Prepared for, and on behalf of

Distribution Systems Testing Application and Research

DSTAR

Electric Utilities and GE in Cooperation
to Promote Pragmatic Distribution Systems Research

Final Report

Distributed Generation-Impact on Distribution Systems

DSTAR Project 8-8

July 9, 2002

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Foreword

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EXECUTIVE SUMMARY

The concept of distributed generation (DG) is presently receiving widespread attention in the power industry. Some forecasts indicate that DG will provide a substantial portion of future incremental generation capacity. Wide proliferation of these devices will necessitate changes in how power distribution systems are designed, operated, protected, and maintained.

At the present time, overall penetration of DG in the North American power system is very small, and any system issues presented by DG are localized to those few feeders where DG penetration has become significant. DG capacity costs and operating costs are generally not competitive with grid power for most applications at this time. Additional factors, however, sway the balance in favor of DG for certain niche applications. Some of these applications include

- Combined heat and power (CHP), or combined cooling, heat and power (CCHP) applications where DG waste heat is recovered.
- High reliability installations where generation is installed primarily for backup purposes, but also used to offset peak demand or participate in the energy market.
- Recovery of "free" fuel, such as landfill gas, or renewable energy sources such as solar power, wind power, or small hydro installations.

The application of DG is also being encouraged by various forms of subsidy such as demonstration project grants, tax credits, and regulatory policies such as net metering.

There are forecasts of DG becoming much more widespread in the future. Whether this happens depends greatly on changes in the economic viability of DG, including technical developments reducing DG costs, increased central generation costs, or constraints on delivering remotely-generated power.

The term "distributed generation" has a wide range of definitions, some based on size, others on location with respect to loads, and yet others based on where the generation interconnects with the electric power grid. In this report, DG is defined as generation connected to a distribution feeder which also serves other loads.

Distribution systems are conventionally designed with the assumption that the flow of power is always from the substation to the end user. Similarly, the only source of short-circuit capacity is assumed to be provided via the primary substation. Installing generation on a distribution system invalidates these assumptions, and introduces a range of system issues. These issues include:

- **Voltage regulation -** Power output from DG distorts feeder voltage profiles, and can interact with voltage control devices such as voltage regulators and switched capacitor banks. This can result in overvoltage and undervoltage conditions for other customers.
- **Fault current contribution** – Additional fault current contributed by DG can result in exceeding equipment withstand capabilities. More importantly, feeder protection can be desensitized, making fault detection more difficult. Uncoordinated operation of fuses and reclosers, caused by DG short-circuit contribution, can result in unnecessary customer outages.
- **Inadvertent islanding** – Operation of feeder breakers, reclosers, fuses or sectionalizers can isolate a DG along with other customers. It is possible for the DG to continue in operation, providing energization which is out of the control of the utility. Such islands are not synchronized to the utility system, and reclosing can widespread damage to utility and customer equipment. Thus, such islands are to be avoided, or quickly detected and eliminated. Conventional means for detecting islands entails relatively sensitive voltage and frequency trip points, which are likely to be falsely triggered by other events.
- **Grounding and distribution system overvoltages** – The DG interconnection can provide an ungrounded source to a normally-grounded primary feeder, making severe overvoltages possible which could lead to widespread destruction of utility and customer equipment. An excessively-strong ground source, however, can interfere with feeder ground fault protection. In ungrounded or uni-grounded primary systems, the DG must not provide an undesired ground source. Thus, attention to grounding considerations is essential DG interconnections.
- **Power quality** – Inverter-interfaced DG equipment can be a substantial injector of harmonic currents, increasing system distortion

levels and possibly leading to equipment heating, capacitor unit failure, and resonant overvoltages. Certain types of DG, with variable output can result in rapid voltage fluctuations causing unacceptable lamp flicker.

- **Network interconnections** – DG interconnection to secondary spot or grid networks are particularly problematic. A number of scenarios can lead to reverse flow through all of the protectors on a network, isolating the network from the utility system. This can lead to outage of the network (which is otherwise the most reliable of all distribution configurations), and to destructive duty on the network protectors.

The severity of these DG impacts are greatly dependent on the DG penetration (DG capacity compared to local load) and the type of DG power "conversion" device used. The conversion device is most often a synchronous generator, which inherently provides a significant source of short-circuit current contribution. Also used are induction generators and electronic inverters. While synchronous generators are the norm for reciprocating engine applications, many of the newly-introduced forms of distributed generation, including microturbines, fuel cells, and photovoltaic arrays require inverters to produce 60 Hz power. Short-circuit current contribution from inverters is very small, and the system impacts are decidedly different from those produced by rotating generators.

A common misconception is that DG will increase distribution system security and reliability. While the DG may provide backup power for the facility where it is installed, the net impact of the DG on distribution system reliability, using current interconnection practices, is more likely to be negative than positive. The presence of DG can potentially lead to undesirable power quality, prolong outages, or even cause outages. DG may not offset the need for transmission and distribution system capacity when it cannot be guaranteed to be available when needed. In fact, the necessity to avoid inadvertent system islands typically requires that the DG trip settings be set rather sensitively. A system disturbance is likely to result in widespread DG tripping, thus removing this resource at a time when the system is most vulnerable. For this reason, it may be necessary to discount the DG capacity when planning system upgrades. It is possible, at higher DG penetration levels, for the DG tripping to greatly aggravate the system disturbance. An extreme example provided in this report shows a hypothetical example of DG tripping leading to power system instability and blackout of the western U.S. power system.

Many of the DG integration issues can be resolved by appropriate application of controls and communications, such that the DG operates as an integral part of the power system instead of autonomously. With better controls and coordination between the DG and the utility system, the DGs can potentially improve system reliability and power quality, and reduce transmission and distribution infrastructure requirements.

Some innovative concepts have been developed for "microgrids" where multiple DGs and loads are interconnected with or without interconnection to a utility grid. Such schemes rely on advanced control techniques to allow coordinated operation and system protection.

Whether or not DG application takes off and becomes widespread, or just remains a special niche application, cannot be predicted with certainty. Therefore, it is prudent for distribution utilities to consider today the potential impacts of greater DG penetration so that practices and policies can be adopted in advance of any large-scale penetration in the future.

1. INTRODUCTION

In the vision of many policymakers, power systems of the near future will include a widespread proliferation of energy resources (generation and storage devices) distributed throughout the system, close to loads. In addition to the large-scale wholesale generators and large industrial cogenerators already integrated into the power system, the vision includes generation on the premises of residential, large and small commercial, and small industrial customers that are connected to the distribution system. Recent technical developments, such as microturbines and residential fuel cells, plus the changing regulatory climate, are making distributed resources increasingly present in distribution systems. Distributed generation include a range of technologies which make it feasible for industrial, commercial, and residential utility customers to generate some or all of their own power needs. These customers may also generate more than their own power demand and sell the power back to the utility or to some non-utility entity such as a load aggregator or energy service provider.

At the present time, distributed generation applications tend to be scattered in systems, applied where special circumstances promote their existence. Essentially, they fill a niche market. It is not yet a certainty if the vision of widespread distributed resources will, indeed, become a reality. While utility engineers are naturally skeptical of such far-reaching prognostications as the concept of a generator at every home, it is illuminating to point out that, not too many years ago, mainframe computer engineers were also skeptical of personal computers. A vast amount of venture capital has been invested in evolving distributed resource technologies, spanning the range from upstart companies to multinational corporations. It is, therefore, a safe assumption that distributed resources will have increasing presence in distribution systems.

In addition to the commercial and economic implications to the existing electric utility industry, there are substantial technical issues to integration of these distributed resources into the interconnected power system. It is essential that utility engineers and managers become familiar with the technical issues associated with distributed resource integration. The purpose of this document is to provide an informative summary of these issues, as well as providing background on the driving forces behind the distributed resource vision and a critical evaluation of ongoing distributed resource interconnection standards.

1.1 Definition of Distributed Resources

Distributed resource (DR) is a term which includes distributed generation (DG), as well as distributed energy storage technologies. There are many variations in the use of the term within the industry, including definitions encompassing conventional industrial cogeneration and massive wind farms producing many tens of megawatts. Some define distributed generation simply by comparison to a given power rating threshold, such as 10 MW; any generation unit with capacity less than this threshold is defined to be distributed generation. However, such a power capacity dividing line does not provide a clear indication of the system integration issues involved. For this reason, the system interconnection point defines what is DR and DG in this report, as this is the most relevant to the system issues discussed. The box below summarizes the definitions.

The critical difference between the emerging distributed resources and the large industrial cogenerators which have long been interconnected with the utility system is that the latter are almost always interconnected through the transmission or subtransmission system, or a dedicated distribution feeder. The new distributed resource technologies, as well as changes in regulatory situation, have brought generation to the distribution systems where the conventional design practices have been for one-way flow of power and short-circuit current contribution. In

DG and DR Definitions Used in This Report

Distributed resources (DR) are power generation and energy storage facilities interconnected to the utility system via a general-purpose feeder which also supplies customers other than the customer or enterprise having the distributed resource

Distributed generation (DG) is a subset of DR, in which energy is converted from a primary source (fuel, wind, etc.) into electrical power.

this document, the definitions of DR and DG are limited to distribution-connected installations. This allows focus on the specific issues of integration of DR and DG systems into distribution systems not designed for interconnection of generation. The issues of larger generation interconnection at the transmission level, or directly to the substation via a dedicated feeder, are more conventional and are similar to the interconnection issues associated with other non-utility bulk generation.

The definition used in this document also excludes generators which are not interconnected to the grid. Backup generators with open-transition transfer switches, and generation which is permanently isolated from the system have no impact on the distribution system other than possible elimination of load which they serve.

While DR is a more all-encompassing term, there are currently very few distributed energy storage installations in existence. The term *distributed generation* (DG) is much more recognized in the utility community than *distributed resources* (DR). In this report, DG is used in many contexts which could also be applicable to energy storage.

1.2 Current Interest in DR

There are a range of ongoing changes which have increased interest in DR by the business community, the general public, and even some electric utilities. These changes can be categorized as follows:

- Technological developments
- Regulatory changes
- Government promotion
- Reliability concerns
- Economic incentives

1.2.1 Technological Developments

Interest in DR has been heightened by the development of several new "prime-mover" technologies applicable to small-scale generation. These include development of fuel cells, microturbines, and more efficient photovoltaic cells. Dramatic improvements in heat rate, reductions in emissions (including NO_x and noise), better and more economical materials, and increased reliability promised by these technologies make their widespread use feasible, where in the recent past they were laboratory curiosities. These particular technologies generate their power at other than 60 Hz, and thus require power converters so that they can work with existing loads and interconnect with the power grid. There have been substantial developments in power converter technology which reduce the cost and improve the efficiency of power conversion, and thus improve the economic viability of the DR concepts requiring their use.

Further descriptions of the DG and energy storage technologies are found later in this document.

1.2.2 Customer Reliability

The increasing importance of a reliable power supply to many customers, along with increasing concerns about the future reliability of the utility grid, have been an incentive for customers to consider installing DG. Some have considered complete energy independence, supplying their entire power demand from their own resources and operating isolated from the grid as a normal mode of operation. Unless the customer's load is relatively constant, and without large transient variations, normally-isolated operation is rarely economically attractive. While standby emergency generation has been a longstanding practice for certain types of customers, there is increasing interest by customers in exploiting their generation capacity to offset some of their own demand, or to even export power to the grid when their native load is less than the generation capacity.

1.2.3 Regulatory and Standards Changes

In the past, utilities have had the authority to prohibit the interconnection of customer-owned generation to the utility grid, or at least the authority to make technical and commercial requirements which effectively rendered small-scale generation economically infeasible. Utility deregulation has

Standards Related to DG Interconnection

IEEE P1547	*Draft Standard for Interconnecting Distributed Resources with Electric Power Systems (currently in draft)*
IEEE 929	**IEEE** *Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*
UL1741	**Standard** *for Inverters, Converters, and Controllers for Use in Independent Power Systems*

brought about a drastic change in the way distributed resources are considered. Vertically-integrated utility monopolies are disappearing, and there is the expectation that independent generators, large and small, will have access to the grid. Some states have implemented net metering rules, which can substantially improve the financial viability of DG from the customer standpoint.

Many utilities and several state regulatory agencies have adopted uniform interconnection standards for DG. Some DG interconnection standards tend to follow the same types of requirements that are imposed on bulk wholesale generating plants, such as extensive utility-grade relaying requirements. Other standards impose relatively minimal requirements on smaller DG.

