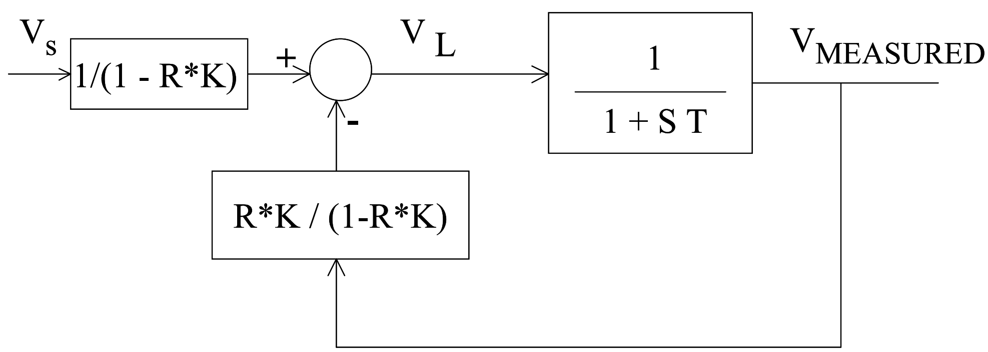


Figure A-3
Simplified SVS Control Block Diagram

The 1/(1+ST) block can be exploded to give the block diagram in Figure A-4.

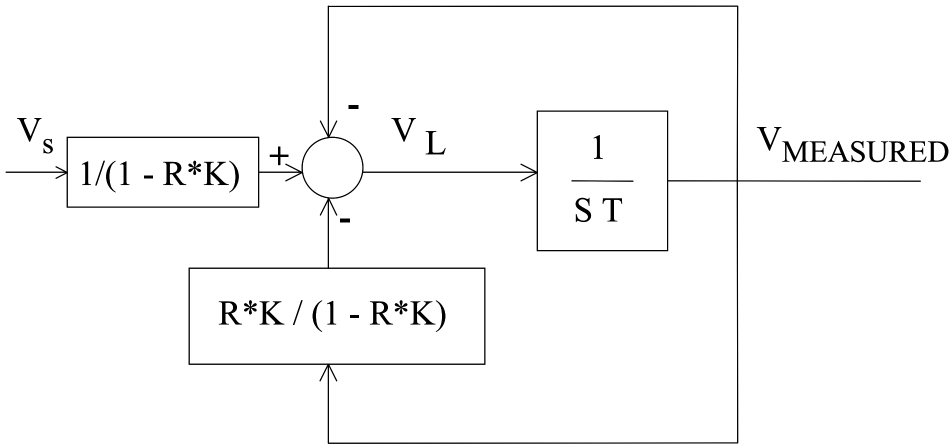


Figure A-4
Exploded SVS Control Block Diagram

It is apparent from Figure A-4 that the net feedback is negative (stable control) if

$$1 + R*K / (1 - R*K) > 0$$

This is true if

$$1 > R*K \text{ (STABLE)} \tag{A-6}$$

The control is unstable if

$$1 < R*K \text{ (UNSTABLE)} \tag{A-7}$$

When the inverter is not connected to the network, the control must be unstable. Substituting equation A-1 into equation A-7 gives

$$K > 1/R_L \tag{A-8}$$

When the inverter is connected to the network, the control must be stable. If the load is purely resistive and the source impedance is only reactive, substitute equation A-4 into equation A-6 to get

$$K < 1 / (X_S^2 * R_L / (R_L^2 + X_S^2)) \tag{A-9}$$

Because normally $X_S << R_L$, this is approximately

$$K< R_L / X_S^2 \tag{A-10}$$

Both equations A-8 and A-10 can be true only if

$$X_S < R_L$$

This will almost certainly be the case in present distribution systems. However, this may not always be the case if as some propose, distributed generation is used to satisfy local loads without upgrading the distribution system.

For stable control when the X/R ratio of the source and load is approximately the same and $Z_L > Z_S$, substitute equation A-5 into A-6 to get

$$K < 1/R_S \tag{A-11}$$

Both equations A-8 and A-11 can only be true if

$$R_S < R_L \tag{A-12}$$

Again, this will almost certainly be the case in present distribution systems. However, this may not always be the case if as some propose, distributed generation is used to satisfy local loads without upgrading the distribution system.

