EPRI

Power Quality Distributed Generation Workbook

Technical Report

Power Quality Distributed Generation Workbook

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PRODUCT DESCRIPTION

Many distributed generation (DG) applications are naturally benign—either they are small relative to distribution system capabilities or they have other characteristics that make difficulties less likely. Some DG applications, however, can prove problematic. This report, EPRI's third in a series, provides a workbook designed to address the most common power quality impacts associated with grid-connected DG applications. The workbook refines and simplifies procedures developed in EPRI report 1000405, Power Quality Impacts of Distributed Generation, adding real-world examples that illustrate the application of each procedure. EPRI anticipates wide usage of this unique industry tool.

Results & Findings

Workbook screening sections will help engineers determine whether power quality issues associated with DG application could pose difficulties or require additional study. Following the screening sections, step-by-step procedures and examples will assist in analyzing existing problems or preventing their occurrence in the first place. Specific power quality categories assessed include transient and temporary overvoltages, steady-state voltage regulation, and momentary interruptions. The workbook also covers dynamic impacts, including voltage flicker, stability, and self-excitation.

Challenges & Objectives

The objective of this workbook is to provide clear, straightforward solutions to power quality problems caused by integrating generation into distribution systems. The main challenge in creating such a workbook involved developing procedures that are sufficiently simple for quick evaluations yet comprehensive and accurate enough to address the majority of scenarios.

Applications, Values & Use

This workbook is intended for utility distribution planning engineers, protection engineers, field engineers, and power quality engineers. The procedures provided effectively address 75 to 90 percent of distributed generator applications. However, for some generators—especially large units or groups of units—detailed studies are needed. Such studies may include relay coordination studies, fault-current analyses, load-flow studies, and stability analysis. When issues clearly require more detailed computer analysis or monitoring, the workbook provides pointers on where to begin.

EPRI Perspective

This concise workbook provides utilities with clear procedures and calculation worksheets for evaluating the impact of distributed generation on grid power quality. A key troubleshooting tool, the workbook will help utilities protect their distribution systems against power quality problems, resolve existing problems more quickly, and better advise end-users who are considering or are already applying distributed generation. In addition, the workbook will increase industry understanding concerning the impact of DG technologies on power quality, while amending misconceptions about the inherent power quality benefits of such technologies.

Approach

The project team identified the most common and significant power quality issues associated with the integration of distributed generation. For each major issue, they developed guidelines and calculation procedures, providing background material and important assumptions. Next, they described the procedures in a step-by-step workbook format. Finally, they developed real-world examples illustrating the application of each procedure.

Keywords

Power Quality
Distributed Generation
Distributed Resources
Overvoltages
Momentary Interruptions
Dynamics

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HOW-TO GUIDELINES

Introduction

This report is the third in a series of reports on the power quality impacts of distributed generation (DG). The two earlier reports are:

- EPRI 1000405: *Power Quality Impacts of Distributed Generation,* 2000
- EPRI 1005917: *Distributed Generation Relay Impacts on Power Quality,* 2001

The 2000 report covered a broad range of topics from harmonics to flicker to overvoltages to voltage sags. Its main conclusion was that the impact of DG on power quality will be neutral at best, and as DG becomes a significant portion of the distribution feeder load, it could have a negative impact. If distributed generators are not interconnected properly, several scenarios can degrade the power quality on a distribution circuit.

This report is a workbook that addresses the most problematic power quality problems that distributed generation might cause. The main topics covered are:

- Chapter 2: Control of steady-state voltages, especially high voltages.
- Chapter 3: Temporary overvoltages, perhaps the biggest concern with DG.
- Chapter 4: Momentary interruptions: DG makes interruptions more likely.
- Chapter 5: Dynamic issues: stability, self excitation, and more.

Within each chapter, specific problems are addressed. Most of the chapters start with a screening section to get a first cut at whether the given issue could be a problem. The screenings are designed to determine when an issue needs more study. Many generator applications are naturally benign; either they are small relative to the capabilities of the system or have other characteristics that make problems less likely. Following the screenings, several topics and procedures are described in each chapter. Within each topic, background is provided, and then clear sets of procedures give direction on how to analyze the problem and how to make sure the problem doesn't happen. Then, most topics have examples on how to apply the given procedures.

Relatively simple procedures as described in this workbook may cover 75 to 90% of the distributed generator applications. However, for some generators, especially large units or groups of units, detailed studies are needed. This can include relay-coordination studies, fault-current analyses, load-flow studies, and stability analysis. Where issues require a more detailed computer analysis or monitoring, pointers are given on where to start.

Summary of Power Quality Issues

Overvoltages

The most troubling power quality problems relate to overvoltages. Whether transient or steady-state, overvoltages are relatively uncommon on most distribution systems, but adding distributed generators adds several new scenarios where overvoltages can occur. The following scenarios increase the risk to utility equipment and to end-use customer equipment (also see Figure 1-1):

- **Steady-state overvoltages**—Because generators inject power into the distribution system, this power injection through the system impedance can cause a voltage rise along the circuit. Larger generators on weak distribution systems are most likely to cause problems.
- **Regulator interaction**—If a generator causes reverse power through a bi-directional regulator, the regulator control will be confused into thinking that the utility source has switched directions and will try to change the source-side voltage. Because the regulator cannot actually change the source-side voltage, the regulator will ratchet all the way to its extreme positive or negative tap. This can cause either very high or very low voltages.
- **Islanding overvoltages**—When a generator and a section of load separate from the utility source, overvoltages can occur. If the generator is bigger than the load on the circuit, it will naturally start to raise the voltage and increase the frequency. And if a generator is not effectively grounded, it can cause overvoltages on the island if one phase faults to ground. Without the utility ground source present, the neutral can float. This can cause high phase-to-neutral voltages. This workbook has several procedures for reducing the risks of overvoltages during islanding. Transformer connections, relay application, and grounding are all addressed.
- **Self-excitation**—Another overvoltage scenario can occur if generators are islanded with capacitance. Both induction generators and synchronous generators can resonate with this capacitance and cause high system voltages.

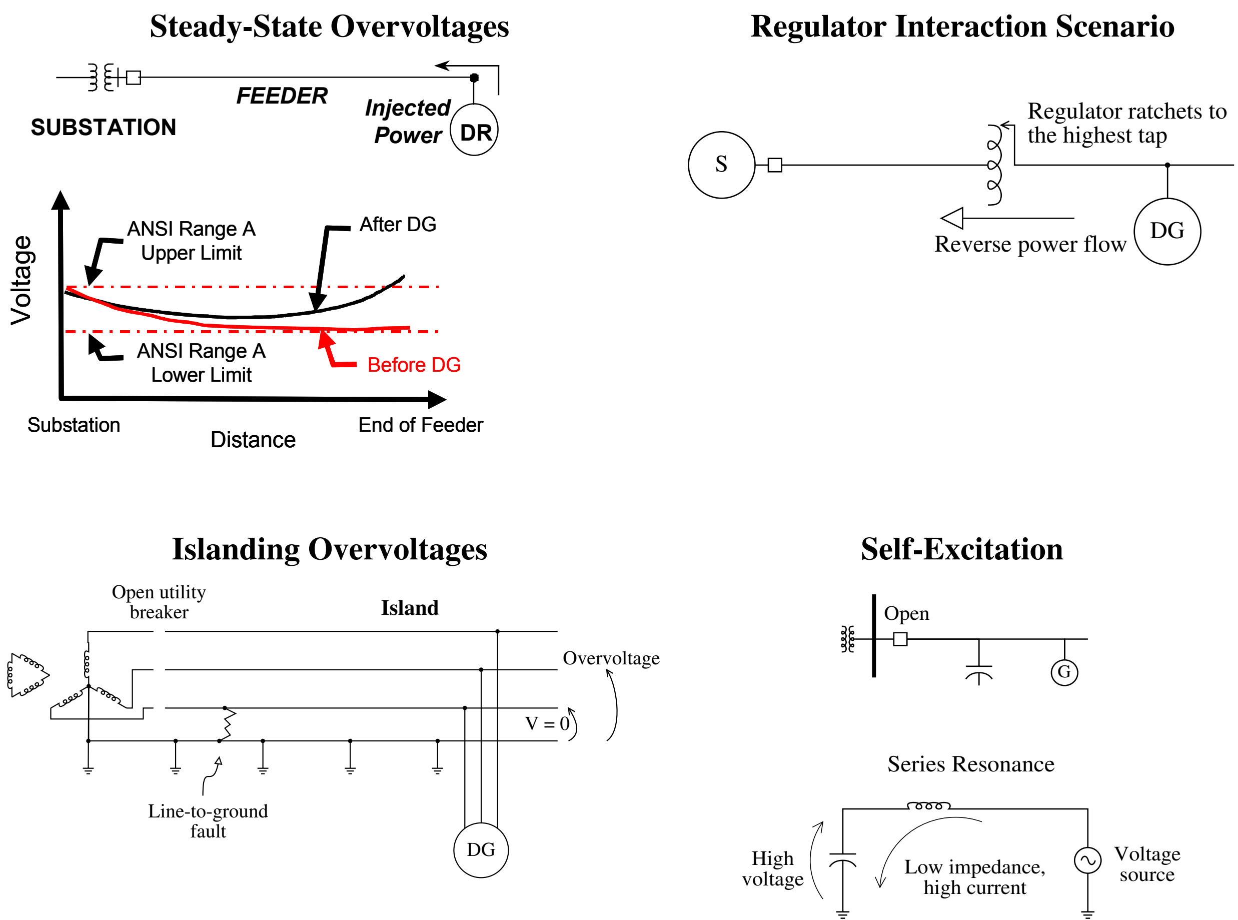

Figure 1-1
DG-Caused Overvoltage Scenarios

Undervoltages

Distributed generators can interfere with the operation of voltage regulators and cause low voltages. A generator just downstream of a regulator can "trick" a regulator into thinking that there is less load downstream than there really is. The regulator does not boost the voltage enough, so points downstream can have low voltage. Additionally, with a bi-directional regulator, reverse power flow can make the regulator ratchet all the way to the lowest tap, causing very low voltages.

Voltage Flicker

Several types of generators have varying power output that can cause voltage flicker; the worst are:

- **Wind turbines**—Changing wind speeds will lead to changing power output. The power output can change cyclically as the rotor blade passes the tower. The frequency of fluctuation is the rotation speed, which may be on the order of 1 Hz. This leads to modulation of power and the line voltage. Larger power swings can occur on the order of a few seconds due to changes in wind level.

- **Internal combustion engine**—An internal combustion engine can create a rapidly changing power output if it is misfiring. This can happen if the engine is operating on low-grade fuel or landfill gas or is not tuned properly. This type of fluctuation is especially noticeable because it usually occurs rapidly and can be near the most sensitive frequencies of the flicker curve.
- **Induction generators**—If an induction generator does not have self-starting capability, starting an induction generator is the same as starting an induction motor: Large inrush currents averaging about 5 times full-load current are drawn from the system. When the generator is large compared to the utility system, the utility voltage will sag for several cycles during starting. This can result in objectionable light flicker, depending on the frequency of motor starts.

Flicker will generally be worse closer to the fluctuating generator. Flicker will be more pronounced when the fluctuating generator is relatively large compared to the electric power system at the point of common coupling. On distribution systems, long rural feeders with a large fluctuating generator near the end would be the most susceptible to flickering lights. Also, lower-voltage circuits that may experience relatively higher voltage changes with changing generation and load are more prone to flicker.

Momentary Interruptions

Generators can increase the number of interruptions, both momentary and permanent. By supplying fault current to distribution-feeder faults, distributed generators interfere with the coordination of utility protective devices. Figure 1-2 shows common scenarios where this could happen. If a generator is connected as a grounded connection, some generators can supply significantly more ground-fault current. This can upset sensitive ground relays on reclosers or breakers. The presence of large distributed generators can also force utilities to extend their reclosing delay on breakers and reclosers to reduce the chance that the utility interrupter closes back in on an out-of-synch generator. This extra delay impacts customers by extending the duration of momentary interruptions: Customers have more blinking clocks.

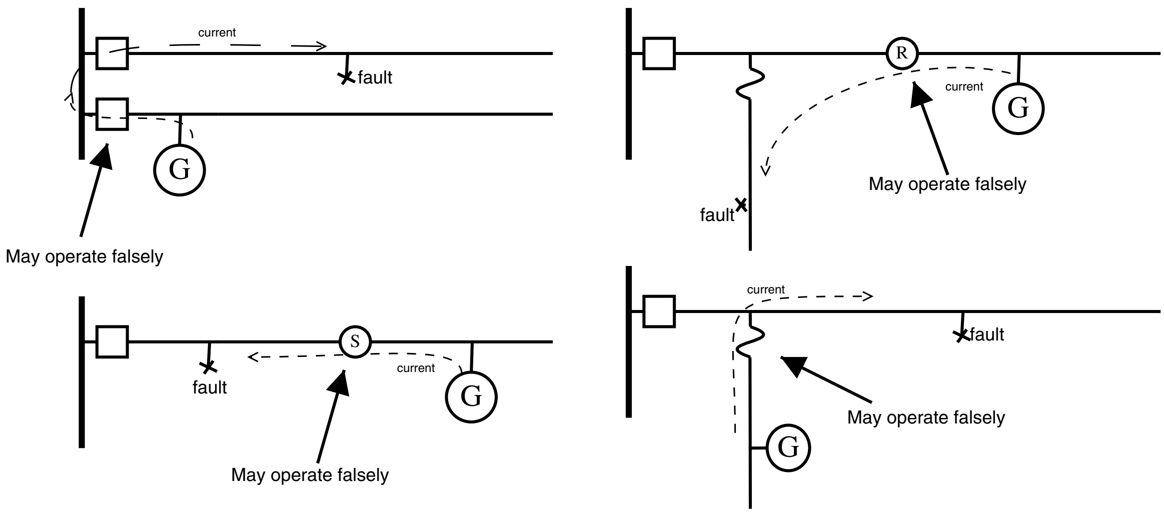

Figure 1-2
Scenarios Where Distributed Generators Can Increase Interruptions by Falsely Tripping Protective Devices

Issues Not Covered in This Workbook

This workbook only covers the highest-risk and most common power quality problems that can occur when distributed generators connect to distribution systems. Distributed generators can cause other power quality problems. Some of these are described below with pointers on where to go for more analysis.

Harmonics

Several types of distributed resources will inject significant harmonics into the system. These include:

- **Synchronous (especially salient pole) and induction generators**—Mostly 3rd harmonic.
- **Single-phase line-commutated inverters—**mostly low-order odd-numbered harmonics will be created, beginning with the 3rd harmonic.
- **Three-phase line-commutated inverters**—Mostly low-order odd-numbered harmonics will be created beginning with the 5th harmonic and similar in magnitude to adjustable-speed drives, with decreasing amounts of 5, 7, 11, 13, 17, 19, and so on.
- **Pulse-width-modulated inverters**—These inverters do not contain significant low-order harmonics, but they do contain higher-order harmonics around the switching frequencies (1 to 10 kHz).

Most DG interconnection requirements strictly limit DG harmonics. In addition, most DG technologies create much less harmonics than adjustable-speed drives, computers, or other electronic loads. So in most cases, distributed generators will not cause harmonic problems.

Where cases require further study, refer to (1) EPRI 1000405: *Power Quality Impacts of Distributed Generation,* 2000, (2) EPRI 1000419: *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems*, 2000, and (3) the draft or final version of IEEE 1547: *Standard for Interconnecting Distributed Resources With Electric Power Systems*.

Voltage Unbalance

Some generators have natural balancing action of some DG connections. When a generator draws unbalanced current because of voltage unbalance on the system, this naturally tends to balance the voltages more than they would have been otherwise. A grounding transformer connection (grounded-wye delta) will reduce the zero-sequence component of the unbalance. Synchronous and induction generators have low negative-sequence impedance, so they can reduce the negative-sequence voltage. Generators are unlikely to cause voltage unbalance. For more information, refer to EPRI 1000405: *Power Quality Impacts of Distributed Generation*, 2000.

Voltage Sags

Of course, voltage sags are a critically important power quality issue. But, DG impact on voltage sags is minor. Distributed generation can actually provide a voltage boost during sags. One important aspect related to sags is that they can trip off DG, especially if the trip settings are sensitively set. This is discussed in Chapter 5. For a detailed analysis of voltage sags, refer to EPRI 1000405: *Power Quality Impacts of Distributed Generation*, 2000.

Initial Screening

Many of the screening procedures in this workbook are good for the initial analysis necessary to respond to interconnection inquiries. These raise flags to identify where additional study is needed. Some important questions to ask during screening are:

- *How big is the generator relative to the system?* Larger generators are more likely to cause power quality problems. This is normally characterized based on the ratio of the generator rating to the short-circuit capability of the system without the generator or as the ratio of the short-circuit capability of the generator to the short-circuit capability of the system. Flicker, interference with utility protective devices, probability of upsetting voltage regulation—all are a function of generator size relative to the system.

  If $I_{SC}/I_L < 30$, more analysis is definitely recommended (where I_{SC} = the system short-circuit capability at the point where the generator connects to the system, and I_L = the current output of the generator at its rating). For example, on a 12.47-kV circuit where the available fault current is 1000 A, a generator with a load current larger than 33 A (720 kVA, three phase) should have more detailed interconnection analysis. On a 24.94-kV circuit where the fault current is 4-kA, the threshold is 133 A (just under 5.8 MVA).

And, any time the rated power output of the generator is within 30% of the estimated minimum load on a possible islanded area, more study is warranted.

- *Will the generator export power into the system?* If the generator will not export power, then power quality issues are less likely.
- *Is the existing transformer connection suitable? What other options are there?* Generator interconnection transformer connection is an important criterion for three-phase generators. A grounded connection helps prevent overvoltages during islanding, but this connection feeds ground faults, which may cause more interruptions by falsely operating protective devices.
- *Is the generator going to operate on a secondary-networked distribution system?* If so, power quality problems could be severe. If a generator causes reverse power flow on network protectors, they will all trip off-line, causing an interruption to customers that otherwise have extremely reliable power. DG on secondary networks needs careful analysis if the generation exceeds 5 to 10% of the minimum load on the network. This is beyond the scope of this workbook; for additional information, see EPRI 1000419: *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, 2000.
- *Are there other generators on the system?* Many power quality problems are a function of the cumulative amount of distributed generators. On a circuit with additional generators, the effect of the total amount should be considered.

Interconnection Planning

Actually planning for a distributed generator interconnection requires more detailed analysis. Some of the most critical power-quality issues are:

- **Grounding—**For three-phase generators connected to four-wire multi-grounded primary distribution systems, check that grounding is compatible. If the generator is ungrounded, it can cause overvoltages. To solidly ground the generator and connection, use a grounded-wye connection on the primary side of the interconnection transformer. For the secondary side, use a delta or a grounded-wye connection if the generator is also grounded. If a grounded generator interconnection is not possible, use appropriate relaying to reduce the risks of islanding overvoltages. Use the “Islanding Overvoltages” section of Chapter 3 for analysis.
- **Nuisance tripping of protective devices—**If generators are situated where they can provide fault current that can trip protective devices, a coordination analysis is needed.
- **Wind or low-speed internal combustion engine—**Check for the possibility of flicker. If a diesel generator gets its fuel from methane recovery or another low-grade fuel source, pay special attention to flicker. Flicker can come and go as the quality of the fuel changes.

The screenings and analysis procedures provided in this workbook should cover at least 80% of the power quality issues associated with interconnecting generators. But some generator applications will require more analysis, possibly quite detailed analysis. These special situations could include very large generators or groups of generators, DG applied on networks, generators wired to provide intentional islanding, or generators applied on very weak systems (low voltage or at the end of rural systems).

Commissioning

At commissioning, tests and measurements should confirm that generators are connected properly, are operating properly, and are unlikely to cause power quality problems.

With the generator at full power, use a power quality meter to measure and check the following:

- *Voltage*—Make sure that the voltage is within ANSI C84.1 on all three phases (both phase-to-phase and phase-to-ground).
- *Harmonics*—Make sure that the generator meets IEEE 519 requirements.
- *Flicker*—Make sure that voltage flicker is not occurring.

If power quality problems are identified, refer to the appropriate section in this workbook for more analysis.

Another important test on generators is to make sure that the anti-islanding relaying is working properly. Proper anti-islanding protection is essential for protecting against power quality problems during islanding. With generators protected by utility-grade relays, testing is straightforward with standard relay test sets. Testing is more difficult to do with inverter-based relays that use built-in logic to perform relay functionality. For a step-by-step procedure, see EPRI 1005917: *Distributed Generation Relaying Impacts on Power Quality*, 2001. The main steps in this test are a generator disconnect test (trip the closest upstream disconnect switch). Optional extended tests include matched-load disconnect (match the generation to the load and then trip the closest upstream disconnect switch), a reverse power test if required, and a single-phase disconnect test. These tests are still inadequate for fully testing inverter-based relays.

Tracking Down Power Quality Problems That Might Be Due to Distributed Generators

Customer power quality complaints often occur due to many causes both on the utility side and the facility side. Sometimes these might be associated with distributed generators, either generators at the facility or other generation connected to the same circuit as the facility. Repeatable or continuous scenarios are the easiest to track down; these often include harmonics, flicker, and steady-state voltage issues. Some approaches to tracking down continuous problems includes:

- **Measurements—**We can use measurements to follow the problem to its source. At the generator, we can measure for harmonics, power output fluctuations, and unbalance. Steady-state voltages can be measured at several points to estimate where the problem voltage drop or rise is occurring.

- **Turn off the DG—**If DG is suspected, turn the DG on and off and watch the result. This provides an almost immediate answer as to whether the DG plays a role in the problem.

If power quality problems are intermittent, then the detective work becomes more difficult. If equipment is dropping out for an unknown reason, then we have to start searching for possible problems and correlations. Some questions to answer include:

- Does the problem occur only when the generator is online?
- Are any of the problems associated with starting the generator or stopping the generator?
- Are there capacitors nearby that could be interacting with the generator?
- Are the generator's fuel supply and power output stable?
- Do problems tend to occur during storms?
- Does the timing of problems correlate with operations of utility protection equipment? If so, check to see that the generators are not making them false trip.

Finding and fixing power quality problems can require a good bit of detective work, especially for intermittent equipment dropouts.

2
VOLTAGE REGULATION ISSUES ASSOCIATED WITH DISTRIBUTED GENERATION

Background

Voltage-regulation practice must account for all of the potential voltage variations that can occur. This includes the varying input voltages to substations caused by voltage variations in the transmission system, voltage drops across substation transformers, voltage drops along primary feeders and laterals, voltage drops at distribution transformers, and voltage drops in the secondary and service conductors leading up to the point of customer service. The point of customer service is usually the meter, and the utility attempts to deliver voltage within the ANSI Range A service-voltage range at this point.[1] Additional voltage drop is expected after the meter along customer wiring up to the utilization point. Therefore, ANSI also specifies the utilization voltage, which is a bit lower than the service voltage. Utilities are not responsible for utilization voltage; however, DG systems must deal with it because they are often deep within customer facilities. DG installations need to work properly over the full range of utilization and service voltages that are possible because they may be installed anywhere at those points.

For radial power systems, voltage-regulation practice is based on a single source of power (the substation) and the power taking only one path from the substation to all loads on the system. This condition leads to the assumption that the voltage will always drop on the primary feeder as the distance from the substation increases. The only exception to this assumption is when there is too much reactive compensation (this will cause a rise in voltage as one moves towards a capacitor bank). Utilities are careful to avoid this condition, so the assumption that voltage drops is a good one for most applications. The condition of radial flow also implies that the voltage (on a per-unit basis) will drop across each distribution transformer and secondary service. DG introduction into the radial distribution system will impact both of these basic assumptions used for voltage-regulation practice.

Switched-capacitors are another voltage-control tool used on distribution circuits. Capacitor banks, which are connected phase-to-neutral or phase-to-phase, increase feeder voltage when they are switched on. For those not familiar with this concept, it seems contrary to intuition that a device that draws current will increase voltage when it is switched on. However, the increase in voltage is mainly caused by the flow of capacitive-reactive current back through the inductive

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[1] ANSI C84.1-1989, American National Standards for Electric Power Systems and Equipment—Voltage Ratings (60 Hz).

reactance of the distribution system. Because the capacitive current leads the voltage by 90 degrees and because the voltage across an inductance leads by 90 degrees, the voltage "drop" vector, due to the capacitive current, ends up being 180 degrees out of phase with the normal resistive drop vector and so becomes "additive" (the voltage rises when the capacitor is switched on). By switching capacitors on at periods of peak load and switching them off at light load, utilities are able to improve the voltage regulation on distribution circuits. Capacitor controls based on voltage, current, or VARs have the possibility of interaction with other regulating equipment or loads on the circuit. Distributed generation adds another major classification of devices that can cause unwanted interaction.

Distributed resources can influence the voltage regulation of electric power systems. This influence will occur whether or not a DG is regulated voltage or whether it is operating in a "voltage following" mode. This is because any device that influences the flow of power on the distribution system will have an impact on voltage drops occurring across impedances in the system, and this will result in changes in voltage at various points on the system. Whether or not these changes are significant and/or of a beneficial nature or pose a problem depends on a number of factors, including the size of the generator relative to the impedance of the power system at the point of application, the way in which the generator is operated/controlled, and the nature of the upstream voltage-regulation equipment (such as load tap changer [LTC] transformers, line voltage regulators, and switched capacitors). DG can provide "support" of voltage. It can also lead to "high" or "low" voltages that are outside the required normal operating range.

This chapter provides a tool to screen a distribution feeder and DG application for impacts on feeder voltage regulation. Various examples are explored to illustrate interactions between DG and line voltage regulators. In addition to primary regulation issues, a simplified approach to determining the effects of a DG on a secondary system is provided.

Screening for DG Impact on Voltage Regulation

Background

Power distribution systems are mainly limited in their capacity to serve load due to either thermal limits or voltage-drop limits. When a system is said to be *thermally limited,* it means that as loading on the system increases, the lines and equipment (such as transformers) will reach their maximum allowable temperature before the voltage drop on the system causes the voltage to deviate outside the acceptable operating range. Thermal limits are determined by factors such as the annealing temperature or sag clearance limit for overhead conductors or the temperature rise limits of insulation in cables and transformers where significant loss of life or damage occurs. Most urban distribution circuits or shorter suburban circuits are thermally limited due to the relatively short feeder lengths and correspondingly smaller voltage drops on such systems.

When a system is *voltage-drop limited*, it means that as loading increases, the voltage eventually deviates outside of the normal range before the thermal limits of the conductors or other equipment are reached. Voltage limits are typically defined as the loading level at which the voltage deviates outside the ANSI C84.1 Range A limits. Many rural distribution circuits are voltage-drop limited because they have long feeders with considerable voltage drop.

Several screening modules were presented in EPRI's *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems* (1000419). These describe basic checks to determine whether either a thermal or voltage limit is likely to be exceeded in any DG application. This is done through various aggregate capacity checks, stiffness ratio tests, comparison of DG output to existing load on the system, and other tests. A DG application that passes the screening should generally not cause a problem with either a voltage or a thermal limit. It should be noted that, unlike the typical case of loads on a distribution system, which lead to line-voltage drop, DG has the potential to raise voltage by injecting power back into the system. So the screening tests must address high-voltage concerns (voltage-rise limits) as well as low-voltage concerns (voltage-drop limits) caused by DG.

Procedure

This screening provides a tool to check distributed generation (DG) installations for characteristics that are known to impact voltage regulation or interact with voltage-regulating equipment. It is should not be considered foolproof and is most certainly not a substitute for an interconnection study.

- To determine whether distributed generation-caused voltage-regulation problems may result from the installation under consideration, navigate the flowchart in Figure 2-1.
- A result of Pass indicates that the installation does not possess any typical characteristics that can lead to voltage-regulation problems. However, it is possible regulation problems may still occur.
- The conclusion for further system study is based on the presence of one or more system characteristics that suggest voltage-regulation problems may result if the proposed generations system is placed into operation.

In preparation for using the flowchart, the following steps should be taken:

Sketch a one-line diagram of the distribution feeder where the DG is to be placed.

Note on the one-line diagram:

- Location of all regulating devices
- Location of DG
- Location of the point of common coupling (PCC) for the DG as defined by IEEE 519

At the PCC, determine:

- Available fault current
- Typical per-unit voltage levels

Determine rated output current of the DG.

Determine peak load current at nearest source-side regulating device.

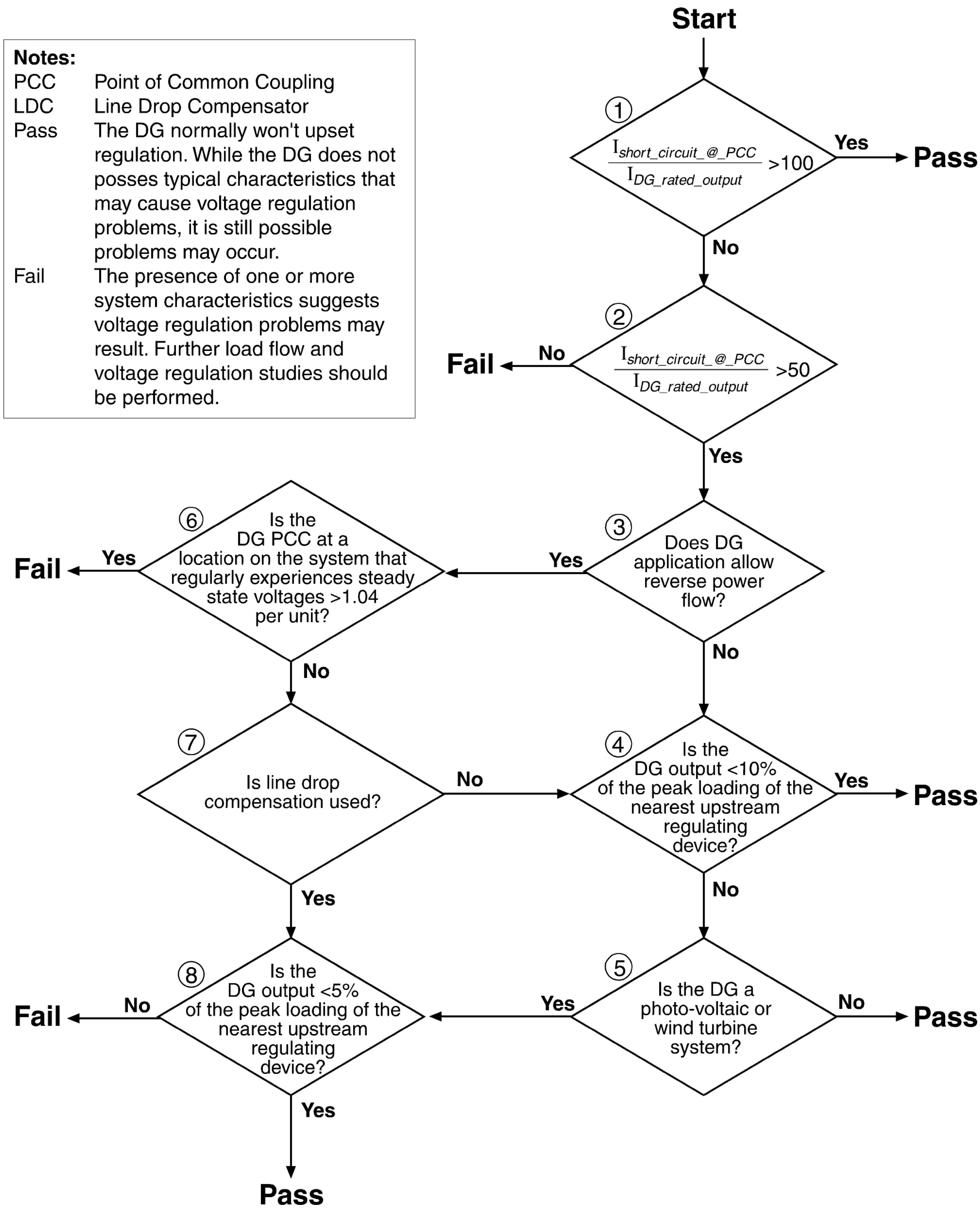

Figure 2-1
Screening Module and Tests for DG Impact on Voltage Regulation

Example

A food-processing plant wishes to install a gas turbine synchronous generator to provide process heat for its facility. Because the electric demand of the plant is small with respect to the process heat requirements, the plant plans to sell excess electrical energy back to the power provider. The generator is capable of producing 1 MW of power at 0.95 power factor. Following the preparation steps outlined above for using the flowchart, a one-line diagram is developed and detailed as shown in Figure 2-2.