In 1988, IEEE Standard 929 (IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems) was developed specifically for inverter-interfaced photovoltaic systems. In 2000, IEEE 929 was substantially updated. This standard has been commonly applied beyond its scope, however, to inverter-interfaced systems of all types. It also serves as the basis for many state interconnection standards, applied to all types of DG. Underwriter Laboratories has developed an equipment certification standard, UL1741, based on IEEE 929.

A working group under IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage (SCC 21) is presently developing a draft standard (P1547) for the interconnection of DR. This draft standard has been put to ballot twice, and both times fell short of the required percentage of affirmative ballots. The draft is undergoing revision in attempt to resolve the negative ballots. If approved by IEEE, there is a substantial probability that this interconnection standard will be adopted and codified by various regulatory agencies.

The interconnection standards all seek to set uniform requirements for DR interconnection. The ultimate goal is "plug and play" interconnection, with DR devices pre-tested and certified, with no site-specific engineering. While the realities of distribution systems and differences in systems and practices make the "plug and play" goal impractical in the near term for all but the smallest DR systems, the standardization process is making DR interconnection simpler and more consistent, thus decreasing total project costs to make DR more viable.

1.2.4 Government Promotion

It is the official policy of the United States Department of Energy to promote distributed resources. The U.S. DOE budget for distributed energy resource development is in excess of $100 Million for Fiscal Year 2002. The DOE promotion extends beyond renewable "green" resources such as small hydro, wind, solar, and landfill gas recovery, and includes fossil fuel conversion technologies. The promotion by DOE includes support of research and demonstration projects, and support of the some of the IEEE P1547 standards development activities.

The utilization of renewable resources has a clear value to the national interests, in terms of energy independence, environmental impacts, etc. The inherent value to the nation of small decentralized generation, as opposed to large centralized plants, is arguable. Some of the advantages cited by DOE of DG over central generation are efficiency, lower costs, reliability, security, and environmental advantages.

While the electrical conversion efficiency of most DG technologies is less than that of the best current central generation technology, recovery of the DG waste heat can provide very high overall thermal efficiency. Because thermal energy is not easily distributed, to does make sense to promote the development of combined heat and power (CHP) technologies as a way to conserve energy and reduce environmental emissions.

Some of the newer DG technologies, such as fuel cells, have much lower pollutant emissions than conventional bulk-plant generation. This is not true for all DG technologies, however. For example, many reciprocating engine generator sets built for standby and emergency service, are now being considered for exploitation by their owners as distributed generators. Typically, these units have very high emission levels.

In addition to DOE promotion of DR, the policies of many states promote development and deployment of DR. These policies are more favorable, and more widespread, for DR technologies employing renewable

Some of the advantages cited by DOE of DG over central generation are efficiency, lower costs, reliability, security, and environmental advantages.

Some popular views on the present power system:

…The existing power system is "leaky"; T&D losses consume much of the generated power.

…Central generating plants are inefficient, and distributed generation is efficient and environmentally-friendly

…The systems are unreliable. Distributed generation will make the system more reliable.

resources. Some states, however, have defined fuel cells as "renewable" even though their primary fuel is generally natural gas. The justification appears to be based on the fuel cell's low environmental emissions.

Government promotion has also included subsidies for DR. Sometimes, the subsidy is direct, most often in the form of grants supporting DR demonstration projects. More extensive, however, are indirect subsidies provided in tariffs implemented by regulatory agencies. These include net metering rules and elimination of standby charges for interconnection of certain types of DR. These can be argued to be subsidies when the cost of service provided by the utility is less than the revenue derived. A net-metered facility which takes power from the utility at on-peak times, and exports to the utility off-peak is paying for high-cost power with power having a lower market value. A facility with DG not taking net kWh from the utility, but retaining a utility connection to provide short-circuit capacity and stabilization is obtaining a service which is not paid for in the zeroed energy charge. Without a standby facilities charge, the customer would receive a free service for which the costs would be borne by other rate payers. Generally, this type of cross-subsidy has been directed toward renewable and environmentally-friendly DG technologies which are perceived to have a public benefit. There now is discussion in the regulatory community of a requirement for utilities to provide payments to DG facilities for the supposed offset in T&D infrastructure investment made possible by the DGs' existence.

1.2.5 Economic Incentives

There are situations where the installation of DG by a customer is justified solely by energy and demand cost savings. Economic viability depends on the capital and maintenance costs for the DG capacity, cost of fuel, total energy conversion efficiency of the DG, and utility rate structure.

Technical developments have brought down the costs of DG capacity and increased its efficiency. There is increased interest in combined heat and power (CHP) applications, where the waste heat from the electric power production process is recovered and utilized by the customer. Such cogeneration has been long applied at large industrial plants and institutions, but there is increased focus on using CHP technology in commercial and residential applications. Further, advances in absorption chiller technology makes cooling with the waste heat possible as well. Such combined cooling, heating and power (CCHP) applications are gaining attention for sites where cooling is a major energy factor. Whether for heating or cooling, recovery of waste heat substantially increases the effective energy conversion efficiency of the DG. Stranded asset recovery and market power cost fluctuations can also make DG-produced power economically attractive relative to utility supplied power.

These are just some of the economic factors driving current interest in DG. Later in this report, the reasons for DG application are described in more detail.

1.2.6 Popular Views Regarding Distributed Generation

While there are many valid rational reasons for promoting distributed generation, the image of DG is also influenced by hype, incomplete information, and emotional reaction.

The inefficiency of primary fuel conversion in the existing bulk power plant infrastructure is often compared with distributed generation technologies. This may be a questionable comparison because many older power plants in the present infrastructure have far less efficiency than newer designs. Also, the statistics include a substantial amount of coal-fired power production. Coal is a much more plentiful resource than natural gas, which is the fuel for much of the distributed generation technology. Comparison of distributed generation efficiency with the efficiency of modern gas-fired bulk power plant technologies might be considered a more equitable comparison. Large, modern combined-cycle gas turbine plants provide a conversion efficiency well above most gas-burning distributed generation technologies, except where DG waste heat is recovered and put to use.

T&D losses typically consume between 5% - 10% of system generation. However, there is a widespread perception that these losses are even larger, and thus distributed generation is, by nature, "green". Many comparisons subtract the T&D losses from the thermal efficiency of central generation, and compare this with the conversion efficiency of various DG technologies. This is a valid comparison where the DG is supplying load at the same secondary service. However, when a DG is exporting power which is consumed elsewhere on the feeder, on other feeders, or even at other substations, that power flow is subject to a portion of the distribution (and sometimes transmission) losses which occur for central plant generation.

It is widely assumed that DG will increase system reliability. This belief is rooted in the following:

- More generation capacity increases the system reserve margin
- DG puts a source downstream of system elements, such as the transmission system and the distribution substation, which may cause loss of service to customers due to failure or capacity limitations.

Further examination of the reliability issue, however, reveals that the effect of DG on system reliability is not necessarily positive. It is likely that the DG will increase the reliability of the facility where the DG is installed, provided that the DG has the capacity and the appropriate controls to supply the local load while isolated from the grid. However, substantial advances in distribution automation infrastructure and DG control will be needed to enable DG to provide an alternate source for customers downstream of a failed utility system component. Certain DG protection requirements may actually burden the grid at inopportune times. The impacts of DG on system reliability are discussed in more detail later in this document.

1.3 Overview of Distribution System Issues

There are significant technical issues involved in the integration of DG into existing distribution systems, as well as in new systems based on today's design practices. Eventually, distribution design will have to adapt to the presence of DG. This can potentially result in a more costly system. How, and by whom, those costs are borne are significant issues outside of the scope of the document.

1.3.1 Conflicts with Conventional Distribution Design

The presence of DG upsets many critical assumptions used in the design and operation of distribution systems. While a few small installations can be treated like negative load, offsetting other loads in its immediate vicinity, larger installations or the cumulative effect of many small DG installations can profoundly affect the system. Consider the following:

- Utility power distribution systems have been conventionally designed assuming one-way flow of power, based on the cumulative demand of customers downstream of any given point on a radial feeder. While the flow of power was not totally within the utility's control, flow at any given time can be forecast with reasonable accuracy. DG exporting power into the distribution system can result in reverse power flow at any point where the total downstream DG production exceeds the downstream load demand. Power flow forecasting is more difficult with significant DG penetration because it depends on the status of the DG. The DG operation will generally not be under the utility's control, and DG status may not be easily determined.
- In conventional radial systems without DG, proper voltage regulation can be achieved through line design, substation transformer load tapchangers, step voltage regulators, and capacitor banks located on feeders. These capacitor banks may be fixed, switched seasonally, or switched automatically based on current flow, power factor, time of day, air temperature, or other parameters. The presence of DG complicates voltage regulation coordination, and can result in incorrect operation of voltage regulation equipment.
- Short circuit contribution to any fault on the feeder has always been from the substation; sources of short circuit current on the feeder were insignificant. Some types of DG can provide a significant source of short circuit. This short-

circuit contribution, added to the existing contribution from the substation, can cause equipment and protective device fault current limits to be exceeded. Also, fault detection and overcurrent protective device coordination are complicated, both by the existence of the DG and by the variability in short-circuit current values due to on-line versus off-line status of the DG.

- Opening of a fuse, recloser, breaker, cutout, or other switchgear on a radial feeder would normally be expected to deenergize the downstream distribution system. Under certain conditions, a DG may support the voltage on the downstream system, creating an unintentional island. This results in voltage and frequency supplied to other customers that is outside of the utility's control. To prevent such undesired islanding, most interconnection standards require specific under/over frequency and under/over voltage protective schemes, and possible additional special protective schemes. The sensitivities typically required of these anti-islanding protections can result in the false trip of many DGs simultaneously due to system faults and other events, with consequential undesired effects on the power system. There is not a wide consensus among DG manufacturers about how to implement anti-islanding functionality, and this subject is undergoing current investigation and research.

These, and other impacts of DG are the focus of this document, and are elaborated in more detail later.

1.3.2 Proponents' Views of Utility Technical Concerns

Utility engineers are justified in treating DG integration with caution and some degree of conservatism. Technical conservatism is often viewed by DG proponents, however, as utility obstructionism. A recent report prepared for, and widely circulated by, the Department of Energy, reviewed a number of DG integration case studies. This report is titled "Making Connections – Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects". The report criticizes almost every utility technical requirement as intentional obstruction of DG, but some of these cases appear to the knowledgeable engineer, familiar with distribution systems, as sound engineering requirements. Excerpts of one case study are shown in the box above. Most engineers familiar with secondary network systems would tend not to agree that the utility was unreasonable to place restrictions on DG operation when one of three feeders serving the network was out, as the risk is greatly increased that another disturbance could isolate the network with the DG as its only source. This would probably lead to outage of the network and the significant potential probability of eventful failure of a network protector. (The unique issues involved with integration of DG onto secondary networks is discussed later in this report) At a recent DOE DR conference, one of the *Making Connections* report's authors clearly stated that the report was "not intended to be objective". A review of the case studies in the DOE report, by the author of this DSTAR document, concludes that the cases cited fit into three basic categories:

1. Seemingly valid technical requirements made of the DG owner by the utility to protect the integrity of the system, or commercial requirements to protect the utility from undue liability.

2. Requirements which are based on the interconnection standards for large non-utility generation plants, and for which the appropriateness to small DG is debatable.

Excerpts from the DOE "Making Connections" Report

"In one case, a distributed generating facility operating in a network distribution system was required by the utility to shut down if one of the network feeders went down. This operational requirement was contrary to the distributed generation facility's purpose of … increasing reliability for the customer,

…the utility appeared to be unfamiliar with network interconnection issues and expressed concern that reverse flows within the network could create system outages over a broader area."

In a number of cases, this pertains to protective relaying requirements.

3. Obstruction by the utility for either commercial reasons or perhaps obstinacy.

With the adoption of industry DR integration standards, the promotion of DR by government agencies, and the requirements made by state regulatory commissions to integrate DR, it is clear that intentional obstruction of DR is a policy which cannot be maintained in the long run. Utilities, or the regulatory agencies, need to have clear and fair requirements for DR interconnection. Where the requirements upon the DR owner are financially burdensome, there is an inherent tendency for DR proponents to tag the requirement as obstruction. Therefore, the utility must be prepared to clearly make the case for their functional needs in a way that can be understood by all parties involved.

