Power Quality Impacts of Distributed Generation

Technical Report

Power Quality Impacts of Distributed Generation

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PRODUCT DESCRIPTION

Distribution systems are designed for one-way power flow and can accommodate only a limited amount of distributed generation (DG) without alterations. This project focused on the economics associated with upgrading and designing distribution systems to support widespread integration of distributed resources, especially distributed generation. Costs were determined in the area of protection requirements and voltage regulation requirements, two of the main areas where changes are required to accommodate DG.

Results & Findings

This report addresses the two most common DG interconnection issues encountered by distribution engineers: voltage regulation and interference with utility short circuit protection schemes. When DR capacity reaches a value where changes have to be made, costs can be significant. The capability for distribution systems to absorb additional DR varies considerably depending on circuit topology and local design criteria. Some systems were designed to utilize nearly all the capacity of transformers and fault interrupters for normal power flow and have little margin for additional contributions from DG. Corrective actions in these systems are quite expensive. To better accommodate DG in the future, new systems should leave more margin for short circuit contributions. Other systems can already accommodate a greater percentage of DG with relatively minor changes such as changing relay settings, although even determining new settings has a significant engineering cost.

One incidental finding of this research is that the cost involved with supporting DG sites after commissioning is probably under-reported. Most DG sites suffer operational difficulties such as nuisance tripping during their first year of operation. These problems require additional attention from utility personnel and, sometimes, additional system modifications. Today, in many cases these costs are usually added to other utility normal operating costs and are not directly charged to the DR operator, although they probably should be. Since the manpower costs involved are not always trivial, this subject warrants further investigation.

Challenges & Objectives

As DG becomes a significant portion of the distribution feeder load, distribution designers will be challenged to maintain the quality of supply. Given current technology, interconnection standards, and utility distribution system practices, the impact of DG on power quality will be neutral at best. Interconnection agreements incorporate stringent protection requirements to reduce the risk of an islanding occurrence. However, the two most common adverse impacts of DG on power quality are voltage regulation issues and interference with utility short circuit protection. These two problems are often encountered well before there is a serious risk of islanding, and they are frequently the most limiting factors in how much DG can be accommodated without making costly changes. The political and business interests pressuring utilities to accommodate widespread DG on their systems often do not properly understand the differences between the types of power delivery systems employed by utilities nor the costs of modifying existing systems designed for unidirectional power flow to accommodate power flow from several sources.

Applications, Values & Use

This report will help distribution engineers and DG owners better understand the costs involved in making the necessary changes to accommodate DG and the reasons for making those changes. It can serve as a reference for prospective DG operators and other interested parties and contribute to industry efforts to understand how to design distribution systems to accommodate widespread DR interconnections.

EPRI Perspective

From the perspective of grid and end-user power quality, one of the most critical impacts of DG will be its effect on voltage regulation in a distribution feeder with a high penetration of DG. If the penetration level increases on particular feeders, traditional means of voltage regulation may be inadequate and adaptive setting of line-drop-compensators, voltage regulators, and capacitor controls may be required. A common technical myth regarding DR is that as long as the power flow is not reversed on the line, DG cannot impact the quality of voltage regulation. However, DG can cause interaction problems with utility system equipment even in situations where the power flow on the feeder is merely reduced by DR. While a certain amount of DG can generally be accommodated without significant changes to distribution system operation, when changes are required, costs can be much higher than the general public or DG owner expects. This work contributes to the understanding of the costs of minimizing the power quality impacts of DG interconnections.

Approach

The research focuses on the costs of distribution design and automation requirements to maintain reliability, voltage quality, and system protection performance for high penetration of DG. The project team considered two case studies that incorporate the most commonly encountered power quality issues with DG. The team identified various modifications to the distribution system that can solve these problems. Utilities in the working group that supported this project submitted scenarios to their cost accounting systems to develop cost estimates for the proposed distribution system changes and additional cost data were gleaned from public utility documents for similar capital projects. The project team coordinated research with working group members by telephone, e-mail, and a web-based workshop.

Keywords

Distributed resources
Distributed generation
Power quality
Voltage regulation
Overcurrent protection
Interconnection costs

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1 INTRODUCTION

Many people continue to promote distributed generation (DG) as a part of the solution to the energy problem. When they look at the utility grid and see that utilities themselves have numerous generators connected, they frequently do not comprehend the resistance they perceive for interconnecting another, relatively small generator. For the most part, the general public fails to recognize that there is more than one face to this entity that is generically called the “grid.” Smaller generation that falls into the category of DG is often proposed for interconnection to the distributions system because it is too expensive to connect it to the transmission system.

The distribution system has some significant differences from the transmission system. It is designed to bring the bulk power supply to the end user at the least possible cost with acceptable reliability. A key attribute is that it is not designed to accept generation while the transmission system necessarily must accept numerous generators. A common myth regarding distributed resources (DR) in general is that as long as the power is not reversed, the DR cannot impact the the quality of power. That is, if the DR is not larger than the load at any given time, there are no adverse consequences of being interconnected. This view considers only the slow-acting, steady state condition and does not take into account the inevitable disturbances that the protection systems are required to handle in milliseconds. Even some technically-trained individuals often do not realize that the key conflicts occur within the first few cycles after something goes wrong (and it always will). DR equipment vendors may market their products as not interfering with the operation of the utility, but this is a virtual impossibility. As long as generation is connected it can have an impact and will participate in all disturbance events. This requires careful attention to the protection systems and to voltage regulation. The latter is one key aspect of electrical power that is shared by all users of the system and must be preserved with high quality.

A certain amount of generation can always be accommodated on a given distribution system without making changes to protective devices or operating procedures. The amount varies considerably from one system to another. It all depends on the design philosophy of the local utility, the history of electrical service to the area, local topology, load characteristics, the proposed generation technology and many other factors. Some systems can handle only a few hundred kW while others can handle several MW. A general rule of thumb that often quoted is 15% - but 15% of what? Some say 15% of system capacity while others use 15% of minimum load or peak load. These are much different numbers and are open to debate.

When these rules are exceeded, studies are generally required to determine if the proposed DG will require changes. The most contentious conflicts in the negotiations for interconnecting DG to the distribution system occur when the penetration of DG is sufficiently large to force changes. A decision must be reached regarding who pays for the changes and how much they will have to pay.

Some changes are relatively minor and the cost is well within the budget of a proposed DG interconnection. Others are very costly and may completely swamp the economics of the DG project if the project is required to bear the entire cost.

Disputes over the interconnection costs will likely continue until all distribution systems have been modified to accept high penetrations of DG. This report is the first step in determining how much it will cost to modify distribution system design so that widespread DG can be better accommodated. The process is to evaluate what are believed to be the two most common scenarios in which changes are required to accommodate a DG project:

1. The DG contribution to short circuit current causes breaker interrupting duties to be exceeded,
2. DG results in voltage variations outside the normal range.

The costs of several different approaches for dealing with the problems are estimated.

By examining these two scenarios, we can get a clearer picture of how to design distribution systems that are more friendly to DG interconnections. Future research can extend this work to take a closer look at what might be done in the future to build a distribution system capable of accepting numerous DG interconnections while monitoring and controlling the DG to the benefit of all parties.

The subsequent chapters of this report are organized as follows:

- First, present distribution system design is discussed, emphasizing the key design aspects that lead to DG interconnection conflicts.
- The first scenario (excessive fault current) is described.
- The second scenario (voltage regulation) is described.
- The final chapter is an extrapolation of the results to the future to help lay the foundation for estimating the cost of designing the system to handle high penetrations of DG while maintaining reliability, voltage quality, and system protection performance.

2

DISTRIBUTION SYSTEMS AND DG INTERCONNECTION

In this chapter, the characteristics of distribution system design pertinent to DG interconnection are concisely described. A comparison is drawn to the transmission system, which is designed to accept multiple sources of generation. Many sites with good potential for economic application of DG are served by low-voltage networks, which present special problems. Therefore, there is a small section of low-voltage networks. After laying this background, some key issues that can result in interconnection conflicts are described.

Since much has been written on this in the past [1 - 6], the description of the issues is intentionally brief and concise. The background material presented here emphasizes the key reasons that certain DG-related issues arise and what must be done to resolve those issues technically.

Distribution System Design

This section provides basic information on the types of utility distribution systems found around the world.

4-Wire Multi-Grounded Neutral Systems

The most common type of distribution system in the United States is a 4-wire multi-grounded neutral system like that shown in Figure 2-1. The main three-phase feeders are constructed with four wires – the three phase wires and the neutral wire. The neutral is connected to ground ("grounded") every few poles and at locations where distribution transformers or other equipment is connected. Most residences and small commercial customers are served from single-phase transformers. Many of the single-phase loads are served from single-phase laterals off the main three-phase feeder trunk. The primary sides of the single-phase service transformers are connected line-to-neutral. If the feeder has capacitor banks, they would be typically connected in grounded-wye as shown, although there are numerous exceptions. Likewise, if voltage regulators (not shown) are present, they would typically be connected in grounded-wye.

Single-phase laterals are very common since they are relatively inexpensive to build. The lateral would consist of one phase wire, fully insulated for line-to-neutral voltage, and one neutral wire that is grounded at regular intervals. The neutral wire need not be insulated and the single-phase pole lines are often built without crossarms, although that may be done in some area. Thus, the line can be constructed at low cost.

Because the common service voltage is low (120V), the primary distribution lines have to brought close to the point of use. This is in contrast to the European-style system that is discussed later in this chapter.

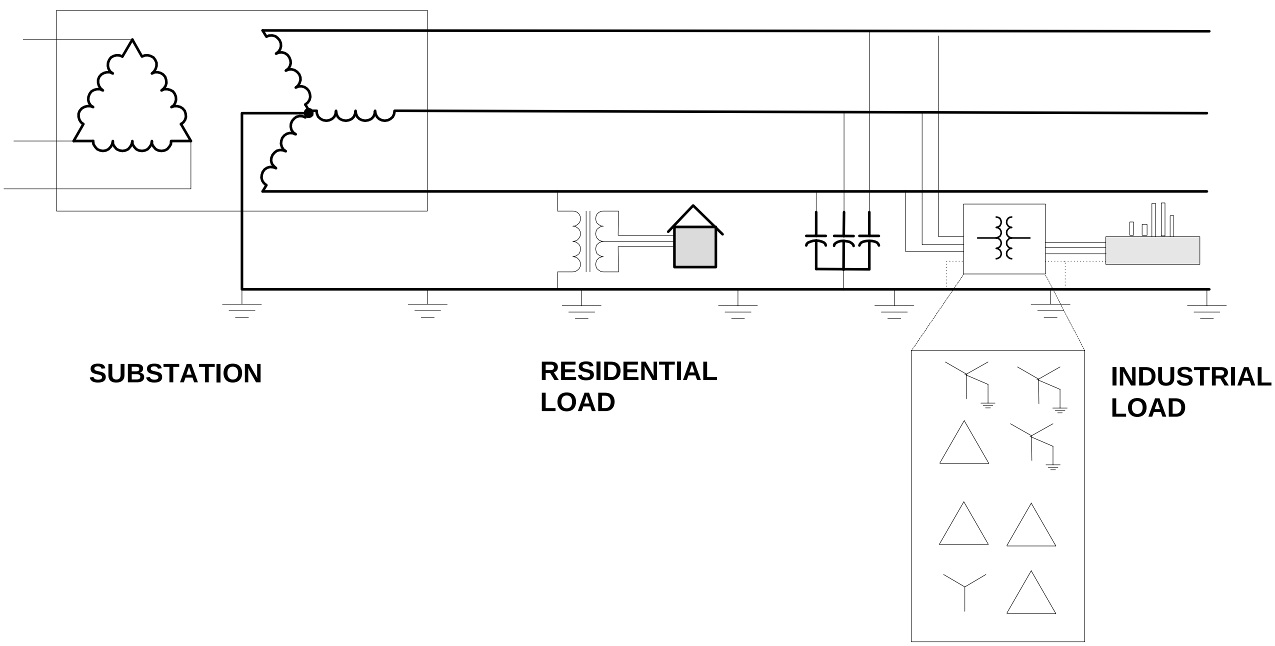

Figure 2-1
Typical 4-Wire Multigrounded Neutral Distribution System

Industrial and larger commercial loads have three-phase service. A variety of transformer connections are used. The most common today are grounded-wye/grounded-wye, followed by delta/grounded-wye. Other connections may also be used as shown. This type of system also permits three-phase loads to be served from only two primary phases by employing an open-wye/open-delta connection. The effectively grounded neutral makes in possible to do this and other similar tricks of the trade to provide service at lower cost. Unfortunately, these sometimes make DG interconnection difficult.