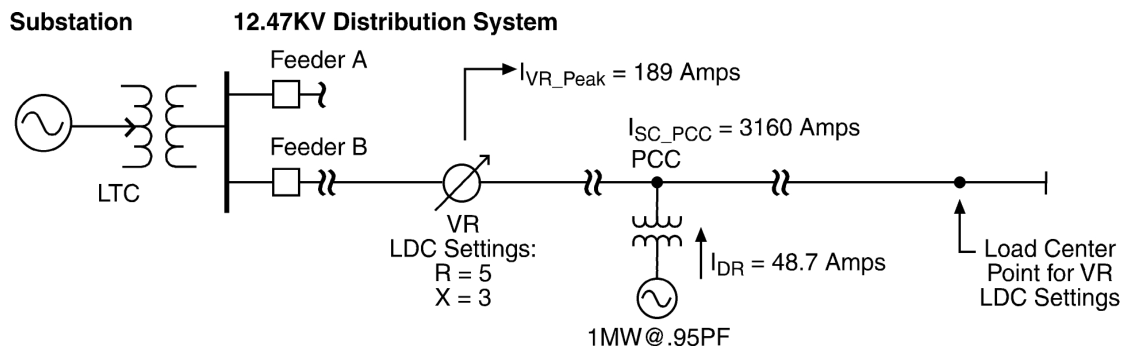

Figure 2-2
Detailed One-Line Diagram of Feeder Serving Food-Processing Plant

In the diagram, note that there are two regulating devices, the load tap changer (LTC) associated with the substation transformer and the line-voltage regulator (VR) on Feeder B. Because the VR is obviously the closest regulating device, peak load current for the device was determined and placed on the diagram. The three-phase short-circuit current (I_{SC_PCC}) at the point of common coupling was determined from computer modeling or manual calculation based on line impedance and available fault MVA at the substation. The DG rated output current (I_{DG}) must be determined based on the distribution system line voltage V_{LL_DIST}, which may be determined based on generator nameplate data and then scaled based on the secondary (Vs) to primary (Vp) voltage ratings of the DG transformer, as shown in Equation 2-1.

$$I_{DG} = I_{DG\_Rated}\left(\frac{Vs}{Vp}\right) \qquad \textbf{Eq. 2-1}$$

For this example, I_{DG} was determined based on the rated power and power factor information given using Equation 2-2.

$$I_{DG} = \frac{Generator\ Power \div Generator\ Power\ Factor}{\sqrt{3} \times V_{LL\_DIST}} = \frac{1{,}000{,}000 \div 0.95}{\sqrt{3} \times 12{,}470} = 487\,Amps \qquad \textbf{Eq. 2-2}$$

With the system details defined, Figure 2-3 presents the flow chart path represented in this example.

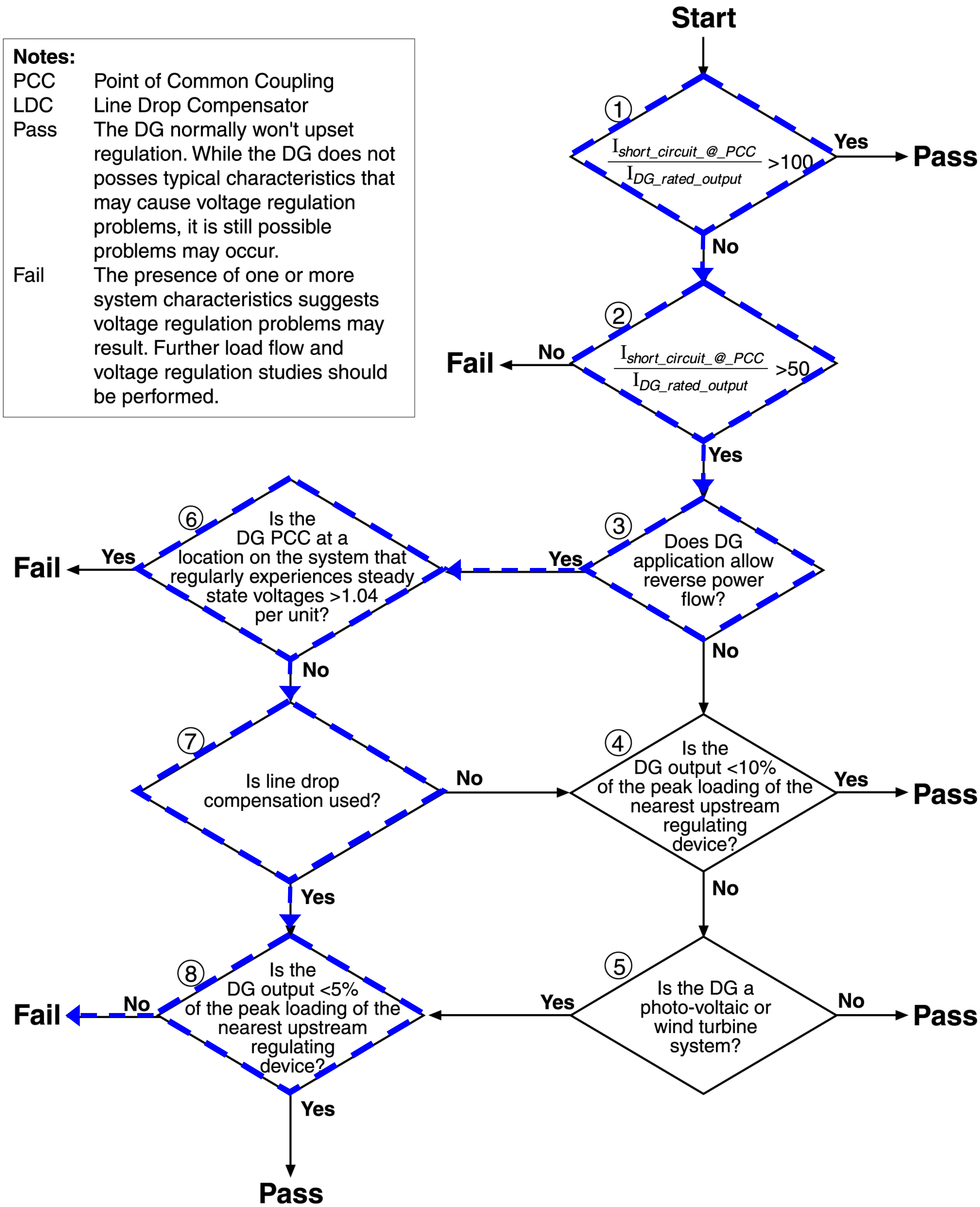

Figure 2-3
Flow Chart Path for Screening Example Food-Processing Plant DG

A the 'Start"of the chart, the I_{SC_PCC}/I_{DG} ratio is 64.8, which fails the first test but passes the following test. Because the generator will be providing power to the system, the positive response to block 3 leads the engineer to block 6, requiring the engineer to determine typical voltage levels at the PCC. Ideally, this data should come from monitoring. However, in the absence of monitored data, field measurements and load-flow analysis should provide a good estimate of typical voltage levels at the PCC. Assuming that the typical PCC voltage levels are less than 1.04 per unit, the next test (block 7) asks whether the generator is between the regulator and the line drop compensator load center point. This is the point on the distribution system on the load side of the regulator at which the compensator settings are calculated to deliver a specified voltage for a specified load current (typically peak load current) at the regulator. Because the generator is located between the regulator and the load center, there is a chance that low voltage could occur as a result of the generator interacting with regulator compensation settings. To test for this possibility, in block 8 a comparison is made between the DG output (I_{DG} = 48.7 A.) and 5% of the peak current at the regulator (5% I_{VR_Peak} = 0.05×189 A = 9.45 A). Because I_{DG} exceeds 5% I_{VR_Peak}, the DG application fails the screening, requiring additional studies to determine the operational impacts of DG on the existing power distribution system.

High Voltage Resulting From DG Operating at End of Feeder

Background

Just as capacitors can result in high voltage when distribution power factors change, distributed generators can cause reverse power flow, resulting in high distribution system voltages. Under light load for a location where the primary voltage is already high, the voltage rise can be enough to push the voltage above ANSI C57.1 range A voltage limits, as shown in Figure 2-4.

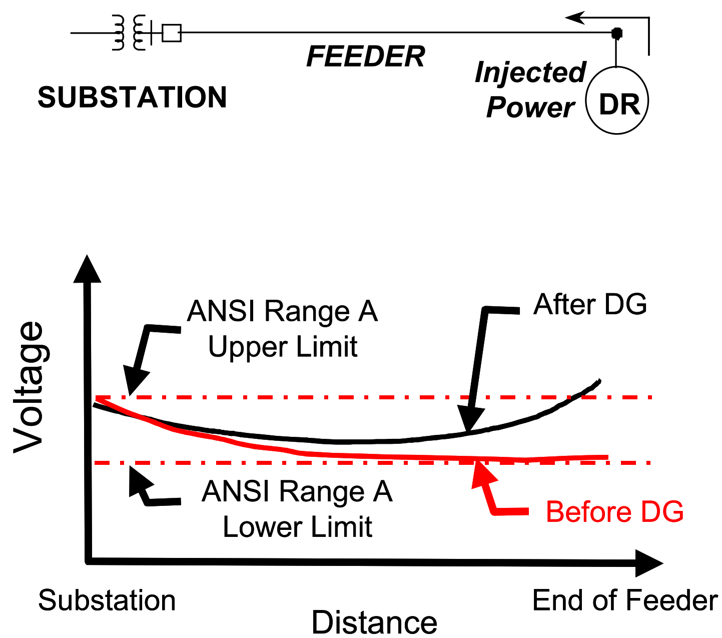

Figure 2-4
DG at the End of the Feeder Leads to High Voltage at the DG Location

Calculation Procedure

Calculation of voltages on a distribution system is best performed utilizing a load-flow computer-modeling program. Such a program utilizes an iterative process that starts out assuming a system voltage for given load and then calculates the resulting voltages. The calculated voltage will affect load current, requiring a new round of calculations. Computer modeling software is ideal for this type of analysis. In the absence of a computer modeling software load-flow program, a simplified approach may be used assuming that load currents do not change as a result of an assumed voltage.

To estimate the voltage rise caused by a generator:

- Find the real and reactive portion of current from the generator (I_R and I_X).
- Find the line R and X.
- Estimate the voltage drop (a negative answer is the voltage rise) with:

$$V_{drop} = R \cdot I_R + X \cdot I_X \qquad \textbf{Eq. 2-3}$$

The most difficult part of this simplified procedure requires the gathering and totalizing of all line resistances (R) and line reactances (X) for the feeder from the substation to the point of common coupling of the DG. With DG three-phase power output (P_{gen}) and power factor (PF_{gen}) known, use the following detailed steps to estimate voltage rise caused by a generator:

1. Determine the generator three-phase Var output (Q_{gen}) based on Equation 2-4.

$$Q_{gen} = \sqrt{P_{gen}{}^{2}\left[\left(\frac{1}{PF_{gen}}\right)^{2} - 1\right]} \qquad \textbf{Eq. 2-4}$$

2. Determine the nominal power distribution system line-to-line voltage and assign the value to the variable V_{nom}.

3. Estimate the real (I_R) and reactive (I_X) currents using Equation 2-5 and Equation 2-6, respectively:

$$I_R = \frac{P_{gen}}{V_{nom}} \qquad \textbf{Eq. 2-5}$$

$$I_X = \frac{Q_{gen}}{V_{nom}} \qquad \textbf{Eq. 2-6}$$

4. Determine and totalize all line resistance (R) and line reactance (X) values for feeder sections from the substation to the point of common coupling of the DG. This data are typically available from conductor tables, in ohms/1000 ft., based on conductor size and line spacing.

5. Calculate V_{drop} from Equation 2-7:

$$V_{drop} = RI_r + XI_x \qquad \textbf{Eq. 2-7}$$

6. Calculate V_{result} from Equation 2-8:

$$V_{result} = V_{nom} + V_{drop} \qquad \textbf{Eq. 2-8}$$

7. Calculate %ΔV from Equation 2-9:

$$\%\Delta V = \frac{V_{result}}{V_{nom}} \qquad \textbf{Eq. 2-9}$$

8. Find the voltage resulting from generator operation by multiplying the percent change in voltage (%ΔV) times the voltage with the generator off.

Example

For the system illustrated in Figure 2-5, find the voltage at the PCC (node 'e') resulting from generator operation. Also determine the operational voltage experienced at the generator terminals, assuming a 120-V base.

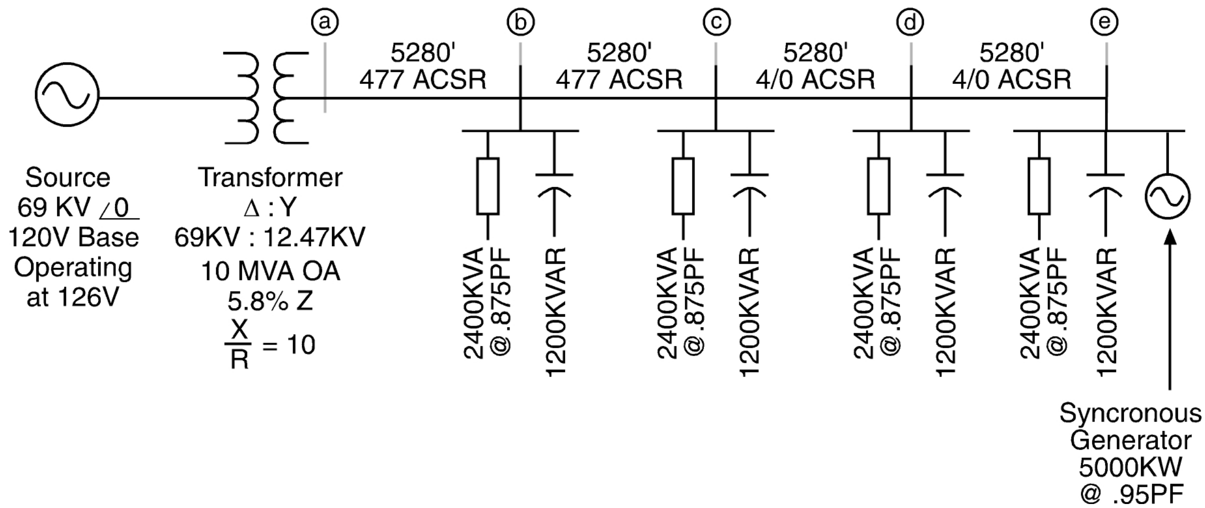

Figure 2-5
Example Power Distribution System One-Line Diagram

From Figure 2-5, it is apparent that:

- DG three-phase power output P_{gen} = 5000 KW
- DG power factor PF_{gen} = unity

1. Determine the generator three-phase Var output (Q_{gen}) based on Equation 2-4:

$$Q_{gen} = 0 \text{ kvar}$$

2. The nominal power distribution system line-to-line voltage is: V_{nom} = 12,470 $V_{LL.}$

3. Estimate the real (I_R) and reactive (I_X) using Equation 2-5 and Equation 2-6, respectively:

$$I_R = \frac{P_{gen}}{V_{nom}} = \frac{5000 \times 1000}{12470} = -500 \text{ amps}$$

$$I_X = \frac{Q_{gen}}{V_{nom}} = 0 \text{ amps reactive}$$

4. Determine and totalize all line resistance (R) and line reactance (X) values for feeder sections from the substation to the PCC of the DG. The line data and associated table data associated with the example system are provided in Table 1-1 along with calculated R and X values for each feeder section that is then totalized.

Table 2-1
Line R and X Data Associated With Figure 2-5

Line Data:				**Table Data:**		**Calculated Data:**	
Line	Length(ft)	Size	Type	R' (ohms/kFt)	X' (ohms/kFt)	R, Ohms	X, Ohms
ab	5280	477	ACSR	0.0409	0.1146	0.2160	0.6051
bc	5280	477	ACSR	0.0409	0.1146	0.2160	0.6051
cd	5280	4/0	ACSR	0.1157	0.1396	0.6109	0.7371
ef	5280	4/0	ACSR	0.1157	0.1396	0.6109	0.7371
					Total Line Impedance:	**R =** 1.6537	**X=** 2.6844

5. Calculate V_{drop} from Equation 2-7:
   $V_{drop} = RI_R + XI_X = 1.6537 \times (-500) + 2.6844 \times 0 = -827$ volts

6. Calculate V_{result} from Equation 2-8:
   $V_{result} = V_{nom} - V_{drop} = 12470 - (-827) = 13297$ volts

7. Calculate %ΔV from Equation 2-9:
   $\%\Delta V = \frac{V_{result}}{V_{nom}} = \frac{13297}{12470} = 1.066$ per unit

8. Find the voltage resulting from generator operation by multiplying the voltage with the generator off times the percent change in voltage (%DV).

   a. For the system illustrated in Figure 2-5, assuming that the voltage at the PCC (node 'b') without the DG in operation is 13,903 V_{LL}, the voltage at the PCC resulting from generator operation is:

      $V_{PCC\_GEN\_ON}$ = 1.066*13903 = 14,820 V_{LL}

   b. Similarly, assuming that the voltage at the generator terminals without the DG in operation is 126 V, the voltage at the generator terminals resulting from generator operation is:

      $V_{GEN\_ON\ (120\ V\ Base)}$ = 1.066*126 = 134 V

Note that the above steps and equations presented in this example assume a three-phase generator where:

- P_{gen} is an aggregated value representing all three phases.
- V_{nom} represents line-to-line distribution system voltage.
- Line impedance R and X values assume no neutral return.

The same equations and analysis may be used to determine single-phase voltage rise associated with the operation of a single-phase DG by:

- Let P_{gen} represent the single-phase power output of the DG.
- Use the distribution system line to neutral voltage for V_{nom}.
- Double all line impedance R and X values to approximate the neutral return path associated with the DG.

More Detailed Procedure

A more accurate approach, taking into account substation transformer impedances while providing a profile of voltages along a feeder, is presented below:

1. Gather system data:
   - Sketch a one-line diagram (Figure 2-5) of the system from the substation transformer high-voltage side to all the points of interest on the primary distribution system.
   - Record substation transformer data (Vp, Vs, MVA, %Z, and X/R ratio) on the sketch.
   - Record primary line section types, conductor sizes, and lengths on the sketch.
   - Record measured or estimated load and generator data on the sketch.
2. Transcribe system data to a spreadsheet. Obtain line impedance data from available conductor characteristics charts.
3. Perform spreadsheet calculations using complex math functions:
   - Determine substation transformer complex impedance in ohms as seen on secondary side.
   - Calculate complex line impedance in ohms for each line section.
   - Convert load data to complex current data assuming nominal line voltage at an angle of zero degrees.
   - Assuming that the substation transformer primary is an infinite bus, utilize calculated load currents and line impedances to determine voltage drop/rise at each distribution node.

Example

The Base Case 1 (Table 2-2) indicates typical distribution system voltages as a result of loading without DG operation. The spreadsheet was developed based on the system illustrated in Figure 2-5. The resulting voltage drop magnitudes are presented in bold under step 4 of the table. Note that the voltage magnitudes are provided for system voltages (|Vn| volts) and then converted to a 120-V base (|Vn| 120 volts) in the far right-hand column. The Base Case indicates gradual voltage reductions as power flows through the substation transformer to the end of the distribution system when the DG is not in operation.

Case 1-2 (Table 2-3) provides a spreadsheet analysis of Base Case 1 with a 5000-kW, 0.95-pf synchronous generator added. The generator is applied at the end of line (point ‘e’’in Figure 2-5). Case 1-2 shows resulting distribution system voltage rise due to reverse power flow from a DG located at the end of the power distribution line.

Table 2-2
Base Case 1, Spreadsheet Analysis of Distribution System Voltage Drop

Case: Base

Description: Loads and capacitors applied at the end of line sections.

Transformer Data:

Vp (kV)	Vs (kV)	kVA	%Z	X/R
69	12.47	10000	5.8	10

Line Data:

Line	Length(ft)	Size	Type	Table Data: R' (ohms/kFt)	X' (ohms/kFt)
ab	5280	477	ACSR	0.0409	0.1146
bc	5280	477	ACSR	0.0409	0.1146
cd	5280	4/0	ACSR	0.1157	0.1396
ef	5280	4/0	ACSR	0.1157	0.1396

Load Data:

Load @ end of line	Magnitude	Unit	PF (lag)
Capacitor ab	1200	kVAR	0
Capacitor bc	1200	kVAR	0
Capacitor cd	1200	kVAR	0
Capacitor ef	1200	kVAR	0
Load ab	2400	kVA	0.875
Load bc	2400	kVA	0.875
Load cd	2400	kVA	0.875
Load ef	2400	kVA	0.875
Generator @ e	0	kW	0.95

Calculations Utilizing Complex Math:

1) Convert transformer data to complex impedance.
As seen from the secondary side of the transformer;
|Zt|=Zpu*Vs^2*1000/kVA
Rt=(|Zt|^2/((X/R)^2+1))^.5
Xt=(Zt^2-Rt^2)^.5

	Rt (ohms)	Xt (ohms)	|Zt| (ohms)	Complex, ohms
Zt=	0.08974	0.89743	0.90191	8.97429235944522E-002+0.897429235944522i

2) Express line impedance data in complex form.
Rxy = Length(ft)*R' (ohms/kFt)
Xxy = Length(ft)*X' (ohms/kFt)

	Rxy (ohms)	Xxy (ohms)	|Zxy| (ohms)	Complex ohms
Zab=	0.21595	0.60509	0.6425	0.215952+0.605088i
Zbc=	0.21595	0.60509	0.6425	0.215952+0.605088i
Zcd=	0.61090	0.73709	0.9573	0.610896+0.737088i
Zde=	0.61090	0.73709	0.9573	0.610896+0.737088i

3) Convert load data to complex form.

Load @ end of line	P(W)	jQ(Var)	|S_n| (VA)	Complex VA
Capacitor ab =	0.000	-1200000.000	1200000.000	-1200000i
Capacitor bc =	0.000	-1200000.000	1200000.000	-1200000i
Capacitor cd =	0.000	-1200000.000	1200000.000	-1200000i
Capacitor ef =	0.000	-1200000.000	1200000.000	-1200000i
Load ab =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Load bc =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Load cd =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Load ef =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Generator @ e =	0.000	0.000	0.000	0

Note: If Q<0, then powerfactor is lagging
Assume: I_n = S_n*/Vs

	Re	Im	|I_n| (Amps)	Complex Amps
I_Cap_ab =	0.0000	55.5590	55.5590	55.5589673638774i
I_Cap_bc =	0.0000	55.5590	55.5590	55.5589673638774i
I_Cap_cd =	0.0000	55.5590	55.5590	55.5589673638774i
I_Cap_ef =	0.0000	55.5590	55.5590	55.5589673638774i
I_Ld_ab =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Ld_bc =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Ld_cd =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Ld_ef =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Gen @ e =	0.0000	0.0000	0.0000	0
I_tot =	388.9128	7.0569	388.9768	388.912771547142+7.05691412273107i

4) Calculate voltage drop from Voltage impedance and current information.
Let the primary system voltage, Vp', be 5% above the nominal at angle 0. Then;
Vp'=
Va=Vp'(Vs/Vp)-(I_tot)Zt
Vb=Va-Zab(I_tot)
Vc=Vb-Zbc(I_Cap_bc+I_Cap_cd+I_Cap_de+I_Ld_bc+I_Ld_cd+I_Ld_de+I_Gen @ e)
Vd=Vc-Zcd(I_Cap_cd+I_Cap_de+I_Ld_cd+I_Ld_de+I_Gen @ e)
Ve=Vdc-Zde(Cap_de+I_Ld_de+I_Gen @ e)

RESULTS

	Re	Im	**|Vn| (Volts)**	Complex Volts	**|Vn| (120 V base)**
Vp'=	72450.0000	0.0000	**72450.0000**	72450	**126.0000**
Va=	13064.9309	-349.6550	**13069.6090**	13064.9309119074-349.654999523547i	**125.7701**
Vb=	12985.2145	-586.5054	**12998.4531**	12985.2144751189-586.505405352096i	**125.0854**
Vc=	12925.4271	-764.1432	**12947.9953**	12925.4271475276-764.143209723508i	**124.5998**
Vd=	12395.9001	-1171.5254	**12451.1370**	12395.9001460209-1171.52541768044i	**119.8185**
Ve=	12163.5165	-1462.4994	**12251.1239**	12163.5164562507-1462.4993952445i	**117.8937**

Table 2-3
Example Case 1-2 Spreadsheet Analysis of Distribution System Voltage Rise Due to DG

Case: 2
Description: Base case with 5000 kW. 0.95 pf, generator applied at end of line (point e).
Transformer Data:

Vp (kV)	Vs (kV)	kVA	%Z	X/R
69	12.47	10000	5.8	10

Line Data:

Table Data:

Line	Length(ft)	Size	Type	R' (ohms/kFt)	X' (ohms/kFt)
ab	5280	477	ACSR	0.0409	0.1146
bc	5280	477	ACSR	0.0409	0.1146
cd	5280	4/0	ACSR	0.1157	0.1396
ef	5280	4/0	ACSR	0.1157	0.1396

Load Data:

Load @ end of line	Magnitude	Unit	PF (lag)
Capacitor ab	1200	kVAR	0
Capacitor bc	1200	kVAR	0
Capacitor cd	1200	kVAR	0
Capacitor ef	1200	kVAR	0
Load ab	2400	kVA	0.875
Load bc	2400	kVA	0.875
Load cd	2400	kVA	0.875
Load ef	2400	kVA	0.875
Generator @ e	5000	kW	-0.95

Calculations Utilizing Complex Math:

1) Convert transformer data to complex impedance.
As seen from the secondary side of the transformer;
|Zt|=Zpu*Vs^2*1000/kVA
Rt=(|Zt|^2/((X/R)^2+1))^.5
Xt=(Zt^2-Rt^2)^.5

	Rt (ohms)	Xt (ohms)	|Zt| (ohms)	Complex, ohms
Zt=	0.08974	0.89743	0.90191	8.97429235944522E-002+0.897429235944522i

2) Express line impedance data in complex form.
Rxy = Length(ft)*R' (ohms/kFt)
Xxy = Length(ft)*X' (ohms/kFt)

	Rxy (ohms)	Xxy (ohms)	|Zxy| (ohms)	Complex ohms
Zab=	0.21595	0.60509	0.6425	0.215952+0.605088i
Zbc=	0.21595	0.60509	0.6425	0.215952+0.605088i
Zcd=	0.61090	0.73709	0.9573	0.610896+0.737088i
Zde=	0.61090	0.73709	0.9573	0.610896+0.737088i

3) Convert load data to complex form.

Load @ end of line	P(W)	jQ(Var)	|S_n| (VA)	Complex VA
Capacitor ab =	0.000	-1200000.000	1200000.000	-1200000i
Capacitor bc =	0.000	-1200000.000	1200000.000	-1200000i
Capacitor cd =	0.000	-1200000.000	1200000.000	-1200000i
Capacitor ef =	0.000	-1200000.000	1200000.000	-1200000i
Load ab =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Load bc =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Load cd =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Load ef =	2100000.000	1161895.004	2400000.000	2100000+1161895.00386223i
Generator @ e =	-5000000.000	-1643420.526	5263157.895	-5000000-1643420.52589432i

Note: If Q<0, then powerfactor is lagging
Assume: I_n = S_n*/Vs

	Re	Im	|I_n| (Amps)	Complex Amps
I_Cap_ab =	0.0000	55.5590	55.5590	55.5589673638774i
I_Cap_bc =	0.0000	55.5590	55.5590	55.5589673638774i
I_Cap_cd =	0.0000	55.5590	55.5590	55.5589673638774i
I_Cap_ef =	0.0000	55.5590	55.5590	55.5589673638774i
I_Ld_ab =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Ld_bc =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Ld_cd =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Ld_ef =	97.2282	-53.7947	111.1179	97.2281928867854-53.7947388331946i
I_Gen @ e =	-231.4957	76.0890	243.6797	-231.495697349489+76.0889561360737i
I_tot =	157.4171	83.1459	178.0263	157.417074197653+83.1458702588048i

4) Calculate voltage drop from Voltage impedance and current information.
Let the primary system voltage, Vp', be 5% above the nominal at angle 0. Then;
Vp'=
Va=Vp'(Vs/Vp)-(I_tot)Zt
Vb=Va-Zab(I_tot)
Vc=Vb-Zbc(I_Cap_bc+I_Cap_cd+I_Cap_de+I_Ld_bc+I_Ld_cd+I_Ld_de+I_Gen @ e)
Vd=Vc-Zcd(I_Cap_cd+I_Cap_de+I_Ld_cd+I_Ld_de+I_Gen @ e)
Ve=Vdc-Zde(Cap_de+I_Ld_de+I_Gen @ e)

RESULTS

	Re	Im	**|Vn| (Volts)**	Complex Volts	**|Vn| (120 V base)**
Vp'=	72450.0000	0.0000	**72450.0000**	72450	**126.0000**
Va=	13153.9905	-148.7324	**13154.8313**	13153.9904663561-148.732438103652i	**126.5902**
Vb=	13170.3065	-261.9391	**13172.9110**	13170.3065026921-261.939137669891i	**126.7642**
Vc=	13206.5516	-315.9332	**13210.3301**	13206.5516482252-315.933235778992i	**127.1243**
Vd=	13072.0328	-475.0149	**13080.6605**	13072.0327507754-475.014920495452i	**125.8764**
Ve=	13234.6572	-517.6884	**13244.7783**	13234.6571650621-517.688374819037i	**127.4558**

Table 2-4 provides the summary of distribution voltages calculated from the above spreadsheets based on the system previously illustrated in Figure 2-5. The spreadsheets summarized in the table provide a side-by-side comparison between Base Case 1 and Example Case 1-2.

Table 2-4
Summary of Secondary Voltage Case Studies

Case>>	Base			2		
	Volts	PU	120 V	Volts	PU	120 V
Vp'=	72450.0	1.050	126.0	72450.0	1.050	126.0
Va=	13069.6	1.048	125.8	13154.8	1.055	126.6
Vb=	12998.5	1.042	125.1	13172.9	1.056	126.8
Vc=	12948.0	1.038	124.6	13210.3	1.059	127.1
Vd=	12451.1	0.998	119.8	13080.7	1.049	125.9
Ve=	12251.1	0.982	117.9	13244.8	1.062	127.5

Base	Loads and capacitors applied at the end of line sections.
2	Base case with 5000 kW. 0.95 pf, generator applied at end of line (point e).

While the actual current through the substation transformers and distribution system is reduced by the addition of the DG, overall voltage control is lost, resulting in high voltage conditions. To control voltage, one or more of the following changes should be considered:

- Reduce generator output.
- Add voltage controls to distribution system capacitor banks.
- Add more regulators or change existing line drop compensation settings.

Load-Flow Programs for Determining Effects of DG

Background

The spreadsheet approach presented above is fairly accurate for simple calculations. However, if line regulators are considered or load tap changers are utilized with line-drop compensation settings, the modeling becomes more complex, favoring a load-flow program that performs analyses based on an iterative calculation algorithm. Many load-flow programs provide the ability to evaluate systems on a per-phase basis while applying voltage-control settings to capacitors, load tap changers, and line regulators.

Procedure

Calculation of voltages on a distribution system is best performed utilizing a load-flow computer-modeling program. Such a program utilizes an iterative process that starts out assuming a system voltage for a given load and then calculates the resulting voltages. The calculated voltage will affect load current, requiring a new round of calculations. Computer-modeling software is ideal for this type of analysis.

The following approach is suggested when performing distribution system voltage studies with load-flow computer-modeling software:

1. Gather system data.
2. Utilize data from step 1 to develop a base case load-flow model of the distribution feeder under study.
3. Add the generator to the base case model.
4. Add capacitors and regulators to the model resulting from step 3.
5. Determine the voltage profile for different load conditions.

In more detail, the steps are:

1. Gather system data:
   - Sketch a one-line diagram of the system from high-voltage side of the substation transformer to all the points of interest on the primary distribution system.
   - Record substation transformer data (Vp, Vs, MVA, %Z, and X/R ratio) on the sketch.
   - Record primary line section types, conductor sizes. and lengths on the sketch.
   - Record measured or estimated load and generator data on the sketch.
   - Indicate locations and sizes of capacitors and regulators along with control settings.
2. Utilize data from step 1 to develop base case load-flow model of distribution feeder under study:
   - Base case model should include loads without capacitors, regulators, or generators attached.
   - Determine voltage profile for different load conditions:
     - Peak load.
     - Minimum load.
     - Pre-determined load if known.

– Some load-flow programs allow individual load profiles to be added for each customer or point of interest based on time of day and day of week. From these profiles, the program may determine overall aggregate load for the system.

3. Add the generator to the base case model. Determine the voltage profile for different load conditions.

4. Add capacitors and regulators to the model resulting from step 3:
   - Add existing capacitors and regulators as indicated from the one-line diagram.
   - For new capacitors, if the load-flow program has the capability, use the program to automatically place capacitors on the system for you. Utilizing this feature may avoid the need for additional regulation.

5. Determine voltage profile for different load conditions:
   - Use load-flow program to experiment with regulator location placement and settings.
   - Determine the voltage profile for different load conditions.

Interaction of DG With Line-Side Voltage Regulator Resulting in Low Voltage

Background

Distributed resources can influence the voltage regulation of electric power systems. This influence will occur whether or not a generator operates in a voltage-regulation mode or whether it operates in a 'voltage following" mode. The generator affects the flow of power on the distribution system and therefore changes voltage drops occurring across impedances in the system. Voltage levels at various points on the feeder also change. Whether or not these changes are significant and/or of a beneficial nature or pose a problem depends on a number of factors including:

- The size of the generator relative to the power system at the point of application.
- The location of the generator relative to load tap changer transformers, line voltage regulators, and switched capacitors.

Low voltage conditions may result from the application of a DG just downstream of a regulator with line-drop compensation (LDC). LDC is the technique commonly applied by LTC transformer controllers and line-voltage regulators to control the voltage on the distribution system based on the line current. Under heavy load, a generator just downstream of the generator will reduce the observed load on the feeder (so the regulator will not boost the voltage as much). This leads to a lower voltage downstream of the regulator, as shown in Figure 2-6.