1.4 Scope and Organization of Document

The scope of this document is to qualitatively review the technical issues related to interconnection of DG to distribution systems, and to provide other related information. The related information includes discussion of the technical characteristics and application basis for various DG technologies, review of ongoing standards activities, suggestions for distribution system design and operating practice changes to minimize the impact of DG, and speculation on how the distribution systems of the future might be configured to allow DG to improve system performance and reliability.

Section 2, the next section of this document, describes the common motivations for customers or utilities to apply DG.

Section 3 describes the various DG technologies, with emphasis on their characteristics which impact the electric power grid.

Section 4 provides an extensive qualitative analysis of DG impact on distribution system performance.

Section 5 discusses the implications of DG on reliability of the distribution system, as well as the potential impacts on the bulk utility system in the future when DG reaches a significant system-wide penetration.

2. DG APPLICATION MOTIVATORS

Although the costs of DG equipment are decreasing with technological developments and product volume, and conversion efficiencies are increasing, DG-produced power for base-load power requirements is generally more expensive than the inherent costs of centrally-generated power. There are a number of additional factors, however, which make DG attractive to a potential implementer. In this section, the motivations for DG application are discussed.

2.1 Net Metering

Some regulatory agencies have required utilities to offer net metering to customers with their own generation. Power generated by the customer in excess of their demand flows back into the system and reduces the kWH for which the customer is charged. This may be implemented by meters which reverse registration with a reversal in power flow direction.

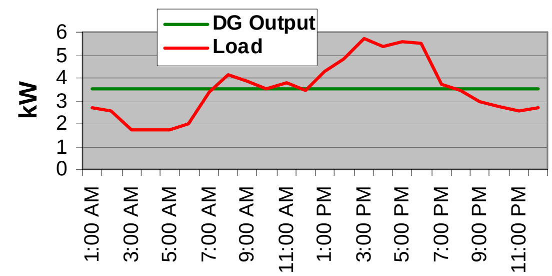
Net metering effectively means that the customer is able to sell power generated in excess of their demand back to the utility at the same price per kWH as the customer purchases power. Generally, the customer is only able to sell back energy at this rate in an amount equal to the power taken from the grid. Energy generated in excess of the customers total consumption in a billing period is generally valued only at the utility's avoided cost under most net metering tariffs, a rate which is substantially less than the customer's purchased power rate.

Net metering can greatly increase the economic viability of a DG project. Such tariffs can be burdensome to the utility, and consequently to other non-DG customers, because the value of energy at periods of peak demand is much greater than at minimum demand. If the usage of the customer follows the system demand curve, the customer takes high cost energy and pays the kWh back when the value of the energy is less. Effectively, net metering is a subsidy of the DG at the expense of other ratepayers.

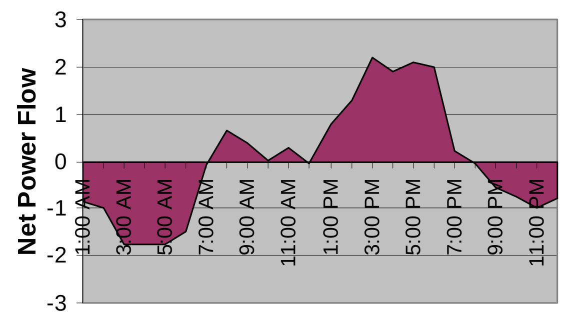
Net metering is often limited to "renewable" resources. The argument is that there is a public benefit from utilization of these resources, thus justifying the draw-high payback-low interchange. Some state regulatory agencies (e.g., Washington) have extended the net metering policy beyond DG based on sources conventionally considered renewable (e.g., solar, wind, hydro, biomass), and have included fuel cells which use natural gas.

Why Net Metering is a Subsidy

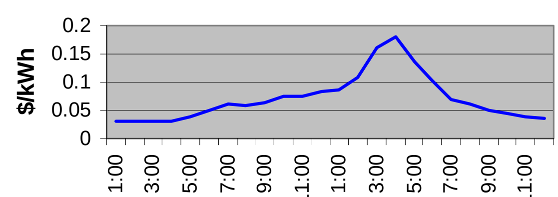
Consider a residential load having a fuel cell running continuously at a load equal to the average load of the residence. The hourly load profile is shown below:



The net flow between the residence and the utility is below. Because the kWh in and out of the load balance to zero, in this example, there would be no energy charge to this customer if a net metering tariff is used.



Energy costs vary hourly as demand and capacity affect the market price. Below is a typical daily cost variation:



In this example, the daily value of power taken from the utility is $1.50, and the value of the power exported to the utility is $0.45. Thus, the DG owner is subsidized by being allowed to pay back for "borrowed" on-peak power with low-cost off-peak power. Other customers, or the utility, pay for this subsidy.

2.2 Stranded Asset Cost Avoidance

With the transition from a regulated to a deregulated (or actually, re-regulated) utility industry, many utilities have been allowed to recover their investment in stranded assets, and this cost is added to kWh rates charged to customers. Because the stranded asset recovery is not a true reflection of the cost to provide present service, it can skew the relationships in costs between utility-supplied energy and DG energy. The costs can more than offset the benefits of scale and load diversity inherent to central generation. The addition of stranded asset recovery to utility tariffs can make DG economically attractive, even for base load requirements. Thus, there is an incentive for a customer to apply DG to avoid contribution to the stranded asset recovery.

To avoid this circumvention, one utility has been able to implement tariffs which allow the utility to bill the DG-owning customer a substantial "power delivery" charge (6 cents/kWh) for all energy produced and consumed by the customer. Thus, the customer must pay the utility for all energy they produce for their own consumption, even if there is no power interchange with the utility. Only by completely severing all electrical ties with the utility can the customer avoid this tariff. While this may seem fair from the utility viewpoint, such a provision is not popular and is not likely to be allowed in other jurisdictions. Thus, the current transition to deregulation provides an artificial incentive to DG implementation.

2.3 Peak Shaving

Industrial and large commercial customers are usually metered on demand as well as energy consumption. Often there is a ratchet clause, where the customer pays a demand charge based on the maximum demand over a substantial period such as one year. Where a customer has a demand curve with a high peak, it may be more economical to supply that peak via DG to avoid the demand charge. The fundamental economics reduce to whether the utility's cost of incremental capacity, considering demand diversity, is less than the cost of the DG capacity. Typically, for peak-shaving applications, the cost of fuel and fuel conversion efficiency are of lesser importance.

The DG can also operate to shave utility system load peaks. With deregulation, independent generators can participate in the real-time power market. Even high-cost generation becomes marketable at high system peaks, or when there is a major generation shortfall.

Figure 2-1: Landfill gas is used to fuel the fifty 30 kW microturbines in this Los Angeles area facility

Generally, a minimum capacity is required to play the market, such as 1000 kW. Larger DGs can meet the threshold independently. Aggregators are now putting together arrangements where the outputs of several DGs (often units primarily installed for backup power) are combined to participate in the market. These aggregated units do not have to be located together; they may be a widely separate locations in the system.

2.4 Renewable Resources

Renewable resources include solar, wind, hydro, and biomass resources. Incremental costs for renewable-resource DG are generally small, but capacity costs for all but biomass DG are generally much higher than for other DG sources. Economic viability of these sources for DG are dependent on their availability and cost of exploitation, and are highly location-dependent. DG based on renewable resources is often eligible for subsidies and preferential treatment based on government (tax and direct subsidies) and regulatory agency policies (e.g., net metering for renewable DG).

Beyond the economic aspects of renewable-resource DG, there is also an environmental motivation for some potential DG owners. There is also a growing market for "green" power, which actually closes the connection from environmental advantages to direct economic advantage for the developer. Further reinforcing this are the requirements for "renewable portfolio standards" by many states, where a certain portion of the electrical energy is mandated to be supplied via renewable resources.

2.5 Combined Heat and Power

DG applications where waste heat is recovered and utilized have potential efficiencies which are very high. For the maximum operating efficiency, the thermal and electrical demand need to be in continuous balance. If the waste heat from electrical generation exceeds the thermal demand (e.g., where waste heat is used for building space heating, which is not needed in summer months), then the generation may need to be operated without waste heat recovery, or electrical generation may be curtailed which reduces the return on the electrical generation equipment investment and will incur increased energy and demand costs for utility power. Often the heat recovered from CHP is used for industrial processes and for water heating, where the utilization is year round. Absorption chillers can be also applied to use waste heat for summer air conditioning needs in a facility using recovered heat for winter space heating (so called CCHP). Efficient CHP implementations can be very capital intensive. CHP probably provides the most significant long-term motivation for DG application.

2.6 Customer Independence and Reliability

DG can provide a power user with a degree of independence from the costs and outages of the utility system. With utility deregulation, variations in market energy prices may eventually be passed on to customers. Provision of part, or all, of a customer's needs by DG can isolate the customer from the market electric power costs, but the customer may still be subject to the market variations in the price of fuel for the DG.

Standby and emergency generators have long been applied in certain facilities, such as hospitals, where power reliability is critical. These units are usually designed to operate isolated from the utility grid, and this operating mode is not within the distributed generation definition used for this document. An owner of standby generation, may consider operation in parallel to the grid to provide some or all of their own demand, and possibly to export power to the grid. The economic incentives include peak shaving and participating in the power market. There have also been instances where owners of standby generation have been requested by the utility to operate in parallel with the grid to reduce demand on the utility system during generation or power delivery capacity shortages. Most existing standby generation units are not designed for high fuel conversion efficiency, do not meet environmental emission requirements for power production facilities, and may not be designed for low maintenance costs under heavy utilization. Therefore, operation of existing standby units as base load DG is not expected to be widespread. In many locations, standby diesel generator units are prohibited from operating more than a specified number of hours per year, due to air quality issues.

***Figure 2-2:* Heat exchangers between groups of microturbines extract exhaust heat which is used to drive a 200 ton absorption chiller.**

With deregulation and adoptions of standards permitting DG interconnection, an increasing number of customers with high reliability needs may be selecting generation units meeting both the need for standby power, and as DG operating during non-emergency normal conditions for economic reasons. Some existing standby capacity may be converted or upgraded to achieve this dual-purpose mission. Typically, these units would have higher efficiencies and lower emissions than units applied strictly for emergency backup.

There have been suggestions that DG is a good way to isolate a sensitive customer from grid power quality problems. The fact is that the DG is operating in parallel with a much stronger grid, and will not normally be able to support the customer's voltage in the event of a grid fault until the connection between the customer and the grid can be opened. If mechanical switchgear is used, grid faults will affect the sensitive customer's voltage for a number of cycles. Static switchgear is available which can sever the connection in a fraction of a cycle, but such devices are quite expensive and lossy.

Total independence requires the customer to operate permanently isolated from the utility grid. Such operation does not fit into the definition of distributed generation used in this document, and will not be discussed as it has no impact on the distribution system other than perhaps the removal of an existing load or the non-addition of a potential load in the future.

2.7 Subsidized Applications

At the present time, the financial basis of many DG applications is based on funding from government agencies and research groups, tax credits, or other subsidies, rather than solely on the financial and technical merits of the project alone. The nature of the subsidies include research and demonstration project grants and tax credits for renewable resources. As DG becomes more common, subsidies for demonstration projects should disappear except when a novel technology is introduced. Subsidies and favorable tax treatment for renewable resources are not necessarily tied to the introduction of new technology, however, but in practice are tied more to the overall public and political outlook regarding energy and environmental issues.

Regulatory policies can also provide a de facto subsidy by transferring costs to other customers. For example, as previously discussed, net metering with a flat rate can be considered a subsidy for a DG facility consuming power during system peaks and exporting power to the system during off-peak periods when the market price of power is less.

2.8 Early Adopters

There is a certain portion of the public who are eager, and have the financial resources, to be the "first on the block" with any new technology. These are the people who have installed various devices on the leading edge of the public's acceptance of these technologies. Generally, this "early adopter" label applies to individuals who might be expected to install residential DG, but might also apply to certain businesses. These businesses can be expected to be highly attuned to the public's perception of their being technology leaders, or might be closely-held businesses where the proprietor or controlling stockholders fit the personal characteristics of the "early adopter".

Some in the DG industry are counting on the "early adopters" comprising a substantial portion of their initial markets for DG products. This should be balanced, however, with the realization that electric power is a house or business facility "utility" which tends to be unglamorous. There are other new technologies for building and home "utility" systems which have not attracted much sales based on prestige and novelty. Examples include super-high efficiency HVAC systems and high efficiency lighting.