B

LIST OF VENDORS AND URLS

Protective and Control Relay Manufacturers

Company	Address	City	St	Zip	Phone	URL
ABB-Automation	7036 Snowdrift Rd., Suite 2	Allentown	PA	18106	(610) 395-7333	www.abb.com
Alstom USA, Inc.	5 Walnut Lane	Fletcher	NC	28732	(828) 684-3853	www.usa.alstom.com
ASCO Power Technologies LP	50-60 Hanover Road	Florham Park	NJ	07932	(973) 966-2474	www.asco.com
Basler Electric Co.	1822 Chateau Drive, E.	Clearwater	FL	33756	(727) 582-9921	www.basler.com
Basler Electric Co.	P.O. Box 269	Highland	IL	62249	(618) 654-2341	www.basler.com
Beckwith Electric Co., Inc.	6190 118th Avenue North	Largo	FL	33773	(727) 544-2326	www.beckwithelectric.com
Cooper Power Systems	P.O. Box 100 11131 Adams Road	Franksville	WI	53126	(262) 835-5761	www.cooperpower.com
Eaton/Cutler-Hammer	One Tuscarawas Road	Beaver	PA	15009	(724) 773-1326	www.ch.etn.com
GE Industrial & Utilities Systems	215 Anderson Ave	Marckam	Ont	L6E 1B3	(905) 294-6222	www.geindustrial.com/geip/GEIPersEntry
GE Zenith Controls	1 Oak Hill Center, Suite 301	Westmont	IL	60559	(773) 299-6928	www.zenithcontrols.com
Schweitzer Engineering Labs	2350 NE Hopkins Court	Pullman	WA	99163	(509) 332-1890	www.selinc.com/selhome.htm
Siemens Westinghouse Power Corp.	4400 Alafaya Trail	Orlando	FL	32826	(407) 281-2000	www.swpc.siemens.com

Electronic Inverter Manufacturers

Company	Address	City	St	Zip	Phone	URL
AAPS Alternative Power Systems	P.O. Box 6045	San Diego	CA	92058	(760) 724-3777	www.podnine.com/airblade/inverters/statpower/inverter
Abacus Controls	80 Readington Rd	Somerville	NJ	08876	(908) 526-6010	www.abacuscon.com
ABB-Automation	16250 West Glendale Drive	New Berlin	WI	53151	(262) 785-3212	www.abb.com
AC Power Technology, Inc.	18210 Redmond Way, Suite 203	Redmond	WA	98052	(425) 885-7493	www.acpower.com/doc/cond.htm
Active Power (Caterpillar)	3701 State Road	Austin	TX	78701	(512) 836-6464	
Advanced Energy, Inc.	P.O. Box 262	Wilton	NH	03086	(603) 654-9322	www.advancedenergy.com
Capstone Turbine Corporation	21211 Nordhoff Street	Chatsworth	CA	91311	(818) 734-5550	www.capstoneturbine.com
Ecostar Electric Drive Systems	15001 Commerce Drive, N.	Dearborn	MI	48120	(313) 621-6350	www.ecostardrives.com/products2.html
ENRON Wind	13000 Jameson Road	Tehachapi	CA	93581	(661) 823-6700	www.wind.enron.com
Exeltech	2225 E. Loop 820 N	Fort Worth	TX	76118	(800) 886-4683	www.exeltech.com.cnchost.com/system.htm
Institute of Gas Technology (IGT)	1700 S. Mount Prospect	Des Plaines	IL	60018	(847) 768-0500	www.igt.org
Inverpower Controls Ltd.	835 Harrington Court	Burlington	Ont. CA	L7N-3P3	(905) 639-4693	www.inverpower.com
L3 Technologies Inc	901 E. Ball Road	Anaheim	CA	92805	(714) 956-9200	www.powerparagon.com/products.html
Omnion Power Engineering Corp.	P.O. Box 879	East Troy	WI	53120	(414) 642-7200	www.omnion.com
R.P. Electronic Components Ltd.	2060 Rosser Avenue	Burnaby	BC	V5C 5Y1	(604) 482-5201	www.rpelectronics.com
S&C Electric	6601 North Ridge Boulevard	Chicago	IL	60626	(773) 338-1000	www.sandc.com/ped/pwproducts.htm
Semikron Inc.	11 Executive Dr.	Hudson	NH	03051	(603) 883-8102	www.semikronusa.com
Siemens/Westing-house Corp.	1310 Beulah Road	Pittsburgh	PA	15235	(412) 256-2590	www.siemens.com
Soft Switching Technologies	2224 Evergreen Road, Suite 6	Middleton	WI	53562	(608) 836-6552	www.softswitch.com
Statpower Technologies Corp.	7725 Lougheed Highway	Burnaby	BC	V5A 4V8	(604) 420-1585	www.wechselrichters.de/
Sustainable Energy Technologies	Suite 200, 422 – 11th. Ave. SE	Calgary	Alb CA	T2G 0Y4	(403) 508-7177	www.sustainableenergy.com