In most areas, surge arresters are used at each distribution transformer and cable riser pole. The 4-wire multigrounded neutral system makes it possible to use arresters rated for line-to-neutral voltage, achieving significant cost savings. This is the predominant practice of North American utilities and has significant consequences with respect to some of the things that can go wrong with DG interconnections.[1]

Larger DG would be three-phase service and could be connected to the primary distribution system through any of the transformer connections shown. As with loads, the most common would be the first two shown. In addition, some DG is interconnected through a grounded-wye/delta connection (not shown) that has certain good characteristics, but also has some significant problems with respect to ground faults because most distribution systems are not designed to handle this connection.

One common exception to the 4-wire multi-grounded neutral system in North America is found on the West Coast. Unigrounded systems are commonly employed for voltages up through 15 kV class. The neutral at the substation is grounded, but only three phase wires are carried along the feeders. Single-phase transformers are connected phase-to-phase just like three-wire delta systems (see next section). Sometimes, these unigrounded systems become effectively grounded due to extensive use of direct-buried underground cable. The neutrals (shields) of the cables are necessarily grounded to achieve uniform dielectric stress on the cable insulation. However, the transformer connections would not necessarily rely on this ground to carry power.

3-Wire Delta Systems

Many older systems were three-wire delta systems like that shown in Figure 2-2. Single-phase service transformers are connected line-to-line. In areas where surge arresters are used, which includes most areas, two would be required for each transformer. Capacitor banks and voltage regulator banks, if present, would be typically connected in delta. Single-phase laterals would consist of two of the phases with full insulation required for each phase.

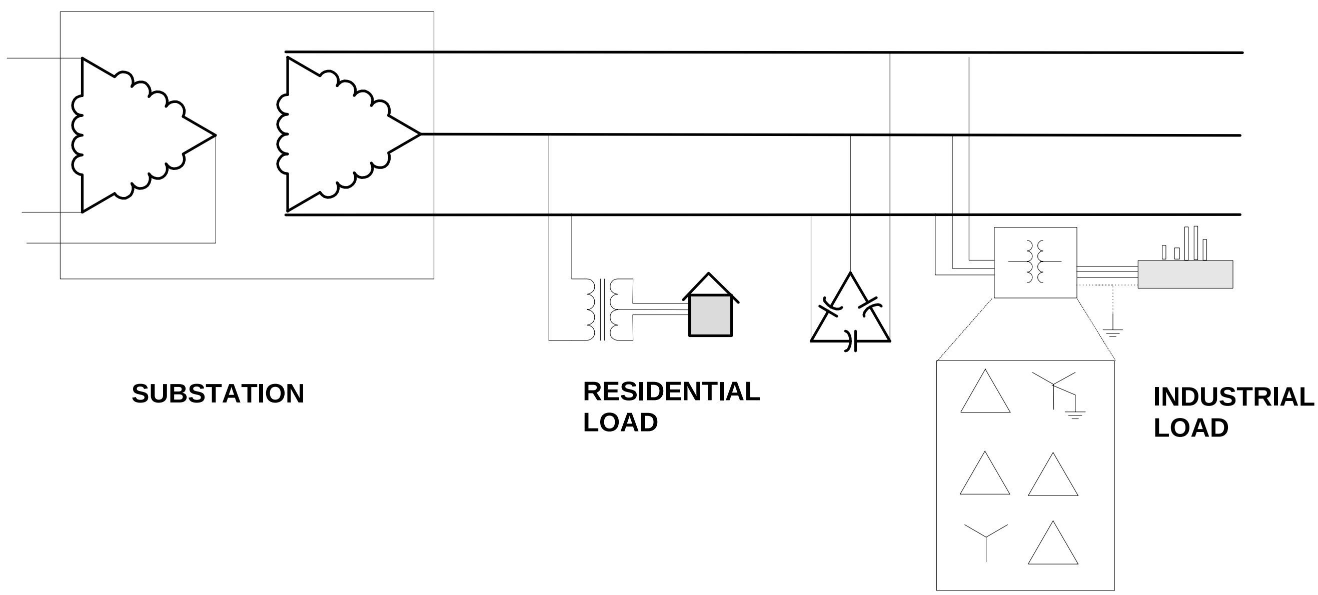

Figure 2-2
Typical 3-Wire Delta Distribution System

There are fewer options for the three-phase service transformer connection. Grounded-wye primary connections are not used on these systems, although they may be used on the low-voltage side.

As higher primary distribution voltages were adopted throughout North America, there were many economies to be realized by switching from 3-wire delta systems to 4-wire multi-grounded neutral systems. This includes systems on the West Coast for voltages above the 15 kV class. Reduced insulation levels can be employed in transformers and other line equipment, result in considerable savings. There are also efficiencies with respect to overcurrent protection, such as fusing, that permit more compact and less costly designs to be used.

European-Style Distribution Systems

European-style distribution systems have some notable differences (Figure 2-3). In North America, "distribution" almost always refers to primary distribution, ranging from 2.4 kV to 34.5 kV. This corresponds to the European medium-voltage (MV) distribution system. The European style design also makes extensive use of low-voltage (LV) distribution, which is generally 400V line-to-line. The term "distribution substation" generally refers to MV/LV transformers, which Americans would typically call distribution transformers. These would nearly always be three-phase transformers supplying perhaps as many as 100 residences. This is possible because of the higher utilization voltage. While a typical North American distribution feeder may have hundreds of distribution transformers, the comparable European-style design might have an nearly an order of magnitude fewer – all three-phase and connected delta/grounded-wye.

The LV distribution system is designed similarly to the 4-wire multi-grounded neutral system described previously. In many nations, all customers receive three-phase service simply by tapping the 400V lines. Lamps and household appliances would be connected line-to-neutral, operating at approximately 230V.

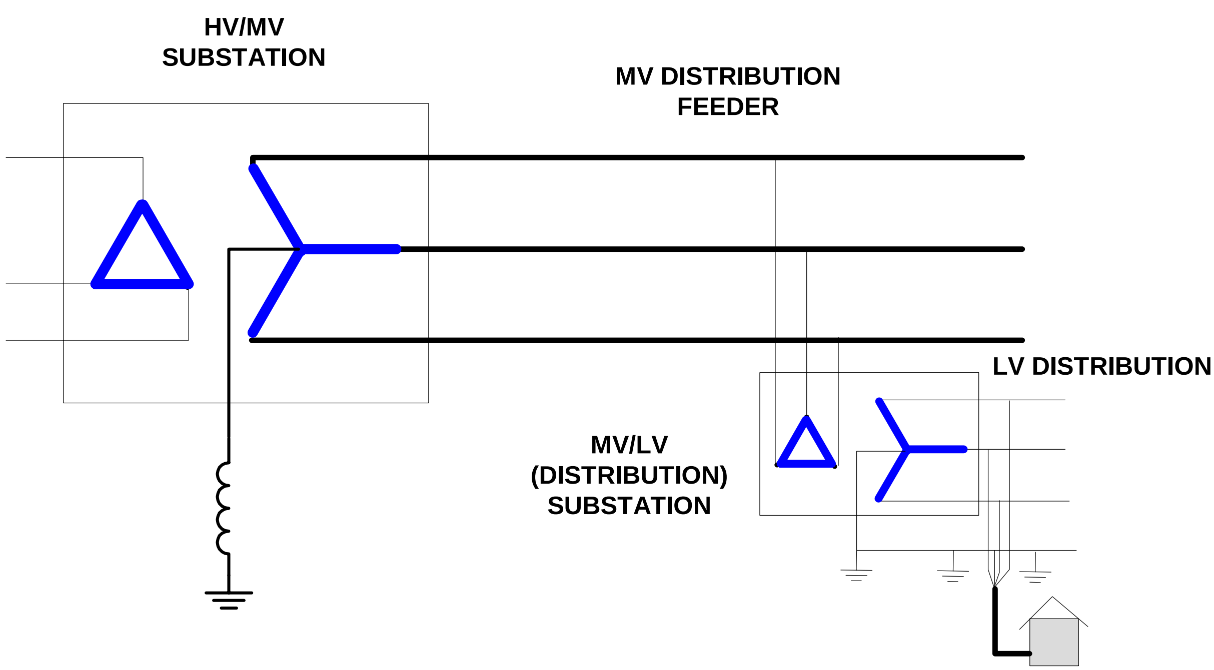

Figure 2-3
Basic European-Style Distribution (MV) System

European-style distribution systems are much more uniformly designed than North American systems. Nearly all transformers are connected delta/grounded wye as shown. HV/MV substation transformers will typically be grounded through an inductance. This would have the purpose of either simply limiting the ground fault current or of attempting to extinguish the ground fault current by resonant tuning with the shunt capacitance of the feeder. This is intended to virtually eliminate voltage sags and interruptions due to the common SLG fault.

Power factor correction capacitors have historically not been common on MV distribution. This may be changing in some areas because of needs to increase system capacities and efficiencies. Power factor correction would be expected to take place at the LV distribution level. The switching of primary distribution capacitor banks that can cause operating difficulties for DR in North America should be less of an issue on these systems.

DR would nearly always be connected directly to the LV system or through a separate MV/LV transformer, if it is large enough to warrant separate service. The transformer would be typically connected delta/grounded-wye as shown. This does not result in the overvoltage issues found in American systems. The arresters and other equipment are designed for line-to-line voltage and can generally withstand the effects of inadvertent islands forming briefly with the generator providing an ungrounded source. There still might be some resonance issues if a SLG fault remains and there is significant cable and line capacitance.

Radial Distribution Structure

Around the world, there is a mixture of North American and European-style designs, depending on which country had the greatest influence on the development of electric power systems in a particular region. Regardless of basic style, most primary distribution systems throughout the world are operated radially for economic reasons. The basic overcurrent protection scheme is illustrated in Figure 2-4.

Engineers will often refer to radial distribution systems as “looped” or “network” systems, but the tie switch between two adjacent feeders is normally open. Thus, it is radial while in operation except for brief periods where the utility may perform closed transition switching during feeder reconfiguration for maintenance purposes.

The radial distribution system is connected to one main source of power at a time (there may be alternate sources in case of emergency). Moving out onto the feeders from the substation, there will be a number of overcurrent protection devices in series. There is at least a feeder breaker, but there may also be other automatic fault interrupters, such as the line reclosers shown, farther down the feeder. The lowest level of overcurrent protection is generally provided by a fuse. This may be a lateral fuse as shown or the fuse in some piece of equipment such as a transformer. These devices predominantly use simple overcurrent measurements to determine if there is a fault. Some will also sense direction to prevent nuisance tripping on faults out of their protective zones.

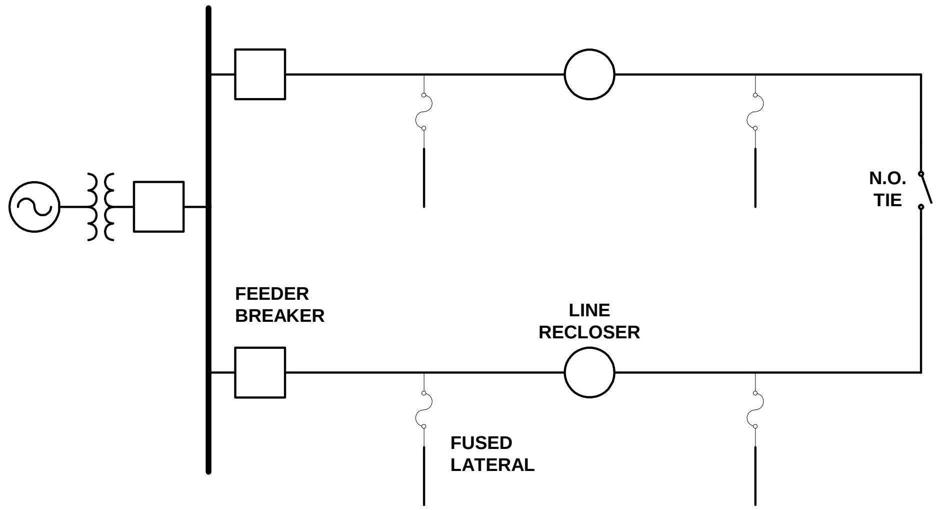

Figure 2-4
Radial Distribution System Overcurrent Protection Design

Breakers are nearly always three-phase devices. Reclosers may be either three-phase or single-phase interrupters. Fuses are always single-phase.

Because fuses are at the lowest level, they dictate the basic timing of all overcurrent devices upstream. Proper coordination for permanent faults is generally to start with the fuse time-current characteristic (TCC) and set each successive upline relay in the automatic devices a little slower. An exception is when fuse saving is employed. Then the breaker or recloser will operate faster than the fuse once or twice in an attempt to save the fuse for temporary faults such as a lightning strike or a tree brushing against the line. This time and current magnitude coordination is responsible for many of the interconnection conflicts with DG. Thus, it may be said that the extensive use of fuses on distribution systems is the root cause of many of the interconnection issues. It can be argued that one way to make the distribution system more friendly to DR in general is to design a distribution fault detection and clearing scheme that does not rely on fuses.