3. CHARACTERISTICS OF DR SYSTEMS

To better understand the impacts of DR on distribution systems, it is very useful to first review the characteristics of the various DR technologies. DR systems can be categorized in two different ways. The first is by the basic energy source or energy storage technology, the second by device or system that generates the 60 Hz ac power (e.g., alternator, inverter).

3.1 DR Energy Sources

Listed below are the various common energy sources for DR systems, with a short description of their application and operating characteristics.

3.1.1 Reciprocating Internal Combustion Engines

While not receiving the same popular attention as newer DG technologies, such as fuel cells and microturbines, reciprocating internal combustion engines are the prime mover for the great majority of DG installations at this time. Reciprocating internal combustion have long been used for electric power generation, primarily for relatively small power plants (e.g., many municipal power plants) or for emergency power. Ratings range from a few kW to several tens of MW per unit. Synchronous generators are invariably used for producing electric power from reciprocating engines.

Electrical conversion efficiencies of reciprocating DGs vary, with relatively low efficiencies for the lower first-cost units commonly used in standby applications, to fairly high efficiencies for some of the larger and more advanced units. Overall thermal efficiency can be high where the waste heat is recovered.

Environmental emissions from reciprocating engines also vary considerably, from relatively high emissions for the lower-cost standby units to moderate for the more advanced units.

The fuels used for reciprocating DG are primarily diesel or natural gas. Biomass gas, such as recovered landfill gas, is also sometimes used. The quality and energy content of recovered gases are inferior to natural gas, and the gas often contains contaminants which are potentially injurious to the engines. Thus, substantial pre-treatment of recovered gas is often necessary before use.

Misfiring and uneven combustion in reciprocating internal combustion engines can occur where inferior fuels, such as landfill gas are used. This results in pulsation in generator power output and can potentially result in voltage flicker in a power system. Recovered gas is often mixed with natural gas to improve the operation of the engines.

Figure 3-1: Mobile 16 MW gas turbine generators.

3.1.2 Conventional Gas Turbines

Gas turbines are an outgrowth of jet aircraft engine technology. They were first applied in utility electric power production as peaking units. Advancements in technology have brought about increased efficiency and the availability of much larger units. Today, most new central generating station units installed in the U.S. are gas turbines. Unit ratings range from a few MW to over 200 MW.

The smaller-sized gas turbines are sometimes used as DG. Most of these are adaptations of aircraft engine designs. These units generally drive synchronous generators via reduction gearing. Fuels used for gas turbines in DG applications include natural gas and light petroleum products (jet fuel or light fuel oil).

Efficiency and environmental emissions of gas turbine units varies with size, with high efficiencies and low emissions for the largest central generating station units and moderate to relatively low efficiency with moderate emissions for the small aeroderivative units in the size category which might be applied as DG.

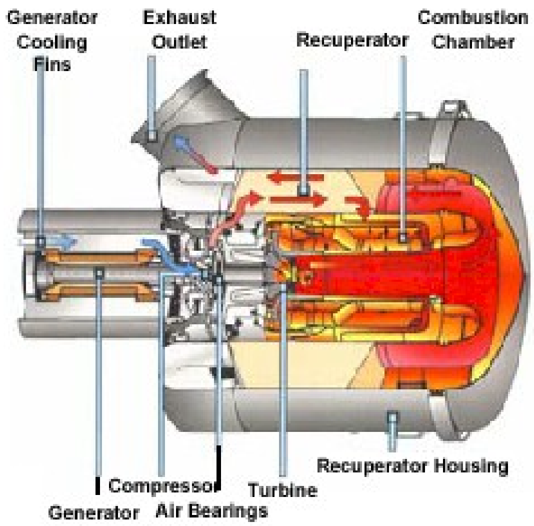


Figure 3-2: Cutaway of a microturbine

3.1.3 Microturbines

Microturbines differ from conventional gas turbines in the following characteristics:

- The microturbine rotor turns at very high speeds, generally from 50,000 to 120,000 rpm. Conventional gas turbines spin at synchronous speed (3,600 rpm), or up to a few multiples of synchronous speed with reduction gearing to drive the synchronous generator.
- The turbine rotor, consisting of both a single-stage compressor section and a single-stage turbine section, is generally a single-piece construction. Conventional gas turbines typically have many compressor and turbine stages consisting of individually-machined blades.

In all but one manufacturer's design, the turbine drives a synchronous generator directly at the high shaft speed. As a result, the produced electric power has a frequency in the kHz. This power is rectified to DC and an electronic inverter is used to produce 60 Hz. The exception design uses a high-ratio reduction gear to drive an induction generator at slightly faster than synchronous speed. The characteristics of inverters and induction generators are described later in this section.

The electrical conversion efficiency of microturbines is generally on the order of 20% to 30%, without heat recovery. Where the microturbine's waste heat is put to use, the overall efficiency can be as high as 80%.

NO_x emissions from microturbines, fired with natural gas, are slightly higher than for state-of-the-art combined cycle central generation plants fired on natural gas.

3.1.4 Fuel Cells

Fuel cells directly convert the fuel to dc electric power without any moving parts in the primary process (a practical fuel cell, however, usually includes a number of auxiliary devices, such as pumps, that contain moving parts). Fuel cells produce a dc voltage which must be converted to 60 Hz ac by electronic inverters.

The energy conversion process in a fuel cell is chemical, similar to a battery, but fuel is consumed instead of an electrolyte. There are a number of fuel cell processes available or in development, as summarized in Table 3-1. The PEM process is more amenable to small-scale application and is being developed by some manufacturers for residential-size units. The most efficient processes involve high internal temperatures and balance-of-plant equipment which makes the technology more appropriate for larger units. Presently on the market are fuel cell DG units in the 250 to 2000 kW range using the molten carbonate technology. Their early applications tend to be for high-reliability power to critical loads, often in an urban environment where noise and emissions are significant issues. Generally, fuel cell technology has a high cost per kW, and fuel cells have not significantly penetrated the DG market except for demonstration projects and certain specialty applications.

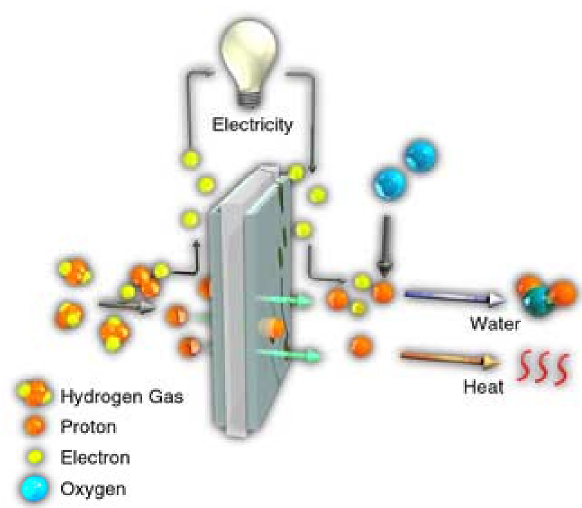


Figure 3-3: Conversion of hydrogen and oxygen to electricity, water, and heat in a fuel cell

Table 3-1: Comparison of Fuel Cell Technologies

Technology	Operating Temp.	Cost	Efficiency
Proton Exchange Membrane (PEM)	160°F	$10,000 / kW	24% - 32%
Molten Carbonate	1250°F	$2,000 / kW	45% - 50%
Solid Oxide	2000°F	$10,000 / kW	45% - 50%

The fuel used in the cell itself is hydrogen, and the emission is water vapor. Fuel cell systems, however can use natural gas or liquefied petroleum gas as the fuel source. Hydrogen is separated from the hydrocarbon gases by a device known as a "reformer", which releases the carbon in the form of carbon dioxide. Smaller amounts of other gases are released by the fuel cell system. From an environmental standpoint, polluting emissions from fuel cells are very small.

Figure 3-4: 7 kW residential PEM fuel cell under development

3.1.5 Photovoltaic Cells

Photovoltaic (PV) cells convert light energy directly into dc electric power. Conversion to 60 Hz ac is by electronic inverters.

There are various PV cell technologies, offering different efficiencies and per-kW capacity costs. PV generation is rarely cost-effective from a purely economic standpoint, due to the high installed costs of the equipment. Most applications are driven by subsidies, incentive, and desires for this renewable, non-polluting energy source.. Power generation from PV is relatively uncontrollable as the electrical power output from the cells is proportional to the incident light striking the panels. Power output varies through the day, and is obviously zero at night. Output also has a seasonal variation, with maximum output during the summer. Most PV array panels are in a fixed position, but others can be rotated to follow the direction of sunlight to maximize output.

Figure 3-5: Rooftop photovoltaic array.

Clouds reduce PV output. A distribution system with substantial PV-based DG penetration could experience voltage fluctuations due to cloud movement over the area served by the feeder.

3.1.6 Wind Turbines

The application of wind-based electric power generation is rapidly expanding both in the US and abroad.. Successful application of wind generation requires a site with consistent, moderately-strong wind on a year-round basis. Mountain passes, open plains, and some coastal areas provide desirable wind conditions.

Typical ratings of a modern wind generator are in the 100 – 1500 kW range for a single unit. Developers have constructed large wind farms with many tens, or even well over one hundred, wind generators interconnected through a power collection system consisting of many line-miles of primary-voltage lines. These wind farms have a total output of many tens of MW, and are usually integrated to the power grid at the subtransmission or transmission level. Large wind farms of this variety do not fit into the definition of DG as used in this document. Discussion of wind DG in this document will be limited to smaller installations of one or a few wind turbines interconnected to a general-purpose distribution system.

Figure 3-6

There are a variety of electrical generator types used with wind turbines:

- Some smaller and older turbines use dc generators. The power produced must be converted to 60 Hz by electronic inverters.
- Most turbines produced today use induction generators. An induction generator requires that the shaft turn at slightly greater than synchronous speed. Turbine blade pitch is controlled to regulate the speed and electrical power output.
- Other wind turbines use synchronous generators. The combination of wind speed and turbine blade pitch angle establish the power output from the machine, but synchronous speed must be maintained. A new type of synchronous machine uses a multi-phase ac field excitation to create an apparent rotation of the generator's rotor magnetic field which is faster or slower than the rotor's rotation. The difference between the turbine's actually mechanical rotation speed and synchronous speed can be made up by the supply of the appropriate frequency and phase rotation order to the generator field. This "doubly" fed generator provides a synchronous voltage source while allowing variation in the turbine speed. The electrical characteristics of induction and synchronous generators, and electronic inverters, are described later in this section.

Table 3-2: Summary of DG Characteristics

Type	Cost	Fuels	Efficiency	Environmental	Electrical
Recip Engine	$500 - $1,000	Natural gas, diesel, flare gas	20 – 40%	Moderate to low emissions depending on fuel and engine technology	Usually synchronous generator, sometimes induction generator.
Microturbine	$1,200 - $1,800	Natural gas, light petroleum, flare gas	20 – 30%	Low NO_x. Particulates higher than NG recips.	Usually inverter, one manufacturer uses induction generator.
Fuel Cells	$5,000 - $10,000	Hydrogen, natural gas via reformer	20 – 50 %	Very low emissions.	Inverter.
Wind	$800 - $1,500	Wind	25%	Aesthetic, bird deaths	Induction generators, synchronous generators, inverters.
Photovoltaic	$5,000 - $8,000	Sunlight	6 – 20%	Virtually no impact	Inverter

Costs are typical 2002 installed system costs

As wind velocity increases, maximum electrical power output increases (available power is proportional to the wind velocity cubed) up to the rating of the generator. For higher winds, the controls of most wind turbines will vary blade pitch to hold a roughly constant power. At very high wind speeds, controls usually will feather the blades and shut down power production to preserve the physical integrity of the system. Wind direction also plays a role in power output. Some wind turbines, built for locations with a strong prevailing wind direction, have a fixed axial direction. Variation in wind direction from this direction reduces output. Most wind turbines can be rotated to align with the wind direction. Gusts and rapid wind direction changes will cause power output variations because the blade pitch and turbine directional controls cannot respond fast enough. This power output can cause variations in the voltage of the distribution system to which the wind generator is connected, resulting in lamp flicker. In addition to variations due to gusts, as the turbine blades rotate into the wind shadow caused by the turbine's support pylon, there is a small fluctuation in power output. The rapid variation in system voltage create flicker at a repetition frequency where the human sensitivity is heightened.