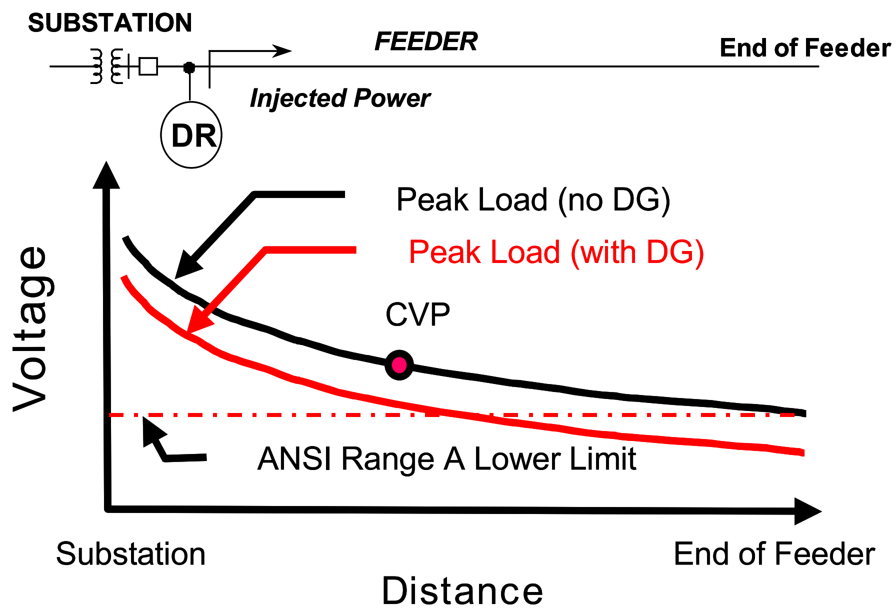

Figure 2-6
DG Near the Substation Leads to Low Voltage at the End of the Feeder

Procedure

Follow the suggested approach for performing distribution system voltage studies with load flow computer-modeling software as suggested in the previous section, 'Load Flow Programs for Determining Effects of DG."

Refer to Figure 2-7 for the following example and associated cases.

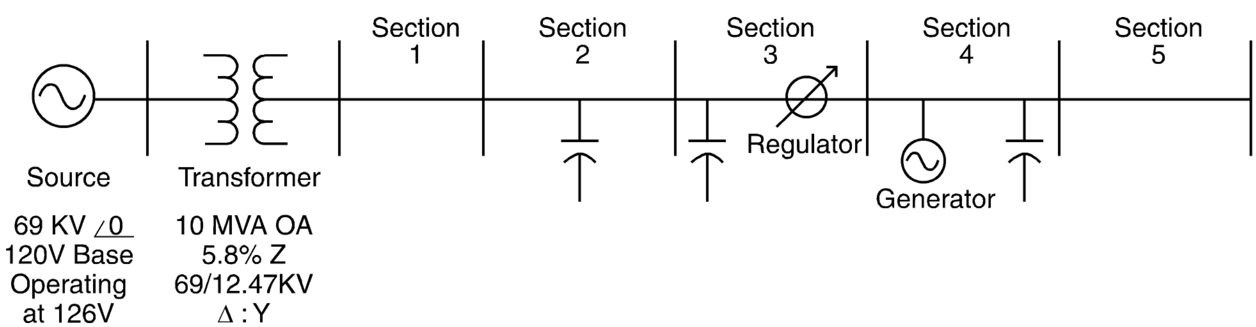

Figure 2-7
One-Line Diagram of Power Distribution With Generator Located Near Load-Side of Regulator (See Table 2-5 for Line and Equipment Specifics)

Table 2-5 provides detailed line and equipment data associated with Figure 2-7 used to support the load-flow modeling example and cases.

Table 2-5
Model Assumptions Associated With Figure 2-7

Model Assumptions

Model Base Voltage: 120 V

Source:

KV LL	R (ohms)	X (ohms)	Analysis Voltage (120 V base)
69	0	0	126

Transformer:

MVA OA	Impedance (%Z)	X/R Ratio	Type	High-side Configuration		High-side Configuration	
				kV	Connection	kV	Connection
10	5.8	10	3-phase	69	Delta	12.47	Wye-ground

Section Construction:

ID	Conductor Type	Configuration	Relative Conductor Spacing (Ft)								Length (Ft)
			Phase 1		Phase 2		Phase 3		Neutral		
			X	Y	X	Y	X	Y	X	Y	
1	Okoguard MV-90 8kV 1000	Cable 12.5 kV duct	0	0	0	0	0	0	0	0	50
2	477ACSR	12.5/7.2 kV Crossarm	0	4	3.6	4	7	4	3	0	10500
3	477ACSR	12.5/7.2 kV Crossarm	0	4	3.6	4	7	4	3	0	10500
4	4/0 ACSR	12.5/7.2 kV Crossarm	0	4	3.6	4	7	4	3	0	15840
5	4/0 ACSR	12.5/7.2 kV Crossarm	0	4	3.6	4	7	4	3	0	13200

Section Loads:

ID	Distributed Balanced Loads		Spot Balanced Loads		Spot Load Location on Section
	KW	kVar	KW	kVar	(Source end, Center, Load end)
2	2400	1500	0	0	
3	2400	1500	0	0	
4	600	300	0	0	
5	1500	600	1500	900	Center

Section Capacitors:

ID	Balanced Capacitors kVar
2	1200
3	1200
4	600
5	0

Section Regulators:

ID	LDC Dial Settings				Tap Side	Regulator Location on Section	Reverse Mode
	Voltage	R	X	B.W.		(Source end, Center, Load end)	
3	124	5	3	2	Load	Load end	None Activated

Section Generators:

ID	Type	Construction	Rating			Exciter	Impedance (ohms)				
			kW	kV	PF%	PT Ratio	R1	X1	Xd"	R0	X0
3	Synchronous	3-Phase	5000	12.47	95	60:1	1	2.1	4.2	0.9	3.4

Example

Utilizing the distribution feeder represented by Figure 2-7 and Table 2-5, a load-flow program was utilized to construct a computerized model of the feeder. Table 2-6 represents the load-flow results, indicating feeder voltages by section with only the line characteristics and load data included.

Table 2-6
Feeder Summary With Allocated Loads Applied at Each Section

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	121.3	121.3	121.3	121.3	0.0%	455	453	453	454	7	0.2%	71	64	0	0	9909	83	1
Section_0002	10.6	113.9	115.0	115.1	114.7	0.7%	455	453	453	454	7	0.2%	68	57	2746	85	9908	83	200
Section_0003	21.1	109.1	110.9	111.2	110.4	1.2%	325	324	323	324	7	0.3%	48	40	2571	85	6687	85	93
Section_0004	36.9	100.4	103.1	103.6	102.4	1.9%	198	196	196	196	6	0.8%	58	49	565	89	3904	87	177
Section_0005	50.1	97.1	100.1	100.8	99.3	2.3%	169	166	166	167	6	1.0%	49	42	2985	89	3076	88	62

As can be seen in Table 2-6, there is a significant need for voltage support on the feeder. Capacitors may be added to improve system power factor and help control voltage. Table 2-7 shows the load-flow results after capacitors have been added to the system.

Table 2-7
Feeder Summary With Capacitors and No Regulator or Generator

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	123.2	123.3	123.3	123.3	0.0%	402	401	400	401	6	0.2%	63	57	0	0	8899	95	0
Section_0002	10.6	118.0	118.9	119.4	118.8	0.6%	402	401	400	401	6	0.2%	60	50	2854	85	8898	95	158
Section_0003	21.1	114.4	115.8	116.6	115.6	1.1%	292	291	290	291	6	0.3%	43	36	2729	85	6216	95	76
Section_0004	36.9	106.3	108.6	109.8	108.2	1.7%	184	182	181	182	5	0.7%	54	46	608	89	3792	93	159
Section_0005	50.1	103.1	105.7	107.0	105.3	2.0%	164	163	162	163	5	0.8%	48	41	3087	89	3174	89	59

As can be seen in Table 2-7, even with the addition of capacitors there remains a significant need for voltage support on the feeder. While additional capacitors may be added to correct this problem, for the purposes of this example, a voltage regulator is applied to the load end of section 3. The LDC R and X dial settings are set to 5 and 3, respectively. Table 2-8 shows the load-flow results with the regulator in operation.

Table 2-8
Feeder Summary With Regulator Activated and LDC R=5 and X=3

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	123.2	123.2	123.2	123.2	0.0%	414	414	413	413	6	0.1%	65	59	0	0	9168	95	0
Section_0002	10.6	117.8	118.7	119.2	118.6	0.6%	414	414	413	413	6	0.1%	62	52	2850	85	9167	95	169
Section_0003	21.1	114.0	115.5	116.4	115.3	1.1%	304	303	302	303	5	0.2%	45	38	2721	85	6468	95	83
Section_0004	36.9	117.7	120.0	121.4	119.7	1.7%	177	176	176	177	4	0.5%	52	44	695	89	4026	94	148
Section_0005	50.1	114.6	117.2	118.7	116.8	1.9%	158	156	156	157	4	0.7%	46	39	3295	89	3375	89	54

As can be seen in Table 2-8, the addition of the regulator to the feeder provides a reasonable voltage profile for operation of the feeder. Addition of a generator may aid or hinder voltage regulation on a feeder. Table 2-9 shows the load-flow results of a generator operating at 50% capacity adjacent to the load side of the regulator.

Table 2-9
Feeder Summary With Generator at 50% Rated Output

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	124.4	124.5	124.4	124.5	0.0%	285	285	286	286	2	0.1%	45	41	0	0	6397	98	0
Section_0002	10.6	121.4	121.9	122.3	121.9	0.4%	285	285	286	286	2	0.1%	43	36	2926	85	6397	98	72
Section_0003	21.1	119.8	120.5	121.1	120.4	0.6%	173	173	173	173	2	0.1%	26	22	2859	85	3798	97	22
Section_0004	36.9	121.5	121.9	122.8	122.1	0.6%	59	59	59	59	1	0.2%	17	15	714	89	1347	93	74
Section_0005	50.1	118.5	119.1	120.1	119.2	0.7%	156	156	155	156	2	0.2%	46	39	3340	89	3418	89	54

While the generator operates at 50% capacity, the voltage profile improves when compared with the system with no generation on the load side of the regulator. The load-flow results presented in Table 2-10 show what can happen when reverse power flows through a regulator with an active LDC scheme in operation.

Table 2-10
Feeder Summary With Generator at 100% Rated Output

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	125.4	125.4	125.4	125.4	0.0%	167	167	167	167	1	0.1%	26	24	0	0	3764	100	0
Section_0002	10.6	124.3	124.5	124.7	124.5	0.2%	167	167	167	167	1	0.1%	25	21	2987	85	3764	100	20
Section_0003	21.1	124.5	124.7	124.9	124.7	0.2%	53	54	53	53	1	0.3%	8	7	2975	85	1199	-100	4
Section_0004	36.9	118.2	118.6	118.8	118.5	0.3%	63	63	63	63	1	0.1%	19	16	686	89	1368	97	76
Section_0005	50.1	115.1	115.8	116.1	115.7	0.5%	157	157	157	157	1	0.2%	46	39	3274	89	3354	89	55

Comparing the feeder summary in Table 2-8 with Table 2-10 indicates that the operation of the generator at 100% results in a lower end of feeder voltage. With no generation, the regulator control drives the regulator to tap position 16 raise (R). With the generation at 100%, the resulting reverse power flow through the R and X regulator control settings causes the regulator control to drive the regulator to tap position 5 lower (L). If additional generation capacity was available and on-line, any additional reverse power flow would drive the tap position even lower, resulting in even lower voltages. A possible solution is to set the LDC R and X dial settings to zero. This results in the load flow feeder summary presented in Table 2-11.

Table 2-11
Feeder Summary With Generator at 100% of Rated Output and Regular LDC Settings Set to Zero

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	125.4	125.4	125.4	125.4	0.0%	170	170	170	170	1	0.2%	27	24	0	0	3840	100	0
Section_0002	10.6	124.3	124.5	124.7	124.5	0.2%	170	170	170	170	1	0.2%	25	21	2986	85	3840	100	21
Section_0003	21.1	124.4	124.6	124.9	124.6	0.2%	57	57	57	57	1	0.6%	8	7	2974	85	1274	-100	4
Section_0004	36.9	122.0	121.6	121.9	121.8	0.2%	57	58	58	58	2	1.2%	17	14	712	89	1295	97	74
Section_0005	50.1	119.0	118.8	119.2	119.0	0.2%	156	156	156	156	1	0.1%	46	39	3335	89	3413	89	54

Interaction of DG With Line-Side Voltage Regulator Resulting in High Voltage

Background

A simple utility voltage regulator may not be able to properly control the voltage if the power reverses due to DG. Without dispersed generation, the power would reverse only when the direction of the feed changed during feeder reconfiguration after a fault. If the regulator is capable of looking in only one direction, it will generally tap all the way to its limit in the wrong direction in an attempt to correct the voltage. This prompted regulator suppliers to provide automatic controls to switch to a reverse control mode when reverse power was detected.

The normal situation is shown in Figure 2-8 (a). The regulator is looking forward, and the tie to the alternate feed is open. In case of emergency, such as a fault as indicated in Figure 2-8 (b), the faulted section is first isolated and then the tie switch is closed. The power flow through the regulator reverses due to the feed direction. To function properly in this situation, the regulator must reverse its control mode and attempt to regulate on the left side in the figure.

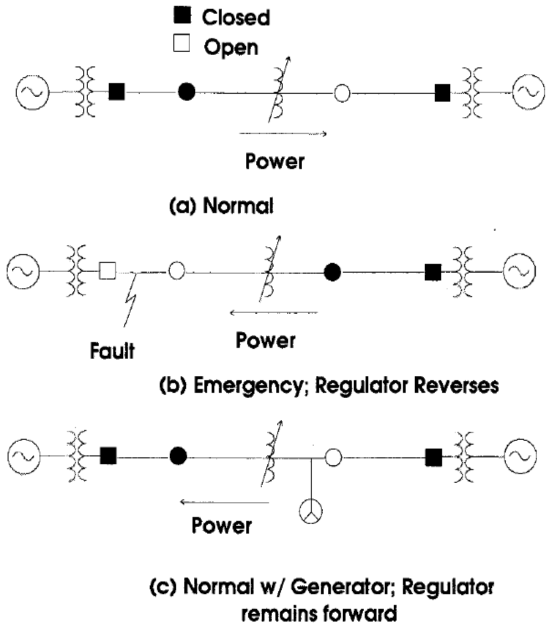

Figure 2-8
Reverse Power Conditions With DG

This mode change assumes that the source of the power was the utility bulk power source. For dispersed generation (Figure 2-8 (c)), you do not want to reverse the direction of the regulator even if the net power in the line is in the reserve direction. This would cause the regulator to try to change the voltage on the utility source side. Because the utility source is generally much stronger, this is not possible, and the regulator will typically tap to its limit without much effect on the voltage on the utility source side. If the regulator reverses control mode when the net power reverses, it will attempt to regulate the voltage on the bulk power side using the DG source. This can result in high voltage on the load side of the regulator.

To understand how this can occur, first consider the normal operation of the regulator with forward power flowing through the regulator from line side to load side. With the regulator taps on the load side of the regulator, lowering the taps will lower the load-side voltage, and the converse is also true. So when a high-voltage condition is sensed on the load side, the regulator control will drive the regulator taps down to an acceptable voltage. When a low-voltage condition is sensed on the load side of the regulator, the regulator control responds by driving the taps up until the voltage reaches an acceptable voltage level. When a DG output exceeds the downstream load, reverse power flow through the regular begins. This typically will raise the voltage on the load side of the regulator, causing the regulator to respond by lowering the taps on the regulator. This process results in a lower voltage at the end of the feeder, as presented in the previous example.

With the regulator control enabled for bi-directional power flow, when reverse power is sensed, the regulator must respond to a low-voltage condition by lowering (instead of raising) the normally load-side taps. Conversely, when reverse power is sensed, the regulator must respond to a high-voltage condition by raising (instead of lowering) the normally load-side taps. When a DG output exceeds the downstream load, reverse power flow through the regulator begins. This typically will raise the voltage sensed by the regulator. Sensing a high-voltage condition, the regulator (with reverse power activated) will respond by raising the load-side regulator taps. Because the source-side voltage is "stiffer" than the load-side voltage, there will be little change in the source-side voltage. However, the regulator load-side voltage will increase. This increase causes the regulator control to once again raise the regulator taps. This process will continue until the regulator goes to a full-raise condition. In this condition, high voltage will be experienced on the load side of the regulator if the generator control is not voltage-limited.

Procedure

To determine if DG can upset regulators from reverse power flow, consider the following:

- Determine how the regulator responds to reverse power flow. If it switches operating direction with reverse power flow, then DG may upset its operations and cause high or low voltage. If it does not switch directions, then this problem cannot occur.
- Determine the size of the DG with respect to the load downstream of the DG. If the DG is within 50% of the minimum load at the regulator, reverse power flow could occur under unusual conditions.
- If DG can cause reverse power flow, consider other control settings. Normally with DG, the "cogeneration mode" or "neutral idle mode" is generally preferable.
- For more detailed analysis, follow the suggested approach for performing distribution system voltage studies with load-flow computer-modeling software as suggested in the previous section, "Utilization of Load Flow Programs for Determining Effects of DG."

From a control perspective in addition to determining the control LTC settings, it will be necessary to know if the control has the advanced capabilities necessary for operation with DG systems.

Example

Refer to Figure 2-7 for the system example and Table 2-5 for the associated details of line and equipment data. Because this procedure considers interaction of DG with voltage regulators, it will be necessary to augment the system data with as much detailed information on the existing line regulator being considered in the study.

Because the same system is utilized from the previous example showing how a DG interacts with a line-voltage regulator resulting in low voltage, the following example extends the results (Table 2-11) of the previous example. The procedure involves editing the model regulator settings so that the reverse-mode setting is set to "bi-directional."

Utilizing the model from the previous example, this example extends the results fromTable 2-11. The model regulator reverse-mode settings are edited to 'bi-directional."The resulting load-flow feeder summary is provided in Table 2-12.

Table 2-12
Feeder Summary With Generator at 100% of Rated Output, Regular LDC Settings Set to Zero, and Regulator Control Mode Set to "Bi-Directional"

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	125.4	125.4	125.4	125.4	0.0%	171	183	185	179	12	4.9%	28	25	0	0	4047	100	0
Section_0002	10.6	124.3	124.2	124.7	124.4	0.2%	171	183	185	179	12	4.9%	27	22	2984	85	4047	100	24
Section_0003	21.1	124.5	124.1	124.9	124.5	0.3%	57	70	71	66	12	13.3%	10	8	2969	85	1481	-100	4
Section_0004	36.9	122.0	134.0	135.2	130.4	6.4%	57	41	40	46	17	23.5%	14	12	782	89	1097	95	68
Section_0005	50.1	119.0	131.3	132.6	127.6	6.8%	156	151	151	152	6	2.1%	45	38	3502	90	3576	89	52

Comparing the feeder summary in Table 2-11 with Table 2-12 indicates that utilization of the bi-directional setting in the regulator control results in high-voltage conditions on the load side of the regulator. A closer inspection of resulting tap position in the load flow indicates that the regulator tap positions are at 16 raise, supporting the theoretical discussion presented in the Background portion of this section.

Presently, the most prevalent method of solving this problem is through the use of intelligent controls on the regulators. Utility step voltage regulators now come with options for advanced controls that have a variety of control modes. One manufacturer's literature lists these six modes:

- **Locked forward**—This mode is used when you do not expect reverse power at all.
- **Reverse idle**—Essentially, the tap change is inhibited if the power reverses past a threshold value so that the regulator remains at the tap prior to power reversal.
- **Bi-directional**—Upon reverse power in excess of a threshold, the regulator completely reverses control direction. This is designed for regulators in feeder sections that can be fed from either direction, depending on how the lines are switched.
- **Cogeneration**—This continues to regulate in the forward direction after the power reverses due to the generation being larger than load in this section. It does permit changing of the R and X settings upon reverse power. Users commonly set R and X to zero for reverse power.
- **Neutral idle**—Upon reverse power, the regulator taps back to neutral and does not attempt to regulate the voltage.
- **Locked reverse**—Similar to locked forward, except in the reverse direction.

For normal operation without DG, the bi-directional mode is preferred. If the DG capacity is always less than the load, this mode can be retained. For larger DGs, or smaller load, the user should select either the cogeneration or reverse idle mode. The cogeneration mode is generally preferable. The neutral idle mode will also suffice, but is not preferred in most cases. Table 2-13 provides a feeder summary of the load-flow analysis with the regulator set to cogeneration mode.

Table 2-13
Feeder Summary With Generator at 100% of Rated Output, Regular LDC Settings Set to Zero, and Regulator Control Mode Set to Cogeneration

Section	Dist	Volts (120V)					Amps						Pct Ldg		Load In		Load Into		kW
Name	kFt	A/AB	B/BC	C/CA	Bal	Imbal.	A	B	C	Bal	Neu	Imbal.	Cont	Emer	kVA	pf	kVA	pf	Loss
Section_0001	0.1	125.4	125.4	125.4	125.4	0.0%	170	170	170	170	1	0.2%	27	24	0	0	3840	100	0
Section_0002	10.6	124.3	124.5	124.7	124.5	0.2%	170	170	170	170	1	0.2%	25	21	2986	85	3840	100	21
Section_0003	21.1	124.4	124.6	124.9	124.6	0.2%	57	57	57	57	1	0.6%	8	7	2974	85	1274	-100	4
Section_0004	36.9	122.0	121.6	121.9	121.8	0.2%	57	58	58	58	2	1.2%	17	14	712	89	1295	97	74
Section_0005	50.1	119.0	118.8	119.2	119.0	0.2%	156	156	156	156	1	0.1%	46	39	3335	89	3413	89	54

Utilization of the cogeneration setting of the regulator control provides a very flat voltage profile across the whole length of the feeder. A problem arises when the power may reverse due to both excess generation *and* switching to an alternate feed. It is not possible for local intelligence to determine the reason for the reverse power easily. The reverse idle or neutral idle modes may be more appropriate for such cases. Discreet case-by-case modeling is necessary to ensure that all feeder configurations, load conditions, and generation settings are considered.

Secondary Voltage Rise Due to DG

Background

Reverse power flows resulting in DG operation may cause high voltages. Under light distribution system loading, for a location where the primary voltage is already high, the secondary voltage rise can be enough to push the voltage above ANSI voltage range A limits, as shown in Figure 2-9. This can even happen for a small DG located on the secondary circuit because of the voltage drop along the service drop, the secondary wiring, and the distribution transformer.

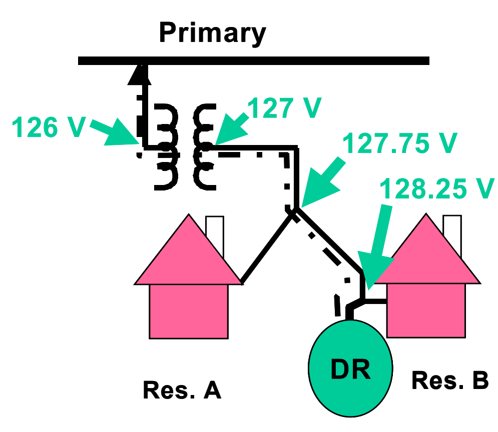

Figure 2-9
DG on End-User Premises Can Cause High Voltage at That Location

Procedure

The following discussion presents a spreadsheet approach to calculating secondary voltage rise or drop associated with the utilization of a DG.

The procedure for calculating voltage rise on a secondary is the same as calculating voltage drop on a secondary. The basics steps are as follows:

1. Gather system data:
   - Draw a sketch (similar to Figure 2-10) of the system from the primary side of the distribution transformer to all services supplied by that transformer.
   - Record transformer data (Vp, Vs, MVA, %Z, and X/R ratio) on the sketch.
   - Record secondary line section types, conductor sizes, and lengths on the sketch
   - Record measured or estimated load and generator data on the sketch.
2. Transcribe system data to spreadsheet. Obtain line impedance data from available conductor characteristics charts.
3. Perform spreadsheet calculations using complex math functions:
   - Determine transformer complex impedance in ohms as seen on secondary side.
   - For each secondary line section, calculate complex line impedance in ohms.
   - Convert load data to complex current data assuming nominal line voltage at zero-degree angle.
   - Assuming transformer primary is an infinite bus, use calculated load currents and impedance to determine voltage drop/rise at each node of the lines serving the loads.

Example

Several case studies are presented utilizing the spreadsheets to demonstrate the effects of DG on secondary voltage depending on how the DG is operated. The case studies assumed that the distribution system is operating at 105% of nominal system voltage. Figure 2-10 illustrates the system that the spreadsheets are based on.

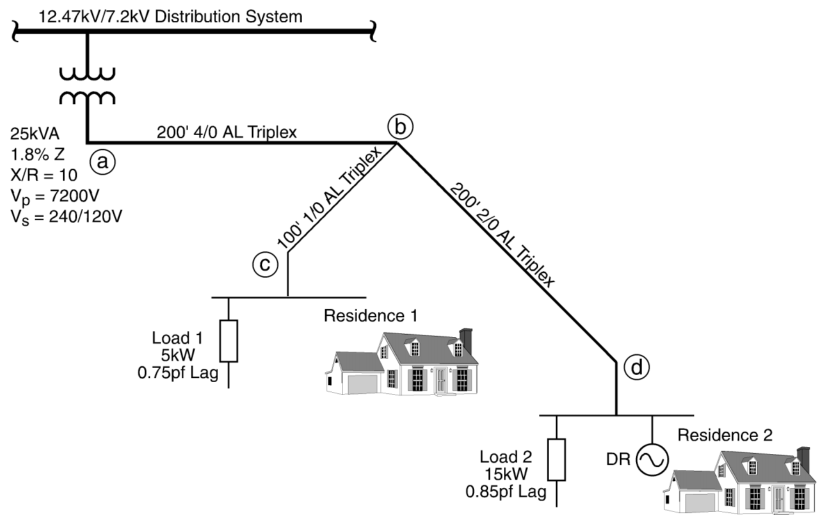

Figure 2-10
Example Secondary Power System for Voltage Drop/Rise Considerations

Table 2-14 presents the base case spreadsheet used to calculate voltages Va, Vb, Vc, and Vd representative of the voltages at locations a, b, c, and d in Figure 2-10. The base case assumes that the generator is off-line. The spreadsheet approach assumes that the distribution system serving the transformer acts as an infinite bus. Step 2 of the spreadsheet multiplies the line impedance data by two, accounting for single-phase voltage drop on both the supply and return conductors. If this were a balanced three-phase system, lack of neutral return current would eliminate the need for doubling the impedance calculations. Another assumption is that load currents may be calculated by conjugating the complex load data and then dividing the conjugated results by the nominal secondary voltage. Note that in Table 2-14, step 3, the term 'S_n*"represents the conjugate of the load 'S_n."In reality, changes in voltage will affect load current. Therefore, a more accurate analysis would require an iterative calculation method, adjusting voltage for iterative current calculations.

The base case (Table 2-14) indicates typical secondary and service voltages as a result of loading without DG operation. The resulting voltage drop magnitudes are presented in bold under step 4 of Table 2-14. Note that the voltage magnitudes are provided for system voltages (|Vn| volts) and then converted to a 120-V base (|Vn| 120 volts) in the far right-hand column. As can be seen, the base case gradual reductions in voltages from transformer secondary to the loads are common where a DG is not utilized.

Table 2-14
Base Case Analysis of Secondary Voltage Drop

Case: Base
Description: Load 1 and Load 2 are motor loads with no DG.

Transformer Data:

Vp (kV)	Vs (kV)	kVA	%Z	X/R
7.2	0.24	25	1.8	10

Line Data:

Line	Length(ft)	Size	Type	Table Data: R' (ohms/kFt)	X' (ohms/kFt)
ab	200	4/0	Triplex Aluminum	0.1000	0.0266
bc	100	1/0	Triplex Aluminum	0.2002	0.0284
bd	200	2/0	Triplex Aluminum	0.1587	0.0277

Load Data:

Load	Magnitude	Unit	PF (lag)
S_1	5	kW	0.75
S_2	15	kVA	0.85
S_2 Gen	0	kVA	0.00

Calculations Utilizing Complex Math:

1) Convert transformer data to complex impedance.
As seen from the secondary side of the transformer;
|Zt|=Zpu*Vs^2*1000/kVA
Rt=(|Zt|^2/((X/R)^2+1))^.5
Xt=(Zt^2-Rt^2)^.5

	Rt (ohms)	Xt (ohms)	|Zt| (ohms)	Complex, ohms
Zt=	0.00413	0.04127	0.04147	4.12661823523887E-003+4.12661823523887E-002i

2) Express line impedance data in complex form.
Rxy = Length(ft)*R' (ohms/kFt)*2
Xxy = Length(ft)*X' (ohms/kFt)*2

	Rxy (ohms)	Xxy (ohms)	|Zxy| (ohms)	Complex ohms
Zab=	0.04000	0.01064	0.0414	4E-002+1.064E-002i
Zbc=	0.04004	0.00568	0.0404	4.004E-002+5.68E-003i
Zbd=	0.06348	0.01108	0.0644	6.348E-002+1.108E-002i

3) Convert load data to complex form.

Load	P(W)	jQ(Var)	|S_n| (VA)	Complex VA
S_1=	5000.000	4409.586	6666.667	5000+4409.58551844098i
S_2=	12750.000	7901.740	15000.000	12750+7901.74031463955i
S_2 Gen=	0.000	0.000	0.000	0
S_2 net=	12750.000	7901.740	15000.000	12750+7901.74031463955i

Note: If Q<0, then powerfactor is lagging
Assume: I_n = S_n*/Vs

	Re	Im	|I_n| (Amps)	Complex Amps
I_1=	20.8333	-18.3733	27.7778	20.8333333333333-18.3732729935041i
I_2=	53.1250	-32.9239	62.5000	53.125-32.9239179776648i
I_tot=	73.9583	-51.2972	90.0069	73.9583333333333-51.2971909711689i

4) Calculate voltage drop from Voltage impedance and current information.
Let the primary system voltage, Vp', be 5% above the nominal 7200 V or 7560 angle 0. Then;
Va=Vp'(Vs/Vp)-(I_tot)Zt
Vb=Va-(I_tot)Zab
Vc=Vb-(I_1)Zbc
Vd=Vb-(I_2 net)Zbd

	Re	Im	**|Vn| (Volts)**	Complex Volts	**|Vn| (120 V base)**
Vp'=	7560.0000	0.0000	**7560.0000**	7560	**126.0000**
Va=	249.5780	-2.8403	**249.5941**	249.577962956237-2.84029414613392i	**124.7971**
Vb=	246.0738	-1.5753	**246.0789**	246.07382751097-1.57532317395383i	**123.0394**
Vc=	245.1353	-0.9580	**245.1372**	245.1353006537-0.957990656627259i	**122.5686**
Vd=	242.3367	-0.0739	**242.3367**	242.336655499777-7.39378607316701E-002i	**121.1683**

Table 2-15 provides the summary of secondary voltages calculated from case studies performed based on the system previously illustrated in Figure 2-10. The spreadsheets summarized in Table 2-15 are provided in Table 2-16, Table 2-17, and Table 2-18.

Table 2-15
Summary of Secondary Voltage Case Studies

Case>>	Base			2			3			4		
	Volts	PU	120 V	Volts	PU	120 V	Volts	PU	120 V	Volts	PU	120 V
Vp'=	7560.0	1.050	126.0	7560.0	1.050	126.0	7560.0	1.050	126.0	7560.0	1.050	126.0
Va=	249.6	1.040	124.8	244.9	1.020	122.4	252.1	1.051	126.1	246.0	1.025	123.0
Vb=	246.1	1.025	123.0	241.5	1.006	120.7	253.5	1.056	126.7	246.7	1.028	123.4
Vc=	245.1	1.021	122.6	239.6	0.998	119.8	251.6	1.048	125.8	244.9	1.020	122.4
Vd=	242.3	1.010	121.2	240.3	1.001	120.2	258.6	1.078	129.3	252.0	1.050	126.0

Case>>	Description
Base	Load 1 and Load 2 are motor loads with no DG.
2	Load 2 has an Induction generator capable of matching load 2's power consumption. Since an induction machine requires Vars to operate, it is assumed the generator consumes the same Vars as required by Load 2.
3	A 25 kVA synchronous generator running at full load exceeds Loads 1 and 2 power requirements while matching Loads 1 and 2's reactive requirement.
4	A 25 kVA synchronous generator running at full load exceeds Loads 1 and 2 power requirements. Voltage is controlled by allowing the generator to consume Vars.

In Case 2 (Table 2-16), while utilization of the generator reduces power consumption through the meter, the additional Vars required by the induction generator results in a net increase in current through the transformer and common secondary conductor. Therefore, the operation of the induction generator DG results in lower voltages experienced by both residences.

The synchronous generator, in Case 3 (Table 2-17), provides all the Vars required by loads 1 and 2 while surpassing these load power requirements, resulting in reverse power flow through the secondary conductors and transformer. With the transformer primary acting as an infinite bus, the voltage on the primary does not change. Therefore, change in voltage across the transformer and secondary conductors resulting from the current associated with the reverse power flow causes the voltage at the load point to be seen as a rise or high-voltage condition. When the primary system is operating at maximum limits allowed by ANSI C84.1, the resulting high voltage due to reverse power flow from a DG may be severe enough to damage end-use equipment.

Case 4 (Table 2-18) demonstrates a method to maximize reverse power flow from a DG while controlling voltage by allowing a synchronous generator to run with a lagging power factor. In this mode of operation, the voltage drop across the conductors and transformer due to the current associated with the Vars consumed by the generator counters the voltage rise associated with the reverse power flow. This mode of operation may be beneficial to the operator of the DG by allowing the operator to reduce or sale back kW-hours to the utility. However, the added Var demand on the system may force the utility to have to add additional power-factor correction to the primary distribution system.