The basic reason for the radial configuration is economics of the protection system design: this configuration requires the least costly protective equipment arrangement to provide adequate reliability. It is also more straightforward to operate and maintain. If better reliability is required, configurations such as the low-voltage networks are employed at somewhat higher cost. (see Low Voltage Networks, below).

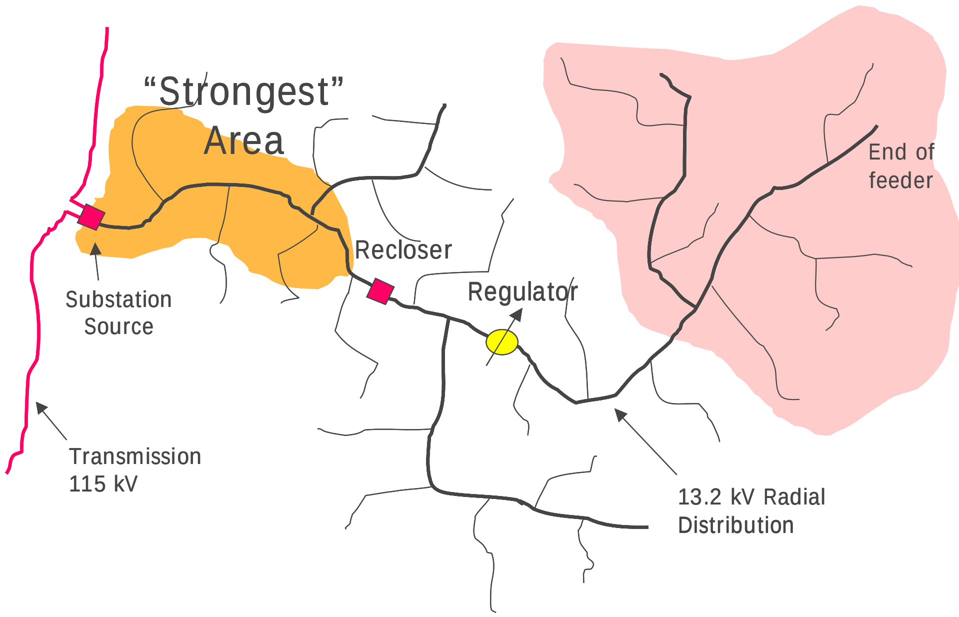

Figure 2-5
Typical Distribution System Layout

Figure 2-5 illustrates some other key features of a radial distribution system that are pertinent to the DG interconnection issue. Different areas of the feeder will have differing capabilities to support DG without requiring costly changes. The area closer to the substation is the "strongest" area. That is, it has the greatest short circuit current availability and the best voltage regulation. This area can theoretically support more DG with less problems – if the system can withstand the additional short circuit current contribution from the DG.

The system grows weaker past the line recloser. The feeder may run for several miles serving suburban and rural areas. The recloser isolates the strong area from the more numerous faults that occur in the more remote areas of the feeder. DG in this area can expect more frequent interruptions than in the strong part of the feeder. Voltage regulation also becomes more of an issue. The circuit shown has a voltage regulator to boost to voltage for the loads. DG operation would have to be coordinated with this device so that it operates properly whether the DG is in service or not.

Some DG technologies are more likely to be sited in the remote areas. For example, landfill gas generators of 2 MW capacity, or larger, are common. These sites are likely to be some distance from the nearest substation, making it difficult to support such large generation without adding more reclosers, changing voltage regulator controls, etc. Although not shown on this diagram, there are often switched capacitor banks scattered throughout the feeder. Improper coordination with these devices can cause frequent nuisance trips of DG and voltage regulation problems for the feeder.

There is a substantial difference between the amount of DG that can be handled without operational impact on the strong part of the feeder than on the more remote section. For example, studies may show that the DG capacity in the strong part of the feeder may reach as high as 30%

of the load capacity before any changes are required. However, similar DG placed at the end of the feeder may be only 5% of the feeder capacity when conflicts begin to appear.

There is not a uniform practice among utilities regarding the design of radial distribution systems. Some build only a few large substations and run feeders for several miles. Others in more densely populated areas will site substations so that feeder lengths are no more than 1-2 miles. The latter design can generally accept a greater penetration of DG without costly changes, assuming that there is sufficient margin in short circuit duties on utility breakers and fuses.

Thus, it is difficult to make any generalizations about how much DG can be accommodated on utility distribution systems. Efforts to standardize policies with respect to DG interconnection, such as those associated with IEEE Std.1547-2003, are commendable with respect to their ultimate goal of simplifying DG interconnection requirements. However, some parts of those efforts may be futile due to the lack of uniformity in distribution feeder design at present.

Low Voltage Network Structure

Many downtown areas of major cities are served by low-voltage (LV) networks. The residents and businesses demand higher reliability than can be achieved with the relatively simple radial circuit design. There are also many potentially attractive DG opportunities in downtown areas. For example large office buildings can frequently achieve significant energy efficiency gains from combined heat and power applications. Unfortunately, LV networks present special difficulties for DG applications and the cost for overcoming those difficulties may completely swamp any potential gain from energy efficiency.

Figure 2-6 shows a simplified schematic of a LV network. The load is connected at the far right of the diagram and is served from a common LV bus. The bus shown may represent one physical bus, which is more common in a spot network, or a series of buses spread out over several city blocks. Two common network voltage ratings are 208/120V and 480/277V.

The LV side is highly interconnected. In some designs, there are at least two lines coming into each load bus so that one can fail without interrupting service. This bears some similarities to the utility transmission system in concept except that the fault interrupters are more commonly fuses than breakers. But that is where the similarity ends. The LV network is served in the case shown by four primary voltage network feeders, commonly of 15 kV class. Each feeder has one or more transformers stepping down to the LV network. Each transformer is typically connected delta/grounded-wye as shown. On the LV side of the transformer is a special circuit breaker called a network protector that, in its simplest form, has characteristics that are decidedly unfriendly to DG.

Such networks can suffer the loss of one or two of the network feeders without interrupting end users. At worst, end users will suffer a brief voltage sag during faults, which may cause some equipment to drop out, but reliability is excellent. When there is a fault in a network feeder, there can be a strong contribution from the other three feeders through the LV network. Therefore, all the network protectors connected to the faulted feeder must open to allow the fault to be cleared. The other network protectors remain closed.

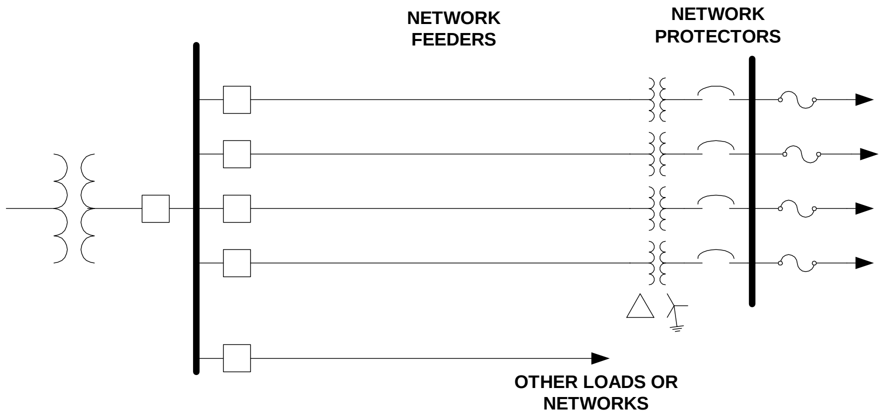

Figure 2-6
Low-Voltage Network Structure

The traditional network protector is tripped by a very sensitive directional power relay. The idea is that the only time power will flow backward through the network transformers is when there is a fault on the associated network feeder. Thus, the network protector is designed to trip very quickly on the slightest reverse power.

This creates a problem for considering any significant amount of DG that employs a rotating machine. If the DG were to feed a net power back into the system even for a brief instant during the synchronization transient swing or after a sudden loss of LV network load, it could trip some or all of the network protectors.

Note that there may be other loads or networks served from the same substation bus. If there is a fault on the other feeder shown, DG could feed back into it and trip all network protectors, completely shutting down the network.

Network protectors may now be purchased with multiple levels of trip settings to accommodate more DG than the older style will permit. It may be economic on some spot networks with only a few protectors to change them out to accommodate DG. However, some downtown network have dozens to hundreds of network protectors and it is difficult to imagine it being economic to change all out for a DG application.

Some common workarounds to allow some amount of DR on LV networks include:

1. If the DG is capable of supporting the entire load at the load site where it is installed (e.g., a building), closed transition switching equipment is installed at the point of interconnection at the DG owner/operator's expense. The load is then served off grid, with the DR being interconnected only briefly during the transition.
2. Allow only DG that is interfaced through modern utility interactive inverters (Figure 3-2) and does not contribute significantly to faults on the primary distribution system. Such DG must still be dispatched to ensure that the power output never exceeds the load (a significant problem in smaller spot networks in which the load can suddenly drop by a large percentage).
3. Limit the total DG to a very small value such as 15% of the expected minimum load.

Comparison to Transmission Systems

Given the above introduction to distribution systems it is useful to compare certain key characteristics with the utility transmission system, which can handle multiple generators.

The main difference pertinent to this project is how faults are cleared. The distribution system is designed so that only one device need operate to clear the fault as illustrated in Figure 2-7. This minimizes the number of protective devices that must be purchased and greatly simplifies the operation of the distribution system. As mentioned above, the overcurrent protective devices in series must be coordinated in time and current values to work properly. This can be achieved because the system is designed assuming the fault current comes from only one source. In the example show, the line recloser operates to clear the fault, but the fuse does not blow. The feeder breaker in the substation does not operate.

In contrast, the transmission system is designed with the assumption that fault current could come from any direction. Rather than relying on simple overcurrent devices, directional distance relaying is employed on nearly every line. The transmission system is also designed as a mesh network in most areas with at least two lines coming into each bus. One line can suffer a fault and be removed from the system without interrupting power delivery. Each line typically has a breaker, of the equivalent thereof, on each end. The breakers on both ends must open to clear the fault(Figure 2-8).

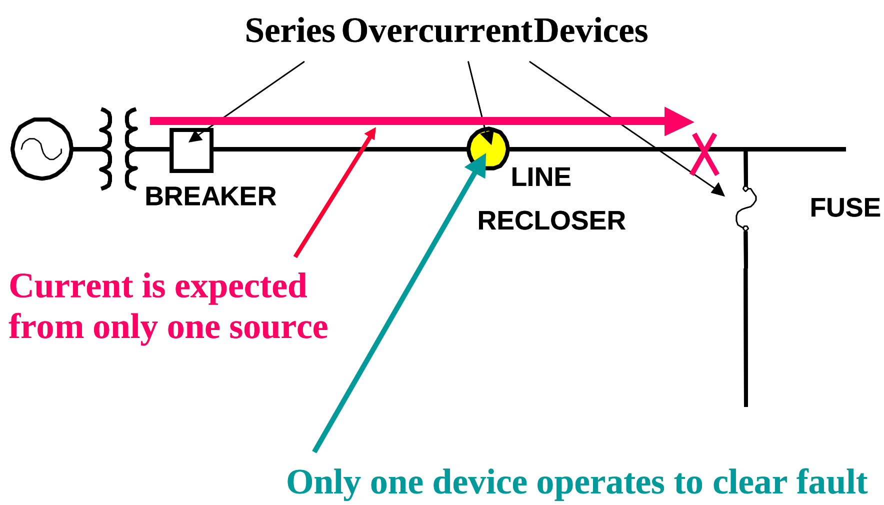

Figure 2-7
Radial Distribution Systems are Designed Assuming Fault Contribution From One Direction

Many DR advocates have the vision that the distribution system of the future will operate more like the transmission system. When a fault occurs the system will automatically sectionalize the faulted line, with the portion of the feeder that becomes isolated from the substation becoming a microgrid supported by DR. This would require placing numerous fault interrupters along the feeders, each with directional and distance relaying so they would not have to be coordinated as tightly with adjacent interrupters. This would be extremely costly and would not resolve all the

DR application issues. Considerable communications and control infrastructure would also have to be added.

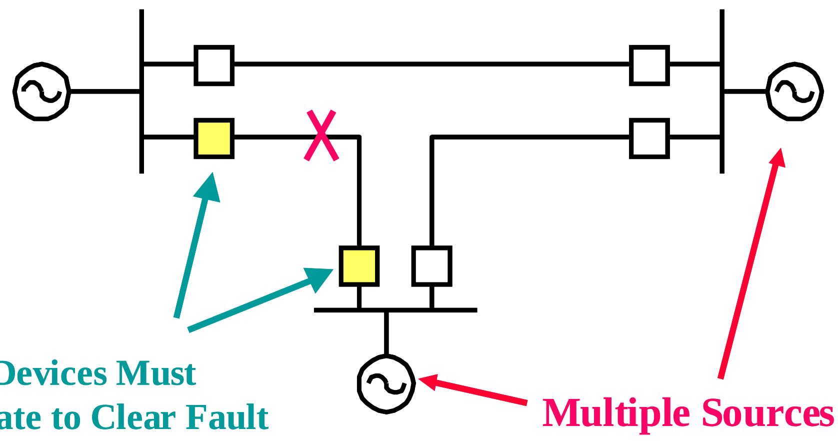

Figure 2-8
Transmission System is Designed to Accommodate Multiple Sources

For the present, the main option that remains for accommodating DG in the typical radial distribution system is to require the DG to disconnect when a fault occurs. This allows the topology to revert to a radial system while the fault clearing process takes place.