3.1.7 Battery Energy Storage

Electrical energy can be stored in electrochemical batteries for backup power and leveling loads. This technology is widely applied in Uninterruptible Power Supplies (UPS) for critical loads. Most UPS installations are in the series configuration shown in Figure 3.7(a). No power can be supplied back into the power system, and these devices are not a form of DR from the grid perspective.

It is also possible to configure battery energy storage in a parallel configuration, as shown in Figure 3.7(b). In this configuration, normal power supply to the load does not have to go through the ac-dc-ac conversion process with the resulting losses and capacity requirements. In the event of utility service interruption, the isolation switch is opened and the battery supplies the load via an inverter. The isolation switch can be mechanical, exposing the load to a several cycles of interruption, or static, allowing sub-cycle transfer and near-UPS quality power supply. When used for backup of local load in this manner, the battery energy storage system (BESS) is not a DR from the grid perspective.

In a few applications, battery energy storage has been applied instead as a distributed resource (DR) for load-leveling in the utility power system. In one application, a BESS was used for an isolated utility system on an Alaskan island to levelize load fluctuations caused by a large sawmill.

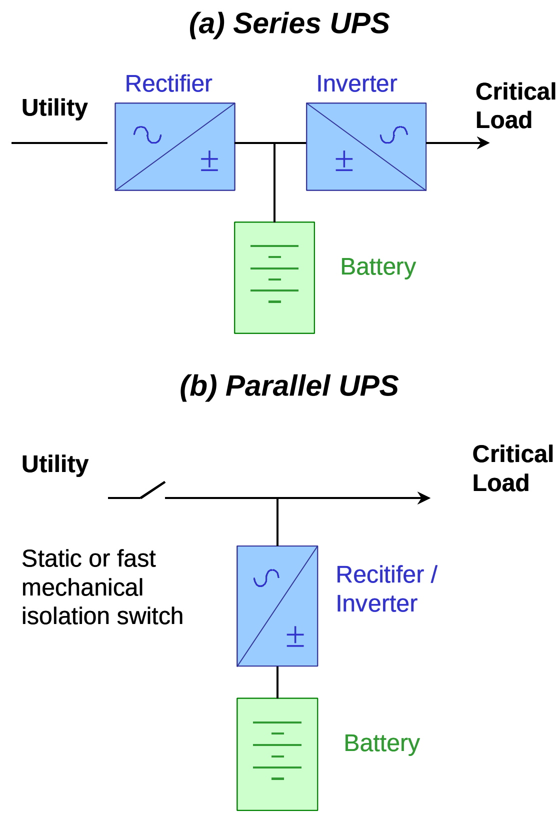


Figure 3-7

BESS systems typically use banks of valve-regulated lead-acid (VRLA) batteries. Installations as large as tens of MW peak capacity have been constructed. The larger units have been applied at the substation level, and are thus not "distributed" according to the definition used here.

Figure 3-8: ***VRLA battery bank in a large battery energy storage system (BESS)***

3.1.8 Super-Conducting Magnetic Energy Storage

Electrical energy can be stored in a super-conducting magnetic coil, with very little losses. The coil must be kept to a very cold temperature to maintain the super-conductive state, and the primary cause of losses is power required for the chilling equipment. The current in the super-conducting coil is necessarily dc, and electronic rectifiers and inverters are necessary to interface with the ac power system.

Figure 3-9: Cryostat holding energy storage magnet in a Distribution Super-Conducting Magnetic Energy Storage System (D-SMES)

Super-conducting magnetic energy storage systems (SMES) are presently being constructed for very short-term (up to a few seconds) to support power system dynamic performance. Current units are being constructed for distribution system interconnection at substation buses, but primarily for transmission system support (interconnection at the distribution level has proven to be more cost-effective than interconnection at the transmission voltages). While it is possible to store energy for load leveling and other longer-term applications, there have been no such applications to date.

3.2 Electrical Power "Converters"

With the exception of voltage flicker due to power output variations from such sources as photovoltaics, wind generators, and misfiring engines fueled by low-quality landfill gas, the primary energy conversion used for a DR is of much less significance to distribution system impact than the device used to convert the power to 60 Hz ac. These "devices" include both rotating generators (synchronous and induction) and electronic power inverters. Described below are the characteristics of each converter type that are relevant to system impact.

3.2.1 Synchronous Generators

Synchronous generators are familiar to the power industry. Virtually all large generation units are of this type as are most customer-owned standby generators. Synchronous machines (generators or motors) have not typically been interconnected directly to most distribution systems, however. Exceptions have been utility-owned generators which are too small for substation interconnection (e.g., very small hydro) and some synchronous motors at industrial and municipal (e.g., water pumping) facilities. With the wider application of DG, this type of generator may be found more frequently on distribution systems.

A synchronous generator provides a relatively low-impedance voltage source capable of providing both real and reactive power. With a constant dc field voltage applied to synchronous generator, the apparent ac source voltage behind the machine's synchronous reactance stays constant. Thus, without any control of the field voltage, the reactive power flow in or out of the machine is governed by the difference between the internal source voltage and the system voltage. If the system voltage is greater than the internal voltage, the generator will consume reactive power and tend to pull the system voltage down. If the system voltage is less than the generator's internal voltage, the reactive power flow will be out of the machine and into the system, supporting the system voltage.

Synchronous generators used in bulk power plants, and in stand-alone small generation systems (e.g., emergency generators) have voltage regulators which control the field voltage in order to hold the generator output voltage (or some other sensed voltage) constant. Regulation of machine terminal voltage, if used on a DG, can interfere with system voltage regulation or cause the machine to source or absorb excess reactive power fighting changes in the distribution system voltage. For these reasons, the excitation control on a DG is normally set to hold a desired power factor or constant reactive power interchange.

The generator is capable of providing a short-circuit current contribution to a fault which is many times its rating. The short-circuit contribution from these machines, if large enough, can have significant impact on a distribution system. The short-circuit current contribution from a synchronous generator changes during a fault, with the current greatest at the beginning of a fault. For a fault at the generator terminals, the initial fault current is the internal voltage of the machine divided by the subtransient reactance. The subtransient reactance of a typical small generator is on the order of 0.1 p.u. of its rating. After a few cycles, the flow of fault current in the armature induces a change reducing the magnetic field created by the generator's rotor. As a result, the fault current magnitude decreases. For a terminal fault, the fault current during this second time period is limited by the transient reactance, which is typically 0.2 – 0.5 p.u.

Connection of a synchronous generator to a power system requires that the generator be brought to the same frequency (speed), and close to the same voltage magnitude and phase angle, as the power system before the interconnecting switchgear is closed. This process is called synchronization, and can be performed manually or automatically. Closing in a machine to a system out of synchronization can harm the machine and can significantly disturb the power system if the machine is not very small. Out-of-synch closing causes large currents in the generator and large mechanical torques on the generator's entire mechanical system, including the prime mover (e.g., engine, waterwheel).

Power system faults and other disturbances will initiate electromechanical oscillations of the generator against the power system. These oscillations will cause variations of the power flow and voltage which will oscillate with a period of a fraction of a second to several seconds. Normally, these oscillations or "power swings" will settle out in a few seconds, but they may cause protective device operation or aggravate the power quality disturbance created by the initial fault. If the initial disturbance is too large, or if the power swings grow instead of damping out, the generator may break out of synchronism.

3.2.2 Induction Generators

An induction machine, such as an induction motor, will generate real electrical power if turned at faster than synchronous speed. Figure 3-10 illustrates the speed-power curve for a typical induction machine, showing the motor and generator modes of operation. Unlike a synchronous generator, an induction generator does not need to turn at exactly the synchronous speed. Within a range, increasing speed results in increased power output.

An induction generator always consumes reactive power and it cannot sustain an output if a source of reactive power is not present. Normally, the reactive power is supplied by the power grid to which the induction generator is connected. It can also be supplied by capacitors, provided the induction generator is previously connected to an ac voltage source. In other words, an isolated induction generator cannot be started up using just mechanical energy and shunt capacitors. But, once an induction generator is in operation, it may continue to generate ac voltage if the generator and shunt capacitors are isolated from the grid. The ac voltage is not easily controlled, however, and the voltage may grow or decline depending on the balance between reactive requirements of the induction generator and reactive power provided by the capacitors. (and the active power balance)

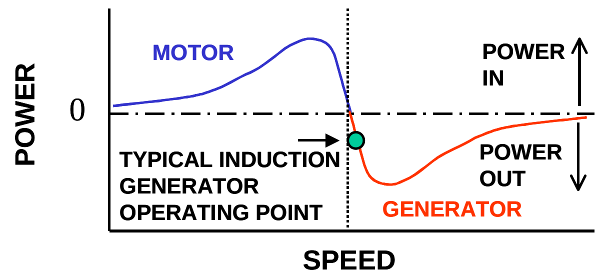


Figure 3-10: Power-speed characteristic for a typical induction machine

Unlike a synchronous generator, an induction generator will not provide a continuous source of fault current contribution. There will be an initial fault current contribution of several times machine rating, but this will decay in a couple of cycles as the machine's internal flux collapses. This short circuit contribution may affect fuses, fast-acting relays, and momentary fault-current ratings of equipment, but does not add to switchgear interrupting requirements because the current decays prior to breaker contact parting. This short-duration fault current contribution is also supplied by induction motors; the fault current contribution of an induction generator is not significantly different than the contribution of a similarly-sized motor.

Induction generators do not need to be carefully synchronized as is required for synchronous machines. Small induction generators can even be started by power from the grid, operating as a synchronous motor. Connecting a large induction generator at standstill to the grid, however, will usually cause an unacceptably large starting current and consequent voltage dip. System disturbance can be minimized by bringing the machine to near synchronous speed before closing in. Also, reduced-voltage starting and other large induction motor starting practices can be applied to bring an induction generator on line without unacceptable disturbance.

3.2.3 Electronic Inverters

Most of the emerging DG technologies, including fuel cells, microturbines, and photovoltaic cells, require the use of electronic inverters to create 60 Hz output. Unlike rotating generators, the performance characteristics of inverters is generally unfamiliar or misunderstood in the electric utility community.

There are two general types of power inverter: line-commutated inverters and voltage-source inverters. Voltage source inverter technology is rapidly advancing and is now available for high power levels. Most new DG designs use voltage-source inverter technology. The older, line-commutated inverter designs are still found in some small photovoltaic DG system designs, and also on at least one higher-power fuel cell system design.

Line-Commutated Inverters

A basic line-commutated inverter uses a 6-pulse thyristor bridge, such as illustrated in Figure 3-11. The thyristors are used to cyclically connect the appropriate ac phase to the appropriate dc polarity. A thyristor allows one-way flow of current, like a diode, but forward conduction does not begin until the thyristor is gated by a control circuit. Once gated, however, the thyristor continues to conduct until its current is forced to zero. In a line-commutated inverter, when the next thyristor in the triplet (the three thyristors across the top of the bridge are one triplet, the three below are a second triplet) is gated, the ac voltage forces current from the outgoing thyristor to the incoming thyristor in a process called commutation. When the current in the outgoing thyristor is forced to zero, the thyristor ceases conduction until it is gated again one cycle later.

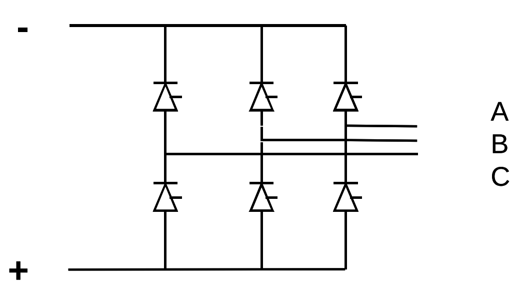


Figure 3-11: 6-pulse load-commutated inverter bridge

The inversion process of a line-commutated inverter is totally dependent on the external source of ac voltage. For this reason, a line-commutated inverter is never used on a DG design which is intended to allow operation isolated from the power grid.

During operation of a line-commutated inverter, removal of the ac voltage source by opening switchgear, or abrupt drop in ac voltage due to a fault, the transfer of current from one thyristor to the next will not be completed. An event called a "commutation failure" results. This event is non-destructive, but control action and a healthy ac voltage are required to reestablish successful inverter operation. This characteristic makes it unlikely that a line-commutated inverter will support an islanded portion of a utility grid (e.g., if a recloser opens). Operation without a synchronous voltage is ideally impossible, but experience has shown that continued operation of line-commutated inverter in a passive system is possible for a narrow range of system conditions due to complex system interactions. Generally, the conditions must include ample amount of shunt capacitive compensation. Control circuits advance or delay the thyristor gating in order to regulate constant power output, or some other control objective.