Table 2-16
Example Case 2 Induction Generator at Load 2

Case: 2

Description: Load 2 has an Induction generator capable of matching load 2's power consumption. Since an induction machine requires Vars to operate, it is assumed the necessary Vars for the generator are the same as the Vars required by the existing load.

Transformer Data:

Vp (kV)	Vs (kV)	kVA	%Z	X/R
7.2	0.24	25	1.8	10

Line Data:

Line	Length(ft)	Size	Type	Table Data: R' (ohms/kFt)	X' (ohms/kFt)
ab	200	4/0	Triplex Aluminum	0.1000	0.0266
bc	100	1/0	Triplex Aluminum	0.2002	0.0284
bd	200	2/0	Triplex Aluminum	0.1587	0.0277

Load Data:

Load	Magnitude	Unit	PF (lag)
S_1	5	kW	0.75
S_2	15	kVA	0.85
S_2 Gen	15	kVA	0.85

Calculations Utilizing Complex Math:

1) Convert transformer data to complex impedance.
   As seen from the secondary side of the transformer;
   |Zt|=Zpu*Vs^2*1000/kVA
   Rt=(|Zt|^2/((X/R)^2+1))^.5
   Xt=(Zt^2-Rt^2)^.5

	Rt (ohms)	Xt (ohms)	|Zt| (ohms)	Complex, ohms
Zt=	0.00413	0.04127	0.04147	4.12661823523887E-003+4.12661823523887E-002i

2) Express line impedance data in complex form.
   Rxy = Length(ft)*R' (ohms/kFt)*2
   Xxy = Length(ft)*X' (ohms/kFt)*2

	Rxy (ohms)	Xxy (ohms)	|Zxy| (ohms)	Complex ohms
Zab=	0.04000	0.01064	0.0414	4E-002+1.064E-002i
Zbc=	0.04004	0.00568	0.0404	4.004E-002+5.68E-003i
Zbd=	0.06348	0.01108	0.0644	6.348E-002+1.108E-002i

3) Convert load data to complex form.

Load	P(W)	jQ(Var)	|S_n| (VA)	Complex VA
S_1=	5000.000	4409.586	6666.667	5000+4409.58551844098i
S_2=	12750.000	7901.740	15000.000	12750+7901.74031463955i
S_2 Gen=	-12750.000	7901.740	15000.000	-12750+7901.74031463955i
S_2 net=	0.000	15803.481	15803.481	15803.4806292791i

   Note: If Q<0, then powerfactor is lagging
   Assume: I_n = S_n*/120

	Re	Im	|I_n| (Amps)	Complex Amps
I_1=	41.6667	-36.7465	55.5556	41.6666666666667-36.7465459870082i
I_2net=	0.0000	-131.6957	131.6957	-131.695671910659i
I_tot=	41.6667	-168.4422	173.5191	41.6666666666667-168.442217897667i

4) Calculate voltage drop from Voltage impedance and current information.
   Let the primary system voltage, Vp', be 5% above the nominal 7200 V or 7560 angle 0. Then;
   Va=Vp'(Vs/Vp)-(I_tot)Zt
   Vb=Va-(I_tot)Zab
   Vc=Vb-(I_1)Zbc
   Vd=Vb-(I_2 net)Zbd

	Re	Im	**|Vn| (Volts)**	Complex Volts	**|Vn| (120 V base)**
Vp'=	7560.0000	0.0000	**7560.0000**	7560	**126.0000**
Va=	244.8771	-1.0243	**244.8792**	244.877090293926-1.02432753672227i	**122.4396**
Vb=	241.4182	5.2700	**241.4757**	241.418198428828+5.27002784585108i	**120.7379**
Vc=	239.5411	6.5047	**239.6294**	239.541144714288+6.50469288050422i	**119.8147**
Vd=	239.9590	13.6301	**240.3458**	239.959010384058+13.6300690987397i	**120.1729**

Table 2-17
Example Case 3 Synchronous Generator Matching Loads 1 and 2 Reactive Power Requirements

Case: 3

Description: A 25 kVA synchronous generator running at full load exceeds Loads 1 and 2 power requirements while matching Loads 1 and 2's reactive requirement.

Transformer Data:

Vp (kV)	Vs (kV)	kVA	%Z	X/R
7.2	0.24	25	1.8	10

Line Data:

				Table Data:	
Line	Length(ft)	Size	Type	R' (ohms/kFt)	X' (ohms/kFt)
ab	200	4/0	Triplex Aluminum	0.1000	0.0266
bc	100	1/0	Triplex Aluminum	0.2002	0.0284
bd	200	2/0	Triplex Aluminum	0.1587	0.0277

Load Data:

Load	Magnitude	Unit	PF (lag)
S_1	5	kW	0.75
S_2	15	kVA	0.85
S_2 Gen	25	kVA	-0.87

Calculations Utilizing Complex Math:

1) Convert transformer data to complex impedance.
As seen from the secondary side of the transformer;
|Zt|=Zpu*Vs^2*1000/kVA
Rt=(|Zt|^2/((X/R)^2+1))^.5
Xt=(Zt^2-Rt^2)^.5

	Rt (ohms)	Xt (ohms)	|Zt| (ohms)	Complex, ohms
Zt=	0.00413	0.04127	0.04147	4.12661823523887E-003+4.12661823523887E-002i

2) Express line impedance data in complex form.
Rxy = Length(ft)*R' (ohms/kFt)*2
Xxy = Length(ft)*X' (ohms/kFt)*2

	Rxy (ohms)	Xxy (ohms)	|Zxy| (ohms)	Complex ohms
Zab=	0.04000	0.01064	0.0414	4E-002+1.064E-002i
Zbc=	0.04004	0.00568	0.0404	4.004E-002+5.68E-003i
Zbd=	0.06348	0.01108	0.0644	6.348E-002+1.108E-002i

3) Convert load data to complex form.

Load	P(W)	jQ(Var)	|S_n| (VA)	Complex VA
S_1=	5000.000	4409.586	6666.667	5000+4409.58551844098i
S_2=	12750.000	7901.740	15000.000	12750+7901.74031463955i
S_2 Gen=	-21758.476	-12311.326	25000.000	-21758.4755033923-12311.3258330805i
S_2 net=	-9008.476	-4409.586	10029.809	-9008.47550339232-4409.58551844099i

Note: If Q<0, then powerfactor is lagging
Assume: I_n = S_n*/120

	Re	Im	|I_n| (Amps)	Complex Amps
I_1=	41.6667	-36.7465	55.5556	41.6666666666667-36.7465459870082i
I_2net=	-75.0706	36.7465	83.5817	-75.070629194936+36.7465459870082i
I_tot=	-33.4040	0.0000	33.4040	-33.4039625282693

4) Calculate voltage drop from Voltage impedance and current information.
Let the primary system voltage, Vp', be 5% above the nominal 7200 V or 7560 angle 0. Then;
Va=Vp'(Vs/Vp)-(I_tot)Zt
Vb=Va-(I_tot)Zab
Vc=Vb-(I_1)Zbc
Vd=Vb-(I_2 net)Zbd

	Re	Im	**|Vn| (Volts)**	Complex Volts	**|Vn| (120 V base)**
Vp'=	7560.0000	0.0000	**7560.0000**	7560	**126.0000**
Va=	252.1378	1.3785	**252.1416**	252.137845400898+1.37845400898392i	**126.0708**
Vb=	253.4740	1.7339	**253.4799**	253.474003902029+1.7338721702847i	**126.7400**
Vc=	251.5970	2.9685	**251.6145**	251.596950187489+2.96853720493784i	**125.8072**
Vd=	258.6466	0.2330	**258.6467**	258.64663917286+0.23298400250931i	**129.3234**

Table 2-18
Example Case 4 Synchronous Generator Consuming Vars to Control Voltage

Case: 4

Description: A 25 kVA synchronous generator running at full load exceeds Loads 1 and 2 power requirements. Voltage is controlled by allowing the generator to consume Vars.

Transformer Data:

Vp (kV)	Vs (kV)	kVA	%Z	X/R
7.2	0.24	25	1.8	10

Line Data:

Line	Length(ft)	Size	Type	Table Data: R' (ohms/kFt)	X' (ohms/kFt)
ab	200	4/0	Triplex Aluminum	0.1000	0.0266
bc	100	1/0	Triplex Aluminum	0.2002	0.0284
bd	200	2/0	Triplex Aluminum	0.1587	0.0277

Load Data:

Load	Magnitude	Unit	PF (lag)
S_1	5	kW	0.75
S_2	15	kVA	0.85
S_2 Gen	25	kVA	0.97

Calculations Utilizing Complex Math:

1) Convert transformer data to complex impedance.
As seen from the secondary side of the transformer;
|Zt|=Zpu*Vs^2*1000/kVA
Rt=(|Zt|^2/((X/R)^2+1))^.5
Xt=(Zt^2-Rt^2)^.5

	Rt (ohms)	Xt (ohms)	|Zt| (ohms)	Complex, ohms
Zt=	0.00413	0.04127	0.04147	4.12661823523887E-003+4.12661823523887E-002i

2) Express line impedance data in complex form.
Rxy = Length(ft)*R' (ohms/kFt)*2
Xxy = Length(ft)*X' (ohms/kFt)*2

	Rxy (ohms)	Xxy (ohms)	|Zxy| (ohms)	Complex ohms
Zab=	0.04000	0.01064	0.0414	4E-002+1.064E-002i
Zbc=	0.04004	0.00568	0.0404	4.004E-002+5.68E-003i
Zbd=	0.06348	0.01108	0.0644	6.348E-002+1.108E-002i

3) Convert load data to complex form.

Load	P(W)	jQ(Var)	|S_n| (VA)	Complex VA
S_1=	5000.000	4409.586	6666.667	5000+4409.58551844098i
S_2=	12750.000	7901.740	15000.000	12750+7901.74031463955i
S_2 Gen=	-24294.725	5896.300	25000.000	-24294.7246600985+5896.3i
S_2 net=	-11544.725	13798.040	17990.736	-11544.7246600985+13798.0403146396i

Note: If Q<0, then powerfactor is lagging
Assume: I_n = S_n*/120

	Re	Im	|I_n| (Amps)	Complex Amps
I_1=	41.6667	-36.7465	55.5556	41.6666666666667-36.7465459870082i
I_2net=	-96.2060	-114.9837	149.9228	-96.2060388341545-114.983669288663i
I_tot=	-54.5394	-151.7302	161.2346	-54.5393721674878-151.730215275671i

4) Calculate voltage drop from Voltage impedance and current information.
Let the primary system voltage, Vp', be 5% above the nominal 7200 V or 7560 angle 0. Then;
Va=Vp'(Vs/Vp)-(I_tot)Zt
Vb=Va-(I_tot)Zab
Vc=Vb-(I_1)Zbc
Vd=Vb-(I_2 net)Zbd

	Re	Im	**|Vn| (Volts)**	Complex Volts	**|Vn| (120 V base)**
Vp'=	7560.0000	0.0000	**7560.0000**	7560	**126.0000**
Va=	245.9637	2.8768	**245.9806**	245.963736435792+2.87676435044165i	**122.9903**
Vb=	246.5309	9.5263	**246.7149**	246.530901831958+9.52627188133056i	**123.3574**
Vc=	244.6538	10.7609	**244.8904**	244.653848117418+10.7609369159837i	**122.4452**
Vd=	251.3640	17.8914	**252.0000**	251.364042121432+17.8913981180573i	**126.0000**

3
TEMPORARY OVERVOLTAGES

Background

Overvoltages may be the biggest power quality concern associated with the introduction of distributed generation to existing distribution feeders. Overvoltages are generally classified according to the following terms:

- **Swell—**An increase to between 1.2 and 1.8 per unit in rms voltage at the power frequency for durations from 0.5 cycles to one minute. It is suggested to use a prefix to indicate swell duration, such as instantaneous, momentary, or temporary[2]. On distribution systems, swells are generally caused by neutral shifts during line-to-ground faults.
- **Transient—**Pertaining to or designating a phenomenon or a quantity that varies between two consecutive steady states during a time interval that is short compared to the time scale of interest. A transient can be a unidirectional impulse of either polarity or a damped oscillatory wave with the first peak in either direction[1]. Transients can be caused by several phenomena, including:
  - Lightning
  - Switching surges
  - Ferroresonance

DG can make overvoltages more likely and introduce additional modes where swells and transients can be created. Most of these situations involve islands that develop when a utility protective device operates and leaves a section of distribution circuit "islanded" without the utility power. This can cause:

- Swells during islanding caused by ungrounded generators
- Ferroresonance during islanding
- Self-excitation during islanding
- Switching surges from reclosing into an island that is out of phase with the utility

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[2] IEEE Std. 1159-1995, *IEEE Recommended Practice for Monitoring Electric Power Quality.*

Voltage Swells

The EPRI Distribution Power Quality (DPQ) study indicates that high-magnitude swells are not as common as sags or momentary interruptions. Figure 3-1 shows that most swells are below 125% of the nominal system voltage. On average, only about 1.7 swells per year above 125% were recorded during the study.

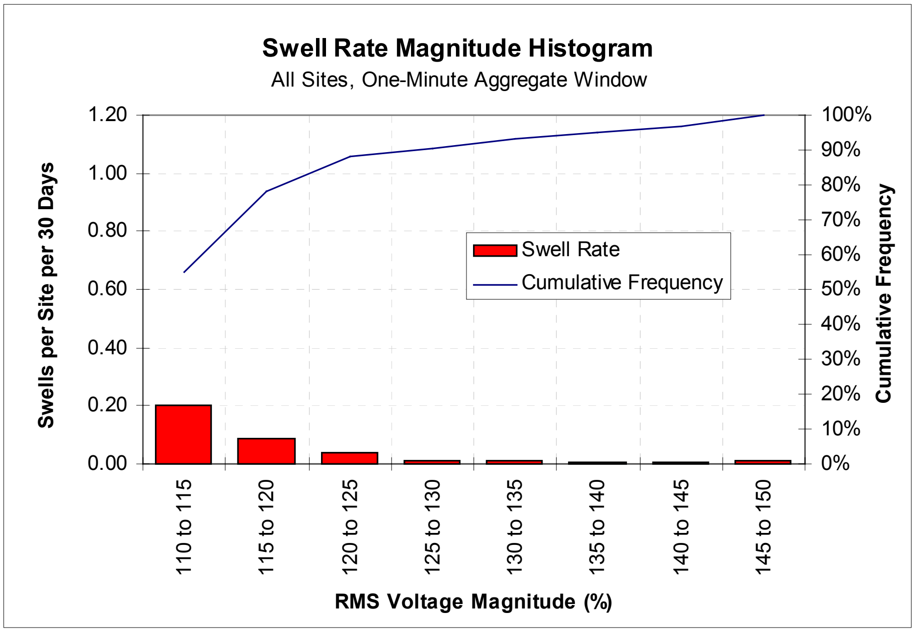


Figure 3-1
DPQ Results for Voltage Swells[3]

Grounding type will determine the magnitude of the neutral shift (and the swell). An ungrounded system presents the worst case—voltages on the unfaulted phases can rise to •3 = 1.73 per unit. The IEEE Working Group on the Neutral Grounding of Distribution Systems provided the multipliers given in Table 3-1. These include the temporary overvoltage plus an extra 5% for a steady-state overvoltage at the same time.

[3] *An Assessment of Distribution System Power Quality- Volume 2: Statistical Summary Report,* EPRI, Palo Alto, CA: 1996. TR-106294-V2.

Table 3-1
IEEE System Overvoltage Magnitude Multiplier as a Function of Grounding

Type of Grounding	Overvoltage Multiplier
Ungrounded	1.82•V_{LG}
Four-wire multigrounded (spacer cable)	1.5•V_{LG}
Three or four-wire unigrounded (open wire)	1.4•V_{LG}
Four-wire multi-grounded (open wire-gapped)	1.25•V_{LG}
Four-wire multigrounded (open wire-MOV)	1.35•V_{LG}*

* Because the metal-oxide varistor (MOV) arrestor is more sensitive to poor grounding, poor regulation, and the reduced saturation sometimes found in newer transformers, many utilities are using a 1.35 factor.

V_{LG} = Nominal line-to-ground voltage of the system

Transient Overvoltages

Transient overvoltages, such as the one in Figure 3-2, are more common than swells. Figure 3-3 shows that events above 1.6 per unit were uncommon in the DPQ study.

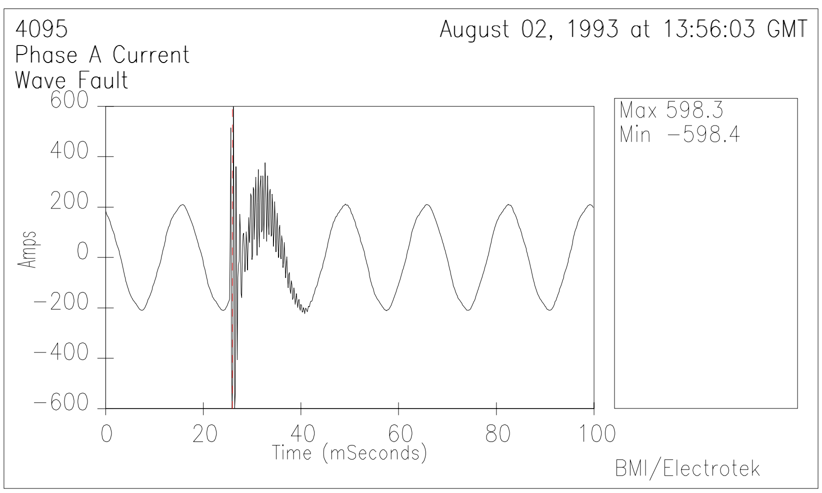


Figure 3-2
Voltage Transient From Back-to-Back Capacitor Switching From the EPRI DPQ Study[2]

Impacts of Overvoltages

The impacts of overvoltages on end-use and utility equipment can usually be broken down into the following categories:

- **Insulation failures**—Failures usually result from breakdown of insulation (including sparkovers through the air). These can be caused by transients (usually lightning) or voltage swells (due to neutral shifts). Motors are also sensitive to temporary and transient overvoltages. Arresters are sensitive to swells.

- **Power electronic failures**—Power electronics do not have much overvoltage capability and are very sensitive to swells and transient overvoltages.
- **Tripping of sensitive equipment**—Because power electronics are sensitive to overvoltages, many electronic devices will trip offline very quickly when an overvoltage situation is detected. The most common occurrence of such tripping is with adjustable-speed drives.

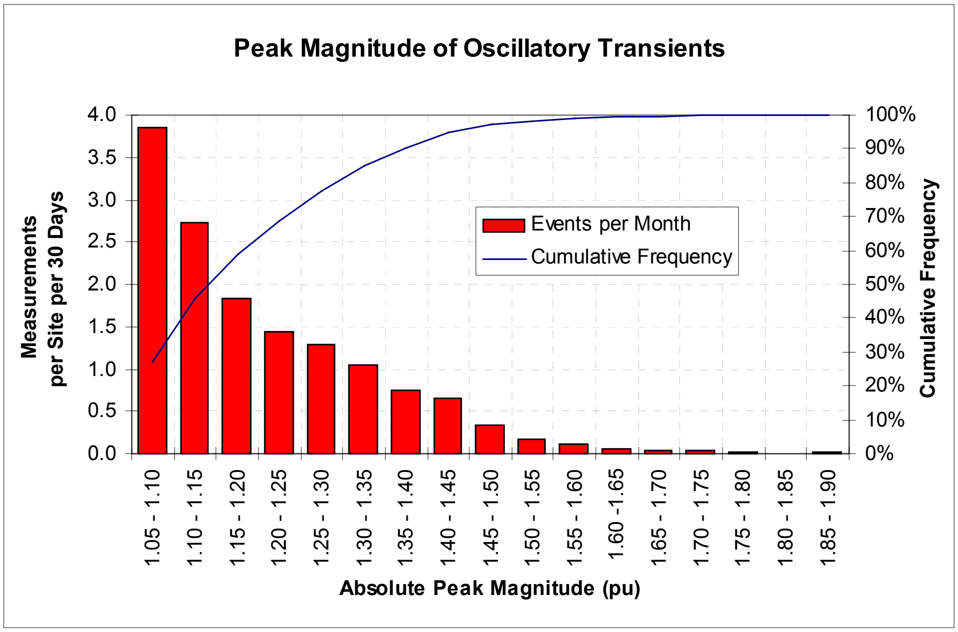


Figure 3-3
DPQ Results for Oscillatory Transients[2]

Screening a New DG Installation for Overvoltage Concerns

Background

In the case of DG-caused overvoltages, some basic information about the type of distribution system, type of DG, the interconnection transformer, and the available protection schemes can help determine the likelihood of future problems. Therefore, navigating a flowchart with a few simple questions about the DG installation can help screen out configurations that may exhibit excessive overvoltages.

Procedure

This screening provides a tool to check distributed generation installations for characteristics that are known to lead to transient overvoltages. It is should not be considered foolproof and is most certainly not a substitute for an interconnection study.

- To determine if a distributed generation-caused overvoltage problems may result from the installation under consideration, navigate the flowchart in Figure 3-4.
- A result of Pass indicates that the installation does not possess any typical characteristics that can lead to overvoltages. However, it is possible that overvoltages will still occur.

The conclusion for further system study is based on the presence of one or more system characteristics that suggest transient overvoltages may be a problem at the installation.

Distributed generation-caused overvoltage considerations are directly related to the various grounding aspects of the installation. To that end, much of the information needed to navigate the following flow chart involves the interconnection components that affect the installation's grounding. Additionally, many of the nodes of the flowchart are examined in further detail later in this chapter. Table 3-2 provides a list of the flowchart nodes and where to find further information on those topics in this chapter.

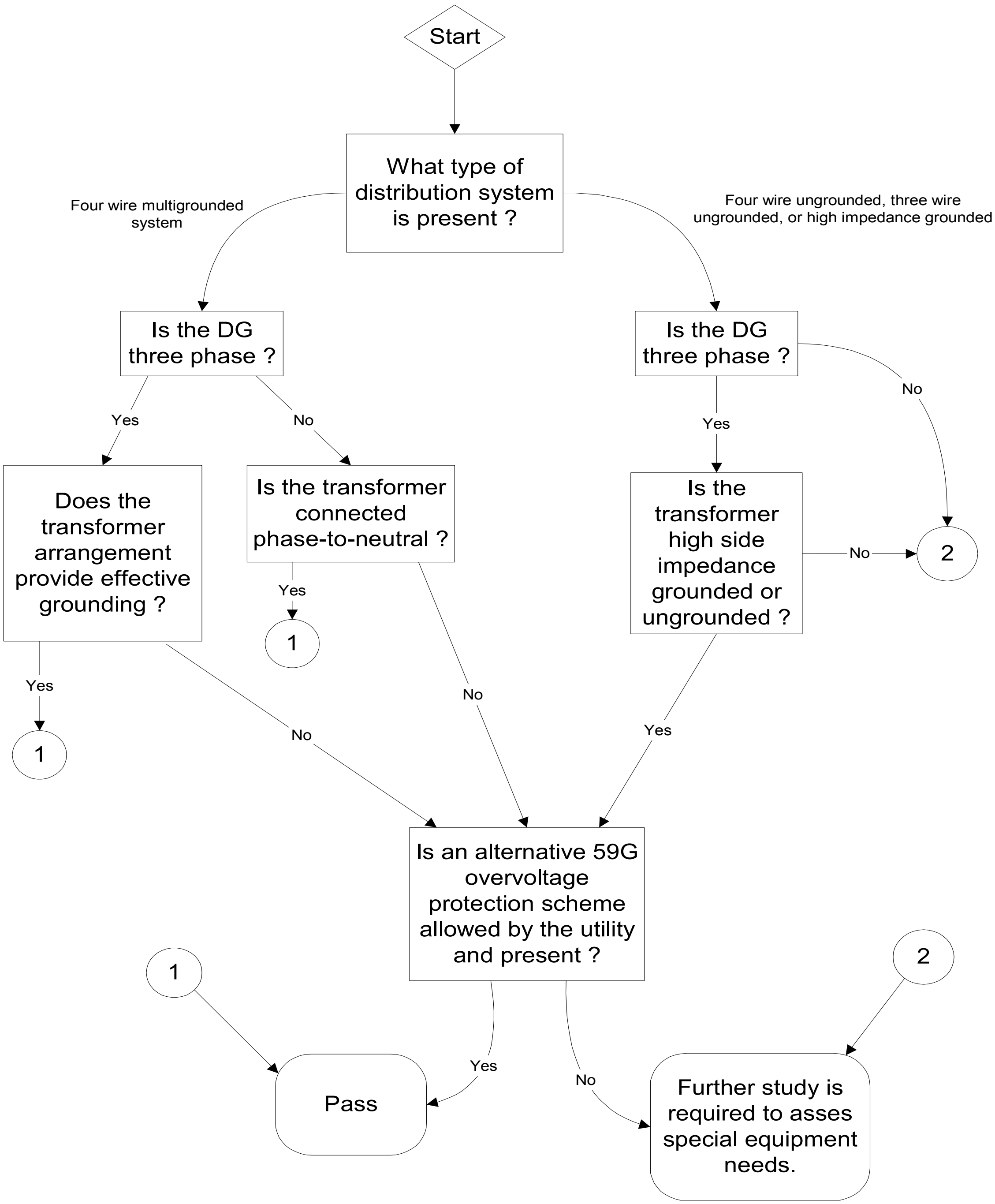


Figure 3-4
Overvoltage Screening Tool for DG Installations

Table 3-2
Further Information About Overvoltage Flowchart Nodes in This Chapter

Node	For Further Discussion (Section Name in This Chapter)
Is the installation effectively grounded?	Islanding Voltages
Is the interconnection transformer high side ungrounded or high-impedance grounded?	Islanding Voltages
Is a 59G relay scheme or transfer trip protection scheme allowed by the utility and used at the installation?	DG Voltage Relay Settings

Examples

Paper Mill Example 1

A paper mill decides to install a 4-MW gas fired turbine to supply facility electrical power and process steam. The installation will be connected in parallel with the utility grid in order to sell excess capacity back to the grid. The utility circuit is a three-phase, four-wire multi-grounded neutral system. The interconnection transformer is a delta high side to delta low side configuration, and there is not a 59G or transfer trip protection scheme planned.

The flowchart for this configuration is shown in Figure 3-5. This example fails the screening, indicating that further study is needed. The primary reason why the system failed the screening is that the system in not effectively grounded (the delta on the high side of the transformer is the giveaway). More information on effective grounding can be found in “Islanding Voltage” in this Chapter.

Paper Mill Example 2

Reconsider the circuit in Example 1 but change the interconnection transformer to a grounded-wye high side/delta low side configuration. The information in “Islanding Voltage” in this chapter indicates that this configuration does provide effective grounding. This alters the path as shown in Figure 3-6, and the result becomes a Pass.

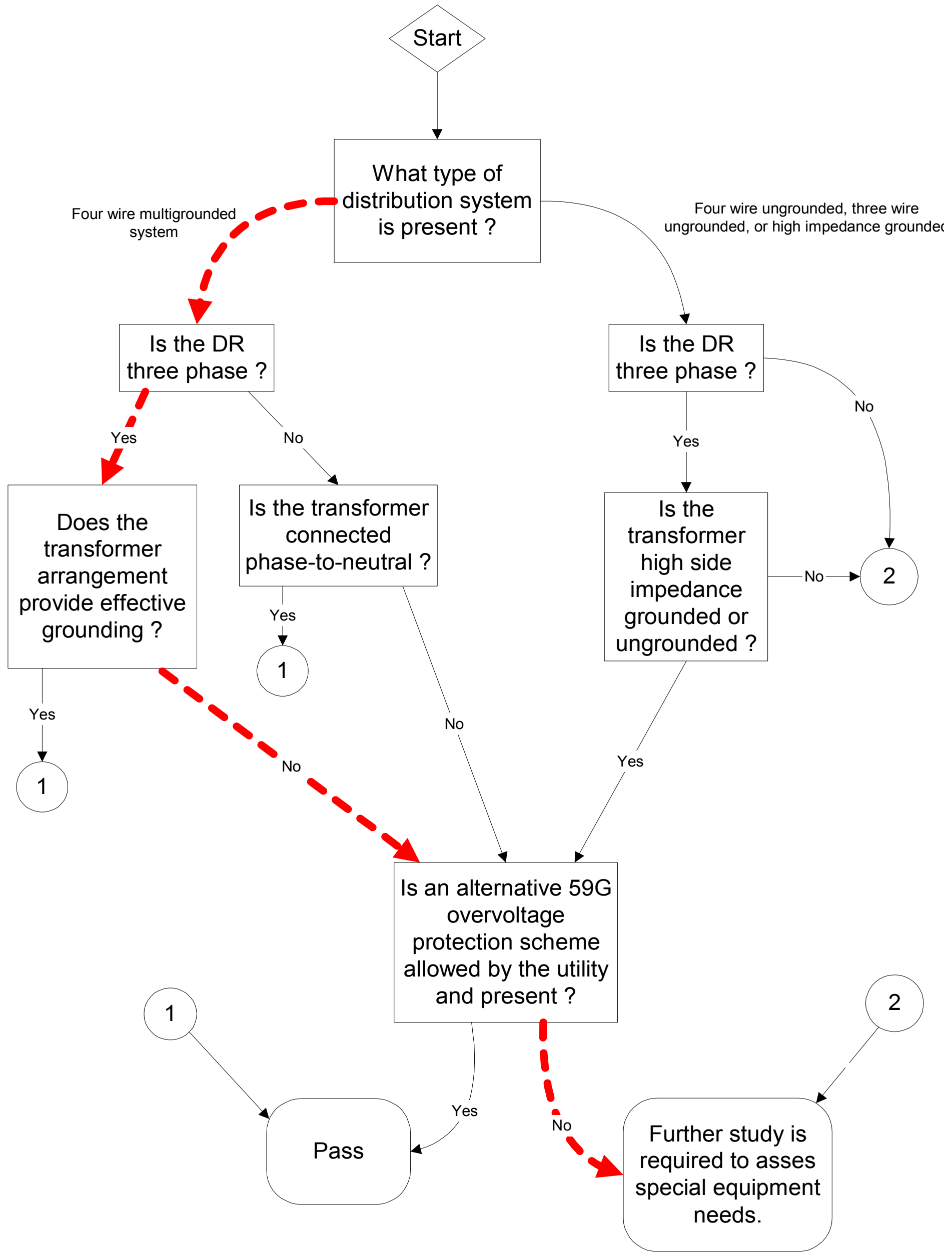


Figure 3-5
Overvoltage Screening for Paper Mill Example 1 – "Failing" Conditions

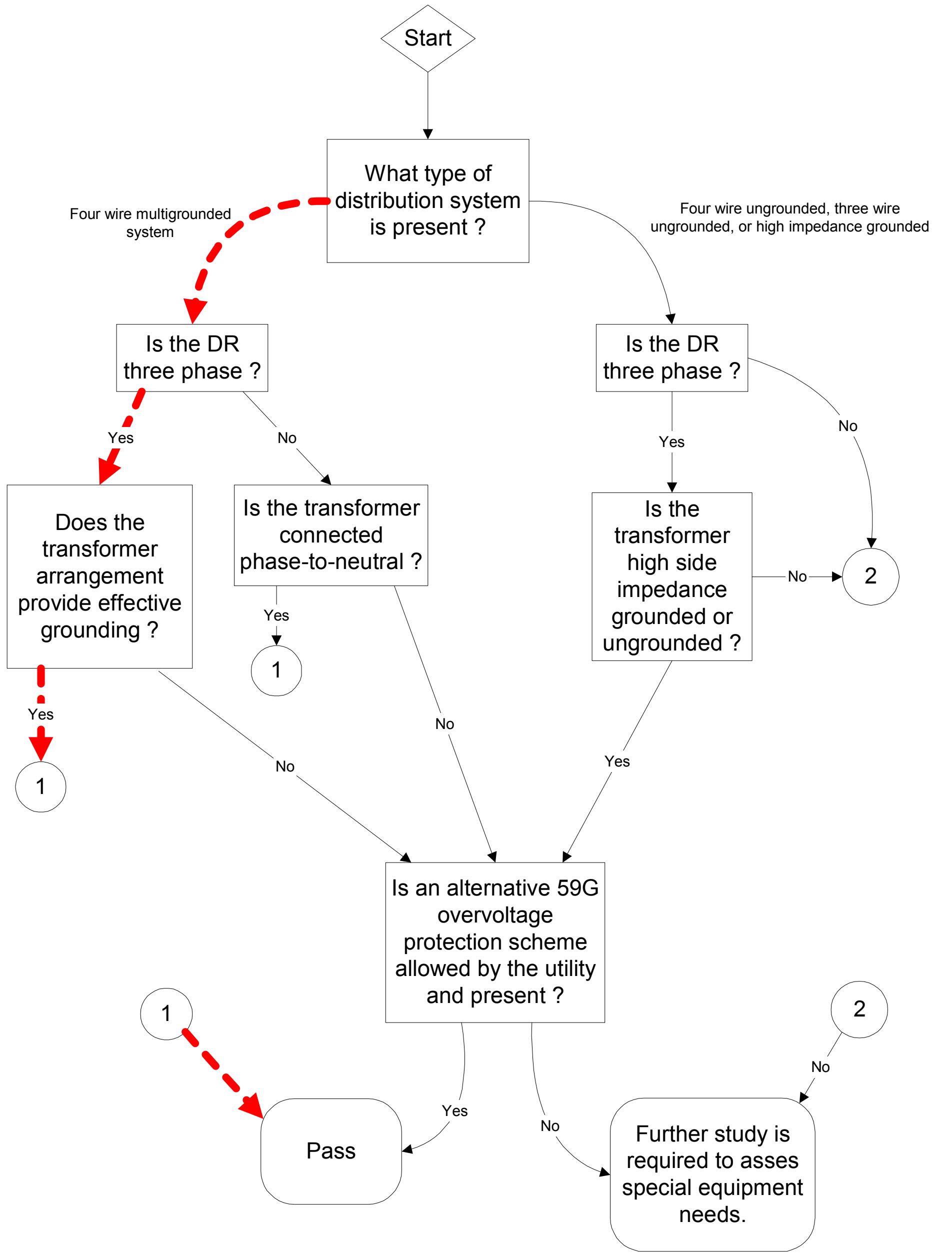


Figure 3-6
Overvoltage Screening for Paper Mill Example 2 – "Passing" Conditions

Islanding Overvoltages

Background

Most electrical distribution systems were designed for single-source radial circuits, and the installation of distributed generation (DG) on these systems can lead to islanded states of operation. An island forms when a breaker or recloser isolates a distributed generator and part of the distribution system, as shown in Figure 3-7. DG that is not effectively grounded can create severe temporary overvoltages under the islanded conditions. The distribution system normally operates as a four-wire grounded system. When the island is isolated from the distribution system during a single-phase fault, the system becomes a three-wire, ungrounded system driven by the ungrounded DG. The line-to-ground voltage of the unfaulted phases is then pushed to line-to-line voltage by the DG.