Interconnection Issues

The references at the end of this chapter contain detailed descriptions of the many issues related to interconnecting DG to the distribution system that result in conflicts. The issues are simply listed here with brief commentary. This report will basically address the costs associated with the first two major bullets. While any of the problems could occur, the first two are more commonly encountered as the total amount of DG becomes large.

- The DG current contribution into faults on the utility results in a number of possible operational issues:
  - Excessive duty on elements that have to withstand and interrupt the fault current, such as circuit breakers, reclosers, and fuses.
  - Interference with overcurrent protection relaying. This can take many forms ranging from relays not being able to detect faults (desensitized) to relays or fuses acting too slow or too fast.
  - Faults fail to clear because the DG continues to supply current too long after the utility breaker operates. Reclose intervals can be extended to alleviate this, but at the loss of some power quality.
  - Sympathetic, or nuisance, tripping of breakers that would not otherwise trip. Thus, some customers are interrupted unnecessarily.
  - The additional contribution makes it difficult to achieve fuse saving.

  - Fault damage is greater due to higher currents and/or longer relaying times.
- There are also a number of voltage regulation issues:
  - The voltage rises too high when the DG comes on line. Normally, there is a voltage drop for points on the feeder farther from the substation or service transformer. Generation counters that voltage drop and may increase the voltage too much.
  - Conversely, there is a voltage drop when DG suddenly disconnects from the system. This will occur because DG must disconnect upon the occurrence of the inevitable fault. Depending on the actions of other voltage regulating equipment, the voltage drop can be too large, particularly if many generators are forced off simultaneously.
  - Reverse power through line voltage regulators can cause the regulators to regulate in the wrong direction. Regulators often are designed to automatically reverse direction when a feeder is fed from another source. A net reverse power because of DG can fool the regulators.
  - Varying generation, such as that often found in renewable generation, can result in poor service voltage quality and overwork regulating devices such as tap changers and switch capacitors.
- The risk of islanding is sometimes mitigated by extending the first reclose interval to help ensure that the DG relaying has had adequate time to detect a fault. This can result in reduced power quality for some customers.
- Overvoltages due to islanding of DG that does not provide an effectively grounded system can damage surge arresters on 4-wire multi-grounded systems that were designed used reduced voltage arresters.
- Some DG will create harmonic distortion. Modern utility-interactive inverters significantly reduce the amount of low-order harmonics, but may excite some high frequency resonances in cable-fed systems. Some synchronous machines produce triplen harmonic voltages, which can create overcurrent problems when interconnected with certain transformer connections. Large induction generations, such as those found in wind turbine generators, may use soft starters that briefly produce significant harmonics that excite system resonances.
- Quickly disconnecting DG for open conductor faults (e.g., blown line fuses) may result in ferroresonance that damages the service transformer or arresters. In general, line fuses between three-phase DG and the next upline mechanical three-phase interrupter should be avoided.
- Utility capacitor switching causes DG to trip or results in high voltages when the DG is running. Control strategies for the capacitor often have to be changed. This may be as simple as flipping a switch, but could require replacing the control.

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3

CASE STUDY 1: FAULT CURRENT CONTRIBUTION

One of the most common barriers to interconnecting DR to the distribution system is that there is insufficient margin in the fault current interrupting rating to allow any additional contributions to fault currents from another source.

Problem Background

When many of today's distribution systems in high-density load areas were built, it seemed like a good idea to make the supply as strong, or stiff, as available breakers, fuses, switches, and lines could withstand. Therefore, substation transformers were ordered with impedances that limited the fault current to slightly less than the momentary and interrupting ratings of the breakers.

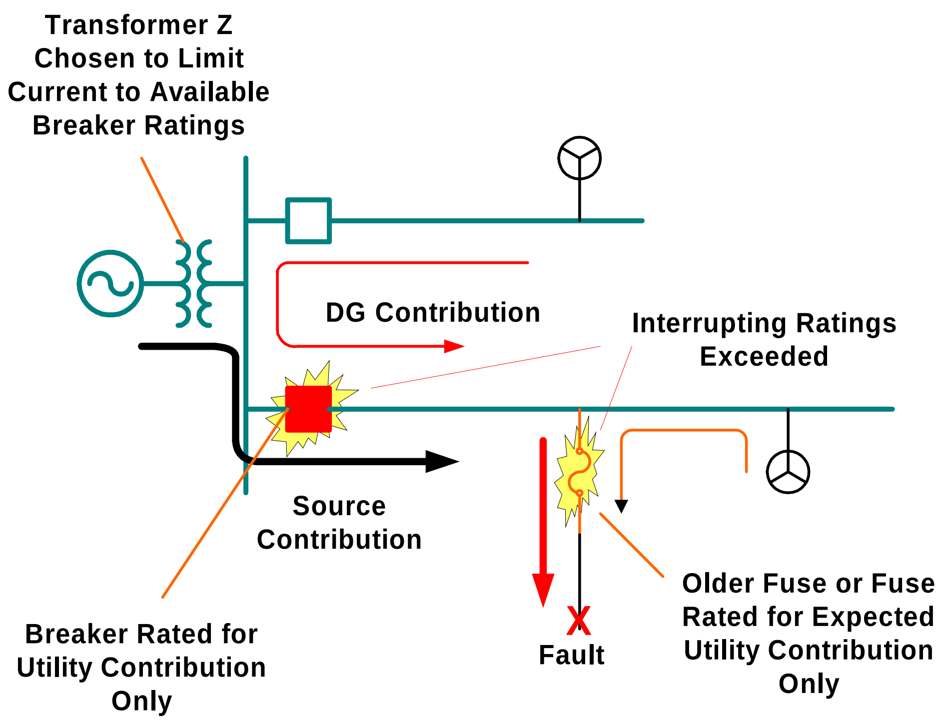

Figure 3-1
Increased Fault Current Contribution Stress Momentary and Interrupting Duties

The margin was slim to begin with and has eroded somewhat as the breakers have operated over several years. Each operation causes the capability to deteriorate slightly. Unfortunately, there are no tests that can determine the actual interrupting rating of a breaker that has been in service for many years without testing it to failure. Therefore, many utilities are reluctant to accept any DG onto the system that can contribute additional fault current.

Figure 3-1 illustrates the problem. Two generators are shown feeding into a fault. Ideally, the fuse should clear this fault without requiring a breaker operation, although both may normally operate for high current faults if instantaneous tripping is used. One generator feeds through the feeder breaker in the substation and the additional current is depicted as causing breaker failure. This would be due to exceeding either the momentary or the interrupting rating. The other one feeds through the fuse alone. The fuse sees the normal source contribution plus the contribution from both generators. If the fuse is older, it may have an interrupting rating of only 8kA. Some utilities stock only this variety because it is sufficient for the vast majority of locations on the system. Only locations near the substation are at risk. The DG contribution increases the risk of fuse failure and could lead to more feeder breaker trips and extended customer outages.

The types of DG that might work compatibly on systems constructed this way are those that contribute very little current to faults. Most DG that employs an inverter for interfacing the prime mover to the power system will fall into this category. Most DG that employs a rotating machine generator would require special means to limit the fault current or would simply be prohibited. The latter class of DG is generally less costly, often by a substantial factor.

Utility Interactive Inverters

The modern utility interactive inverter will limit the current out of necessity to prevent damage to the semiconductor switches and can cease operation very quickly by power system standards once a problem is detected. Figure 3-2 illustrates schematically how modern utility-interactive inverters are commonly constructed. The semiconductor switches are switched very rapidly (3 kHz or more) and the ac waveform is constructed in pieces from the dc power source (e.g., via pulse-width modulation). A filter on the output removes most of the high frequency components and reduces the amount entering the interconnection transformer.

One advantage of this technique is that the troublesome low-order harmonics prevalent in line-commutated inverters found on many early DG devices are virtually eliminated. Occasionally, there will be a resonant interaction with repect to the switching frequency components and a part of the power system that results in some high-frequency distortion. One potential disadvantage is that these self-commutated devices can create unintentional islands when the connection to the utility power source is lost. Therefore, such inverters essentially operate as current sources when interconnected with the utility system, producing a current waveform that follows the voltage provided by the grid. This is referred to as utility-interactive mode and is part of the technique for minimizing unwanted islanding. This has implications for voltage regulation as well as short circuit contributes.

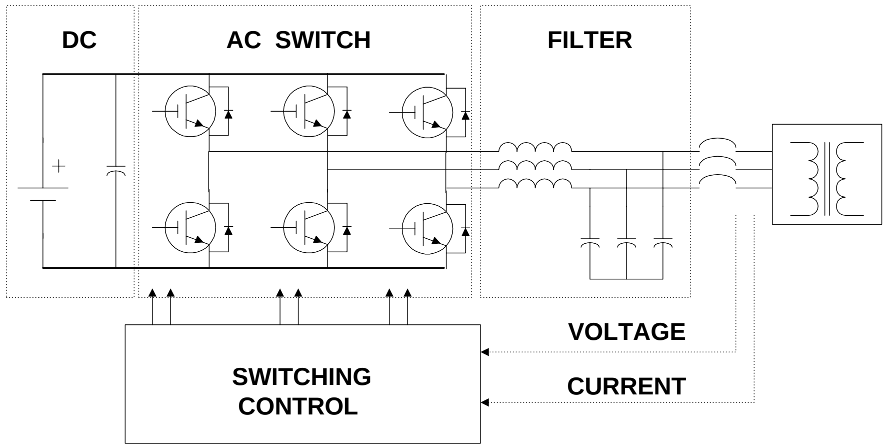

Figure 3-2
Simplified Schematic Diagram of Switching Inverter

If a fault is detected, the switching control can be programmed to simply stop, effectively cutting off any current contribution within milliseconds.

Common types of DG interfaced through inverters includes:

- Solar photovoltaic generation
- Fuel cells
- Some wind turbines
- Microturbines
- Battery storage

Any type of generation that produces power with dc - or with ac at a frequency other than power frequency - is interconnected to the utility grid through inverters. While not sources of fault current, inverter-interfaced DR can still contribute the same voltage regulation issues as rotating machines and may have other issues with fault clearing.

Rotating Machines

The other main class of DR interface is rotating machines – either synchronous or asynchronous (induction). Rotating machines are a mature technology and generally much less expensive than inverter interfaces of similar rating. Therefore, there is great interest among DG developer in using rotating machines.

Rotating machines must always be assumed to contribute to short circuit faults. Many standard engineering analysis packages have the capability to compute the machine contribution. It is sometimes difficult to obtain the actual machine parameters, particularly, if the machine is old or previously installed elsewhere. However, estimates of the fault current contribution can be made satisfactorily from typical values.

Common wisdom is that alternators, or synchronous machines, contribute to faults but induction machines do not. However, it is a fallacy to assume that induction machines do not contribute to faults. This is a common selling point for some types of cogeneration. While it is true that induction machines are somewhat simpler to interface than synchronous machines, it should not be assumed that they do not contribute to fault currents.

The source of this misconception is the common textbook presentation that shows the current in an induction machine decaying upon the application of a fault (usually on its terminals). The current decays rapidly because it no longer has any excitation. Once the residual energy is extracted from magnetic components, the machine is no longer capable of producing significant current. A typical example of this decay is shown in Figure 3-3.