The output current in a line-commutated inverter is a series of square steps, such as shown in Figure 3-12. This current is after a delta or floating-wye isolation transformer winding blocks the zero-sequence harmonic components. Still, the current has a substantial harmonic component. By combining two 6-pulse inverters, with a 30 degree ac phase shift accomplished by an appropriate transformer winding connection, a 12-pulse inverter is created. The current output of a 12-pulse inverter is composed of more, but smaller steps. The current distortion of the 12-pulse inverter is reduced due to cancellation of some of the harmonic components. Utilization of line-commutated inverters in DG applications generally requires the addition of harmonic filters in order to meet harmonic distortion requirements.

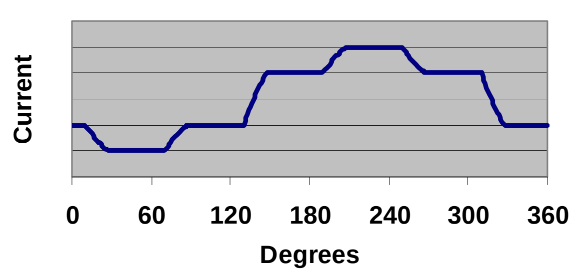


Figure 3-12: 6-pulse load-commutated converter phase current (after isolation transformer)

Voltage-Source Inverters

A voltage-source inverter (VSI) is a substantially different technology than the line-commutated inverter technology described above, as it is not dependent on an external ac voltage source for operation. Most voltage-sourced inverters (VSI) used today are based on pulse-width modulated (PWM) technology. A PWM inverter uses transistors to connect the ac line to the dc source for periods of time which are varied such that the smoothed value of the on- and off-times approximate a 60 Hz sine wave. Unlike a line-commutated inverter, an external ac voltage source is not required for a voltage-source inverter to operate because a transistor is able to turn off, as well as turn on current flow. The on-off cycle rates of a PWM inverter are in the range of hundreds of Hz to kHz. Figure 3-13 shows the electrical connection of a single-phase VSI, and the modulated voltage created by the switching action. Figure 3-14 shows the phase-to-phase voltage generated by a three-phase PWM inverter. Typically, PWM inverters have an output inductor to smooth the current. Depending on the PWM switching frequency, the size of the output inductor, and any filtering used, the current distortion produced by a PWM inverter can be much less than that of a thyristor line-commutated inverter.

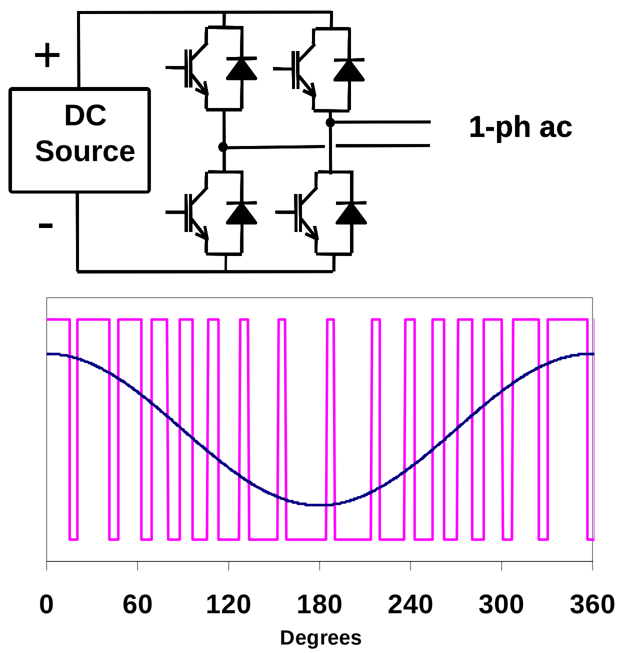


Figure 3-13: Single phase VSI and generated voltage. Sinusoid is fundamental frequency component of pulse-width-modulated pattern.

As the name suggests, a VSI is able to create a virtual 60 Hz voltage source. This is useful when a DG is to provide power when isolated from an operating power grid. The inversion process is also much less sensitive to grid voltage disturbances than a line-commutated inverter.

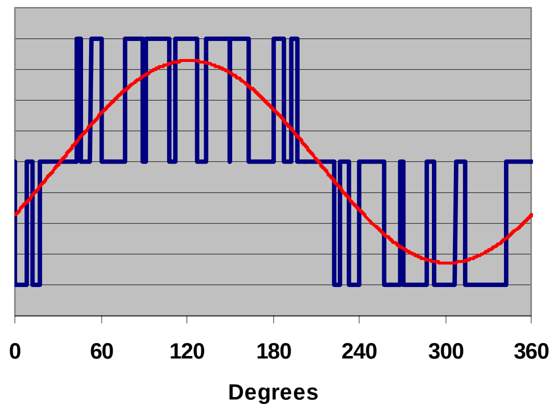


Figure 3-14: Phase-phase voltage generated internally in a 3-phase VSI. Sinusoid is 60 Hz component of voltage created by PWM pattern.

As a virtual voltage source, a VSI could potentially provide a source of short-circuit current contribution. The transistors used in a VSI are very sensitive to overcurrent. Therefore, as a matter of practicality, the current is limited by a very fast control loop having a typical response time of a few milliseconds. When operating isolated from a power grid, the VSI is generally controlled to regulate the ac voltage and the fast current control loop is a backup control which takes over whenever the current flowing exceeds the equipment rating. When operating interconnected to an ac power grid, however, the constant-current control loop is normally in control. The short-circuit current contribution, therefore, is not much more than the load current.

Voltage-source inverters provide considerable control flexibility. Both real and reactive power can be independently controlled. Changes to the real power, however, are reflected as changes to the current on the dc side of the inverter. This may cause interactions with the “prime mover”, and power control flexibility may be limited. For example, a decrease in inverter power output in a microturbine will cause the turbine to accelerate until the combustion controls react. To avoid excess speed variations, the magnitude and rate of VSI power changes may need to be limited. Reactive power control, however, does not affect the prime mover and can be regulated very rapidly.

When operating interconnected to the grid, the 60 Hz current waveform objective, to which the VSI output is regulated, must be synchronized to the power. One could make the current reference an image of the bus voltage into which the inverter is operating. The VSI current output would, however, tend to follow any distortions of the voltage waveform. The distorted output could increase the distortion, and control instability could easily result. Therefore, most VSI designs use a phase-locked loop to synchronize an internal 60 Hz control oscillator to the bus voltage. The phase locking must be much slower than the response of the current regulation loop, but will generally be fast enough to follow system voltage phase angle changes.

Large-scale implementation of DG with VSI technology could result in closed-loop interactions between the utility grid dynamics and the VSI controls. These dynamic interactions have largely been unexplored, as DG penetration in most systems will be minimal for the near future.

Table 3-3: Summary of DG Electrical Power "Converters"

Type	***Synchronous Generator***	***Induction Generator***	***Load Commutated Inverter***	***Voltage Source Inverter***
Fault Contribution	5x to 10x rated generator current	4x to 6x rated current for approximately one cycle.	None	1x to 2x load current
Requires Synchronization	Yes	No	Inherent to control	Inherent to control
Capable of Standalone Op.	Yes	Not usually. Once started can operate, but needs VAR source and a means of voltage regulation	No	Yes (requires control mode shift)
Reactive Power	Supply or absorb	Absorb	Absorb	Supply or Absorb
Controllability	Real power controlled by prime move, reactive power controlled by excitation. Relatively slow response 500 ms – 2 sec.	Real power controlled by prime mover speed. Generator requires reactive power. Switched capacitors compensating generator may provide reactive control..	Fast control, on the order of tens of milliseconds response. Consumes reactive power, limited reactive power control.	Very fast control. Current control responds in milliseconds. Prime mover may limit practical power control response.
Harmonics	Low injections, except for low quality designs	Very low injection	Substantial harmonic currents. Filtering is usually needed.	Depends on design. Can create high frequency harmonics.

4. DISTRIBUTION SYSTEM PERFORMANCE ISSUES

Prior sections of this document provide the background to understand DG and its characteristics. This section begins the detailed discussion of how DG can potentially affect a power system. The potential impacts on system performance are covered in this section, and reliability implications are covered in the next section (Section 5). System performance impacts can be divided into the following general categories:

- Fault performance
- Power quality
- Unintentional islanding
- Network issues

4.1 Issues Related to Fault Performance

A significant focus of distribution system design is related to fault performance, including the following aspects:

- rating equipment to withstand fault current
- design of system grounding to avoid overvoltages during fault and to allow ground faults to be detected
- detection and isolation of faults (i.e., relaying and fusing)
- schemes to reestablish the system after faults are cleared.

DG interconnected to a distribution feeder has the potential to substantially affect each of these aspects of fault performance. Whether or not there is such an impact is dependent on the nature and design of the DG power converting device (generator or inverter), the number and rating of DG devices, the location of the DG on the distribution system, and the characteristics of the distribution system itself.

4.1.1 Short Circuit Contribution Issues

Radial distribution systems have been conventionally designed assuming that the sole source of short circuit current is the primary substation. A DG, however, can introduce a short-circuit source located on the distribution system, which can change both the magnitude and direction of short-circuit currents in the system.

Maximum short-circuit contribution impact is for DG using synchronous generators, with lesser impact from DG using induction generators. (Note that the short-duration short-circuit current contribution from an induction generator is very similar to that of a similar-sized induction motor, and induction motors typically form significant portion of a typical feeder's load.) Short-circuit current impact from inverter-based DG is practically insignificant.

Equipment Overcurrent Withstand

DG fault current contribution can increase the fault currents to which equipment is subjected, possibly requiring increases in utility equipment ratings in order to withstand the currents. Short-circuit current withstand limits of distribution equipment are based on thermal, mechanical, and current interruption constraints. The thermal effect of fault current is proportional to the current magnitude squared times duration (I^2t). Electromagnetic forces created caused by short circuit current are proportional to the square of the maximum current magnitude, but are independent of the fault duration. There are other forces placed on equipment, such as pressures on transformer tank walls created by internal faults, which are of a thermo-mechanical nature. These forces are roughly dependent on the I^2t, and are thus dependent on both current magnitude and duration. Current interrupting devices such as switchgear and fuses are sensitive to the fault current magnitude at the time of interruption, as well as the dc offset in the current. The decay of fault current offset is related to the X/R (reactance to resistance) ratio of the system.

DG increase fault current impact in the following ways:

- Maximum fault currents are increased, affecting thermal, mechanical, and interruption duties.
- Fault durations can be lengthened due to desensitization of protective relays by the DG fault current contribution (relay desensitization is discussed later in this section).
- The X/R ratio of a generator is generally greater than that of a distribution system, particularly at locations remote from the substation. This results in slower decay of fault current offsets, affecting the ability of breakers, reclosers, and fuses to clear.

Fault current contributions based on the DG synchronous generator or induction generator subtransient reactance are used for determining mechanical duties, breaker close and latch (momentary) current requirements, instantaneous relay settings, and the ability of fuses to interrupt the fault current. For synchronous generator DG, fault current contributions based on the transient reactance are used for calculating thermal duty, time-overcurrent relay settings, and interrupting requirements for breakers and reclosers. (The operating time of breakers and reclosers are such that the subtransient time period will normally have passed before contact parting.) The duration of induction generator fault current contribution is generally insufficient to be of significance to these criteria. As mentioned previously, the fault current contribution of an inverter DG is usually not much more than rated load current, and is rarely of any significance to distribution system fault current levels.

The impact of DG on primary distribution system short-circuit duty can be significant if the DG uses synchronous or induction generators, and one or more of the following apply:

- Short circuit current magnitudes on the feeder are on the threshold of excess without the DG
- The DG is of large rating
- Many DG are connected to the distribution system.
- The DG is connected at a weak point on the distribution system, where its fault current contribution is significant compared to the contribution from the system.

A synchronous or induction generator DG can easily be a significant contributor to faults on the secondary system to which the DG is connected. Secondary-side short-circuit currents are usually more an issue for customer equipment (e.g., circuit breakers, panelboards) than for utility equipment. Where the owner of the DG is the only customer connected to a secondary system the impacts are limited to the party responsible. If a distribution transformer serves multiple customers, a DG connected one customer's service can potentially over-duty other customers' service equipment. This is one of several reasons why some utilities require that a dedicated distribution transformer be used for customer services having a DG connected.