The extreme overvoltage can reach 173% of nominal. The overvoltage can cause arrester failure, can damage both utility and customer equipment, and presents a hazard to life safety.

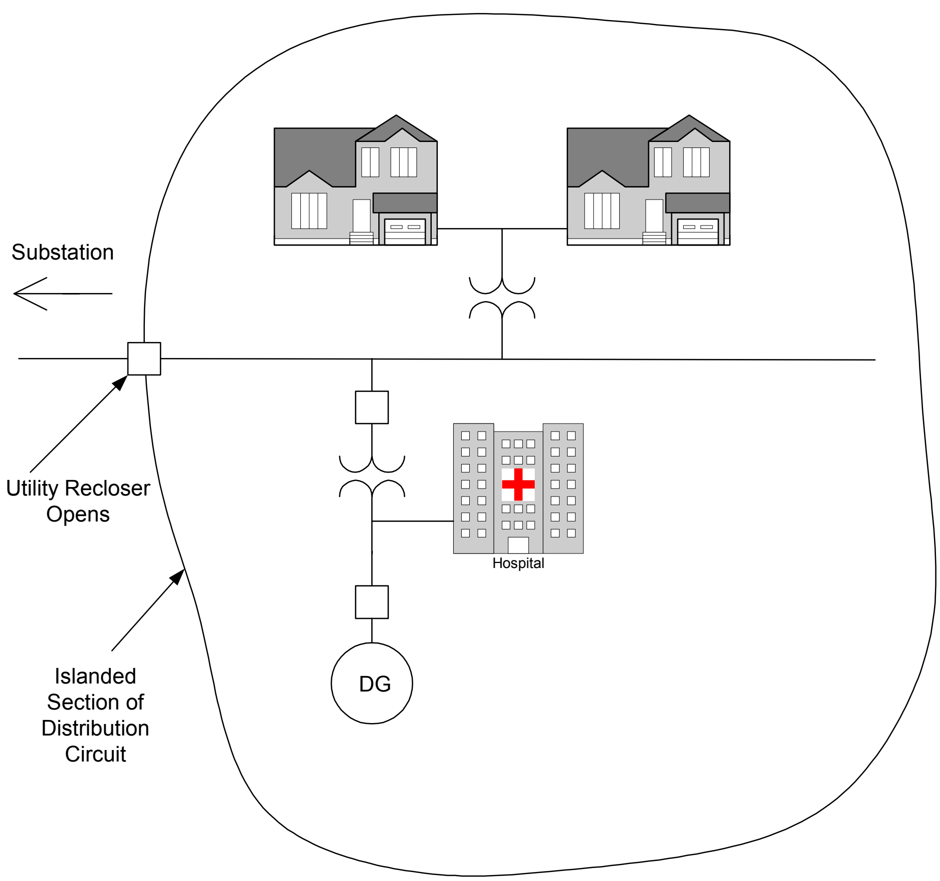


Figure 3-7
DG Island Due to Recloser Operation on a Distribution System

Effective grounding means that the zero-sequence path (the neutral and ground return path) has a sufficiently low impedance compared to the positive-sequence path. An effectively grounded system limits the neutral shift, thereby limiting the overvoltage magnitude.

Effective grounding for a distributed generator installation is measured by its X_0/X_1 ratio. X_1 is the positive-sequence reactance value for the DG installation at its point of connection to the utility feeder. X_0 is the zero-sequence reactance at the same point. Although other circuit components influence the ratio, the X_0/X_1 ratio is dominated by the transformer connection as shown in Table 3-3.

Table 3-3
Effects of Transformer Winding Type on X_0/X_1 Ratio

Winding Configuration	Effect on X_0/X_1 Ratio	X_0/X_1 Ratio
Grounded-wye/ Grounded-wye	**May be effectively grounded**—This connection allows zero-sequence currents to flow on both sides of the transformer. Zero-sequence currents will also flow within the DG facility outside of the transformer *if the DG is solidly grounded*. This connection presents a low X_0/X_1 ratio.	Low
Grounded-wye/ Ungrounded-wye	**Ungrounded**—This connection does not permit the flow of zero-sequence currents through the transformer and therefore represents a source with a very high X_0/X_1 ratio.	Very high
Grounded-wye/ Delta	**Effectively grounded**—Zero-sequence currents originating on the utility system will flow in the wye primary winding. These currents will be restricted to circulating within the delta winding of the transformer, and no zero-sequence currents will flow within the DG facility. This connection results in a low X_0/X_1 ratio, and care must be taken not to overload the transformer. Additionally, the ground protective relays for the DG breaker must be connected to current transformers on the utility side of the transformer.	Low
Delta/ Grounded-wye	**Ungrounded**—Because there is no zero-sequence path through the delta winding, the X_0/X_1 ratio is infinite.	Infinite
Delta/ Delta	**Ungrounded**—This connection is not recommended for a DG installation. The lack of a grounding point on either side of the transformer makes protection difficult and creates complications in disconnecting the DG in case of a utility fault and de-energizing the utility line in case of a DG fault. The X_0/X_1 ratio is infinite.	Infinite

Overvoltage magnitude can be estimated by transformer type because it dominates the X_0/X_1 ratio. Figure 3-8—a plot of voltage (as per unit of nominal) versus the X_0/X_1 ratio—shows that the overvoltage magnitude reaches a maximum of 173% for X_0/X_1 ratios of 30 to infinity.

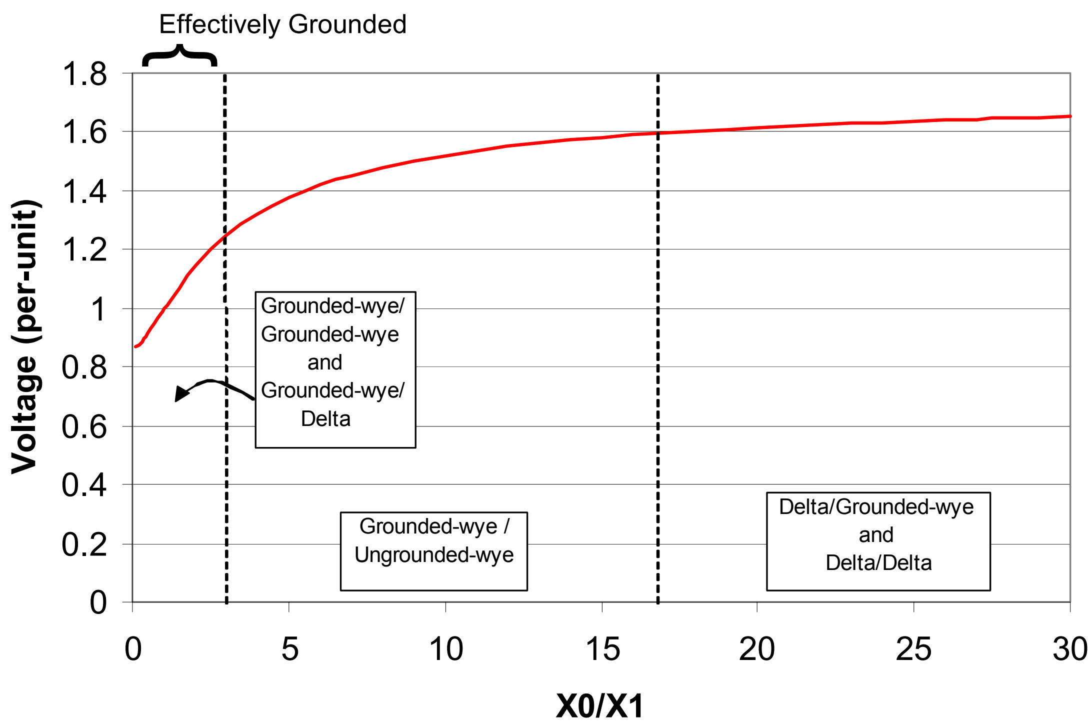


Figure 3-8
Unfaulted Phase Voltage During a Line-to-Ground Fault

Procedure

An estimate of islanding overvoltage magnitude can be made in a few simple steps:

1. Determine the winding configuration of the interconnection transformer.
2. Determine X_0/X_1 ratio for the winding type of the interconnection transformer from Table 3-3.
3. Determine the overvoltage magnitude in per unit from Figure 3-8 for the X_0/X_1 ratio determined in step 2.

A more precise determination of the overvoltage magnitude can also be made from the following equation if it is deemed necessary. The voltage on the unfaulted phases of an islanded system with a single line-to-ground fault is:

$$|V| = \sqrt{0.866^2 + \left(0.5 + \frac{(X_0/X_1) - 1}{(X_0/X_1) + 2}\right)^2} \qquad \textbf{Eq. 3-1}$$

where:

$|V|$ is the magnitude of the unfaulted phase voltage in per unit.

Certain protection practices that should be used with distributed generation, especially with a poor X_0/X_1 ratio, to limit the impact of islanding overvoltages:

- Overvoltage time-delay (59T) and instantaneous (59I) relays should be used to quickly trip the DG and limit the duration of severe overvoltages.
- Anti-islanding relaying schemes that monitor system voltage and frequency should be used to prevent an island from forming.
- Utilize transfer trip techniques to trip out the DG when the utility circuit breakers open, thus preventing the formation of an island.

DG Voltage Relay Settings

Background

Interconnection standards have been established in order to help ease the complications arising from connecting distributed generators to established electric power systems (EPSs). Recent industry standards for DG interconnection set forth trip thresholds specifying the power system conditions for which a distributed generator must trip off-line. The thresholds are intended to avoid damaging both utility and end-use equipment during abnormal power system conditions. IEEE 929, *Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*, took the lead in adopting standardized trip thresholds in 2000. The IEEE 929 recommendations are targeted at “small” systems rated at 10 kW or less. In 2001, these same trip thresholds were developed into UL 1741, *Inverter, Converters, and Controllers for Use in Independent Power Systems*. UL 1741 applies to *all* inverter-based DG, including photovoltaic systems, microturbines, fuel cells, and other inverter-based systems. The voltage-trip thresholds in 929 and 1741 are shown in Table 3-4.

In addition to IEEE 929 and UL 1741, the IEEE Standards Coordinating Committee 21 (SCC21) on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage is currently revising a standard for DG interconnection. IEEE P1547, *Draft Standard for Interconnecting Distributed*

Resources With Electric Power Systems, is currently in its tenth revision and is expected to be accepted in the near future. When accepted, IEEE P1547 will supersede IEEE 929 and UL 1741 and provide the industry standard for DG interconnection. IEEE P1547 contains DG trip thresholds similar to those found in IEEE 929 and UL 1741, as shown in Table 3-5.

Table 3-4
Standard Trip Threshold for DG Operation per IEEE 929 and UL 1471

Voltage Setting (% of Nominal)	Trip Time (Cycles)	Trip Time (Seconds)
V < 50%	6	0.1
50% • V < 88%	120	0.2
88% • V • 110%	Normal operation	Normal operation
110% < V < 137%	120	2
V • 137%	2	0.033

Table 3-5
Standard Trip Threshold for DG Operation per IEEE 1547 Draft 10

Voltage Setting (% of Nominal)	Clearing Time[a] (Seconds)
V < 50%	0.16
50% ≤ V < 88%	2
88% ≤ V • 109%	Normal operation
110% < V < 120%	1
V • 120%	0.16
Note. (a) DR ≤ 30 kW, Maximum Clearing Times DR > 30 kW, Default Clearing Times	

Nuisance Tripping

Sometimes, DG units will unnecessarily trip offline due to short-term excursions of voltage that are slightly outside the maximum steady-state operating limit of 127 volts on a 120-volt-nominal system, as defined by ANSI C84.1 Range B. Temporary high voltages on the distribution system can occur for a variety of reasons, including the loss of a single large block of load when a fuse, switch, or breaker interrupts power flow. The switching of a large power-factor-correction capacitor can also 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 will cause nuisance trips of DG that strictly adhere to the ANSI C84.1 standard.

To prevent nuisance DG trips, IEEE 929 PV, UL 1741, IEEE P1547, and many utility interconnection standards utilize voltage trip settings that allow the DG to continue to operate indefinitely while the voltage is slightly outside of ANSI C84.1 limits. For example, IEEE 929 and UL 1741 allow operation up to 130 volts (10% above normal) before they are required to trip. Draft IEEE P1547-D10, which is still in development, also allows for a +10% limit. The +10% voltage limit of these standards is in stark contrast to the +6% allowed by ANSI C84.1 but greatly reduces the number of nuisance trips on the DG system while providing overvoltage protection for the system.

Protective Relaying Solutions

Basic Protection Scheme

Protection, including over- and undervoltage and frequency relays as well as reverse-power relays (for non-exporting applications), tends to be the minimum requirements for DG interconnections, as shown in Figure 3-9. In addition to these requirements, utilities may require further protection, depending on the situation:

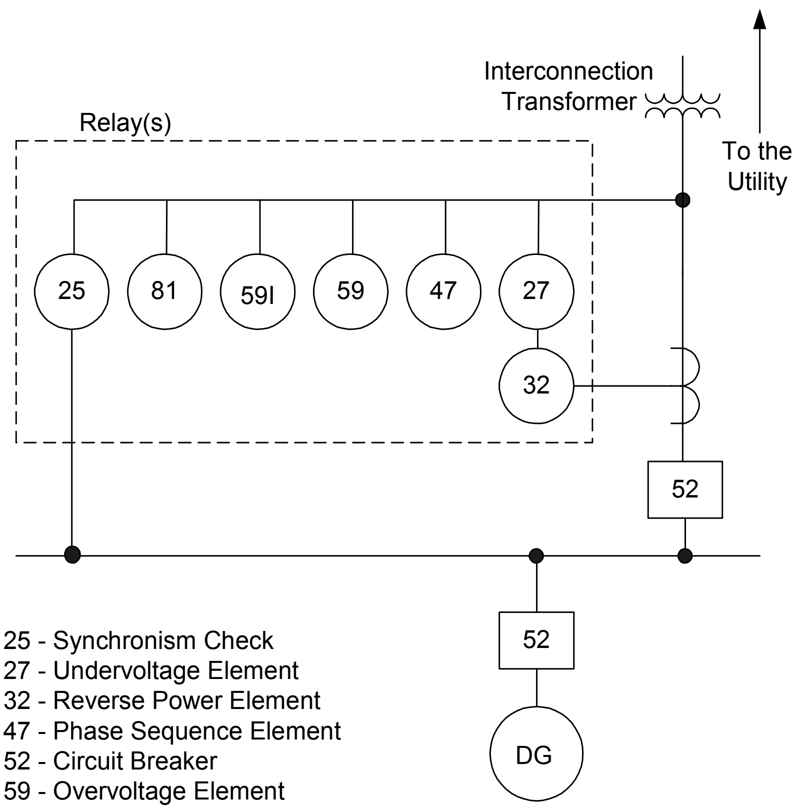
- IEEE P1547, *Standard for Interconnecting Distributed Resources With Electric Power Systems,* is recognized as the industry standard, and the trip curve presented therein should be adhered to when possible.
- Overvoltage protection should use a 59T time-delay relay with a pickup of 5 to 10% above nominal voltage. The time setting should be set above the normal clearing time of the feeder relays but less than the substation breaker reclosing time; 30 to 60 cycles is a reasonable setting[4].
- An instantaneous overvoltage element (59I) is also used. A higher setting (such as 40% above nominal) may be needed to prevent excessive nuisance trips.
- It may be desirable to place the detecting potential transformers (PTs) on the primary side of the DG transformer, especially if the primary winding is ungrounded (the neutral shift on an

[4] ANSI / IEEE Std. 1001-1988, *IEEE Guide for Interfacing Dispersed Storage & Generation Facilities with Electric Power Systems.*

ungrounded island with a ground fault will not be detected on the secondary side of the transformer).

- Relays should be on each of the three phases (not just on an individual phase and not on an average of the three phases).

In addition to magnitude, duration of a swell is important. The protective relaying should remove the overvoltage before sensitive equipment fails or trips off-line. The settings in IEEE P1547-D10 and IEEE 929 may be too high for some sensitive equipment. Figure 3-10 shows the ITIC/CBEMA curve plotted against the settings presented in the interconnection standards. There is a large area where overvoltages above the ITIC curve are allowed before the DG disconnects. Therefore, this level of protection may not be adequate for all sensitive loads.



Note: 25 - Synchronism Check
27 - Undervoltage Element
32 - Reverse Power Element
47 - Phase Sequence Element
52 - Circuit Breaker
59 - Overvoltage Element
59I - Instantaneous Overvoltage Element
81 - Frequency Element

Figure 3-9
Simple Protective Relaying Scheme for a Distributed Resource

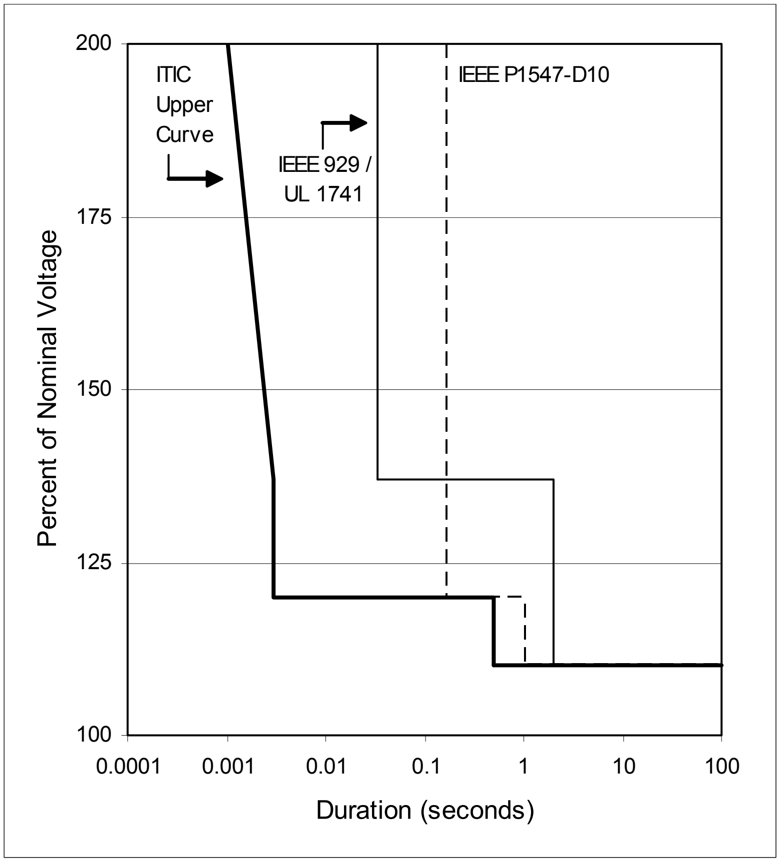


Figure 3-10
Interconnection Standards Compared to the ITIC Curve

59G Ground Fault Overvoltage Detection

Special consideration must be given to distributed generators that are connected to the distribution system through transformers with ungrounded primary windings (wye or delta). In these instances, ground fault overvoltage relays (59G) are used to detect line-to-ground faults on the distribution system causing neutral shift. The 59G protection scheme is implemented as shown in Figure 3-11 with some of the key aspects as follows:

- The relaying scheme requires the use of high-side voltage transformers (VTs) connected line-to-ground.
- The VTs should be rated for line-to-line voltage.
- The relay operates on the measurements of the sum of the three line-to-neutral voltages obtained from the grounded-wye/broken-delta PT arrangement.
- The sum of the line-to-neutral voltages will be zero under normal operating conditions but will increase substantially during fault conditions.

- The relay should be set to trip for system overvoltages in the range of 125% to 135%. This range provides adequate system protection while avoiding nuisance tripping due to background levels of zero-sequence current in the feeder.

It is important to note that the maximum overvoltage of 173% will not be reached until the substation circuit breakers open. Prior to their opening, the grounding bank effect of the substation holds the overvoltage to a somewhat lower level. Given that the overvoltage will be held below 173%, setting the relay to trip at the maximum overvoltage possible will not provide adequate protection. Conversely, there is a minimum level (1 to 3%) of zero-sequence voltage present on the feeder at all times. The relay trip point should be set above this level to avoid nuisance tripping.

Unfortunately, there are several drawbacks to this type of overvoltage protection:

- Because this protection responds to the overvoltage, it cannot stop the overvoltage from occurring. The duration of the overvoltage is then determined by the clearing time of the relay and breakers.
- If the relaying fails to operate, the overvoltage could be sustained for a significant time period.
- Primary-side PTs are required, which increases the cost and complexity of the protection scheme.

Some alternatives to the 59G ground fault detection described above include:

- Connecting a grounding bank to the high side of the interconnection transformer.
- Utilizing a transfer-trip protection scheme coordinated with the substation breakers.

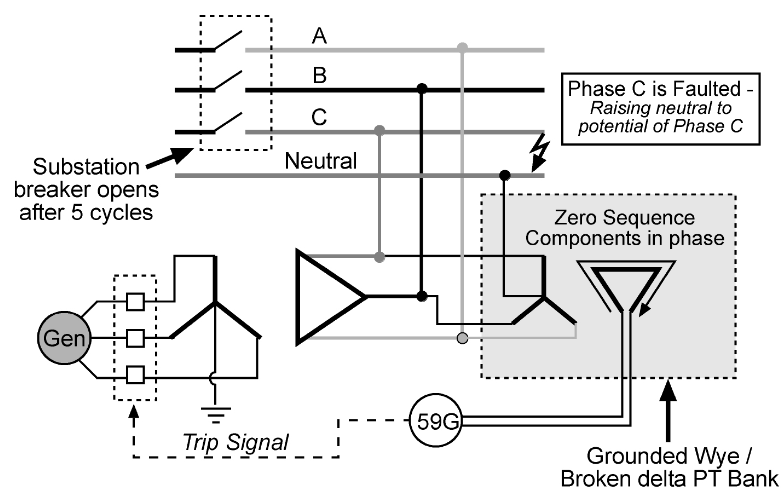


Figure 3-11
Ground Fault Overvoltage Detection Scheme (59G)

Sizing a Neutral Reactor

Background

Effectively grounded distributed generation installations limit the overvoltages caused by neutral shifts to 25% above nominal (1.25 pu). However, not all transformer configurations provide effective grounding. A grounded-wye (high side) to delta (low side) configuration is advantageous because it presents a low X_0/X_1 ratio and thus provides effective grounding. Unfortunately, the winding configuration and low zero-sequence impedance of this transformer conspire to allow large currents to circulate in the delta winding during phase-to-ground faults on the distribution system. The circulating delta current can overload the transformer, causing serious damage, and must be prevented. This configuration also feeds utility-side faults and can interfere with utility overcurrent protection.

A neutral grounding rector can be used to limit the current available from the transformer during phase-to-ground faults. Placing a grounding reactor in the return path on the neutral of the wye winding limits the available fault current and thereby limits the circulating delta current.

One drawback to using a neutral grounding reactor in this fashion is that it increases the X_0/X_1 ratio of the installation. Another way to view this situation is that adding a grounding reactor makes the installation less effectively grounded (increasing overvoltages) while it limits the available fault current for phase-to-ground faults. Therefore, the reactor must be sized to balance the level of transformer protection with the level of overvoltage reduction.

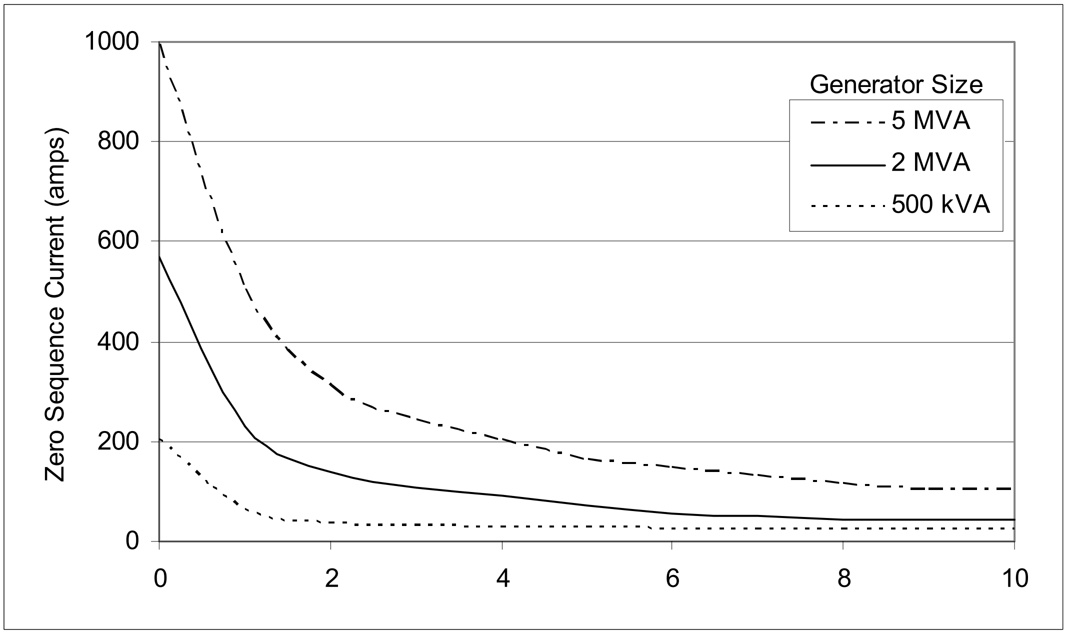
Procedure

Figure 3-12 shows the effect of neutral reactor size on overvoltage magnitude and zero-sequence fault current during a single line-to-ground fault. Use this as guidance to evaluate the best reactor size to use:

- Determine the neutral reactor size (in pu of transformer impedance) that provides the best balance of fault current and overvoltage magnitude using Figure 3-12.
- Determine the impedance of the reactor from the pu value and the system characteristics.

The grounding reactor size in Figure 3-12 is measured as a per-unit quantity of the transformer impedance. That means that if the reactor size is 1 pu it has the same impedance as the transformer. A 2 pu size equals twice the impedance of the transformer and so on. Notice that while the zero-sequence fault current contribution varies with generator size, the overvoltage magnitude does not. The graphs of Figure 3-12 are used to select a reactor size that sufficiently reduces fault current contribution while maintaining as little overvoltage magnitude as possible.

For this case, the circuit parameters were assumed to be a grounded-wye (high) to delta (low) interconnection transformer on a 12.47-kV system with 20% positive- and zero-sequence generator reactance and 5% transformer impedance. The DG is 4 miles from the substation.



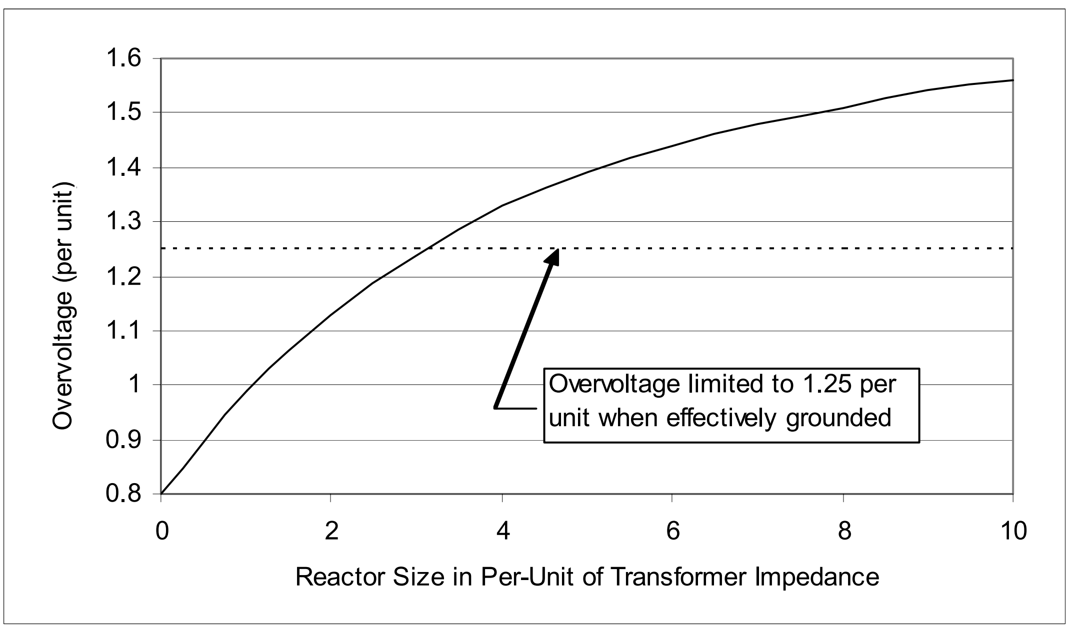


Figure 3-12
Zero Sequence Fault Contribution and Overvoltage Magnitude for a Grounded-Wye to Delta Interconnection Transformer

Example

Size a neutral grounding reactor for the system described above using the 5-MVA generator:

Step 1. Determine neutral grounding reactor size from Figure 3-12.

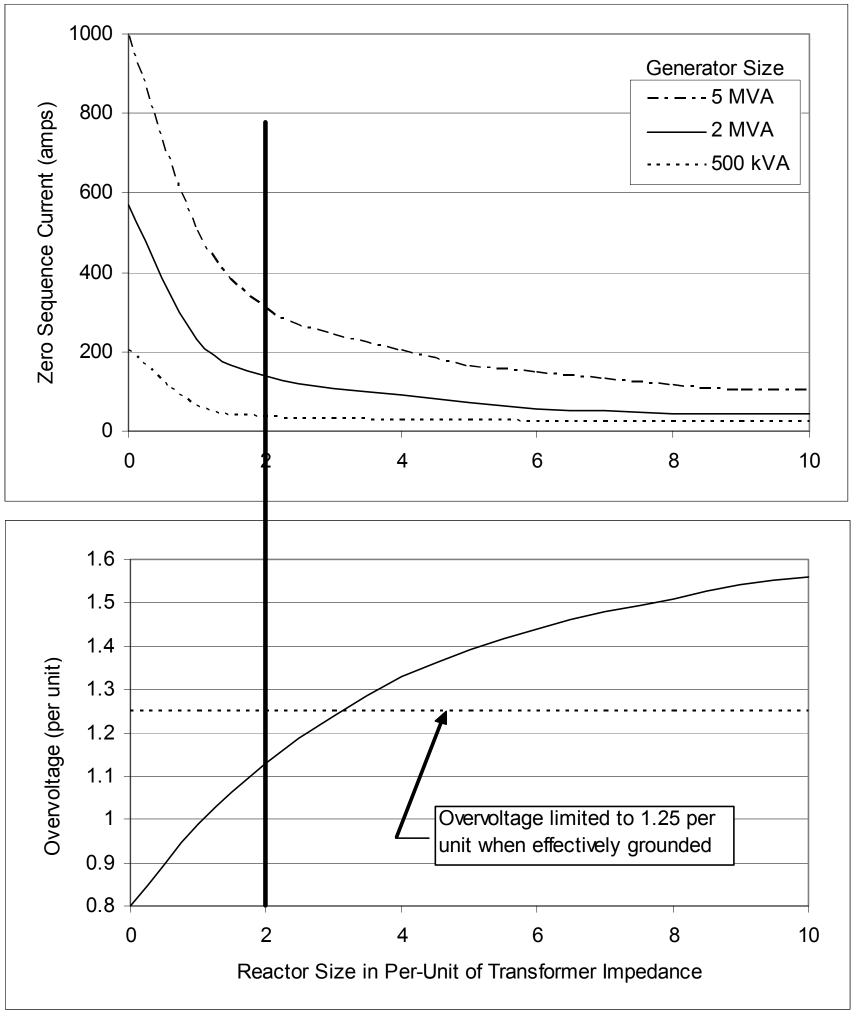


Figure 3-13
Example Application of Figure 3-12

You can see that a reactor that has twice the impedance of the interconnection transformer will limit the zero-sequence fault current contribution to 375 amps while still maintaining overvoltages below 1.15 per unit.

Step 2. Determine the impedance of the selected reactor.