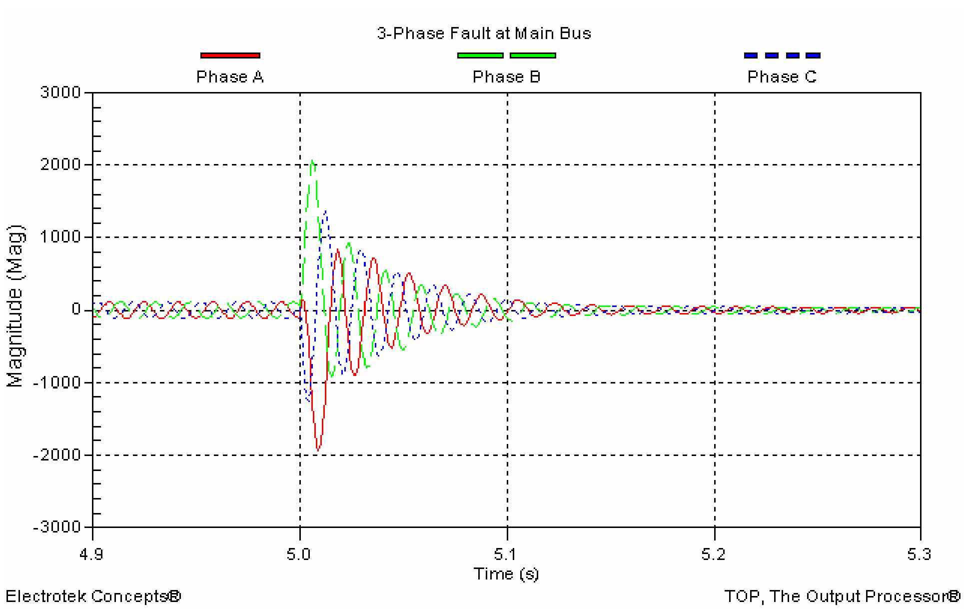

Figure 3-3
Induction Machine Current for Three-Phase Fault

While the current does decay to the value in about 3 cycles that it likely will not impact the interrupting rating of breakers, note that the first loop of current is very significant. Therefore, the machine's contribution to three-phase faults must be considered for momentary duty on breakers. This is a severely limiting factor in some locales where the margins are slim and there are already induction motors that will contribute some fault current.

The misconception about induction machines is often compounded by the idea that because the induction machine is not grounded, they cannot contribute to ground faults. Most distribution systems in North America are constructed as 4-wire multi-grounded neutral systems. This allows induction machines connected in delta or ungrounded-wye to contribute to SLG faults back through the substation transformer. The flow of currents through a three-phase distribution feeder is illustrated using sequence diagrams in Figure 3-4 connected in series for a SLG fault.

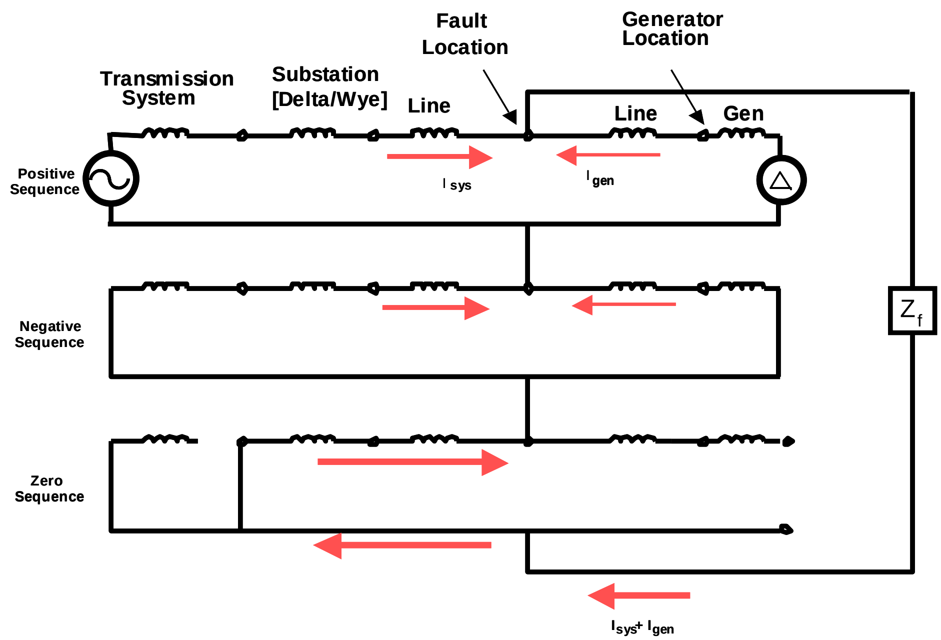

Figure 3-4
Sequence Networks Showing How a Machine Wth No Neutral Connection Contributes to Ground Faults

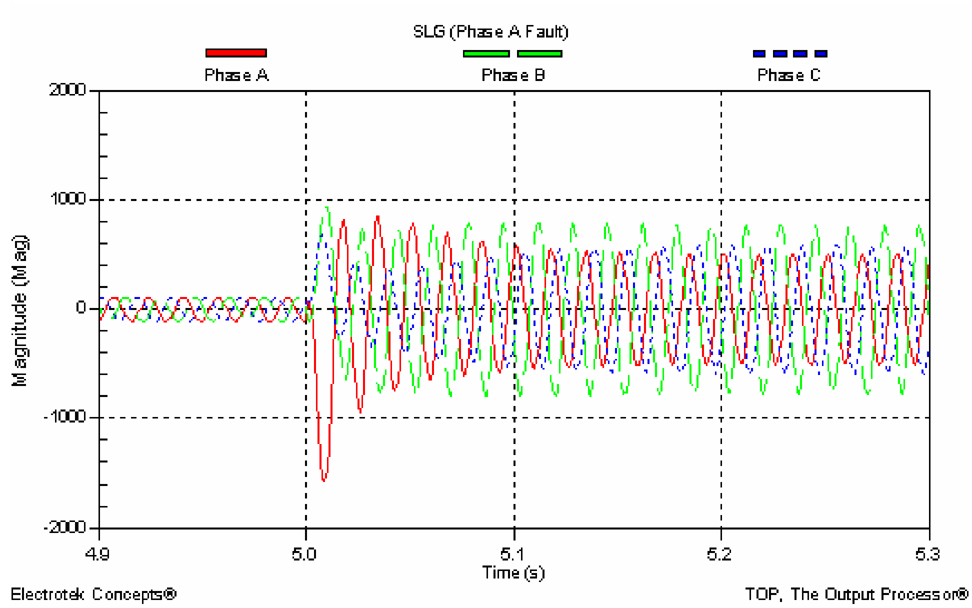

Figure 3-5
Induction Machine Contribution for a Single Line-to-Ground Fault (4-Wire Multigrounded Neutral System)

SLG faults are by far the most common (80-90% of all faults). Therefore, it should be assumed that induction machines will contribute to all faults for design purposes.

One common rule-of-thumb is that if the voltage on the machine's terminals remains above 60%, an induction machine will continue to feed into the fault almost as a synchronous machine would under similar circumstances. In fact, some analysts will conservatively estimate induction machine fault contributions by assuming they are synchronous machines with high impedance grounded neutrals.

Transformer Connections and Fault Contributions

A related issue is the transformer connection. Many engineers would prefer to interconnect all three-phase DR through a grounded-wye/delta transformer. There are a number of advantages to this connection, including:

- Easier and more reliable detection of utility-side faults for which the generation must disconnect
- If the generator should become isolated from the utility substation, it continues to present an effectively-grounded system, reducing the risk of dangerous overvoltages.

Unfortunately, there is a major disadvantage for most North American radial power systems: the transformer connection itself contributes strongly to ground faults. This is illustrated in Figure 3-6.

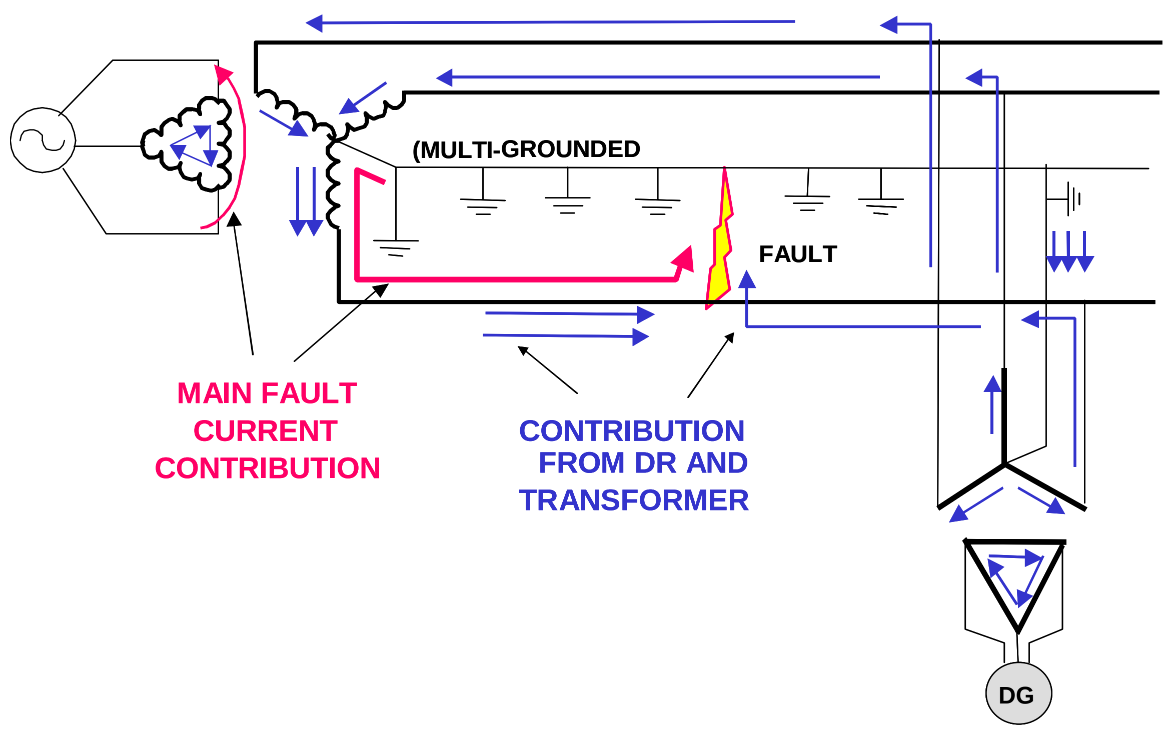

Figure 3-6
Grounded-Wye/Delta Interconnection Transformer Feeding SLG Faults

The zero-sequence currents circulate in the delta winding and induce currents to flow not only in the faulted phase but in the unfaulted phases as well. The latter flow back through the substation, adding to the fault contribution of the electric power system (EPS). The generator contribution will be an additional amount, although in some cases the generator contribution is nearly irrelevant.

This strong fault contribution commonly disrupts ground fault relaying and causes nuisance tripping of other breakers. When the fault interrupters are applied with little margin, it is not possible to accept the additional current contribution that will arise from this connection without doing something to limit the current.

Other transformer connections are more benign in this regard, although they have other issues. The selection of an interconnection transformer is often a compromise between operating restrictions and the preferences of designer.

Solutions to Excessive Fault Current Levels

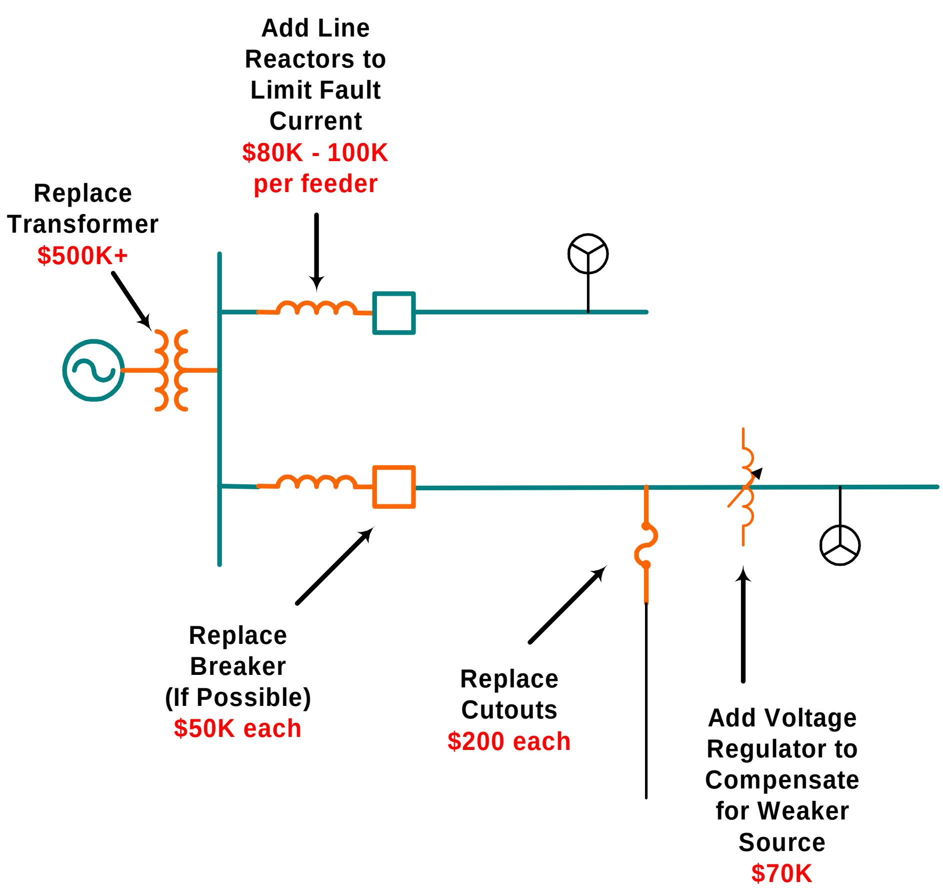

Figure 3-7
Some Options for Solutions to Excessive Fault Currents

Figure 3-7 illustrates in a nutshell several of the practical solution options for the case in which added DG fault current contributions causes excessive duty on fault interrupting equipment. Not all of these solutions would have to be implemented for any particular case. This figure simply illustrates the various options and rounded-off estimates of the associated costs. The source data for these costs is derived from the tables in Appendix A.