Trace Technologies Corporation	161-G South Vasco Rd	Livermore	CA	94550	(925) 245-5453	www.oasismontana.com/Trace-SW.html
Trace Technologies Corporation	3547-C Higuera Street	San Luis Obispo	CA	93401	(805) 543-4520	www.oasismontana.com/Trace-SW.html
Visteon Automated Systems	15041 Commerce Dr South, Ste 401	Dearborn	MI	48120	(313) 621-6775	www.visteon.com/technology/systems/energy.html
Xantrex Technology, Inc.	7725 Lougheed Hy	Burnaby	BC	V5A 4V8	(604) 420-1585	www.xantrex.com/xantrex/index.html

Interconnection Support Equipment Manufacturers

Company	Address	City	St	Zip	Phone	URL
ASCO Power Technologies LP	56 Hanover Road	Florham Park	NJ	07932	(973) 966-2474	www.asco.com/
Connecticut Electric Products	19 W. 11th Street	Anderson	IN	46016	(765) 608-3807	www.connecticut-electric.com/6-5000.html
Cutler-Hammer	1 Tuscarawas Road	Beaver	PA	15009	(724) 773-1344	www.ch.cutler-hammer.com/apc/main.html
Cyberex LLC	5335 Avion Park Dr.	Highland Hgts	OH	44143	(440) 995-3200	www.cyberex.cm-d.com/members/products/sts/100_600a/
Delhomme Industries, Inc.	3006 Northside Rd.	New Iberia	LA	70562	(318) 365-5476	www.home.att.net/~kstansbury/meter_base.htm
DynaGen Systems	19 Marlborough Drive	Sydney Nova Scotia	CA	B1S 1W7	(902) 562-0133	www.dynagensystems.com/products/ast.html
Electro Industies Incorporated	2150 W. River St. PO Box 538	Moniticello	MN	55362	800-922-4138	www.electromn.com/products/genconn.htm
ENCORP, Inc.	621 Innovation Circle	Windsor	CO	80550	(970) 686-2017	www.encorp.com
Gen/Tran Corporation	P.O. Box 1001	Alpharetta	GA	30004	(770) 552-1417	www.gen-tran.com
Midwest Electric Products	PO Box 910 Hwy. 22 North	Mankato	MN	56002	(507) 345-2530	www.midwestelectric.com/products/ts/ts.html
PDI	510 Eastpark Court, Suite 150	Sandstone	VA	23150	(804) 737-9880	www.acpower.com/doc/stswitch.htm
Pepco Technologies	1801 K Street NW, Suite 1210	Washington	DC	20006	(202) 775-7361	www.pepcotechnologies.com
Zenith Controls Inc.	830 West 40th St	Chicago	IL	60609	(773) 247-6400	www.zenithcontrols.com