- The base system impedance is: $\dfrac{12{,}470^2 \text{ volts}}{5{,}000{,}000 \text{ VA}} = 31.1\,\Omega$
- The transformer impedance is 5% of the base impedance: $31.1\,\Omega \bullet \dfrac{5}{100} = 1.55\,\Omega$
- The selected reactor size is twice the transformer impedance: $2 \bullet 1.55\,\Omega = 3.1\,\Omega$
- Therefore, a 3.1   neutral grounding reactor is required.

4

MOMENTARY INTERRUPTIONS

Background

Momentary interruptions are primarily the result of utility practices to clear temporary faults by isolating the faulted circuit through the use of reclosers or circuit breakers. IEEE Std. 1159-1995, Recommended Practice for Monitoring Electric Power Quality, defines momentary interruptions as those between 0.5 cycles and 3 seconds in duration.

The frequency of short-duration interruptions has been quantified by various power quality surveys, including the EPRI Distributed Power Quality Project. The EPRI DPQ project yields some insight to the average frequency of these events in distribution systems, as shown in Figure 4-1. The EPRI DPQ project also shows that the frequency of short-duration interruptions increases when moving from the substation to the load.

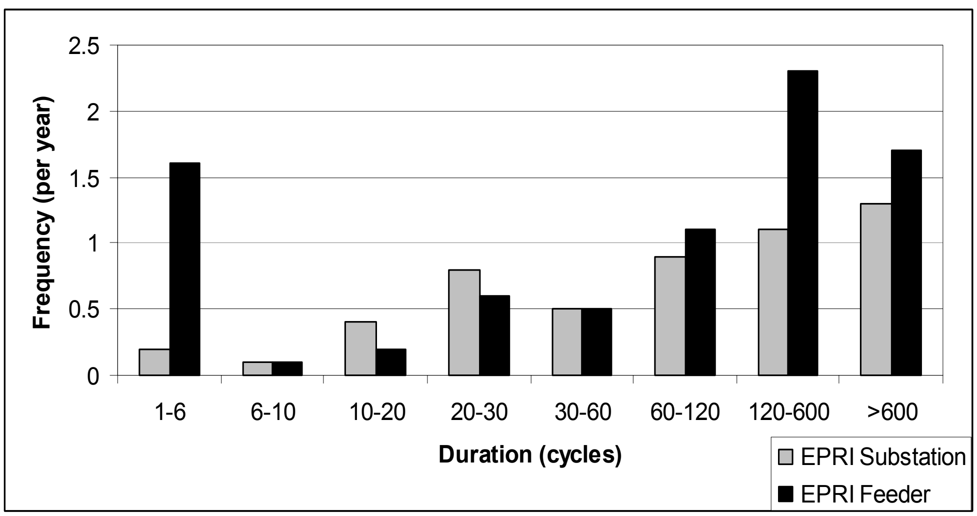


Figure 4-1
Interruption Frequency, per Year, From EPRI DPQ Study

The installation of distributed generators on radial distribution lines can impact a variety of operational parameters. This chapter presents the impact of distributed generators on:

- Nuisance tripping
- Alterations to fuse saving schemes
- Alterations to reclosing schemes

Screening a New DG Installation for Fault Current Contribution

Background

Some basic information about a distributed generation installation and the feeder it is placed on can help determine if fault current contribution from the DG will have a detrimental effect on system performance. Therefore, navigating a flowchart with a few simple questions about the DG installation can help "screen out" configurations with possible fault current contribution problems.

Procedure

This screening provides a tool to check distributed generation installations for characteristics that indicate that a fault current contribution problem may exist. It should not be considered foolproof and is most certainly not a substitute for an interconnection study.

- To determine whether fault current contribution problems may result from the installation under consideration, navigate the flowchart in Figure 4-2.
- A result of Pass indicates that the installation does not have any characteristics that typically lead to fault current contribution problems. However, it is still possible that problems will arise.
- The conclusion for further system study is based on the presence of one or more system characteristics that suggest that problems may occur due to the installation.

Examples

Educational Facility Example

An educational facility that is 6 miles out on a 13.8-kV feeder installs a 5-MW internal combustion engine/generator set to supply facility electrical power and hot water. The installation will be connected in parallel with the utility grid in order to sell excess capacity back to the grid. The installation is a three-phase, four-wire multi-grounded neutral system. The interconnection transformer is a grounded-wye high side to delta low side configuration. The generator interconnection has a primary-side short-circuit level of 1.7 kA for three-phase faults and 1.1 kA for single-phase faults (without the generator or transformer present).

The flowchart for this scenario is shown in Figure 4-3. Short-circuit analysis of the feeder with the installed DG yields an increased fault current of more than 5% for many fault locations on the feeder. The generator supplies 0.8 kA to three-phase faults and 1.5 kA to single-phase faults, both well over 5% of the utility short-circuit levels. Therefore, the screening tool result is that further consideration needs to be given to the current protection scheme to ensure adequate protection.

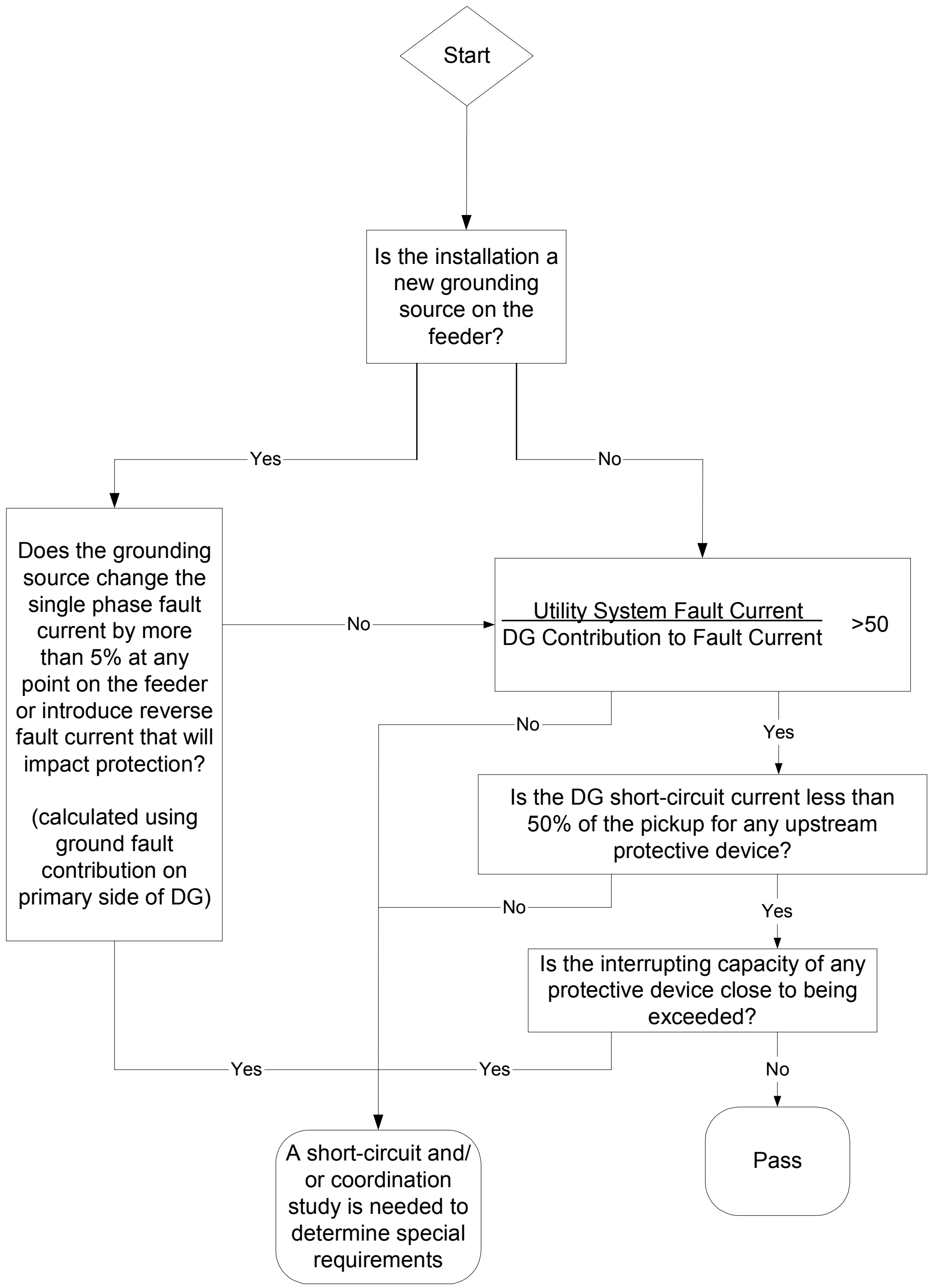


Figure 4-2
Fault Current Contribution Screening Tool for DG Installations

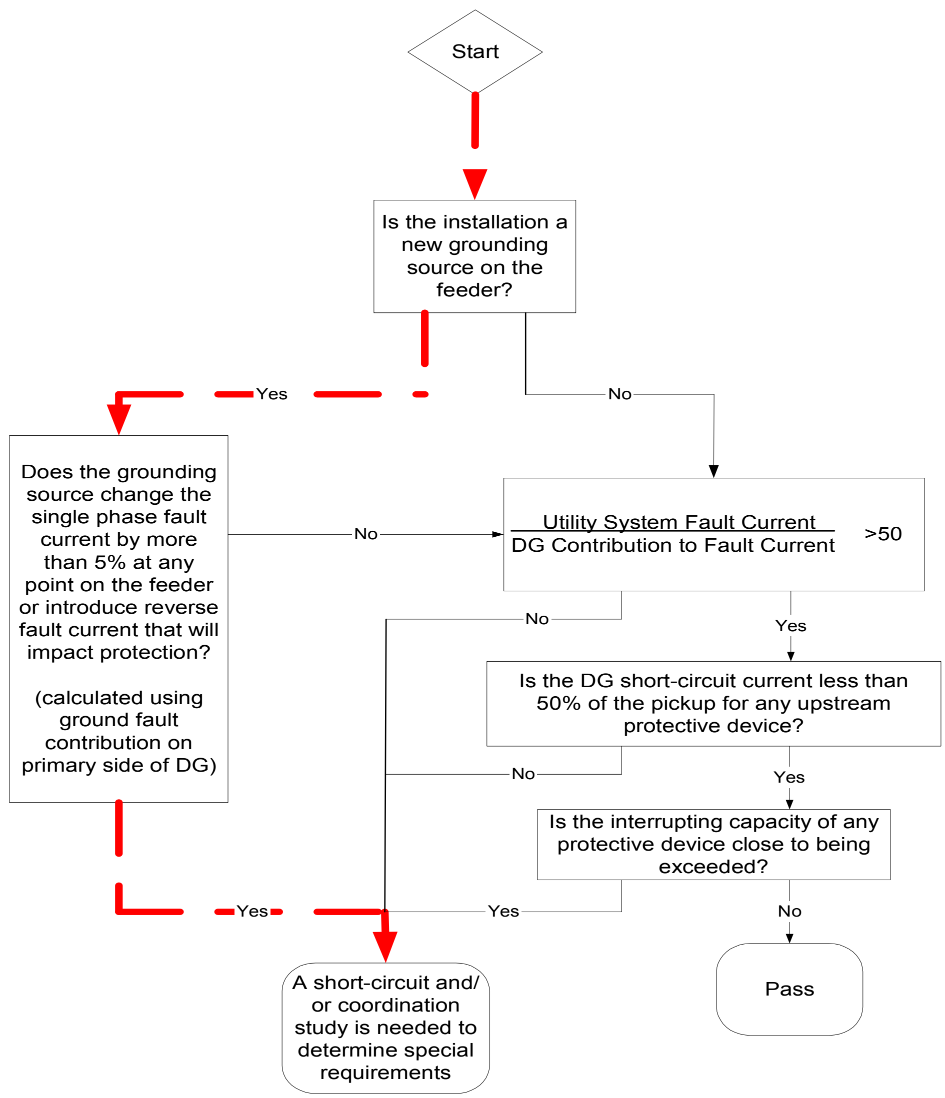


Figure 4-3
Fault Current Screening Tool for Example 1

Nuisance Tripping

Background

The application of distributed generators on electric power systems will have an influence on the operation of various overcurrent-protective devices. Because most distribution systems are radial designs intended to have only one source, the available DG fault current can cause the following undesirable events:

- False tripping operations by upstream breakers, reclosers, sectionalizers, or fuses
- Failure of sectionalizers to operate because of continued line energization
- Desensitization of breakers and reclosers
- Sympathetic tripping

While small units alone will not contribute large amounts of fault current, the aggregate total contribution of installed DG can be enough to alter short-circuit current levels. A lesser number of large DG units can have the same effect. Figure 4-4 and Figure 4-5 demonstrate scenarios where distributed generation causes an upstream protective device to operate in error.

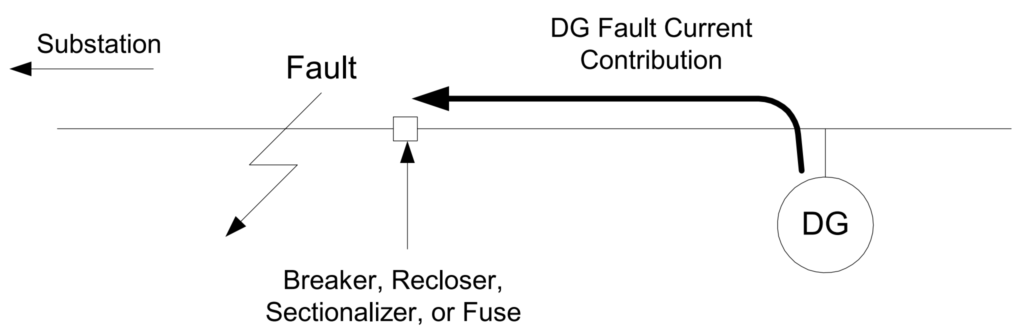


Figure 4-4
False Tripping of an Upstream Device

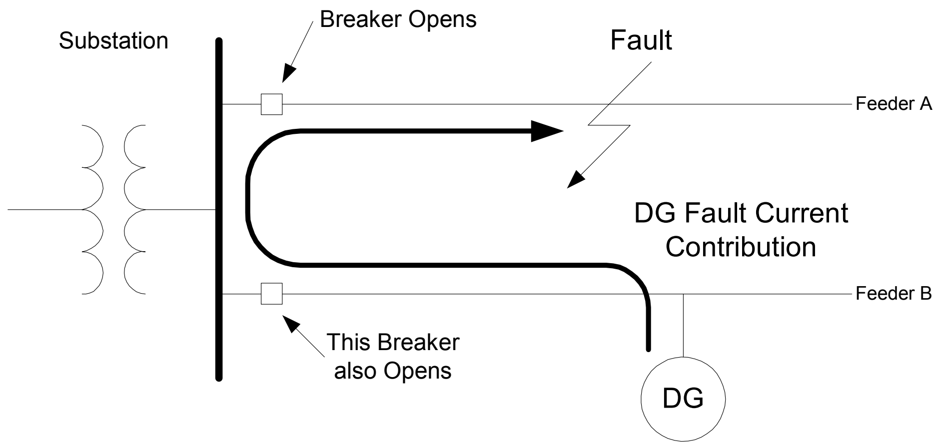


Figure 4-5
Sympathetic Tripping of a Feeder With DG

The primary factors affecting the available fault current are:

- Generator size and grounding
- Transformer type
- Fault location

Although three-phase faults generally possesses greater fault currents, this section will consider line-to-ground faults in detail for the following reasons:

- Some common DG configurations present higher ground fault currents than three-phase fault current. An example of this is a grounded rotating generator connected through a grounded-wye/grounded-wye transformer that is near the fault.
- The commonly used grounded-wye/delta interconnection transformer acts as a ground source. This allows high levels or zero-sequence current to flow towards the fault even if the generator is off-line.
- Many protective devices use ground fault pickups that are set lower than phase pickups.

The influence of the generator size and transformer type on single-phase-to-ground fault current is presented in Figure 4-6. Notice that the lowest fault contributions come from installations that are not effectively grounded. While this limits the available fault current, it does present the worst line overvoltages upon islanding. It is often necessary to compromise between low fault-current levels and low islanding overvoltages by using a neutral grounding reactor on a grounded-wye to delta interconnection transformer.

Figure 4-6 is based upon a DG installation that is 3 miles out on a 12.47-kV distribution line. The data represent the peak fault contribution to a single-phase-to-ground fault at the point of common coupling to the distribution system (the worst case). Fault contribution will decrease for faults at increasing distances from the DG.

In addition to distributed generator size, the DG grounding also impacts the available fault current contribution. Even with a grounded-wye/grounded-wye interconnection transformer, the DG will not act as a ground source unless it is properly grounded. Therefore, a grounded-wye/grounded-wye installation with an *ungrounded* generator will exhibit the same characteristics as the grounded-wye/ungrounded-wye installation in Figure 4-6.

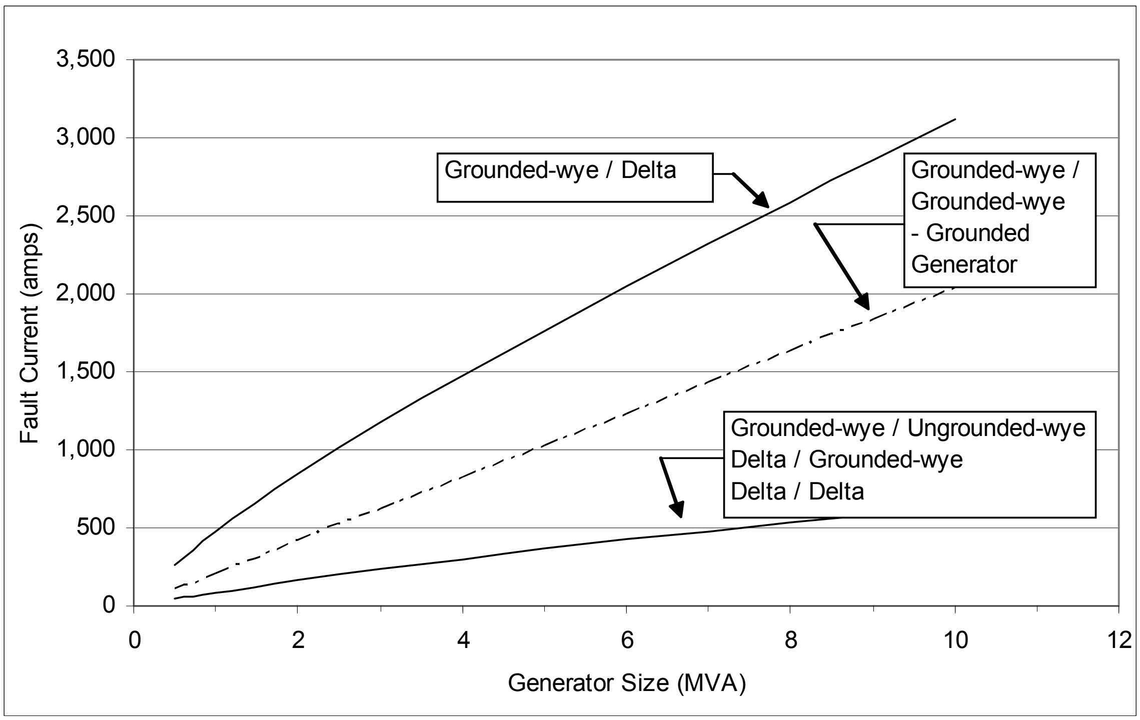


Figure 4-6
Influence of Generator Size and Interconnection Transformer Type on Single-Phase-to-Ground Fault Current Contribution

Procedure

To determine if upstream device coordination may be a problem, compare the available fault current to the pickup setting of the device. Check both three-phase faults and single-phase-to-ground faults:

- If the available fault current is below the device pickup, then the likelihood of coordination problems is greatly reduced.
- If the available fault current exceeds the device pickup, then the time characteristics of the device need to be examined. Further short-circuit analysis should be performed to verify device coordination.
- If the generator's output current is near to or more than the instantaneous pickup of the device, poor coordination can be assumed.

There are several possible solutions if a coordination problem is found:

On the distributed generation side:

- Limit the size of the generator to achieve coordination.
- Increase the impedance of the interconnection transformer or generator.
- Add a grounding reactor to the generator neutral ground connection.

On the utility side:

- Add time delay or completely disable instantaneous elements.*
- Use a higher pickup setting or slower time characteristic to coordinate with the DG.*
- Increase fuse size if it a fuse coordination problem.*
- Add a grounding reactor if the interconnection transformer has a grounded primary.

*Note that coordination with downstream protective devices must be considered when these changes are made.

The installation should be analyzed in detail when a protection coordination problem is suspected. The relatively low complexity of the problem does not warrant an EMTP type study. A short-circuit analysis program such as EPRI's DEworkstation should provide the desired functionality.

Example

Figure 4-7 shows a 5-MW synchronous DG placed 4 miles from the substation on a 12.47-kV line. A single-phase-to-ground fault develops on a lateral that is one mile from the substation and protected with a 100T fuse. There is a 200-amp hydraulic recloser on the feeder 2 miles from the substation. The utility contribution to the fault (I_sub) is 5,600 amps, while the DG fault current (I_dg) is 1,700 amps. The total fault current on the lateral (I-fault) is then 7,300 amps.

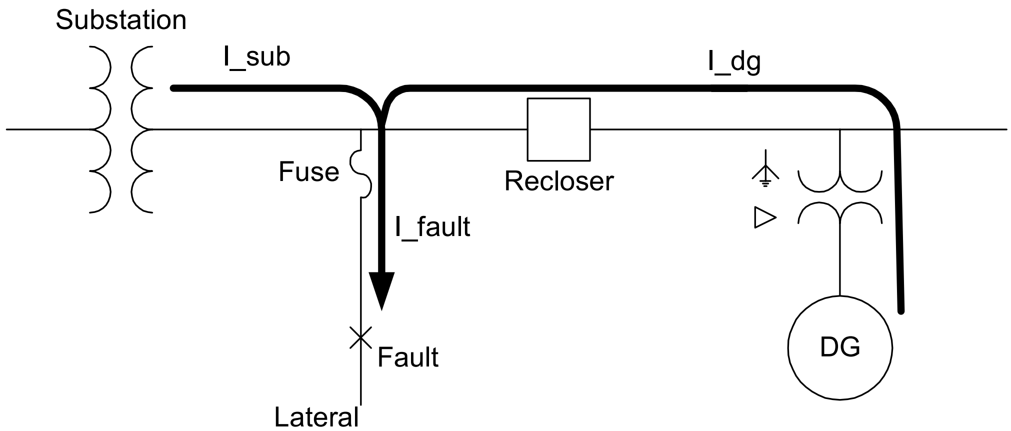


Figure 4-7
Current Flow Through a Recloser During an Upstream Fault With a Generator Downstream of the Recloser

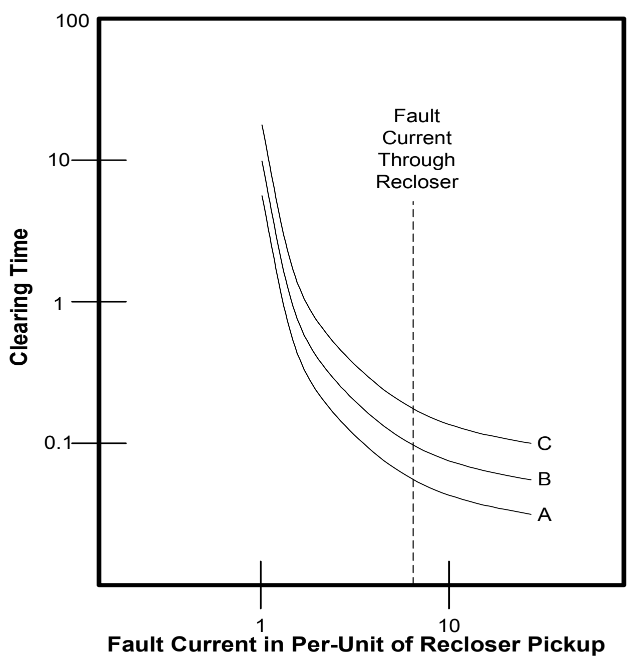


Figure 4-8
Example Recloser Curves

The feeder is operated in a breaker-saving mode, so the intended operation is for the substation circuit breaker and the recloser to remain closed while the fuse operates to clear the fault. However, as shown in Figure 4-8, the reverse flow of fault current through the recloser (I_dg) will cause it to trip for the fault on the lateral, thereby causing an unnecessary outage for all downstream customers.

In addition to false tripping of the recloser, the ability of the recloser to sense faults in the proper downstream direction may be compromised. This occurs because the DG can decrease the level of the utility fault current flowing through the recloser in the forward direction for faults downstream of the recloser.

Several options are available to correct the recloser operation:

- Change the recloser trip settings so that it will not trip for upstream faults. This may involve switching to a less sensitive trip curve and/or disabling ground fault trip settings. Care must be taken not to limit the downstream zone of protection provided by the recloser by desensitizing too much.
- Replace the existing (non-electronic) unit with an electronic recloser that allows more trip curve flexibility.
- Move the recloser to a new location on the line.
- Reduce the distributed generator's fault contribution by adding a grounding reactor or use an interconnection transformer with higher impedance.

It is important to re-evaluate all protective devices downstream of the recloser when changes are made. Both single-phase and three-phase faults must be considered. Pay particular attention to situations in which the recloser is desensitized or moved.

If the feeder is operated with a fuse-saving scheme, the intended operation will be for the substation breaker to momentarily de-energize the feeder before the lateral fuse can melt (fuse-saving is discussed in the last section of this chapter titled "Impact of Fuse Saving"). The whole feeder will see a momentary interruption, but the scheme will operate properly if:

- The substation breaker operates faster than both the lateral fuse and the recloser.
- The recloser is set to operate slower than the lateral fuse. Poor coordination could cause the recloser to trip and possibly lockout during permanent faults on the lateral.

As with the previous example, all downstream protection must be re-evaluated for any change to the protection scheme of the feeder.

Impact on Reclosing

Background

Utility reclosing practices should be re-evaluated when placing distributed generators on distribution lines. Many utilities use an instantaneous trip followed by a fast reclose to clear temporary faults on the distribution system. Synchronous or induction generators (used for DG) that are downstream of the breaker or recloser (Figure 4-9) can be seriously damaged if they are no longer in phase with the utility upon reclosing. The generator shaft and stator ends are particularly susceptible to damage from the severe torques and magnetic forces present during out-of-phase reclosing. The breaker may also be damaged during the out-of-phase reclosing.

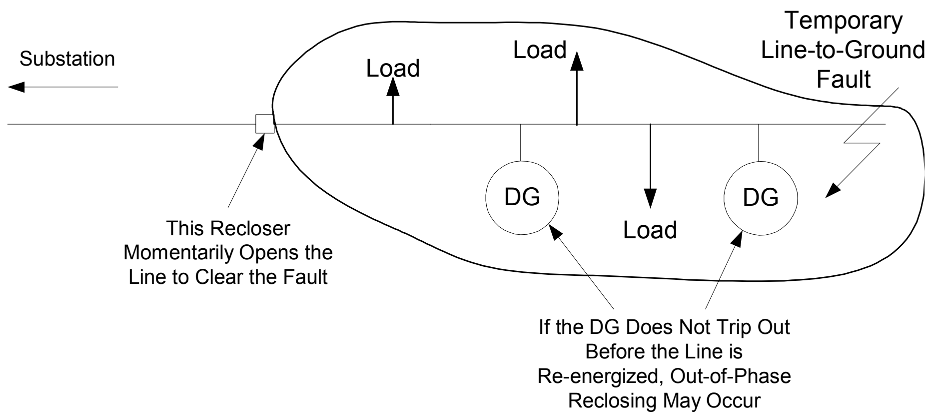


Figure 4-9
Scenario for Out-of-Phase Reclosing Between the Feeder and DG

IEEE P1547-Draft 10 addresses this issue in Clause 4.2.2, Area EPS Reclosing Coordination, as follows:

> "The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS."

Additionally, IEEE P1547-Draft 10 recommends that the DG be tripped off-line in 0.16 seconds or less when the Area EPS line voltage drops below 50%. If complied with, this level of protection will usually prevent an out-of-phase reclosing between the DG and the feeder by tripping off-line for either the initial ground fault or the resultant de-energization of the line. However, this may not hold true for situations in which the aggregate total of DG installed on the isolated feeder section is comparable in size to the connected load. These circumstances can stop the DG from tripping fast enough to avoid an out-of-phase reclosing.

Procedure

Standards pertaining to DG interconnection are still being defined as more experience with distributed generation is gained. Furthermore, it is not always possible to exactly conform to the standard. The best course of action is to examine new installations for reclosing coordination problems as well as existing installations for which coordination problems are suspected.

In order to determine if a reclosing coordination problem may exist:

1. Determine the total DG capacity on the isolated section of the feeder.
2. Determine the total load connected to the isolated section of the feeder.
3. Determine the minimum reclosing time employed.
4. Determine the maximum time in which the DG installation will trip off-line when the feeder voltage drops to zero volts.
   - If the total DG capacity on the isolated section of the feeder is 50% or more of the total load on that section, a reclosing coordination problem may exist due to islanding conditions.
   - If the minimum reclosing time of the feeder is less than the maximum tripping time of the DG a reclosing coordination problem may exist.

Several possible solutions exist to correct reclosing coordination problems:

- Simply delaying the reclosing may provide enough of a window to allow the DG to trip. Some utilities delay reclosing up to 5 seconds, depending on the situation.
- Equip the isolating device with voltage-sensing capabilities to block reclosing if voltage is present on the downstream side of the device.
- Use a transfer trip scheme to trip the DG off-line when the feeder breaker, recloser, or sectionalizer is opened. Using a transfer trip has the additional benefit of ensuring that an island will not form.
- Apply a ground switch between the isolating device and downstream DG. The switch is controlled to shunt the line to ground when the isolating device opens, thus eliminating the possibility of out-of-phase reclosing. This will also block the formation of an island.

Example

Figure 4-10 shows a section of distribution feeder that will be isolated for a fault downstream of the breaker. The isolated section of feeder contains several loads and two separate DG sources. The breaker opens instantaneously for ground faults and attempts to reclose after 0.5 seconds. Both DG installations will trip off-line in 0.16 seconds for feeder voltages below 50% nominal. Follow the steps outlined in the procedure section to determine if reclosing coordination problems are likely.

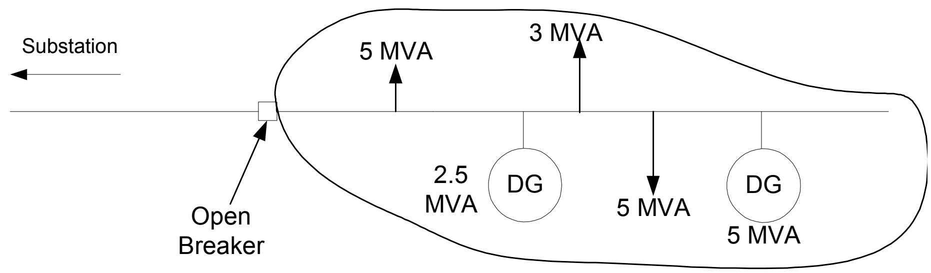


Figure 4-10
Example of Isolated Circuit Due to Temporary Ground Fault

1. Determine the total DG capacity on the isolated section of the feeder.

   7.5 MVA

2. Determine the total load connected to the isolated section of the feeder.

   13 MVA

3. Determine the minimum reclosing time employed?

   0.5 seconds

4. Determine the maximum time in which the DG installation will trip off-line when the feeder voltage drops to zero volts.

   0.16 seconds

Although the DG installation should trip off-line quickly enough to avoid reclosing problems, the installed DG is more than 50% of the total load. That is enough installed DG to suggest the isolated section of feeder may island upon separation. This could delay or completely prevent the DG from tripping off-line, thus creating a possible reclosing coordination problem.

Impact on Fuse Saving

Background

Distribution circuits often use several different devices to provide cascading layers of protection starting with the substation circuit breaker. Farther out on the line, fuses are used to connect laterals to the main line. The fuses provide a means of breaking the connection between the lateral and the main feeder in the event of a fault on the lateral. However, many of the faults on distribution lines are temporary, meaning that they can be cleared by momentarily de-energizing the line. Because fuses are one-time-use (non-resetable) devices, they are not capable of momentarily de-energizing the line, and long-term outages are created when a fuse operates. To overcome this, many utilities use fuse-saving techniques to clear temporary faults.

In a fuse-saving scheme, the substation circuit breaker is set to trip instantaneously for faults on the line. Then an attempt is made to reclose, followed by a time-delayed trip if the fault is still present on the line. The instantaneous trip is intended to clear temporary faults before the lateral fuse can melt. If the fault is still on the line when the circuit breaker recloses, the fuse will then melt due to the time-delayed action of the second trip.

The tripping coordination of the breaker and fuse can be significantly altered by the addition of distributed generation on the feeder. If the DG changes the fault current flowing through the fuse, it may cause the fuse to melt before the circuit breaker can open the line. Figure 4-11 and Figure 4-12 illustrate the increased fault current effect from adding DG to a feeder.

Procedure

To determine whether a fuse-saving scheme will be adversely affected by the installation of distributed generation:

1. Determine the maximum fault current that will flow through the fuse under consideration.

2. Using the manufacturer’s minimum melting curve, determine the minimum time in which the fuse will melt for the fault current determined in step 1.

3. If the fuse will melt in less time than the breaker can trip (instantaneous trip setting plus the time it takes the breaker contacts to open, which is typically five cycles), then fuse-breaker coordination is disrupted.