The solutions depicted either reduce the fault current contribution from the utility source or deal with the consequences of other solutions.

The key element controlling the utility fault current contribution is the utility distribution substation transformer. Therefore, one obvious solution would be to replace the existing one with one of higher impedance. This might be practical for an aging substation that is due for replacement after 40-50 years of service. However, the cost is quite high to consider changing a younger transformer simply to allow more short circuit current margin for DG infeed. The replacement costs would typically total at least $500K and can easily exceed $1M per transformer in some cases (see Appendix A). Assessing this cost to DG owners would overwhelm the economic benefit in many cases.

While this seems like a high cost, other options are also expensive. Line reactors may be installed in front of the utility breakers to limit the current seen by the breaker during faults. While this is a simple concept, there are many ancillary considerations. There frequently is insufficient space for these reactors in the substation as built. Therefore, there must be some rearranging of the buswork and, perhaps, moving of the existing breakers. The reactor installation must be able to achieve the necessary BIL, which is sometimes a challenge.

An alternative would be to install the line reactors after the breakers, taking the risk that a rare fault in the bus or a reactor will not yield maximum available fault current. This could reduce the cost of line reactors in some cases.

Reducing the fault current contribution from the utility source will protect both feeder circuit breakers and any fuses close to the substation. An alternative is to replace both with devices that can handle the increased fault current. This assumes that there are higher-rated breakers available. A typical breaker change-out cost is estimated to average approximately $50K with a range of $25K - $80K, depending on the style of breaker and rating. For reliability, buses are often switched to alternate sources during outages and for maintenance purposes. Therefore, all breakers on any bus to which DG might be connected would have to be upgraded. The substation will typically have at least two three-phase breakers per bus with an average of perhaps four in the USA. In high load density areas, particularly those served by LV networks, there might be dozens of breakers that would have to be changed.

Fuses are relatively inexpensive at approximately $200 per site. If current-limiting fuses are chosen, the cost could be higher. The number of fuses that have to be changed will vary considerably from one utility to another. The area of risk is typically 0.5 – 1.0 mile from the substation. Some utilities will have many fuses in this zone while others may typically have none. One concern of distribution engineers is that line operating personnel will have to exercise more caution when replacing blown fuses. If they are accustomed to carrying only one kind of fuse in the truck, there is a risk that they will replace a failed fuse with the wrong kind, creating a safety hazard should the fuse explode during the re-fusing operation when the fault is still present.

As suggested in Figure 3-7, there can be consequences to measures to reduce the fault current contribution from the utility source. A significant one is that by making the source weaker, it becomes difficult to maintain adequate voltage at the ends of the feeder. This will require the addition of line voltage regulators, which could add as much as $70K in cost per installation. This cost is somewhat dependent on local utility practice and the circuit characteristics. The lower range on the cost for a regulator installation is approximately $25K for a smaller regulator. However, if the feeder is designed to be picked up from the other end in an emergency, a large regulator is required.

Table 3-1 and Table 3-2 show total costs of various options for modifying two relatively simple distribution system design:

1. A single-transformer, 4-feeder substation,
2. A two-transformer, 6 feeder substation.

For options that weaken the source, it is assumed that half the feeders will require the installation of voltage regulator banks to maintain adequate voltage at the ends of the feeders.

These two examples use the lower range of cost estimates for substation transformer replacement, but that option is still the most expensive.

In each of these cases, the option of changing out the circuit breakers at $50K each is the least costly. Of course, this assumes that it is possible to obtain the increased fault interrupting ratings. The margin between this option and the line reactor option is such that even if the breaker change out is twice this estimated cost, this option will still be the least costly. Cost estimates typically ranged from $25K to $80K. One special type of breaker was $200K to replace. Thus, there can be quite a variation depending on the type of break employed. Where this option becomes a very serious barrier to DG is in urban areas with there may be dozens of breakers than must be changed for a large generator installed on just one feeder.

When aging stations are upgraded, the cost of creating more margin for DG fault current contribution may be absorbed in the renovation cost with little incremental impact, if any. For example, newer breakers may have higher interrupting ratings.

There is another issue that may preclude simply upgrading the feeder breakers in the substation. If the feeders have any customers with primary-side switchgear (e.g., those taking service at primary voltage), the interrupting ratings of their breakers and the fault duty must also be considered. Some utilities with numerous large three-phase customers have indicated that they have made commitments that their fault current levels would never exceed a certain amount. Whether that exceeds breaker ratings or not, DG can take the fault current magnitudes over those promised limits. Then the only remaining alternatives are those that reduce the contribution from the utility source.

Table 3-1
Costs of Fault Current Limiting Options for Single-Transformer, 4-Feeder Substation

Option	Item	No.	Cost, ea, ($000)	Total ($000)

Replace Substation Transformer				
	Transformer	1	$500	$500
	Voltage Reg.	2	$70	$140
	Total			**$640**
Install Line Reactors				
	Reactor Sets	4	$100	$400
	Voltage Reg.	2	$70	$140
	Total			**$540**
Replace Circuit Breakers				
	Feeder Breakers	4	$50	$200
	Total			**$200**

Table 3-2
Costs of Fault Current Limiting Options for Two-Transformer, 6-Feeder Substation

Option	Item	No.	Cost, ea, ($000)	Total ($000)
Replace Substation Transformer				
	Transformer	2	$500	$1,000
	Voltage Reg.	3	$70	$210
	Total			**$1,210**
Install Line Reactors				
	Reactor Sets	6	$100	$600
	Voltage Reg.	3	$70	$210
	Total			**$810**
Replace Circuit Breakers				
	Feeder Breakers	6	$50	$300
	Total			**$300**

When a greater margin cannot be economically obtained, the main recourse is to restrict the DG to types that do not contribute significantly to fault currents on the primary feeder.

4

CASE STUDY 2: SOLVING VOLTAGE REGULATION PROBLEMS

In this case study, the costs of addressing common steady state voltage regulation problems are investigated.

Excessive Voltage Change Upon Connection or Disconnection

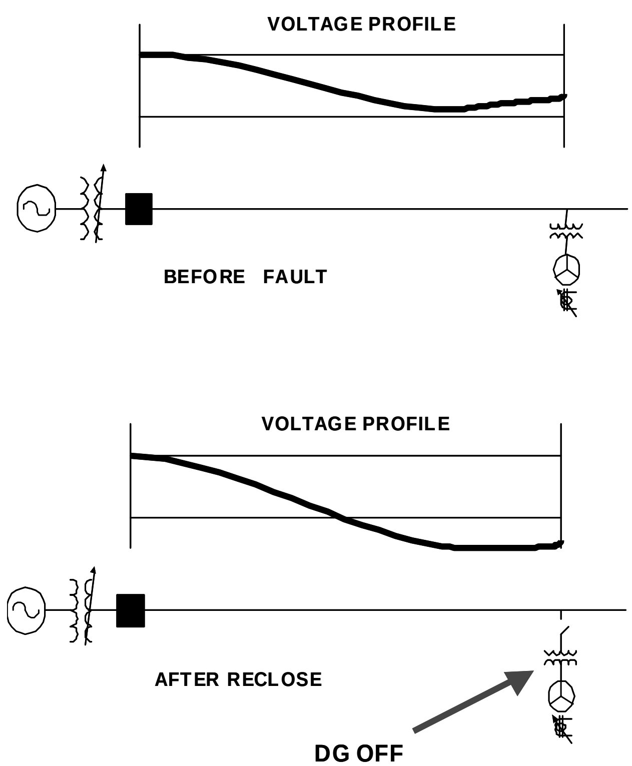

Figure 4-1
Voltage Drops Too Low When DG Disconnects

Figure 4-1 illustrates a classic case where a benefit nominally expected from DG can give an unexpected result. This represents a feeder that is overloaded and a generator is placed toward the end to help hold up the voltage. This may be done on a temporary basis until another substation can be built to better serve the load in that area. It may also be a more permanent solution if the load is growing too slowly, or not at all, to justify a new feeder or substation.

Whatever the case, if a fault were to occur while the generator is running at peak load, the generator will be forced to disconnect so that the utility fault clearing process may proceed. This is the normal requirement of IEEE Std. 1547-2003. When the breaker recloses, low voltage will result at the end of the feeder until the generator is resynchronized with the system.

This condition occurs under a variety of scenarios, including the next one described in this chapter.

The converse can also occur when DG is brought on line. If too much generation is brought on too quickly, the voltage can rise above limits.

It is typically easier to control how fast the generation is brought on than how fast it disconnects. Bringing the generation up slowly will assist in voltage regulation, although it will generally require additional communications and control systems that are not commonly part of the local distribution system. The normal utility voltage regulation devices are quite slow in comparison to how fast DG can come up to full power. They would typically take at least 30 seconds to decide to act and then several more seconds to adjust the voltage.

When there are multiple DG installations, the natural diversity may make it rare that they would all come on at once. However, it is certain that they will all disconnect at once when a fault occurs. Faults will happen. Therefore, the system must be able to accommodate the change. On longer distribution feeders, this phenomena is one of the more limiting in terms of how much generation can be accommodated without making an upgrade to the distribution system.

Solutions and Costs

If the generation is operated as cogeneration by a customer with a similar-sized load, one solution is to require the customer to disconnect the load as well and make a transition to back up power. This would be accomplished with essentially no cost to the utility. However, there will be many DG sites where this is not practical.

One distribution-side solution is to install fast-acting voltage regulators. Devices are now coming on the market that are considerably faster than their predecessors. Other vendors will undoubtedly develop other devices to address the special needs brought about by DG interconnection. This typical cost for installing a sizeable line voltage regulator bank is about $70K (see Appendix A). If there are not adequate poles on which to place the regulators, additional poles will have to be set at about $6000 per pole.

A lower cost solution may be to place some capacitor banks in the area to be energized quickly if the voltage were to drop below limits. The cost for this would be on the order of $12K - $20K per bank. A typical sized capacitor bank would raise the voltage approximately 2 percent. However, many feeders in the USA with potential low voltage problems already have substantial capacitor compensation and it may not be practical to place any more. The voltage rise may be too high when the DG reconnects. The fast-acting voltage regulator would likely give a wider range of control and the asset would be useful at other times. The capacitors, while cheaper, might be seldom used.

Interference With Voltage Regulation Devices

Large amounts of DG such as large cogeneration installations have the potential to interfere with the operation of the tap-changing voltage regulation devices and force them into undesirable tap positions. A typical small DG does not attempt to regulate voltage when interconnected to the utility distribution system. For one thing, it is not large enough to effect the voltage. The typical mode of operation when running in parallel with the utility system is to control power and power factor. This also greatly assists in avoiding unintentional islanding. For large generators, it may be necessary to perform some degree of automatic voltage control to obtain good feeder voltage.

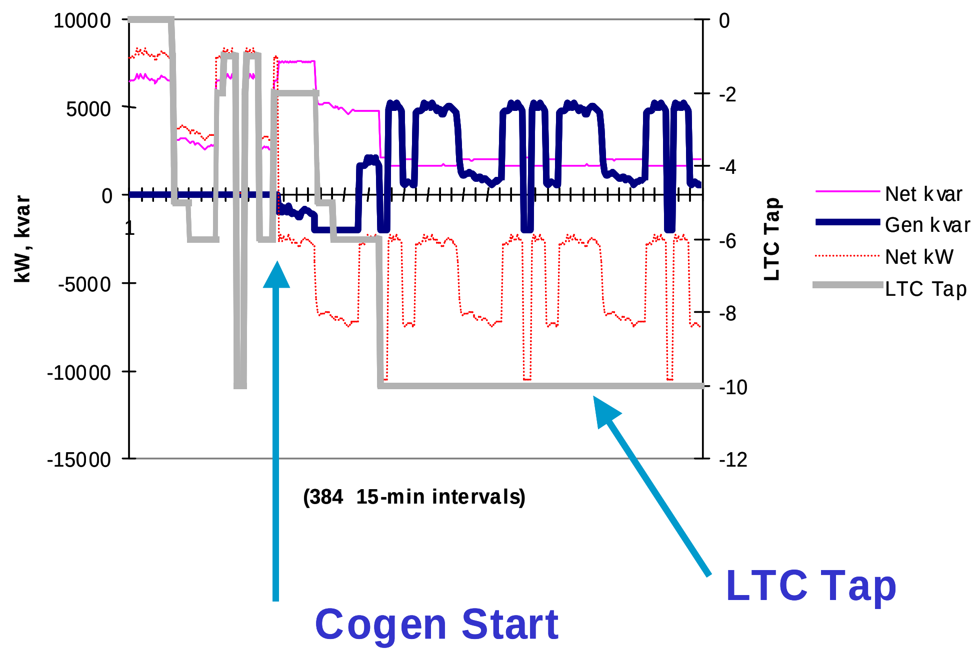

Figure 4-2
Large Cogen Takes Over Feeder Voltage Regulation Forcing LTC to Bucking Position

Besides the increased threat of islanding, allowing a large generator to control voltage can cause conflict with other regulating equipment. Figure 4-2 shows the results of a simulation using the EPRI Solutions Distribution System Simulator (DSS) program of one such case. The simulation extends over four days. The load cycles up and down daily and periodically shuts down completely for maintenance. The cogeneration output remains a constant 10 MW to maintain the thermal load requirement. The generator easily assumes voltage regulation responsibilities for the feeder and actually does a much better job than the LTC was doing previously. The LTC is bucking 4.25% (-6 tap) to compensate for a large capacitor when the cogeneration starts and quickly returns toward neutral as the generator takes over regulation, actually absorbing vars. When the load suddenly drops, the generator exciter hits its negative var limit causing the LTC to increase the tap down to where it was originally. When the load picks up again, the generator produces reactive power to regulate the voltage before the LTC control can time out and act. Finally, when the load shuts down for maintenance, taking the capacitor with it, the voltage rises because the generator is still putting out 10 MW. The exciter again hits the negative rail in an attempt to hold the voltage down, but it cannot. The LTC tap drops to 6.25% bucking (-10 tap) where it stays. The capacitor never comes back on even when the load comes up because the generator has taken over the voltage regulation.