Distributed Generation System Manufacturers

Company	Address	City	St	Zip	Phone	URL
AeroVironment Inc.	222 E. Huntington Drive, Suite 200	Monrovia	CA	91016	(626) 357-9983	www.aerovironment.com
American Superconductor Corp.	2114 Eagle Drive	Middleton	WI	53562	(608) 828-9109	www.amsuper.com/
Ballard Generation Systems	4242 Phillips Avenue, Unit C	Burnaby	BC	V5A2X2	(604) 444-2467	www.ballard.com/
Bergey Windpower Co.	2001 Priestly Avenue	Norman	OK	73069	(405) 364-4212	www.bergey.com/
Bowman Power Systems	20501 Ventura Boulevard, Suite 285	Woodland Hills	CA	91364	(818) 999-6709	www.bowmanpower.com/
BP Solarex	630 Solarex Court	Frederick	MD	21703	(301) 698-4375	www.bpsolarex.com/
Capstone Turbine Corporation	18700 Oxnard Street	Tarzana	CA	91356	(818) 598-5715	www.capstoneturbine.com/
Caterpillar International Power	P.O. Box 610	Mossville	IL	61552	(309) 578-8328	www.cat.com
Caterpillar International Power	3701 State Road	Lafayette	IN	47905	(765) 448-5518	www.cat.com
Caterpillar, Inc.	8300 FM 1960 W., Suite 340	Houston	TX	77070	(281) 677-2528	www.cat.com
Detroit Diesel Corp.	13400 W. Outer Drive	Detroit	MI	48239	(313) 592-5990	www.detroitdiesel.com
Dresser Industries/Waukesha Engine	1000 West St. Paul Ave.	Waukesha	WI	53188	(262) 549-2904	www.waukeshaengine.com
East Penn Mfg. Co. Inc.	Deka Road	Lyon Station	PA	19536	(610) 682-6361	www.svensson.com/public/c000354.html
Elliott Energy Systems, Inc.	2901 S.E. Monroe Street	Stuart	FL	34997	(561) 219-9449	www.elliott-turbo.com/
Fuel Cell Energy	3 Great Pasture Road	Danbury	CT	06813	(203) 825-6068	www.ercc.com/products.html
GE Corporate R&D	P.O. Box 8	Schenectady	NY	12309	(518) 378-5516	www.gepower.com
GE Distributed Power Systems	1 River Road, Bldg 59E-1	Schenectady	NY	12345	(800) 443-3278	www.gepower.com
GENERAC Power Systems, Inc.	Hwy. 59	Waukesha	WI	53186	(262) 968-2561	www.generac.com/corporate/index.cfm
GNB Technologies (Exide)	829 Parkview Blvd.	Lombard	IL	60148	(630) 629-5200	www.gnb.com/index.html
H Power Corporation	1373 Broad Street	Clifton	NJ	07013	(973) 450-4400	www.hpower.com
H Power Enterprises of Canada, Inc.	1069 Begin	St-Laurent	CA	H4R 1V8	(514) 956-8932	www.hpower.com
Hamilton Sundstrand	4747 Harrison Avenue	Rockford	IL	61125	(815) 226-2750	http://www.hamiltonsundstrandcorp.com/Aerospace/electric/electric.htm
Honeywell Power Systems	8725 Pan American Freeway	Albuquerque	NM	87113	(505) 798-6031	www.honeywell.com/
Honeywell Power Systems	2525 W. 190th Street	Torrance	CA	90504	(310) 512-4178	www.honeywell.com
Kohler Co.	N7650 County Trunk	Sheboygan	WI	53083	(920) 459-1651	kohlerco.com/powersystems/generators/home.html
M-C Power Corporation	8040 S. Madison Street	Burr Ridge	IL	60521	(630) 986-8040	apollo.osti.gov/html/fe/mcpwr.html
McDermott Technology	PO Box 11165	Lynchburg	VA	24506	804-522-6743	www.mcdermott.com
Modular Cogeneration Corporation	10209 Menlo Avenue	Silver Springs	MD			none found

Mosaic	1700 S. Mount Prospect Road	Des Plaines	IL	60018	(847) 768-0842	none found
Northern Power Systems	182 Mad River Park	Waitsfield	VT	05673	(802) 496-2955	www.northernpower.com
ONSI Corporation	195 Governor's Highway	South Windsor	CT	06074	(860) 727-2325	www.onsicorp.com/index/fl.htm
Plug Power Inc.	968 Albany Shaker Road	Latham	NY	12110	(518) 782-7700	www.plugpower.com/home.cfm
Power Works (Ingersal Rand)	32 Exeter St	Portsmouth	NH	3801	(603) 512-1724	www.powerworks.com
Siemens Westinghouse Power Corp.	4400 Alafaya Trail, MC 381	Orlando	FL	32826	(407) 281-2500	www.siemens.com
Solar Turbines, Inc.	P.O. Box 85376 2200 Pacific Highway	San Diego	CA	92186	(858) 694-6000	www.cat.com/products/solarturbines/solarmain/solarmain.html
SONAT Power Systems, Inc.	P.O. Box 2563	Birmingham	AL	35202	(205) 327-2340	www.sonat.com/home/sps/product5.htm
Trigen Energy Corp.	650 S. Clinton Avenue	Trenton	NJ	08611	(609) 396-1892	www.trigen.com
Trigen Energy Corp.	One Water Street	White Plaines	NY	10601	(914) 286-6691	www.trigen.com
U.S. Fuel Cell Council	1625 K Street, NW #790	Washington	DC	20006	(202) 293-5500	www.usfcc.com/

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