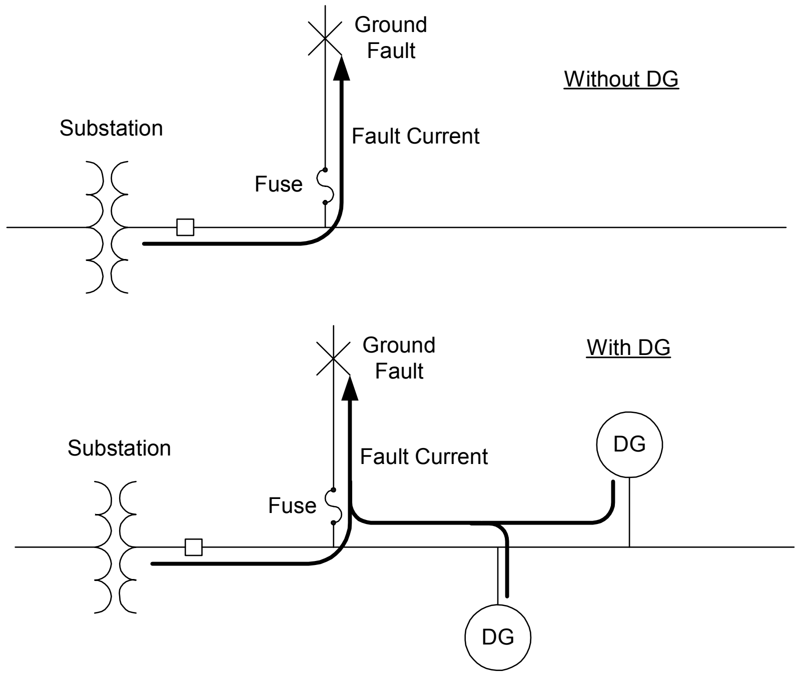


Figure 4-11
Fault Contribution of DG May Disrupt Fuse-Breaker Coordination

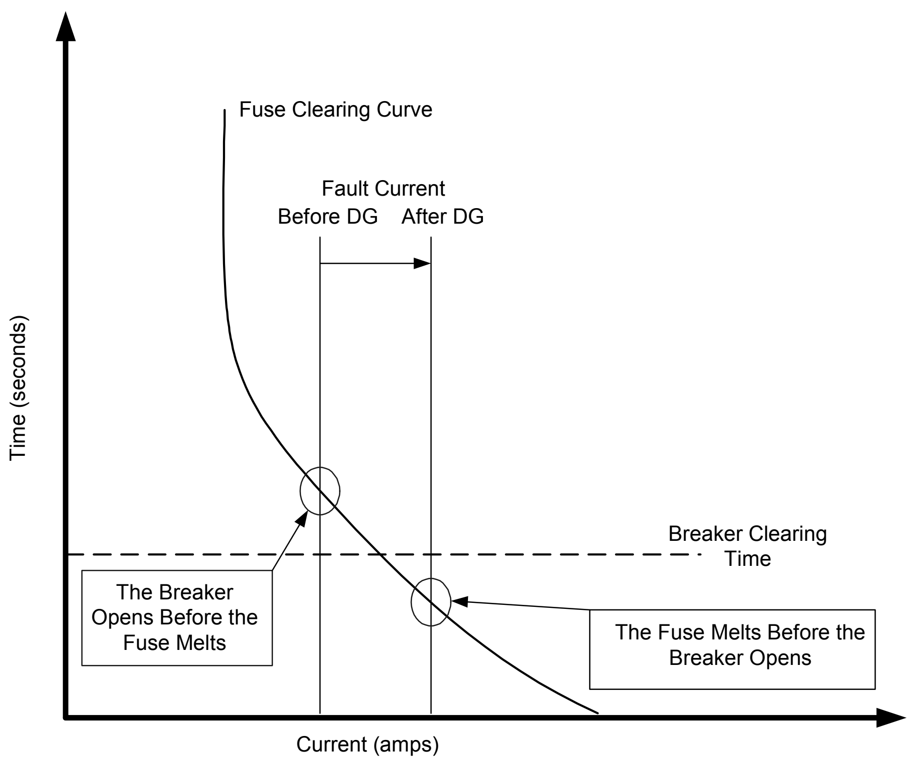


Figure 4-12
Fault Current Contribution of DG Causes Fuse to Melt Before the Breaker Opens

5
DYNAMIC ISSUES

Background

Introducing generators into the distribution system brings up a whole new set of issues that distribution engineers never had to deal with before: dynamic interactions. While these issues are often addressed in industrial settings and for analysis of bulk transmission areas, these are totally new areas for distribution. Concepts of inertia, stability, time constants, and control diagrams are foreign to most distribution engineers. This chapter explains some of these difficult concepts and provides procedures for a first cut at analyzing the problems. Note that many of these concepts are difficult to analyze without using a full-blown stability program.

Making things more difficult is the fact that the penetration of distributed generation is not yet large enough to get much field experience with some of these dynamic issues. This chapter reviews some of the dynamic issues that could happen when distributed generators are applied on distribution systems. The main issues analyzed are:

- **Self-excitation—**Generators can resonate with system capacitance during an islanding scenario and cause overvoltages.
- **Induction motor interaction—**During starting, induction motors can depress the voltage enough to trip off nearby generators.
- **Stability—**During system disturbances, distributed generators can dynamically interact with the system.
- **Voltage flicker—**Wind generators and some reciprocating-engine generators can cause fluctuating power output. The frequency of power fluctuations and the inertia of the generator are important factors.

Distributed Generation Self Excitation Following Islanding

Background

Following a power system disturbance, one or more distributed generators and a portion of the distribution system may become isolated from the rest of the power system. In most cases, the distributed generation will disconnect or stop producing electrical energy when islanded. In some circumstances, however, the distributed generation and connected equipment can remain energized even while islanded. Contrary to popular belief, even induction generators may self-excite and continue to produce power while separated from a synchronizing source. For the safety of the utility personnel and the proper coordination of the power system protection, this is not acceptable. With the “right” conditions, damaging overvoltages can also result if protective devices do not operate promptly.

Whether the distributed generation continues to produce electrical power and how high and how fast the voltage increases or collapses depends upon what power system equipment remains connected as well as upon the characteristics of the distributed generation. Some important factors are:

- Are the distributed generators induction generators or synchronous generators?
- What are the generator ratings and impedances?
- If synchronous generators are used, how is the excitation system controlled?
- How much power is each generator producing before islanding occurs?
- How much load remains connected to the island?
- What types of load are connected to the island?
- What is the rating of any shunt capacitors connected to the island?
- What is the capacitance of any cables?
- What are the characteristics of any transformers connected to the island?
- What protection will operate to disconnect the generators or capacitors?

In many cases, a few simple checks can be used to quickly establish that there is no possibility that the distributed generators will remain energized following the formation of an island. It may be necessary to perform a detailed study when this is not possible.

Procedure

To estimate the possibility of self-excitation:

1. Determine what groups of generation, load, and power system equipment can remain connected as islands after separating from the main utility grid; and for each potential island, answer the questions poised in the previous section.

2. Determine if the generators can remain connected and continue to produce electrical power after the island forms. The procedure for making this determination is different for induction generators and synchronous generators. The following subsections describe the two procedures.

3. If the generators might remain connected, then detailed studies may be needed. The last part of these subsections gives some guidance on how to select the worst-case scenarios for the detailed studies.

Induction Generators

Is it possible that the machine will self-excite and continue to produce power after separating from the main utility grid?

The induction generator can continue to supply energy after the system separates only if 1) there is sufficient shunt capacitance or cable-charging capacitance to self excite the generator and 2) the prime mover can produce enough electrical torque to support the remaining load.

The following procedure may be used to determine whether an induction generator that is unloaded after the system separates might self-excite:

1. Obtain or estimate:
   – The capacitive admittance, Yc, in per unit on the generator kVA base, Yc=(rated shunt kVA)/(generator base kVA).
   – The generator synchronous reactance, X, in per unit on its own base; this is also equal to the sum of the magnetizing reactance, Xm, and the leakage reactance, X_L, Figure 5-1.
   – The generator step-up transformer (GSU) leakage reactance, Xt, in per unit on the generator kVA base; if there is no GSU, Xt=0.0.
   – The maximum electrical frequency, f, following the formation of the island in per-unit.
   – For North America, f =(cycles per second)/60.0.

2. If the following equation is true, the generator may self excite:

   $(Yc * f^2) * (X+Xt) > 1.0$ **Eq. 5-1**

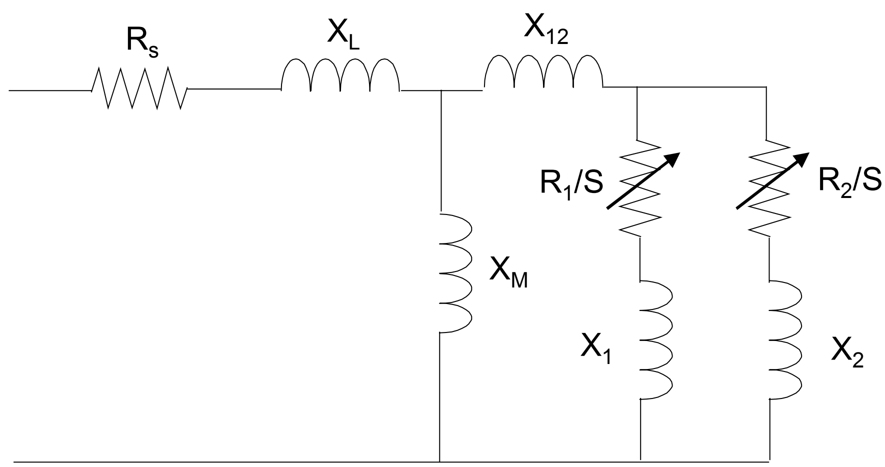


Figure 5-1
Equivalent Circuit for Induction Generator

For these calculations, everything is per-unitized on the same base kVA. Usually, this is chosen to be the induction generator kVA rating.

If more than one generator is connected to the island, the generator reactances are paralleled and the sum of all the rated kVA bases is used to per-unitize the paralleled quantity. For more than one generator, substitute:

Sum(rated generator kVA)/Sum[(rated generator kVA) * 1.0 / (X+Xt)] **Eq. 5-2**

for (X+Xt) in equation 5-1 above and let:

Yc = (rated shunt kVA)/Sum(generator base kVA) **Eq. 5-3**

If the induction generator is carrying load after the system separates, more capacitance is required for self-excitation. If the reactive power supplied by the capacitance is more than half the active power required by the load, self-excitation may be possible. If sufficient capacitance is available, the generator may be able to carry, at a reduced frequency, up to 3 times its rated load if the prime mover can supply the required torque.

The following criteria may therefore be used to determine if an induction generator might be able to supply the required electrical power after the system separates:

$Yc * V^2 > 0.5 * Pload(f)$ **Eq. 5-4**

and

$Pmax(f) > Pload(f)$ **Eq. 5-5**

where:

V is the post separation voltage magnitude in per unit.

Pload(f) is the amount of island load supplied by the generator after separation in per unit.

Pload(f) = (kilowatt load)/(rated generator kVA).

Pmax(f) is the maximum prime mover output at the post-separation frequency in per unit.

The (f) in these equations indicates that the quantity is frequency-sensitive. Some generator prime movers are capable of supplying several times their rated power at low speeds. Some loads, such as pumps, also decrease with frequency, so it may be possible to support loads that required much more than the rated generator output at normal speeds before separation. Detailed simulation will be required if the analysis above indicates that the induction generator might self-excite after separating from the system.

What is the worst scenario?

- Large shunt capacitors or large amounts of cable charging
- Little or no load after separation
- Load that decreases with frequency
- High generator magnetizing reactance
- Maximum generator loading before isolation
- Low generator inertia
- Slow-acting governor action to control over-speed following isolation
- Generator prime movers capable of supporting the load remaining after separation
- Individual tripping of multiple generators before tripping capacitors and long cables
- Slow-acting protection

Synchronous Generators

Is it possible that synchronous generators will continue to produce power after separating from the main utility grid?

Synchronous generators do not need shunt capacitance to support voltage. Their prime mover, however, must be suitably controlled and must be able to produce sufficient power to support the load that remains connected to the island. The following criteria may therefore be used to determine if a synchronous generator might be able to supply the required electrical power without stalling after the system separates:

$$Pmax(f) > Pload(f) \quad \textbf{Eq. 5-6}$$

where:

Pload(f) is the portion of the island load supplied by the generator in per unit.

Pmax(f) is the maximum prime mover output at the post-separation frequency in per unit.

In many cases, continued operation of a generator after it is separated from the utility grid is, in itself, unacceptable. Continued operation, however, may also result in damaging overvoltages if the post-separation conditions are right. The voltages with a small amount of capacitance may be modest. But, if enough shunt capacitance is connected to the island, very high voltage may develop over a period of time. With even more capacitance, a synchronous generator may self-excite, creating very high voltages moments after islanding.

Detailed simulation will be needed if the following conditions can exist after a credible outage:

$$(Yc * f^2) * (Xd+Xt) > 0.5 \qquad \textbf{Eq. 5-7}$$

where:

Yc is the capacitive admittance in per unit on the generator kVA base,
Yc = (rated shunt kVA)/(generator base kVA).

Xd is the generator direct axis synchronous reactance in per unit on its own base.

Xt is the generator step-up transformer (GSU) leakage reactance in per unit on the generator kVA base; if there is no GSU, Xt=0.0.

f is the electrical frequency following the formation of the island in per unit; for North America, f = (cycles per second)/60.0.

For these calculations, everything is per-unitized on the same base kVA. Usually, this is chosen to be the generator base kVA rating. If the excitation system is used to control voltage and negative-field current capability is provided, then the quadrature axis synchronous reactance, Xq, can be used in equation (5-7) instead of Xd.

If more than one generator is connected to the island, an equivalent generator and transformer reactance, Xeqiv, can be used to replace (Xd+Xt) in equation (5-7), and the shunt admittance, Yc, is per-unitized on the total generator kVA base. The criterion for needing a detailed simulation then becomes:

$$(Yc * f^2) * Xeqiv > 0.5 \qquad \textbf{Eq. 5-8}$$

where the equivalent reactance is given by

$$Xeqiv= Sum[rated generator kVA] / Sum[(rated generator kVA) * 1.0/(Xd+Xt)] \qquad \textbf{Eq. 5-9}$$

and

$$Yc =(rated shunt kVA)/Sum[generator base kva] \qquad \textbf{Eq. 5-10}$$

When a single generator is isolated by an outage, Equation 5-11 can be used to find the electrical frequency, f, assuming that:

- The generator power output is P kW before the outage.
- The prime mover does not change its output for several seconds following the outage.
- The generator is left with no load following a network outage.
- H is the generator inertia constant.

- T is the time in seconds after the outage.

  $f = 1.0 + P/(\text{rated generator kVA})/(2*H) * T$ **Eq. 5-11**

If a generator is fully loaded, P/(rated generator kVA) equals its rated power factor, PF, so the frequency T seconds following the outage is also given by:

$f = 1.0 + PF/(2*H) * T$ **Eq. 5-12**

If several generators are left connected to an island, the following equation can be used to find the frequency T seconds after the outage:

$f = 1.0 + \text{Sum}(P)/\text{Sum}(\text{rated generator kVA}) / (2*H_{AVE}) * T$ **Eq. 5-13**

The average inertia, H_{AVE}, is given by:

$H_{AVE} = \text{Sum}[H * \text{rated generator kVA}] / \text{Sum}[\text{rated generator kVA}]$ **Eq. 5-14**

If a detailed simulation is required, what is the worst scenario?

- Large shunt capacitors relative to the connected generation and/or large amounts of cable charging
- Maximum generator loading before isolation
- Little or no load after separation
- High field voltage before isolation
- High generator Xd and Xq
- Low generator inertia
- Slow-acting governor action to control over-speed following isolation
- Excitation system control:
  - Fixed power factor – worst
  - Fixed field voltage – bad
  - Slow-acting voltage control – better
  - Fast-acting high ceiling voltage control - best
  - No negative-field current capability
  - Individual tripping of multiple generating units before tripping capacitors and long cables
  - Slow-acting protection

If multiple generators are individually protected and shunt capacitors and cables are not disconnected first, the worst case may be after the second-to-last generator trips.

Examples

A power system outage isolates five synchronous generators with a 500-kvar shunt capacitor and no load. The machines are fully loaded before the outage, and the mechanical power delivered by the prime movers does not change for the first few seconds following the outage. The over-frequency protection is set to trip the generators 10 cycles after the frequency exceeds 60.5 Hz. The synchronous generators have the following ratings:

Table 5-1
Example Machine Characteristics

	Machines 1–4	Machine 5
kVA	500	1000
PF	0.85	0.85
H	0.5	0.8
Xd	2.38	1.95
Xq	1.10	1.00
Transformer reactance, Xt	0.06	0.05

Is a detailed simulation needed?

Because there is more than one non-identical machine, equation 5-15 will be used to see if a detailed simulation is needed. Equation 5-16 will be used to calculate the equivalent machine and transformer reactance, and Yc will be per-unitized on the total generator kVA base.

We begin by finding the frequency when the capacitor is tripped. The average generator inertia is given by:

$$H_{AVE} = \text{Sum[H * rated generator kVA] / Sum[rated generator kVA]} \qquad \textbf{Eq. 5-15}$$

$$H_{AVE} = (4*500*0.5 + 1000*0.8)/(4*500 + 1000) = 0.6 \qquad \textbf{Eq. 5-16}$$

The over-frequency relay picks up when the frequency exceeds 60.5 Hz:

$$f = 1.0 + 60.5/60.0 - 1.0 = 1.0083 \text{ pu} \qquad \textbf{Eq. 5-17}$$

The per-unit frequency, f, is given by:

$$f = 1.0 + \text{Sum(P) / Sum(rated generator kVA)} / (2*H_{AVE}) * T \qquad \textbf{Eq. 5-18}$$

Because all the machines are fully loaded, and their rated power factor, PF, is the same, 0.85:

Sum(P) / Sum(rated generator kVA) = 0.85 **Eq. 5-19**

The speed deviation T seconds after the outage therefore equals:

$f = 1.0 + PF/(2*H_{AVE}) * T$ **Eq. 5-20**

$f = 1.0 + 0.85/(2.0 * 0.6) * T$ **Eq. 5-21**

If setting f is equal to 1.0083, we calculate the time when the over-frequency relay picks up:

1.0083 = 1.0 + 0.85/(2.0 * 0.6) * Tpickup **Eq. 5-22**

Solving for time we get:

Tpickup = 0.0083 * (2.0 * 0.6)/0.85 = 0.0117 seconds **Eq. 5-23**

The breaker will take 10 more cycles, 0.1667 seconds, to operate. The generators will therefore trip about 0.18 seconds after the disturbance. The per-unit frequency will then be:

f=1.0 + 0.85/(2.0*0.6) * 0.18 = 1.13 **Eq. 5-24**

The equivalent machine and transformer reactance is given by:

Xeqiv= Sum[rated generator kVA] / Sum[(rated generator kVA) * 1.0/(Xd+Xt)] **Eq. 5-25**

Xeqiv = (4*500 + 1000)/(4*500/(2.38+0.06) + 1000/(1.95 +0.05))

Xeqiv =3000/(820 + 500) = 2.27 **Eq. 5-26**

The per-unitized capacitive admittance, Yc, is given by:

Yc =(rated shunt kVA) / Sum[generator base kva] **Eq. 5-27**

Yc = 500/3000 = 0.167 pu **Eq. 5-28**

We can now check to see if a detailed analysis is justified. A detailed analysis is needed if:

$(Yc * f^2) * Xeqiv > 0.5$ **Eq. 5-29**

In this case:

$(Yc * f^2) * Xeqiv = (0.167 * 1.13^2)*2.27 = 0.48$ **Eq. 5-30**

Because this is less than 0.5, a detailed study is not needed if the generators trip as indicated. But, suppose the generators do not all trip at once. If they each have their own breakers, one of them may trip later than the others. The last generator to trip will be isolated with the capacitor. Because only one generator is left, Equation 5-31 can be used to see if a detailed study is justified:

$$(Yc * f^2) * (Xd+Xt) > 0.5 \qquad \textbf{Eq. 5-31}$$

If the last unit is one of the 500-kVA generators, Yc must be per-unitized on a 500-kVA base:

$$Yc = 500 \text{ kVAR}/ 500\text{kVA} = 1.0 \qquad \textbf{Eq. 5-32}$$

Equation 5-31 is then equal to:

$$(Yc * f^2) * (Xd+Xt) = (1.0 * 1.13^2)*(2.38+.06) = 3.11 >> 0.5 \qquad \textbf{Eq. 5-33}$$

Leaving one generator islanded with the capacitor, even for a short time, is very likely to be dangerous. This is avoided if all of the generators are behind a common breaker and the interconnection relays trip that breaker. With several distributed generators on a circuit, another option to prevent overvoltages due to self-excitation is to apply over- and under-frequency relaying to the capacitors. Frequency deviations could trip the capacitor before the generators start tripping.

Induction Motor Starting

Background

When three-phase induction motors are started, by connecting them directly to the power network, the current they draw will be approximately five times their normal load current. The starting current is almost all reactive current; it will cause a voltage drop that is proportional to the short-circuit impedance of the network. The torque produced by an induction motor is proportional to the square of the voltage. The motor will not start if the voltage drops so much that the torque produced by the motor is less than the torque needed to drive the mechanical load. If the electrical and mechanical torques are almost equal, the motor will accelerate slowly, and it can take many seconds for the motor to come up to speed. Mechanical loads that require full torque even at low speeds, such as an elevator, will be more difficult to start than loads that require less torque at low speeds, such as a fan.

The voltage will remain depressed while an induction motor comes up to speed. The anti-islanding protection for a distributed generator often includes undervoltage relays that will disconnect it if the voltage is depressed for too long. The distributed generation may therefore trip inappropriately when nearby motors start. On the other hand, if the distributed generation remains connected, it may help to limit the magnitude and duration of the voltage dips when motors start.

An induction motor will be harder to start if:

- It is larger.
- The electrical power supply is weak (high impedance).
- The mechanical load is large, and the load torque does not decrease with speed.
- The motor's locked rotor torque is small for its size.
- The motor draws high starting currents for its size.

Various techniques may be employed to help start large motors:

- Special starting circuits may be used to reduce the starting current drawn from the power system.
- Power system voltage support may be added.
- An induction motor that draws lower starting currents and produces higher starting torques may be chosen.
- The induction motor may be replaced with a different kind of motor or variable-speed drive.
- The mechanical load may be applied only after the motor is up to speed.

Procedure

Use the following two-step check to see if a problem might exist:

1. Estimate the voltage while the motor is starting.
2. Compare this voltage with the undervoltage relay set points to see if distributed generation will be tripped.

To do a preliminary analysis, the following information must be obtained or estimated:

- X – the positive-sequence driving point reactance of the network seen from the motor
- Iamps – the motor starting current in amps at the motor's rated voltage
- Vo – the line-to-line rms voltage before starting the motor

Sometimes this information is not directly available. A discussion later in this section indicates how this data can be calculated or estimated when information is provided in different forms.

Estimate the Voltage While the Motor Is Starting

The following shows how this information can be used to calculate the terminal voltage at the motor when it is starting.

The motor starting current, I, is proportional to Vpu, the per-unit voltage at the motor terminals while starting. The actual current will therefore be:

$$I = Iamps * Vpu \qquad \textbf{Eq. 5-34}$$

The voltage while starting the motor is:

$$Vpu = Vo - I/Ifault \qquad \textbf{Eq. 5-35}$$

where:

Ifault is the current in each phase for a three phase fault.

Vo is the per unit voltage before starting the motor.

Equation 5-34 may be substituted into equation 5-35, giving:

$$Vpu = Vo - Iamps * Vpu/Ifault \qquad \textbf{Eq. 5-36}$$

Solving this for Vpu, we get the voltage while starting the motor:

$$Vpu = Vo/[1 + Iamps / Ifault] \qquad \textbf{Eq. 5-37}$$

This gives the voltage at the motor terminals while it is starting. If a distributed generator is electrically close to the motor, it will see the same voltage. If the distributed generator is not electrically close to the motor that is starting, it will probably see a higher voltage. In this case, a short-circuit program can be used to find the voltage at the generator with the expected motor starting current.

Compare the Voltage With the Relay Set Points

Once the voltage at the distributed generation is known, a quick check will often show if the distributed generation will be tripped by an undervoltage relay. has the proposed IEEE P1547 standards for over/undervoltage tripping of distributed generation.

Table 5-2
Proposed P1547 Voltage Trip

Voltage Range	Clearing Time
p.u.	Seconds
V < 0.5 p.u.	0.16
0.5 < V < 0.88	2
0.88 < V < 1.1	Sustained operation
1.1 < V < 1.2	1
1.2 < V	0.16

This proposed standard has not yet been adopted and is subject to change. IEEE standard 929-2000 requires faster disconnection for bridge-connected distributed generation in some cases (Table 5-3). Some utilities have their own criteria for tripping distributed generation.

Table 5-3
IEEE 929-2000 Voltage Trip

Voltage Range	Clearing Time
p.u.	Seconds
V < 0.5 p.u.	0.1
0.5 < V < 0.88	2
0.88 < V < 1.1	Sustained operation
1.1 < V < 1.375	2
1.375 < V	0.033

In many cases, the voltage while starting the motor will be high enough so that even long starting periods will not cause the distributed generation to trip or low enough so that even very short dips will cause the generation to trip. When the duration of the dip is critical, a detailed simulation is needed to determine if the distributed generation will trip.

Useful Relationships

When it is not directly available, the data used in the analysis above can sometimes be calculated or estimated from other types of information. Some useful relationships for doing this are given below.

The motor's starting current in amps at rated voltage, Iamps, may be found from the per-unitized value:

Iamps=Ipu * (motor kVArating)/[SQRT(3) * (motor kVrating)] **Eq. 5-38**

Ipu approximately equals the inverse of the positive sequence reactance, 1.0/ Xpos. If this is not available, it can be approximated by the inverse of the subtransient reactance, 1.0/X. If this is not available, it may be assumed to be approximately 5.0.

The motor kV rating may be different from the base voltage of the bus to which the motor is attached. The motor kVA rating is given by:

(motor kVArating) = HP * 0.746/(PF*EFF) **Eq. 5-39**

where:

HP is its rated horsepower.

PF is its rated power factor.

EFF is its rated efficiency.

Examples

A motor with the following ratings draws 5.0 pu starting current:

- 1000 HP
- 4000 volts line-to-line rms
- 0.918 efficiency
- 0.925 power factor

The short-circuit current at the motor terminals has been calculated to be 2000 amps. Before starting the motor, the voltage at its terminals is 1.0 pu on the system 4160-volt base. What will the terminal voltage be when it starts?

First, we calculate the motors kVA rating using:

(motor kVArating) = HP * 0.746/(PF*EFF) **Eq. 5-40**

(motor kVArating) = 1000 * 0.746/(0.918 * 0.925) = 878 kVA

Then, we calculate the starting current at the motor's rated voltage in amps:

Iamps=Ipu * (motor kVArating)/[SQRT(3) * (motor kVrating)] **Eq. 5-41**

Iamps = 5.0 * 878/(1.73 * 4.0) = 633 amps

Using Equation 5-37, we calculate the starting voltage:

Vpu = Vo/[1 + Iamps / Ifault] **Eq. 5-42**

Vpu = 1.0/[1 + 633 / 2000] = 0.76 pu

This is equal to 3160 volts. If the motor takes 2 seconds or more to start, locally connected distributed generation will trip. The actual relay tripping times may be less than the standards require, so distributed generation may trip even if the motor starting time is less than two seconds.

Power System Stability

Power system stability problems are commonly divided into three categories: 1) dynamic stability, 2) transient stability, and 3) voltage stability.

Dynamic stability is associated with undamped oscillations. It usually involves inner area oscillations between large groups of machines that are remotely connected. High-gain excitation systems are usually a contributing factor. Dynamic stability is not normally a problem for distributed generation.

The second type of instability, transient instability (also called first-swing instability), is created by a severe disturbance, such as a short circuit, that temporarily interrupts the flow of electrical power from one or more generators. Because the prime mover driving a generator does not respond quickly, the mechanical energy delivered to a generator stays relatively constant for several seconds. The surplus energy delivered by the prime movers accelerates the generators that cannot export electrical power during the disturbance. Their rotor angle therefore advances relative to the rest of the power system. If a generator's rotor angle advances past a point of no return, it will lose synchronism with the rest of the power system or pull out of step.

The following:

- Describes the classical transient stability problem in more detail
- Shows why distributed generation is not likely to pull out of step with the rest of the system in the classical way
- Indicates how it may contribute to the transient instability of other machines by tripping inappropriately

A synchronous machine is cleverly designed so the phase angle of the generated sinusoidal voltage waveform is linked to the mechanical position of the generator's rotor. The voltage angle therefore increases as its rotor accelerates. More electrical power will normally flow from the machine when the voltage angle increases. Classically, transient instability is caused by a short circuit in a power-exporting area, which has little local load compared to the generation. The electrical power exported from the area is given by Equation 5-43. If there is no local load, this is also equal to the electrical power generated.

$$Pexport = Vs*Vr*\sin(a)/X \qquad \textbf{Eq. 5-43}$$

where:

Vs is the voltage magnitude for the generator.

a is the voltage angle of the generator relative to the receiving system.

Vs is the voltage magnitude for the receiving system.

X is the reactance of the transmission system tying the generator to the receiving system.

This equation is expressed graphically in Figure 5-2. A star on the graph indicates the steady-state voltage angle when the generator's electrical power output is P_G. Neglecting losses, P_G will also equal the mechanical power, P_M, delivered by the prime mover.

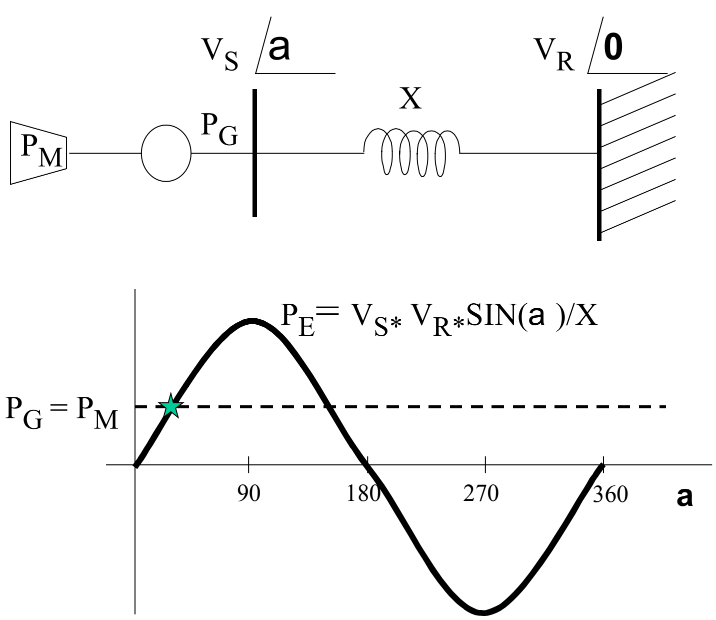


Figure 5-2
Power Transfer Versus Voltage Angle

The voltage is zero during a short circuit, so no electrical power can be exported from the machine, and the machine accelerates. If a significant amount of transmission capability must be disconnected to clear the fault, the transmission reactance, X, will be increased, and the power transfer capability given by Equation 5-43 will be less. The star in Figure 5-3 shows the operating point immediately after the fault is cleared, and the arrow shows the direction of travel.

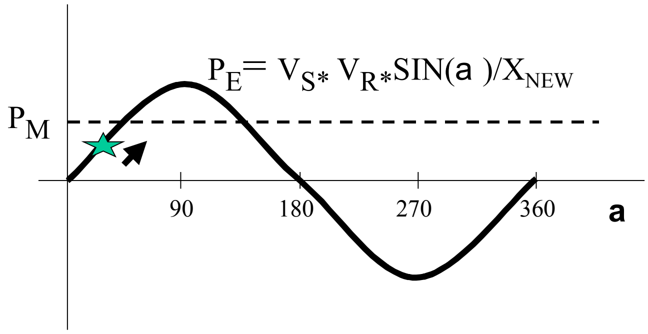


Figure 5-3
Voltage Angle Immediately After the Fault Is Cleared

The generator will continue to accelerate until its electrical power output exceeds the mechanical power delivered by the prime mover. At this point, the machine will start to slow down. However, because it is going faster than the rest of the system, the angle will continue to advance relative to the rest of the system until the rotor reaches synchronous speed again. In some cases, the machine rotor angle may advance so that it leads the rest of the system by approximately 90 electrical degrees. At this point, the electrical power will decrease with further increases in the voltage angle and the rotor angle. If the electrical power decreases until it is again less than the mechanical power provided by the prime mover (Figure 5-4), the machine will start increasing speed again and pull out of step with the rest of the power system.