This condition would not necessarily exhibit a problem – as long as the generator is running. The other customers would have a very stable voltage and now wear and tear is occurring to the LTC because it is not moving. However, generators trip off for any number of reasons and must disconnect for utility faults. A generator trip would leave several other feeders with very low voltage because the LTC is perhaps 8 or 9 taps from where it should be.

Solutions and Costs

There are a number of issues with running large generation on a distribution feeder that are resolved by establishing communications and control between the generator and the substation. The conflict with the LTC described above is just one. The increased possibility of islanding because the generator is operating with active voltage control is another.

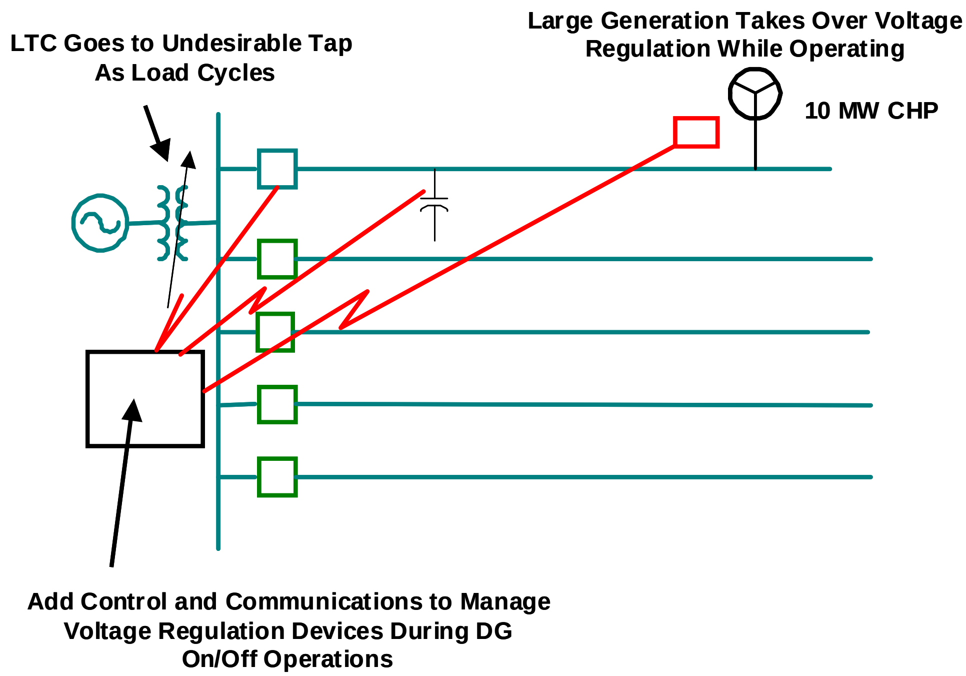

Figure 4-3
Controlling Voltage Regulation for Large DG

Figure 4-3 depicts the control and communications solution for this scenario. Not only can the voltage regulation be coordinated, but transfer tripping can be implemented as well to ensure that an unintentional island does not form.

The desired LTC behavior for this case is to return to the neutral tap when the generator is operating and turn the capacitor off because it is not needed. This allows the generator to operate at a better power factor. Both the capacitor and LTC control would have to be replaced in the system that was studied. The material cost for each will be in the neighborhood of $5000, but adding fully loaded labor and engineering costs would escalate the cost to $21.5K according to one estimate. The communications for the small control network depicted can be handled by some systems used for direct transfer trip, which typically cost $40K - $55K, but can run to over $100K depending on local terrain, terminal equipment required, and special programming. It is assumed the other functions can be piggybacked on this system. There are relatively simple programmable logic controllers and relays that can handle the simple on/off logic required here. No estimates were obtained for the cost of the equipment. Programmable relays with similar capabilities can be obtained for less than $10K. However, there will be some programming involved. The typical loaded cost for utility engineers to determine the settings and for technicians to execute the settings is on the order of $5000. While this may seem to be an exorbitant amount, keep in mind that all such changes must be carefully planned out, tested, documented, and archived to help ensure the reliable operation of the system decades into the future.

Thus, the total cost for this dedicated communications and control solution would be expected to be between $85K and $145K. If there were already a high speed communications and control system in place that included the LTC, capacitor, and DG site, the incremental cost for adding this logic would have been a fraction of this, although there would still be some labor and documentation cost that the utility would have incurred.

Fluctuating Voltage

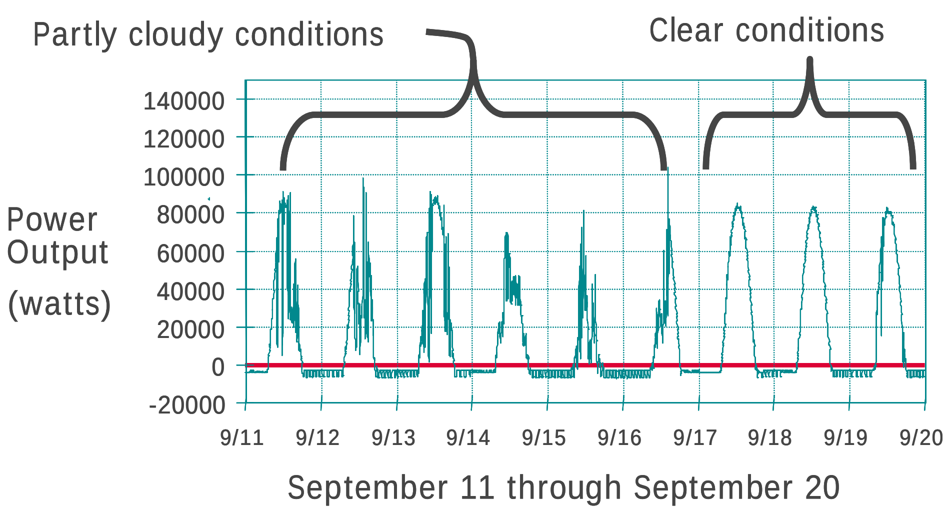

Figure 4-4
Fluctuating Power Output From Solar Generation

Some types of DG, notably wind and solar generation, produce fluctuating power according to the forces of nature they are attempting to harness. Figure 4-4 shows an output from a solar photovoltaic site. There is a daily fluctuation even during clear conditions, but it is very slow and few would ever notice the change in voltage. On the left side of the chart is the output during partly cloudy conditions. The fluctuating voltage that results from the fluctuating power may not change fast enough to be noticed by humans, but it certainly could cause excessive duty on voltage regulation equipment.

Wind generation (Figure 4-5) changes much more rapidly than solar generation. It can go from minimum output to maximum in several seconds under gusting conditions. Most wind turbine generators in North America are in large wind farms connected to the transmission system. However, distributed wind applications – common in Europe – are becoming more common. The turbines tend to be sited in remote locations quite some distance from the substation. This places special challenges on feeder voltage regulation. While solar generation typically does not change faster than traditional utility tap-changing regulators can keep up with, wind generation fluctuates faster.

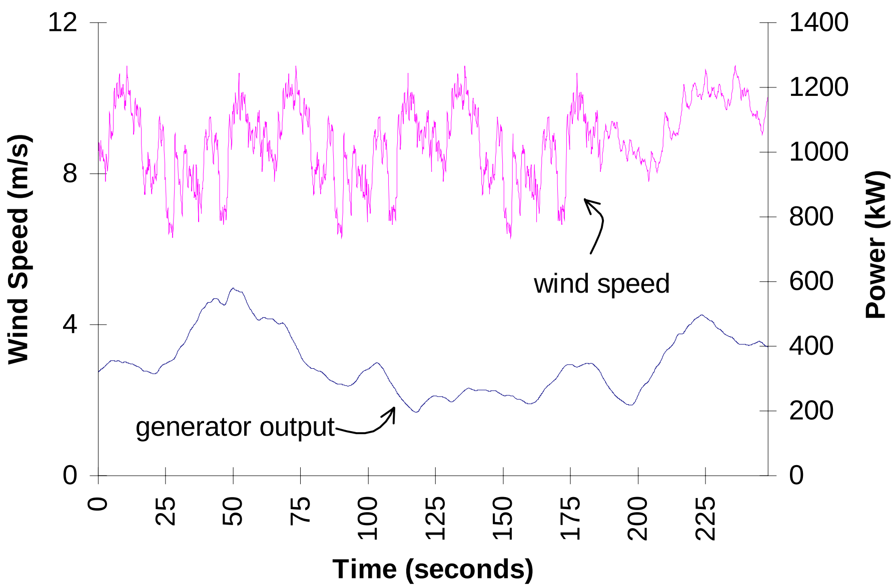

Figure 4-5
Wind Turbine Power Output Variation

Solutions and Costs

If customers are not noticing the fluctuations, the main issue will be to prevent damage to utility voltage regulators and capacitor switches. This can often be accomplished by changing the settings of controls. The costs can be as little as $1500 for a line crew to field set a control so that it does not operate as often. If a consultant is retained to study the problem to determine the settings, the cost could be as high as $20K.

If the customers are noticing the fluctuations, something must be done to counter the voltage excursions. The voltage changes are a function of the impedance. One has the choice of lowering the apparent impedance or compensating for the impedance drop. Options include:

- Conventional voltage regulators can keep up with solar generation, but are probably inadequate for wind generation. Cost of an installation is approximately $70K.
- Fast tapchanging regulators can keep up with wind generation. However, wind generation has been known to cause regulators to fail quickly, particularly if sited near the generation.. Therefore, this solution is not necessarily recommended unless there is no other solution. Siting the regulator midway between the wind turbines and the substation will reduce the number of operations. Approximately $70K.
- Some form of static var compensation. This is commonly used in large wind farms to compensate for the voltage fluctuations caused by the wind generation. Costs are typically $125-$250/kvar.
- Certain types of wind turbines have active voltage control. Others have inverter interfaces with similar capabilities. This will add $200/kW, or more, to the cost of a turbine. However, it shifts the cost and responsibility from the utility system to the developer. These are generally able to hold the voltage band very tight near the turbine site, but the fluctuating power will still cause some voltage fluctuation as the power flows toward the substation. Figure 4-6 shows a 24-hour simulation from the EPRI Solutions DSS computer program of the mid-feeder voltage resulting from a wind turbine with active voltage control at the end of the feeder.