Fault Detection and Protection Coordination

Short circuit current contributions from DG on a distribution system can upset overcurrent protection coordination in the following ways:

- Short circuit current contributions from one or multiple DG into faults on the distribution system can decrease the short-circuit contribution from the substation. Effectively, the substation relays are desensitized and may not detect faults as quickly (or, potentially, not at all). Figure 4-1 illustrates this.

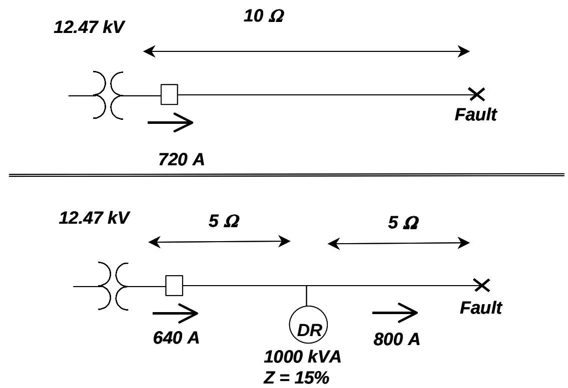


Figure 4-1: Illustration of how DG can de-sensitize feeder protection

- Short circuit currents at a particular location on a distribution feeder are usually fairly constant. DG located upstream from a fuse or recloser, however, can change the short circuit currents through these devices into downstream faults. This variability in short-circuit currents, which is not within the control of the utility, can complicate the protection coordination.
- Depending on distribution transformer and DG neutral connection, the DG installation can provide a grounding source on the distribution system. This ground current contribution can desensitize ground fault detection. (See the following section on primary grounding issues.)
- The decrease in short circuit current levels at the substation, combined with increased current through fuses located downstream of DG but upstream of the fault, can result in the fuse melting prior to the breaker operating. This defeats fuse-saving schemes, where the protection coordination is designed such that the substation breaker operates before the fuse to clear temporary faults.
- Fuse saving can be further defeated by DG short-circuit current contributions continuing beyond the time when the substation breaker or recloser clears. Protective devices which trip the DG may not be sufficiently sensitive, or fast-acting, to remove the DG fault contribution as fast as the system (substation) contribution is removed. (Illustrated in the top one-line in Figure 4-2.
- Fuses and reclosers located downstream of a fault location, but upstream of DG, will see the fault current contribution provided by the DG. This can make a lateral fuse melt for a fault which is actually on the main feeder, or on a different lateral. This nuisance fuse operation will result in

unnecessary outage of the customers on the lateral. Reclosers, too, can open for upstream faults. Depending on the reclosing scheme used, the interruption of the customers downstream of the recloser may be protracted by the misoperation. This is illustrated in the bottom one-line in Figure 4-2.

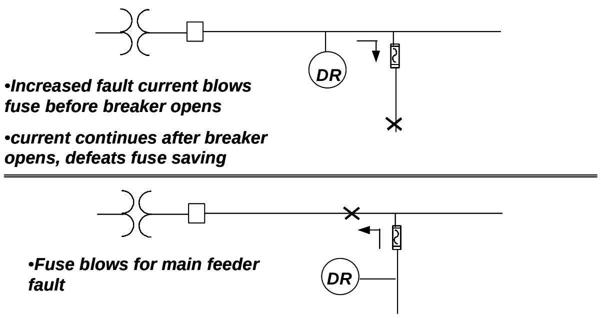


Figure 4-2: Two examples of DG short-circuit contribution leading to nuisance lateral fuse operation

Whether or not DG causes any of the above protection coordination problems is dependent on a wide range of application factors. As a general guideline, protection problems are not likely if the total DG contribution (from all DG on the distribution system) at any fault location is less than a small percentage of the total fault current at that location. Inverter-based DG is unlikely to cause the protection coordination issues discussed above, unless the inverter has an isolation transformer or distribution transformer connection which provides a ground source to the feeder.

Sectionalizer Performance

A sectionalizer isolates a lateral after a predetermined number of high-current events occur within the sectionalizer's reset time. The intention is to isolate a lateral having a permanent fault which does not clear during the reclosing delays of the upstream circuit breaker or recloser. Typical sectionalizer coordination assumes that there is no significant source of short-circuit current on the lateral, and that the incidents of high current flowing through the sectionalizer is indicative of a fault on the lateral where the sectionalizer is applied.

A DG can possibly supply enough fault current contribution so that a fault on the main feeder or another lateral can cause enough current through the sectionalizer such that it is interpreted to be a fault on the lateral to which the DG is connected. As a result, the sectionalizer may unnecessarily isolate that lateral for a fault elsewhere on the system.

4.1.2 Primary Grounding Issues

On a three-phase power system which is not grounded, a ground fault on one phase will cause the phase-to-ground voltage on the unfaulted phases to rise to the magnitude of the phase-to-phase voltage (173% of normal phase-ground voltage) as illustrated in Figure 4-3. To avoid these overvoltages, most distribution systems are designed for grounded operation. An exception is some older 5 kV-class delta distribution systems which have the insulation required to withstand these neutral-shift overvoltages. Grounded systems include three-wire delta systems which are grounded at the substation (uni-grounded systems) and the more common four-wire multi-grounded wye systems.

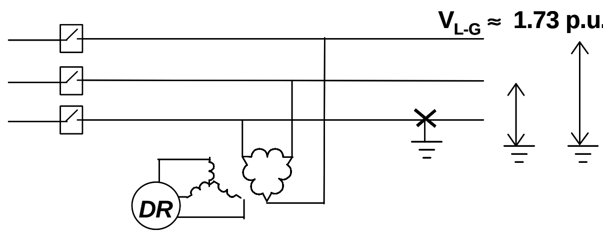


Figure 4-3: Illustration of elevated primary phase voltage due to loss of grounding in island fed by DG

The dominant source of grounding on a four-wire multi-grounded wye distribution system is the primary substation. Operation of a breaker, recloser, or fuse can isolate a portion of a distribution system from the substation. If one or more DGs are operating on the isolated subsystem, the DGs may support the continued presence of voltage. This is called "islanding". (See the more detailed discussion of islanding later in this report section.) Depending on the connection configuration of the DG generator or inverter, and the distribution transformer winding configurations used with the DG, the islanded subsystem may or may not be adequately grounded. Failure to provide adequate grounding can result high overvoltages in the event of ground faults combined with subsystem islanding. These overvoltages, even if present only for the short time until DG protection detects the island and shuts down, can result in failure or damage of utility equipment (e.g., lightning arresters) and to load equipment at the same and other customer locations.

An effectively grounded system, by definition, is one where the ratio of zero-sequence reactance to positive sequence reactance is less than or equal to three ($X_0/X_1 \leq 3$) at any location on the system. A DG will nearly always be interconnected to the distribution system via a transformer. To maintain effective grounding when a portion of the system is islanded with DG, the X_0/X_1

ratio of the primary-side impedance looking into transformer connecting the DG to the system must not exceed three. The necessary grounding source can be provided in the following ways:

- A transformer with a grounded-wye primary (distribution system side) and a delta secondary (low-voltage, or customer side) can be used. The X_0 is the impedance of the transformer, and the X_1 is the sum of the transformer, DG generator, and any secondary service cable impedance. Therefore, the X_0 will be much less than X_1, and the transformer connection alone will provide more than the minimum necessary primary system grounding to prevent overvoltages due to neutral shift during ground faults. This transformer connection, however, has serious shortcomings. The very low zero-sequence impedance of the transformer will cause the transformer to draw currents which tend to balance any primary system voltage unbalance. The transformer may carry substantial zero sequence current in steady state due to normal feeder voltage unbalance, even without any flow of current through the transformer secondary terminals to the load or DG. These currents can easily exceed the thermal capability of the transformer, or at least increase the winding currents such that the combination of zero sequence and load current components cause transformer overload. Primary-side ground faults in the distribution system will cause very large currents to flow through a grounded-wye delta transformer, and may easily cause transformer operation. The second limitation of this transformer connection is that it does not provide a ground source on the secondary side. A grounded secondary system may or may not be needed, depending on the design of the secondary service.
- A wye-delta transformer can be used which has the primary neutral grounded through an impedance. The magnitude of the impedance is selected such that adequate primary system is maintained, but the zero-sequence impedance is not so low that the transformer carries excess current due to feeder voltage unbalance or primary ground faults. This connection does not create a grounded secondary system.
- A transformer with a grounded-wye primary and a grounded-wye secondary can be used, as long as the DG generator or inverter has a grounded neutral. Grounding a generator or inverter neutral can present difficulties, however. Grounding a rotating generator's neutral, unless it has a 2/3 winding pitch design, can introduce substantial triplen-order harmonics (multiples of three) due to the fact that the generator windings are not ideally distributed on the armature. Many inverter topologies are inherently three-wire, and cannot be grounded.

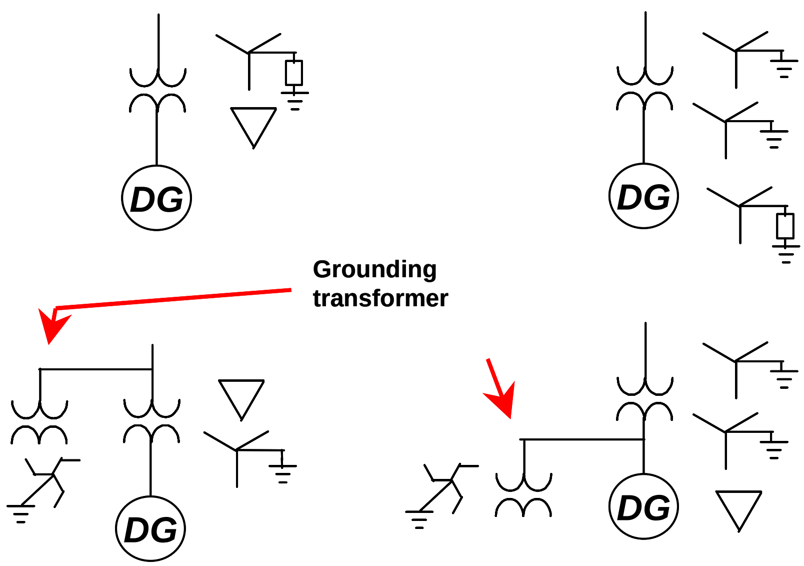


Figure 4-4: Acceptable distribution transformer connections to provide primary grounding

- A separate grounding transformer (zig-zag or grounded-wye delta), of the appropriate impedance to provide effective grounding, can be connected to the primary side. The distribution transformer connecting the DG to the system can then use any winding connection, including a delta-wye transformer, or a grounded-wye grounded-wye transformer without generator neutral grounding.
- A transformer providing the necessary grounding can be connected to the secondary side of a grounded-wye grounded-wye distribution transformer connecting the DG to the distribution system, allowing the generator or inverter to be ungrounded. This secondary voltage transformer can either be a grounding transformer in parallel with the DG, or an additional transformer between the DG and the distribution transformer.

A single phase DG cannot, by itself, provide primary system grounding. If a phase-neutral (wye) connected distribution transformer is used, primary grounding will be maintained. If a phase-to-phase connected distribution transformer is used, the primary system can operate ungrounded in case of islanding. Generally, however, phase-to-phase connection of single phase transformers is not common on distribution systems designed for grounded operation. Also, single-phase DG tends to be small. It is often assumed that these units will not be able to maintain islanded operation for even a few cycles in the event of an upstream fuse, recloser, or breaker opening. This might not be the case in rural systems where the load downstream of the switchgear may be similar to the capacity of the DG, or where many small DG devices are connected.

4.1.3 Circuit Reclosing Issues

Circuit breakers and reclosers on most overhead distribution systems are set to reclose after a short delay. Most faults are temporary (e.g., lighting-caused flashovers across open-air insulation), and the reclosing will often reestablish service to all customers on the circuit. DG connected to the distribution system can affect performance during reclosing in the ways described below.

Reclosing into a DG Island

A significant concern is the possibility of a breaker or recloser reclosing into an islanded feeder energized by DG. If the islanded subsystem remains in synchronism with the power grid, the reclose should be uneventful. If the subsystem has drifted out of phase with the power grid during the switchgear open time, the reclose can have significant impact on the DG equipment, utility system equipment, and the equipment of other customers connected to the subsystem downstream of the reclosing switchgear.