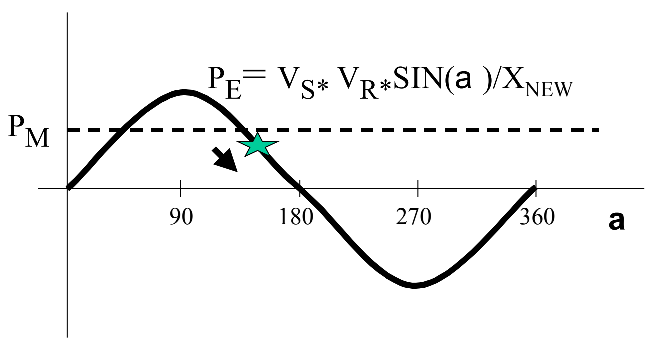


Figure 5-4
Generator Pulling Out of Step With System

As the angle continues to advance past 180 degrees, the machine will actually absorb electrical energy rather the generate it. When the rotor angle has advanced 360 degrees relative to the rest of the system, the machine will have slipped one pole; it will again generate power, but its rotor speed will be high. If there is no local load, once a machine pulls out of step with the rest of the network, it will usually continue slipping poles until it is tripped. This can be seen from Figure 5-5. When P_E is less than P_M, the machine accelerates; but when P_M is less than P_E, the machine decelerates. The area between the line representing P_M and the line representing P_E in Figure 5-5 is proportional to the energy that is used to accelerate or to decelerate it. Over a complete 360-degree slip cycle, more energy is used to accelerate the machine, so its speed increases even more and it continues slipping poles.

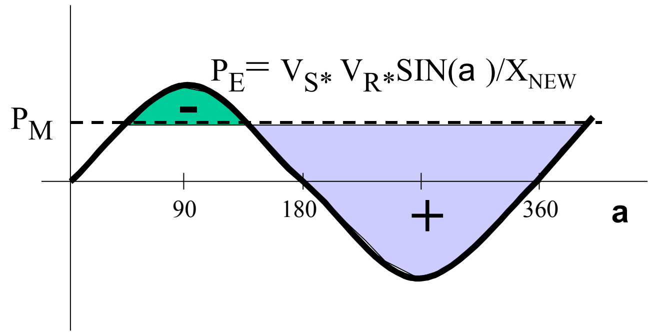


Figure 5-5
Energy Used to Increase Speed and Decrease Speed

Transient stability depends upon the following factors; in each case, the condition that decreases stability is indicated in bold type:

- The duration and impedance of the short circuit that initiates the event – **longer duration & lower impedance**
- The number of faulted phases – **all 3 phases**
- The location of the fault relative to the generator – **at the high side of the generator step-up transformer**
- The point on the sinusoidal voltage waveform when the fault is applied – **peak**
- Whether the machine is in a power-exporting area or a power-importing area – **maximum power export (minimum local load)**
- The impedance of the transmission system connecting this area to the rest of the power system after the fault is cleared **– highest possible**
- The machine inertia **– lowest possible**
- The type of excitation system control – **constant power-factor control, low gain if controlling voltage**

Distributed generation is usually in a power-importing area. The local load exceeds the generation. The generated power with a local purely resistive load is given by:

$$Pgen = Pexport + Pload = Vs*Vr*\sin(a)/X + Vs^2/R \qquad \textbf{Eq. 5-44}$$

where:

Vs is the voltage magnitude for the generator.

a is the voltage angle of the generator relative to the receiving system.

Vs is the voltage magnitude for the receiving system.

X is the reactance of the transmission system tying the generator to the receiving system.

R is the load resistance.

This equation is expressed graphically in Figure 5-6. The sinusoidal waveform is offset from the vertical axis by P_{LOAD}.

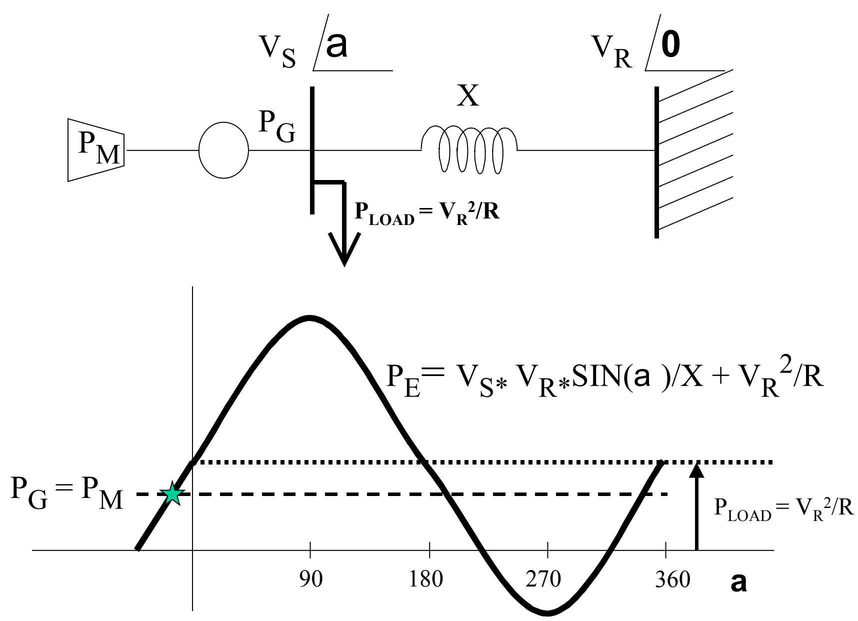


Figure 5-6
Generator Voltage Angle in Power-Importing Area

During normal operation, the voltage angles in a power-importing area, a, lags the voltage angles of the rest of the network (it is negative; see the star on Figure 5-6). It therefore takes additional energy during a disturbance to increase the rotor angle enough to pass the other machines before pulling away from them. After a fault is cleared, the power used to supply local load will help decrease the speed of the machine along with the additional power export (or decrease in power import) due to the voltage angle increase. For these reasons, machines in power-importing areas, and distributed generation in particular, are almost always transiently stable for reasonable fault durations. If during an extremely long power interruption they do speed up enough to start slipping poles, over a complete 360-degree slip cycle, less energy is used to accelerate the machine than is used to decelerate it (Figure 5-7), so the machine slows back down and stops slipping poles.

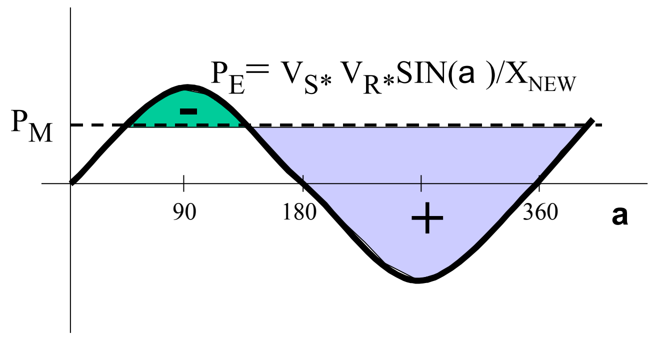


Figure 5-7
Energy Used to Increase Speed and Decrease Speed With Local Load

A distributed generator is therefore not likely to pull out of step with the rest of the system if it is in a power-importing area, which is normally the case. As we shall see, it may, however, indirectly (by inappropriately tripping) contribute to stability problems for other machines.

One might hypothesize that it should be possible to make a machine in a heavily loaded area drop out of step by slowing down too much during a disturbance instead of pulling out of step by speeding up too much. This requires a disturbance that substantially increases the generator's electrical output without completely disconnecting it from the network.

Some faults will in fact cause distributed generation to initially lose speed instead of increasing it. This is because the decaying fault current dc offset creates a 60-hertz component of electrical torque that has a net negative value. The dc offset is higher for DG machines that do not use a generator step-up transformer. However, in most cases, this effect will not be sufficient to destabilize the generator. If the fault is initiated at a voltage peak on all three phases, there is little dc offset, and the machine accelerates during the fault as expected.

The third type of instability, voltage instability, is a runaway voltage collapse situation. Voltage instability may take some time to develop following the initiating disturbance. Often, the system can support voltage immediately following a disturbance because local generation has short-term reactive power capability, and some loads decrease their power demands as voltage drops. However, many loads are directly or indirectly controlled to perform their intended function, and this requires a given amount of power. As time passes following an electrical disturbance, these loads will adjust to again increase their power usage to its pre-disturbance level even if the voltage remains low. This will require more current, so the voltage will drop further. Also, the reactive power capability of generators is thermally limited, so automatic controls or operator action may reduce the reactive power delivery from certain machines. This decreases their ability to support voltage. Because of these effects, the voltage may collapse some time after an initial outage.

One might at first expect that adding distributed generation to a system can only improve voltage stability. This is indeed often true. However, other voltage-support equipment such as switched capacitors may not be in service before a disturbance if the distributed generation supports the voltage. If the distributed generation trips during the disturbance, reducing the reactive power support and increasing the power delivery requirements, the system may be worse off than if the distributed generation was not initially present. Distributed generation installed with additional load, as part of a package, could also be detrimental if the generation trips during a disturbance, leaving the load. Distributed generation may therefore be an important factor in voltage instability.

Voltage instability can sometimes create or contribute to a transient stability problem. Depressed voltage in the center of the system will reduce the power that can be transferred between two regions. With limited power transfer possible, the two parts of the system may pull out of step with each other. Distributed generation that trips on system swing may thus help create stability problems for other generators.

Procedure

As indicated above, transient stability is not normally a problem in a power-importing area. If the distributed generation is located in an area that imports power, it may improve voltage stability as long as it stays connected. It may improve the transient and dynamic stability of other machines when it is centered between two parts of a transmission system that swing against each other during critical power system disturbances.

However, the beneficial effects of the distributed generation may be lost if it trips off at an inopportune moment because of voltage or frequency deviations. If other voltage-support devices are out of service because distributed generation has been added, the total effect could be negative. Distributed generation that is a significant portion of the total generation in a power-exporting area could potentially degrade transient stability, but this is not likely to be the case until distributed generation becomes a much larger component of the total generation mix.

There may be different requirements for distributed generation interconnection studies and for other types of studies. For a distributed generation interconnection study, it will normally only be necessary to show that the distributed generation will not adversely impact the stability of the system and that it will provide any benefits that are contracted for. Because distributed generation itself is normally expected to improve stability, stability simulations may only be needed for interconnection studies when:

- It is part of a package that includes additional system load.
- It is expected to affect the in-service status of other voltage-support equipment.
- It is being justified because it benefits stability.

- It is a significant portion of the total generation in a power-exporting region.

Representation of existing distributed generation in general stability studies is another question. The results of stability simulations may be pessimistic if distributed generation is not represented at all.[5] Completely ignoring the distributed generation can, however, be justified if it can be shown that it will have no significant impact on system voltages or flows.

If distributed generation is represented simply by making a corresponding reduction in the local load, the results may be optimistic because the actual distributed generation might trip off at an inopportune moment. Lumping it with the load can be justified if it can be shown that:

- It will not trip for the system disturbances being represented[6] or
- It will have no significant effect on the system voltage if it does trip.

Ironically, detailed representation of distributed generation, including the dynamic voltage support that it may provide, is most needed for simulating disturbances where it is likely to trip off early in the simulation. This is because the dynamic voltage support that the distributed generation provides may be a critical factor in determining whether or not it does trip. Present standards require tripping of distributed generation for relatively minor deviations in voltage and frequency. If it can be conclusively shown that the distributed generation would not trip, even without the dynamic voltage support that it provides, then local dynamic voltage support is most likely not a critical factor in the simulation anyway.

Figure 5-8 is a decision tree for determining how distributed generation should be modeled for general stability simulations.

[5] If the distributed generation is a significant portion of the generation in a power-exporting area, the results could be optimistic, but this scenario is unlikely.

[6] One might argue that it is also necessary to prove that the dynamic voltage support that it provides is not significant, but if it can be conclusively shown that it will not trip without this dynamic voltage support, then local dynamic voltage support is most likely not critical.

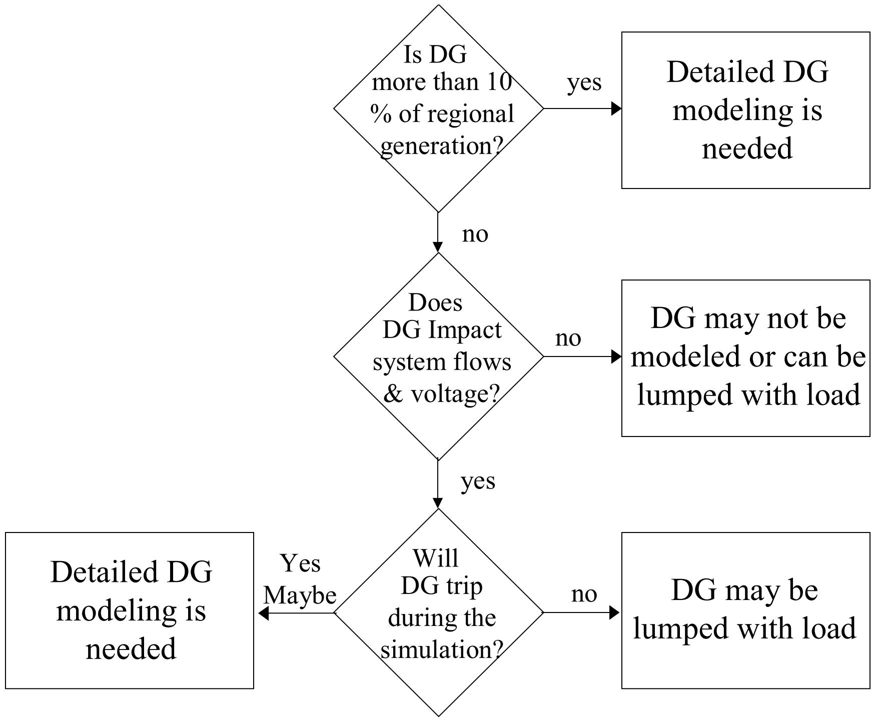


Figure 5-8
Selecting a DG Model for Dynamic Simulations

If removing the generation does not change the flows or voltage significantly, then detailed stability simulations representing the distributed generation will normally not be needed. Detailed representation will almost always be needed when distributed generation becomes a significant portion of the total system generation in a particular region. When this occurs, distributed generation will need to be modeled in stability simulations as a matter of course. The level of distributed generation penetration required is presently a subject for speculation. It may need to be modeled in all stability simulations when it becomes 5 to 10% of the total generation.

Load-flow cases with and without the distributed generation can be used to see if the distributed generation significantly affects the system flows and voltages. Significant transmission system outages that would be represented in simulations should be modeled in some of these load-flow cases.

The results of previous stability studies and a few preliminary short-circuit program calculations may be used to see whether the distributed generation might trip. The short-circuit calculations will indicate whether the distributed generation will trip during short circuits that can initiate transient instability. Results of previous stability simulations will indicate if the voltage during system swings can get low enough and long enough to trigger tripping of distributed generation.

Table 5-4 has the proposed IEEE P1547 standards for over/undervoltage tripping of distributed generation.

Table 5-4
Proposed P1547 Voltage Trip

Voltage Range	Clearing Time
p.u.	seconds
V<0.5 p.u.	0.16
0.5<V<0.88	2
0.88<V<1.1	Sustained operation
1.1<V<1.2	1
1.2<V	0.16

This proposed standard has not yet been adopted and is subject to change. Some utilities have their own criteria for tripping distributed generation. IEEE standard 929-2000 requires faster disconnection for bridge-connected distributed generation in some cases (Table 5-5).

Table 5-5
IEEE 929-2000 Voltage Trip

Voltage Range	Clearing Time
p.u.	seconds
V<0.5 p.u.	0.1
0.5<V<0.88	2
0.88<V<1.1	Sustained operation
1.1<V<1.375	2
1.375<V	0.033

To determine whether detailed modeling of distributed generation is needed, start by identifying the locations of system faults that are known to stress the transient stability of the system. If the voltages calculated without the distributed generation and without the voltage-support equipment that it may displace deviate enough from normal so that the distributed generation would trip if it were present, then a detailed representation of the distributed generation should be used for the dynamic simulations. If the voltage at the distributed generation is less than 0.5 pu with a three-phase fault at one of these locations, then the distributed generation may trip, and additional stability simulations may be needed. Most power system databases only include voltage levels down to the sub-transmission level. There may of course be additional voltage drop in the substation transformer and distribution system. Some distributed generation may therefore trip when the sub transmission voltage is slightly above 0.5 pu.

After the fault is cleared, the distributed generation might of course also trip, due to high or low voltage or frequency. Previous stability simulations can be checked to see if the voltage may deviate enough after the initiating fault is cleared to trigger tripping of the distributed generation. If the voltage is less than 0.5 pu for more than 0.1 seconds, then the distributed generation may trip, and detailed simulations may be needed. Otherwise, the distributed generation won't trip until at least 2 seconds after the initial disturbance, if at all. This is normally too late to have any effect on the transient stability of the system but may contribute to a voltage collapse. If the voltage is less than 0.88 pu for more than 2 seconds, detailed models of the distributed generation should be used for voltage stability simulations.

Table 5-6 has the proposed P1547 over/under-frequency trip points. For bridge-connected distributed generation, the over/under-frequency trip points in Table 5-7 apply. Previous stability simulations can be checked to see if the frequency may deviate enough after the initiating fault is cleared to trigger tripping of the distributed generation on or before the first swing.

Table 5-6
P1547 Frequency Trip Points

Generator Rating	Under Frequency		Over Frequency	
	Hz	Cycles	Hz	Cycles
<10 kW	59.3	10	60.5	10
>10 kW	59.3	delayed	60.5	10

Table 5-7
IEEE 929-2000 Frequency Trip Points

Under Frequency		Over Frequency	
Hz	Cycles	Hz	Cycles
59.3	6	60.5	6

The following paragraphs give general guidance on how to do transient stability simulations involving distributed generation if they are needed. Because the distributed generation itself normally improves the stability of other machines, the most critical cases may represent tripping of the distributed generation shortly after a disturbance is initiated. The distributed generation will probably have most impact on transient stability when it is centered between two parts of a transmission system that swing against each other during critical power system disturbances. Transient stability of the distributed generation itself is normally not a concern.

The transient stability criteria may require that the system be stable for both three-phase faults cleared normally and for less severe faults cleared by backup protection. For three-phase faults, six-cycle (0.1 seconds on a 60-hertz system) clearing times are commonly assumed for stability simulations. With a six-cycle clearing time, the low voltage during the fault will last long enough to cause bridge-connected distributed generation to disconnect (Table 5-8). However, if directly connected distributed generation is not tripped faster than is presently required by P1547 (10 cycles), it will not last long enough to cause directly connected distributed generation to trip. With backup clearing times, the low voltage will last long enough to also cause directly connected distributed generation to trip.

Table 5-8
Tripping Criteria During Fault

Tripping Criteria During Fault	
Fault Duration Cycles	Type of DG to Trip
0 to 6	None
6 to 10	Bridge Connected
>10	All Types

For studying the stability of other machines, the faults on the transmission system are normally of most interest; their effects are also more far-reaching than faults on a distribution feeder. To trigger tripping of distributed generation, the voltage during the fault must be low enough and long enough. The voltage that triggers tripping is of course the voltage measured at the distributed generation.

Some distributed generation is only connected to one feeder phase, and the undervoltage protection for three-phase generation may only be connected to one or two feeder phases. Therefore, at least one Y-delta transformer normally separates the critical faults from the voltages that control the tripping of distributed generation. During a single-phase fault in the transmission system, all three feeder phases will therefore still have some voltage. For a low-impedance line-to-line fault, two feeder phases will still have voltage. The example at the end of this section shows:

- During a line-to-ground fault in the transmission system, the voltage at the distributed generation is not likely to be low enough to trigger disconnection.
- During a line-to-line fault in the transmission system, the voltage on two distribution feeder phases will most likely be too high to trigger disconnection, but the voltage on the third phase can be low enough so that it may trigger tripping of distributed generation.
- During a three-phase fault in the transmission system, the voltage on all three feeder phases may be low enough to cause tripping of the distributed generation.

Table 5-9
DG Tripping Criteria During Fault

DG Tripping Criteria During Fault		
Fault Type	Number of feeder phases tripped	Simulation voltage used to trigger trip
1-phase	None	
2-phase	One	Subtransmission L-L or distribution L-G
3-phase	All	Phase to neutral or L-L or Positive Seq.

Table 5-9 shows for different types of faults how many distribution feeder phases may lose their generation during the fault. A fault in the transmission system may of course reduce voltage in a large area, so all the distributed generation in the area disconnects.

Most transient stability programs only calculate the positive-sequence voltage. For a three-phase fault, this also equals the phase voltage, so the tripping of distributed generation in a simulation can be automated based upon the calculated voltage. Most power system databases only include voltage levels down to the sub-transmission level. There may of course be additional voltage drop in the substation transformer and distribution system. For a three-phase fault, some distributed generation may therefore trip when the sub transmission voltage is slightly above 0.5 pu.

For a fault involving two phases, the tripping of distributed generation is hard to automate in a stability simulation because the positive-sequence voltage is not equal to the lowest distribution feeder phase, or phase-to-phase voltage. A short-circuit program can be used to find the per-unit sub-transmission line-to-line voltage. Again, most power system databases only include voltage levels down to the sub-transmission level. Because the substation transformer feeding the distribution system is delta-Y connected, the feeder phase voltage in per unit will equal the sub-transmission line-to-line voltage. Distributed generation on one feeder phase will therefore trip if the per-unit sub-transmission voltage is less than 0.5 pu. Some may trip if the voltage is only slightly higher. Once the extent of distributed generation tripping is found using a short-circuit program, it can be manually tripped in a stability simulation.

After the fault is cleared, the distributed generation might of course also trip, due to low voltage or frequency. The low voltage trip points for bridge-connected and directly connected distributed generation are summarized in Table 5-10. If the voltage is less than 0.5 per unit for 6 cycles (10 cycles), bridge-connected (directly connected) distributed generation will trip. Most power system databases only include voltage levels down to the sub-transmission level. There may of course be additional voltage drop in the substation transformer and distribution system. Some distributed generation may therefore trip when the sub transmission voltage is slightly above 0.5 pu.

Table 5-10
Low Voltage Tripping of DG After the Fault is Cleared

Low Voltage Tripping of DG After the Fault is Cleared		
P.U. Voltage	Bridge Connected DG	Directly Connected DG
<0.5	6 cycles	10 cycles
<0.88	2 seconds	2 seconds

If voltage stability is the primary concern, another approach can be used to identify situations that must be studied in detail. In most voltage stability studies, it will only be necessary to show that the distributed generation will work with a given amount of power delivery. To find the maximum power-delivery capability, a more detailed study is needed. As indicated above, the presence of distributed generation normally improves voltage. The first step in studying voltage instability is to determine whether the voltage can be supported when the distributed generation is lost during a disturbance. A standard load-flow calculation may be used for an initial assessment. A case representing the heaviest loading with the critical outage will need to be looked at. Compare the following voltages:

- Without the distributed generation and
- Without any voltage-support equipment that may be initially disconnected because of the distributed generation but
- With any load that may be part of the distributed generation package to the voltages:
- With all the voltage support equipment and
- Without any load that may be part of the distributed generation package

If the voltage is reasonable and not significantly less in the first case, no additional study may be needed. If the voltages are not reasonable or if there are significant differences between the two cases, then it may be necessary to do more detailed calculations representing the time-varying response of various devices, including the voltage-control equipment, the load, the protective devices, and the distributed generation.

Examples

The distribution transformer feeding a small distributed generator is fed by one phase of a distribution feeder. The distribution feeder is fed from a strong 69-kV utility grid by a delta-Y-connected substation transformer. The solidly grounded Y winding is on the distribution feeder side. Assume that the distributed generation is too small to significantly affect the voltage at its terminals, and the 69-kV utility grid is solidly grounded. What will the voltage be at the distributed generator during a low-impedance line-to-ground fault on the 69-kV side of the substation transformer?

The assumptions were picked to find the lowest credible voltage. Because the 69-kV system is assumed to be strong (low impedance) and well grounded, one side of the transformer delta winding will still have line-to-line voltage across it, and the other two sides will only have the normal phase voltage across them. One distribution feeder will therefore have near normal voltage, and the other two will have 1/sqrt(3) times the normal voltage or approximately 0.577 pu voltage. If the pre-fault voltage on the feeder was on the low end of its normal range (0.9 pu), the phase voltages during the fault might be 0.9/sqrt(3) = 0.52 pu. Because there also may be some voltage drop through the distribution transformer, a few distributed generators might see voltage low enough, <0.5, to trip; the vast majority will not trip during a line-to-ground transmission system fault.

For a line-to-line fault, one phase will see zero voltage, and the other two phases will have 1/sqrt(3) times the pre-fault voltage. The distributed generation on one feeder phase will trip if the fault stays on long enough, but the distributed generation on the other two phases will probably not trip for reasonable fault-clearing times.

For a three-phase fault, the distributed generation on all three phases may of course disconnect during the fault.

Flicker

Background

Voltage flicker is a rapidly changing level of voltage magnitude that may lead to visible fluctuations in the light output (especially from incandescent lighting systems). The eyes' sensitivity to these fluctuations depends upon their frequency, magnitude, and shape. Figure 5-9 is the limit on voltage fluctuations specified by the IEEE 141 standard plotted for a range of frequencies. Fluctuations at approximately 5 hertz are the most objectionable. Fluctuations that are shaped like a square wave are also more objectionable than sinusoidal fluctuations.

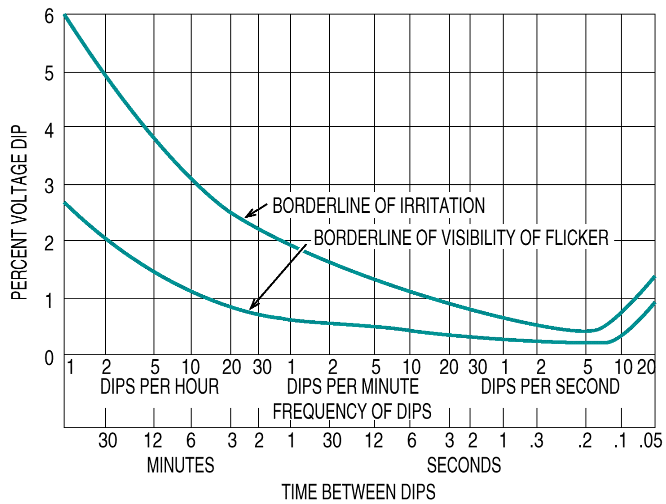


Figure 5-9
Flicker Limits

Local generation normally helps to smooth voltage variations and reduce flicker. However, if the output of the prime mover that drives a distributed generator varies, the electrical output of the generator may also vary, causing voltage flicker. Possible sources of mechanical power variation are tower wind shadowing and wind gusts for wind-driven generation, cloud shading for solar converters, and misfiring for diesel-driven generation.

A four-stroke, internal-combustion engine only delivers energy on the power stroke. Because the energy delivery is not continuous, the speed of rotation of a motor-driven generator also varies. The generator's electrical frequency and induced voltage magnitude depend upon the speed of rotation. So, they also vary. These pulsations are particularly objectionable for low-RPM motors because the resulting electrical variation will be at a frequency that the eye can readily detect.

The mechanical power delivered by a wind turbine also varies during each rotation because the turbine blade passes through the wind-shadow created by the tower. This may translate into 1- or 2-hertz electrical pulses.

The variation in electrical power does not necessarily equal the variation in mechanical power. At frequencies that are significantly below the characteristic frequency of oscillation, it will. For rotating generators, the characteristic frequency of oscillation is approximately 1 hertz. Mechanical oscillations near this frequency must be avoided for many reasons. Above this frequency, the electrical power oscillations will be inversely proportional to the square of frequency. If the source is bridge-connected, a dc-side capacitor may absorb some of the power deviation. For small changes, the voltage variation is approximately proportional to the electrical power variation. Above 5 hertz, the sensitivity of the eye decreases rapidly, so variations in mechanical power above 5 hertz are not likely to be a problem.

Traditional load-flow modeling is designed to represent steady-state operation of the power system. However, enhanced load-flow programs that include alternate source and load models to more accurately represent the operating state following a disturbance are also available. Power system engineers can use such programs to check for potential voltage flicker problems. To dynamically model DG for its potential flicker impact requires a detailed knowledge of the prime mover response, generator exciter controls, and machine impedance characteristics that can be constructed within a transient stability program.

Procedure

A quick two-step check can often be used to see whether a problem might exist:

1. Estimate the voltage difference between the minimum and maximum level of electric power generation.
2. For the expected frequency of variation, determine if this change exceeds the limits specified in Figure 5-9.

The following information is needed to do this preliminary analysis:

- R and X - the fault impedance, resistance and reactance, of the network seen from the generator
- The frequency of power variation
- DP and DQ, the change in active and reactive power generation

For a rotating generator, the variation in electrical power, DP, caused by a variation in mechanical power, DPm, is given by equation:

$$DP/DPm = T/(2\ H\ S^2 + D\ S + T) \qquad \textbf{Eq. 5-45}$$

where:

T is the synchronizing coefficient.

D is a damping coefficient.

H is the inertia constant for the shaft train.

S is the Laplace operator.

If the variation in mechanical power is sinusoidal at a frequency of w radians per second, then this equation can be converted to a phasor equation by substituting jw for the Laplace operator, S. The characteristic frequency, wo, for normal power system oscillations is equal to $\sqrt{(T/2H)}$. This is normally about 6.28 radians per second or 1 hertz. Mechanical oscillations near this frequency would result in unacceptably high oscillations and cannot be permitted. For mechanical oscillations at significantly higher frequencies, Equation 5-45 may be approximated by Equation 5-46. The electrical power oscillations are inversely proportional to the square of frequency:

$$DP/DPm = T/(2\ H\ S^2) \qquad \textbf{Eq. 5-46}$$

For mechanical oscillations at significantly lower frequencies, Equation 5-45 becomes:

$$DP/DPm = T/T = 1.0 \qquad \textbf{Eq. 5-47}$$

Low frequency changes in mechanical power are directly converted to electrical power oscillations.

Estimate the Voltage Change

The following shows how this information can be used to calculate the terminal voltage variation at the generator.

Complex electrical power is the voltage multiplied by the complex conjugate of current.

$$P + jQ = E \times I^* \qquad \textbf{Eq. 5-48}$$

For small changes in voltage, complex power is approximately proportional to D**I***.

$$DP + jDQ = E \times DI^* + DE \times I^* \cong E \times DI^* \qquad \textbf{Eq. 5-49}$$

The change in current will therefore be:

$$DI = (DP - jDQ)/E^* \qquad \textbf{Eq. 5-50}$$

The voltage drop due to this current is:

$$DE = DI \times (R + jX) = (DP - jDQ)x(R + j\ X)/E^* \qquad \textbf{Eq. 5-51}$$

$$DE = [(DPxR + DQxX) + j(\ DPxX - DQxR)]/E^* \qquad \textbf{Eq. 5-52}$$

The new value of voltage is **E** + D**E .** If the voltage reference angle is chosen so that the initial voltage has an angle of zero, then the vector **E** just equals the initial voltage magnitude, E, and **E*** also equals E. The new voltage is therefore given by:

$$E + DE = E + (DPxR + DQxX)/E + j(\ DPxX - DQxR)/E \qquad \textbf{Eq. 5-53}$$

The magnitude of the new complex voltage is the square root of the sum of the squares of the real and imaginary parts. Because the imaginary part is small, this equals the real part:

$$|E + DE| = E + (DPxR + DQxX)/E \qquad \textbf{Eq. 5-54}$$

The change in the voltage magnitude, DE, is just the new magnitude minus the old magnitude, E, or:

$$DE = (DPxR + DQxX)/E \qquad \textbf{Eq. 5-55}$$

Equation 5-55 can be used to estimate the change in voltage magnitude that is due to the change in electrical power. If the reactive power does not change with the active power, the change in voltage is given by:

$$DE = DPxR/E \qquad \textbf{Eq. 5-56}$$

where:

DE is the change in voltage magnitude in per unit.

DP is the change in electrical power in per unit.

R is the real part of the per-unit fault impedance of the network.

E is the voltage magnitude in per unit.

The voltage variation given in Figure 5-9 is given as a percent. This is 100 times the per-unit value. If 100 times the variation calculated by Equation 5-56 is greater than or close to the borderline of irritation given in Figure 5-9 for the frequency of variation, then flicker may be a problem, and a detailed analysis will be needed.

Examples

A diesel-driven generator has an inertial constant equal to 0.5. Stability simulations indicate that its rotor angle oscillates at a frequency of 1 hertz following a disturbance.

What is the per-unit value of its synchronizing coefficient?

The rotor angle swings at the characteristic frequency of oscillation 1 hertz = 2P radians/sec. In radians per second, this is equal to $\sqrt{(T/2H)}$.

$$\sqrt{(T/2H)} = 2P = 6.28 \qquad \textbf{Eq. 5-57}$$

Solving for T, we get:

$$T = 2\ H\ 6.28^2 = 39.4 \qquad \textbf{Eq. 5-58}$$

The diesel operating at 900 RPM is misfiring, and this generates a 7.5-hertz (47 radians/second) variation in mechanical power. What portion of this variation is transferred into electrical power?

Use the following equation to find the portion transferred:

$$DP/DPm = T/(2\ H\ S^2 + D\ S + T) \qquad \textbf{Eq. 5-59}$$

where:

T is the synchronizing coefficient.

D is a damping coefficient (typically equal to 1.0).

H is the inertia constant for the shaft train.

S is the Laplace operator.

Substituting in T = 39.4, H = 0.5, and D = 1.0, we get:

$$DP/DPm = 39.4/(2 \text{ x } 0.5\ S^2 + 1.0\ S + 39.4) \qquad \textbf{Eq. 5-60}$$

Letting S = j 47, we get:

$$DP/DPm = 39.4/(\ -47^2 + 47j + 39.4) = 39.4/(-2169.6 + 47j) \cong 0.018 \qquad \textbf{Eq. 5-61}$$

Target:
Power Quality for Transmission and Distribution

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