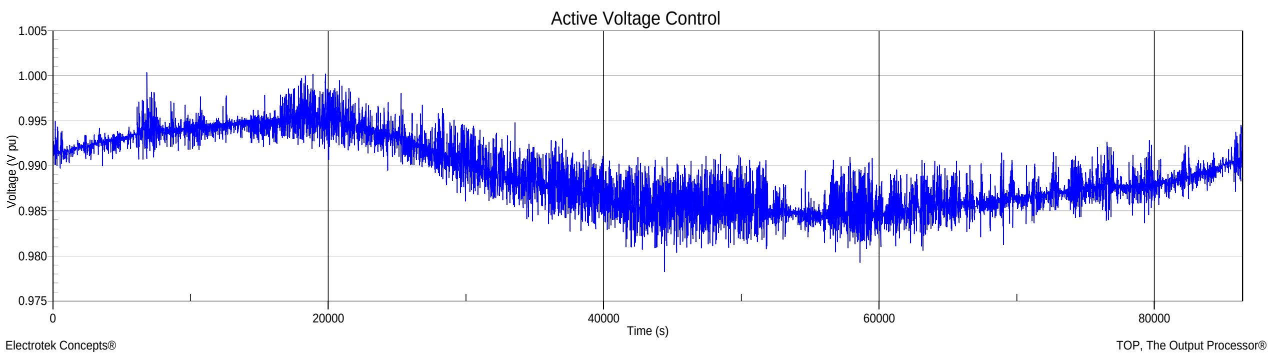

Figure 4-6
Simulation of Mid-Feeder Voltage for Wind Turbine Generator With Active Voltage Control

- Reconductoring lines. Perhaps $20K -$30K per mile cost, but with limited benefit unless the existing wire is very small. The reactance of the line is largely responsible for the voltage fluctuations and reconductoring with not significantly change the reactance unless the spacing is decreased.
- Building an express feeder. The typical cost of building a new overhead distribution line is $80K - $125K per mile. Underground cable can be as high as $1M per mile. This is quite expensive. To minimize cost, an express feed may tap into the middle of a feeder rather than going all the way back to the substation. This usually will avoid subjecting load customers to the largest voltage swings. A recloser and voltage regulator would often be applied at the tap

point, adding $95K - $140K to the cost. Building three miles of line would yield a project cost of $335K - $515K, or about half the cost of a 1 MW wind turbine.

- Building a substation closer to the DG. This is the ultimate solution that is employed particularly in the case of wind generation when the amount of generation becomes too great for the existing feeder to handle. It is also employed in other remote DG applications such as landfill gas operations. Costs vary from $800K for a compact substation to $3M for a large wind farm.

The fluctuations from renewable DG would typically not be fast enough to be classified as flicker although flicker solutions will likely be effective.

5

CONCLUSIONS AND RECOMMENDATIONS

The cost of modifying existing distribution systems to accommodate high penetrations of DG can be quite high compared to the economics of proposed DG installations. When the amount of DG crosses the threshold of needed modification, the potential economic benefit of DG can be swallowed up by the costs of required changes.

As shown by the two examples, when something is done for one feeder on a substation, there are frequently modifications required on all feeders because of the interaction between feeders. The cost per substation bus can easily exceed $100K and sometimes exceed $1M, depending on how the system was originally built and how it has evolved over the years. As many have already discovered, the existing design of distribution systems is not always friendly to DG. The typical distribution system is designed to deliver power from the bulk delivery system to end user in as large a geographic area as possible with the lowest practical cost. The design objectives for such a system are not necessarily compatible with accepting levels of DG on the system that might be a substantial percentage of the load served.

It will probably never be practical to build distribution systems like transmission systems that can easily accept multiple sources of power. Too many sectionalizing devices would be required and losses from circulating currents would be too great. However, if new distribution systems were designed initially with the possibility of serving high penetrations of DG the cost would likely be more palatable and the operational behavior more acceptable.

The key lessons learned from this work are that to better accommodate high penetrations of DR, distribution systems should have:

- Some means to control or accommodate the short circuit contribution of multiple generation sources.
- Means to prevent, or respond more quickly to, voltage variations outside normal limits.

There are at least two ways of managing the short circuit contribution:

1. Restrict the type of DR to those types that have no significant short circuit contribution. This may require advancements in inverter technologies that will achieve higher conversion efficiencies and greater capacities economically so that they can provide significant reactive power as well as active power.

2. Design and build distribution systems with a sufficiently large margin to accommodate short-circuit current contributions from as much rotating machine generation capacity as the system would be expected to support.

Voltage control can be better achieved with

- Stiffer systems.
- Faster regulating devices installed in more locations.
- High speed communications overlaying the service territory to allow adequate monitoring and control to ensure high quality voltage regulation.

These changes would increase the cost of building distribution systems and would also likely require changes in regulatory policies that would permit utilities to recover costs for building such systems, which would be considered too conservatively built by today's standards.

Distribution Design for High Penetration of DG

Based on the findings of the research in this project, some general design principles for future distribution systems that will permit high penetrations of DG include:

1. Select a substation transformer impedance that leaves room for the short circuit contribution of DG without excessive duty on feeder breakers, fuses, and primary service customer protection gear. This will create a weaker system that may exacerbate the voltage regulation issues.
2. Therefore, substations should be closer together so that feeders are shorter to minimize voltage regulation problems.
3. Use higher primary distribution voltages to provide better voltage regulation over a larger area.
4. When the above is not economical, or practical, apply voltage regulators more frequently. This will likely require the development and application on new regulating devices such as fast tap-changing regulators and static power converter based systems better able to support the needs of a system with high penetrations of DG of various types.
5. Overlay the distribution system with communications that permit very detailed monitoring and fast control for such functions as direct transfer trip, capacitor switching, LTC mode and generator dispatch. These functions would be necessary to recover from interruptions and outages should the level of DG penetration reach a point where the system is dependent on DG to serve the load. This system could be applied to other distribution automation functions as well.

Thus, the design of distribution systems will likely always involve compromise between conflicting goals. On one hand, a weaker system is needed to allow for short circuit contributions from local generation sources. However, a stronger, more robust system is needed to avoid voltage regulation problems.

The state of the art with LV networks makes it prohibitively expensive to accommodate high penetrations of DG on large LV networks. It is unlikely that consumers on large downtown networks would accept substantially reduced reliability to accommodate DG. As time passes, the older-style network protectors can be changed out with more modern ones that have more adjustable tripping levels. This will allow a somewhat larger amount of lower-cost rotating machine DG to be interconnected. The maximum amount will always have to be below minimum load levels in contrast to radial systems where DG output may exceed load without immediate consequences.

A Vision for the Future

If DG is to be one of the major sources of energy in the future, a different design mindset will have to be adopted. One concept for the future has the energy being supplied by unpredictable, fluctuating renewable resources and supplemented by large amounts of storage on each distribution feeder to meet demand[1]. Faster, more responsive voltage regulation will be a key as will monitoring and control. The paradigm may shift to a model more like the natural gas and water delivery systems that have a pressure (voltage) regulator at every point of use. More voltage variation would be permitted on the primary distribution system and corrected on the secondary system.

There are similarities between this concept and the EPRI initiative on Advanced Distribution Automation[2].

This better fits the European style of distribution systems with their more extensive low-voltage systems. Fewer regulating devices would be required than in North America and in other places that have followed the North American model. Nevertheless, residential voltage regulators [3] have already been developed for energy conservation that could in theory also apply to other voltage regulation needs. The proposed Intelligent Universal Transformer [4] would also fit in well with this concept.

The Trouble With Robust Distribution Systems

The robust systems proposed above are a mixed blessing for DG. One consequence of building such systems will no doubt be troubling to some DG proponents. Making the system sufficiently robust to handle high penetrations of DG in plug-and-play fashion with make it significantly overbuilt, or “gold-plated,” in terms of the present vision of what constitutes an adequate distribution system. The losses would be lower and the reliability substantially improved. While this will lower the cost of interconnection, it will also lower the cost for bulk power suppliers to deliver power to customers through the improved distribution system. This would largely remove some of the present key economic reasons for distributing the generation.

The justification for DG would then have to rely on environmental, system security, and energy efficiency benefits. The active distribution system of the future envisioned in [1] to support large amounts of wind generation might be a good example of sufficient justification to undertake such an effort. Utilities in the USA should have many years to observe the evolution of such systems in the UK and Europe before having to make a decision about choosing such a direction.

Hidden Costs of Support DG on Distribution Systems

Much of the data presented in this reported was collected from utility distribution engineers who routinely do job cost estimation. The contact was initially made by telephone followed by a list of questions appropriate for that utility sent by e-mail. In several cases, there was additional telephone contact to clarify the response. This provided ample opportunity to strike up conversations about experiences with DG projects.

Since this investigation dealt with the actual cost of making system modifications, the engineers were asked to describe their experiences with actual DG installations in order to determine each step that was done to commission the project. The intent of the telephone interview was to identify as many individual sources of cost as possible. The conversation invariably turned to the difficulties encountered in getting the installations to operate properly after the commissioning. Nearly everyone interviewed had at least one quite interesting "war story" in which the utility personnel had to respond several times to problems with the DG operation.

It soon became apparent that utilities are spending a disproportionately large amount of labor hours servicing these installations, particularly in the first year of operation. In one case, an engineer was assigned to the site for two weeks to supervise the installation, setting of relays, and operation to gain the assurance that the generation was not harming the system. At a typical loaded labor rate of $50/hr, this amounts to $4000 cost that was not recovered. Perhaps, utilities are being overly cautious because DG is still relatively new, but this extra attention can amount to several hundred labor hours for which the cost is not being recovered.

While there are only few examples that may be found where the DG caused a problem for the utility system or another utility customer, nearly all DG installations experienced startup difficulties adjusting to the realities of life on the electric power system. Some continue to experience difficulty after years in service. Generators trip for all sorts of normal utility occurrences including:

- capacitor switching,
- minor voltage sags resulting from remote faults on some transmission line,
- feeder voltage imbalance,
- switching operations for seasonal feeder reconfiguration,
- large motor starting on adjacent or the same feeder, and
- tree faults on adjacent feeders.

This frequent generator tripping results in numerous trouble calls and site visits by utility line personnel and engineers to help resolve the problem. Much more attention is required for a 2 MW generator than for most 2 MW loads.

In some cases, consultants were contracted to assist in the resolution and this cost was passed on to the DG owner or operator. However, in most cases the cost is simply absorbed as a normal utility customer service function and is not reported separately nor charged back to the DG owner or operator.

Recommendation for Technology Transfer of DG Interconnection Experience

This recommendation is inspired by the "war stories" encountered during the data collection. It is apparent that there is now a substantial body of practical experience with DG installations. While there are still many utilities without any experience, there are several that have at least one recent installation. The question now is how to capture and disseminate that knowledge that has been gained. Two options are proposed for consideration as follow-on to this work at some point in the near future:

1. Establish a project to collect the case histories and publish them. A living web document for sponsoring members has been suggested where contributions may continue to be submitted. Many of the case histories will have to be edited to remove sensitive proprietary information.
2. Sponsor a conference or training course in which case histories – appropriately sanitized - are presented.

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A
APPENDIX – COST DATA

Participating utility members were asked to submit fully-loaded cost estimates using their typical costing approaches for several modifications to distribution systems that are commonly made for higher levels of DG capacity. Table A-1 lists the range of cost estimates provided. In addition, average unit cost data gleaned from public documents supplied for general rate cases in California and Connecticut are included for some items as a reference to confirm the cost values. The rate case unit cost data may tend to be loaded more heavily than job cost estimates depending on accounting procedures. Also, there is considerable variation in the types of equipment used in different locales. However, there was substantial overlap in the data, giving credibility to the cost estimates.

Table A-1
Cost Estimates Provided by Utilities for Common Changes Required to Support Higher Penetrations of DG

Item	Min. Cost Estimate	Max. Cost Estimate	Unit Cost Range from Rate Cases
Replace Substation Transformer	$500K	$1M	$800K - $1.6M
Line reactors, each feeder	$80K per feeder	$100K per feeder	
Line recloser replacement	$40K	$60K	$30K - $70K
Relay change (Engineering)	$1500	$5000	
Relay change (Technician)		$5000	
Add PT's in Substation for directional overcurrent relaying or reclose block	$13.5K	$18K	
Add PT's at line recloser location to implement for directional overcurrent or reclose block.	$18K	$70K	
Replace simple overcurrent relay with directional overcurrent	$8100	$10K	
Add direct transfer trip between substation and DG site	$40K - $55K	$100K - $200K	

Table A-1 (Continued)
Cost Estimates Provided by Utilities for Common Changes Required to Support Higher Penetrations of DG

Item	Min. Cost Estimate	Max. Cost Estimate	Unit Cost Range from Rate Cases
Change voltage regulator control for handling reverse power from DG	$5000 (mat'l only)	$21.5K (incl. 90 m-hr labor)	
Install recloser at large DG site as interconnection breaker		$25K	$30K - $70K
Change LTC/VR control setting	$2500	$5000	
Hire outside consultants to analyze DG interconnection	$2500	$20K	
Replace substation breaker		$50K	$25K - $80K (one type: $200K)
Change fused cutouts		$200 ea	$300
Add new fused cutouts on laterals where none exist	$300 (mat'l only)	$2400 (incl. 19.5 m-hr labor)	$2400 - $3200
Change fuses downline from recloser		$25K	
Add a line voltage regulator	$25K	$70K	$125K
Capacitor bank replacement	$12K	$20K	$20K - $80K
Replace a line voltage regulator with 3-250kVA regulators		$70.5K (incl. 180 m-hr labor)	
Replace cutouts with 3-phase switch	$11.5K	$13.6K (incl. 62 m-hr labor)	$21K
Replace cutouts with 3-phase recloser or sectionalizer		$25K	
Assigning technician to supervise installation		$6000	
Set or replace pole			$5000 - $7850

Table A-2
Typical Labor Rates Used to Compute Costs

Job Classification	Hourly Rate
Engineer	$50 - $60
Technician	$40

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