Reclosing delays for breakers and reclosers are generally in the range from a fraction of a second, to as long as several tens of seconds. These devices also can be set for no intentional delay, called “instantaneous” reclosing, where reclosing begins as soon as the contacts have fully opened. The minimum period from the first interruption until conduction through the breaker or recloser resumes is typically twelve cycles.

In most situations, a DG will not keep the system downstream of the feeder energized during the open time of the switchgear. Continued operation requires that the real and reactive power output of the DG be in reasonable balance with the real and reactive power demand of the subsystem to which it is connected. If closely balanced, the DG voltage phase angle may not drift significantly (>90°) relative to the power system for a short reclose delay, and the reclose will be inconsequential. Slightly larger power mismatch, longer reclose delays, or the phase-shifting effects of active anti-islanding controls used in some DG can easily cause the voltage phase angle in the islanded system to be out-of-phase with the utility system at the time of reclose. The potential consequences of such a reclose is discussed in more detail later in this document.

Load Pickup Currents

DG should trip due to faults on the distribution feeder or laterals to which it is connected, or soon thereafter when the breaker or recloser opens. When reclosing occurs, the load previously carried by the DG must now be picked up by the system, as the DG is normally not allowed to come back on line until after the utility system has been reenergized without further tripping for some period. (Typically, DG is not allowed to reconnect to the utility system unless the utility system voltages have been normal for at least five minutes.) The additional load increases the pickup current seen by the recloser or substation relays. If settings for these devices are based on the served load, not considering the offsetting generation by the DGs, this additional pickup current should not present a problem. If, however, the protection settings are based on the net load with DG in operation, the pickup current could cause undesired tripping. This might become a concern at some future time when DG penetration becomes significant and the distribution system design becomes dependent on the DG.

4.1.4 Automated Reconfiguration Schemes

Various automated reconfiguration schemes are applied to improve distribution system reliability. The impact of DG on these schemes is very dependent on the logic and sensing used. In general, the input logic to are absence of voltage and fault current sensing. DG can potentially confound such schemes by:

- Causing "upstream" fault current contribution through the reclosers, which may be interpreted as a fault condition downstream of that recloser.
- Causing voltage to persist on a section after its upstream recloser opens; i.e., islanding. This islanding may need to be only very short in duration to interfere with some automation schemes.

4.2 Power Quality

The presence of DG can affect the power quality experienced by other customers on the same circuit. Some impacts are positive, and others reduce power quality. The impacts are dependent on the characteristics of the DG, whether or not the DG exports power into the power system, the number and rating of DGs, and their location on the feeder circuit.

4.2.1 Steady-State Voltage Regulation

An important aspect of distribution design is the maintenance of voltage magnitudes at customer services on the system within a prescribed range over the range of loading conditions. While utilities do not have significant control over the loads applied by customers, the loading at any point on the circuit can usually be predicted with sufficient accuracy. The existence of DG on a circuit, which is not under control of the utility and which may not follow predictable patterns, complicates the design and operation of the feeder circuit with respect to voltage regulation.

Impact on Voltage Drop

To a good approximation, voltage drop on a feeder is proportional to the real power flow times resistance (P•R) plus the reactive power flow times line reactance (Q•X). On a normal, uncompensated feeder circuit without any voltage regulators, this voltage drop results in a voltage profile in which the voltage magnitude decreases as one moves out along a feeder.

When a DG has less power output than the secondary load on the same service, it will have the same effect on feeder voltage regulation as a reduction in load. When the DG output exceeds the load on a distribution transformer secondary, power is exported to the primary system. The reverse power flow reverses the sign of P in the P•R part of the voltage drop equation, and voltage can rise instead of drop in the parts of the system with reverse flow. Depending on the reactive power output of the DG, the Q•X part of the voltage drop equation may also reverse. Generally, however, DG is operated at unity power factor or at a power factor where a small amount of inductive VARs are taken from the system.

The impact of power export depends on the amount of nearby load. If the net DG export is small compared to the local load, the voltage rise may have no significant impact, or the impact may be limited to the secondary system to which the DG is connected. Secondary system voltage rise is one reason why many utilities require that a secondary customer with DG have a dedicated distribution transformer, particularly where net power export is planned or possible.

DG power export which is large compared to the local system load can have significant impact on the overall feeder voltage regulation. Note that the relevant system load is that which is present at any time the DG is exporting. Most distribution systems have large variations in loading with time of day and season. Because the DG owner's load may also follow a similar pattern, there can be the tendency for DG export to be greatest when the system load is the smallest. This can be encouraged by some tariffs, such as net metering.

The impact of DG export on feeder voltage regulation depends on the location of the DG on the system, and on the design of the feeder. To illustrate the impact of DG on system voltage profiles, some examples based on typical feeder parameters are discussed below.

In the first example, light load is assumed to be 30% of the peak load, and this feeder has no capacitive compensation or voltage regulators. The substation bus voltage is held constant. (The impact of DG export on substation LTC and feeder voltage regulator load drop compensation is discussed later.) Voltage regulation is acceptable over the feeder length for the full load range. Now assume that there is a DG penetration of 30%, relative to the peak feeder load, and this DG penetration is uniformly distributed over the feeder. The feeder voltage profile remains acceptable over the load range, as shown in the two graphs at the top of Figure 4-5. In fact, regulation is improved because the DG provides support during peak load conditions. If the DG, however, is lumped at the end of the feeder, excessive voltage occurs during light load toward the end of the feeder. This is illustrated in the two bottom graphs in Figure 4-5.

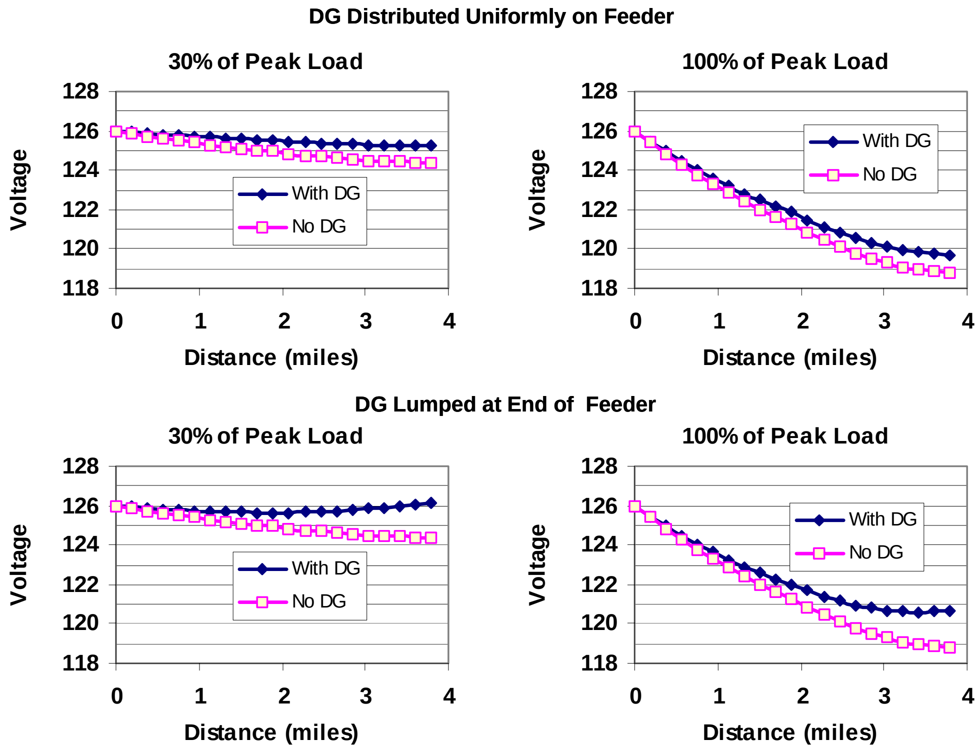


Figure 4-5: Voltage profiles in a typical feeder with 30% DG penetration.

The DG need not be concentrated near the end of the feeder to cause voltage regulation problems when fixed capacitor banks are used to support the feeder profile. Figure 4-6 shows a light load condition for a feeder containing a fixed capacitor bank located at approximately the 2/3 point, with and without DG. The DG is uniformly distributed on the feeder, and its output (20% of peak feeder loading) is less than the load connected to the feeder (30% of peak). The feeder voltage regulation design makes use of the load P•R drop at light load to counteract the -Q•X rise caused by the capacitor bank exceeding the load's reactive requirements at light loading. The DG export cancels much of the loading, leading to excess voltage at light load. While the capacitor bank could be decreased in size, or the substation bus voltage lowered, the feeder voltage regulation design must provide adequate performance with or without the DG exporting. A reduced substation voltage or capacitor bank size, in this example, would lead to undervoltage at peak load without the DG exporting. Unless the DG operation is predictable, or controlled by the utility, the voltage regulation design must accommodate a wider range of net system loading. This can require changes to the system, such as additional voltage regulation equipment, such as voltage-controlled switches on the capacitor bank.

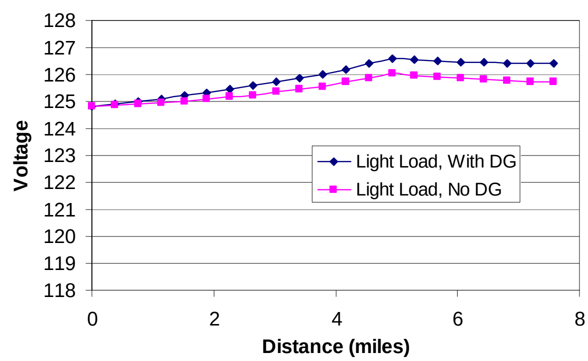


Figure 4-6: Elevation of feeder voltage outside of ANSI C84.1 Range A; 20% DG penetration distributed over feeder. Fixed capacitor bank located at 5 mi.

Interaction With Voltage Regulation Controls

Various automatic controls are often used to improve feeder voltage regulation, such as automatic voltage regulation controls on substation power transformer load tapchangers, step voltage regulators (SVRs) on the feeder, and switched capacitor bank controls. While the objective of voltage regulation is to provide acceptable voltages over the extent of the system, the regulation controls base their actions on locally-measured parameters. These parameters are voltage, current, reactive power, or power factor. Normally, these parameters at the measured locations are generally reflective of behavior elsewhere on the feeder, because most loads follow similar cycles. DG, however, can make localized changes to the measured parameters which can negatively affect the system voltage regulation performance.

One type of automatic capacitor bank control is based on feeder current. When current is high, heavy feeder loading is inferred, and the capacitor bank is switched in to supply the reactive power requirements and support voltage. A DG located downstream of such a capacitor control will cause the local flow to be reduced when the overall feeder loading is at the peak. As a result, the capacitor may not switch in as desired, and undervoltages can appear toward the end of the feeder. Such a situation can arise, even if the DG penetration is a fraction of the total feeder load as long as the DG is concentrated just downstream of the point where current is measured. With a larger DG, power flow at the capacitor bank may be reversed during light load demand conditions. Current-based capacitor controls are non-directional and the reverse flow may be interpreted as heavy feeder loading. As a result, the capacitor may switch in when the voltage is already high, due to the combination of light load demand and reverse flow caused by the DG. Excessive service voltages may result.

Overall feeder voltage profile is improved when a voltage regulation device such as a substation LTC or a feeder SVR holds a voltage constant at a point downstream from the device's actual location. To avoid the expense of communicating a remotely-measured voltage, the remote voltage is synthesized using load-drop compensation (LDC). LDC increases the voltage regulation device's voltage output in proportion to the assumed voltage drop between the regulation device and the remote location. This assumed voltage drop is calculated using the real and reactive components of current measured locally, and the feeder impedance to the remote location. Inherent to this is the assumption that the local current is reflective of the load current profile over the distance to the remote point. Localized changes in power flow patterns on a feeder, due to DG, can cause the LDC to inappropriately affect the voltage regulating device output voltage. As a result, service voltages can fall out of bounds at both heavy and light load conditions.

Figure 4.7 shows voltage profile performance for a DG exporting power equal to 100% of the feeder peak demand. The DG in this example is located immediately downstream of the SVR location. Because the real power flow at the regulator is reversed, the LDC does not boost the voltage enough to support adequate voltage at the end of the feeder. Figure 4-7 also shows the same system with loads at 30% of peak, and the DG exporting the same level of power as in the previous figure. This results in a net reverse flow for the entire feeder, which is a severe example but one which could occur if a fairly large DG is connected. The strong reverse flow in this case cause the LDC to set the SVR to buck voltage. As a result, voltage upstream of the regulator is excessively high, and the voltage at the end of the feeder is low.

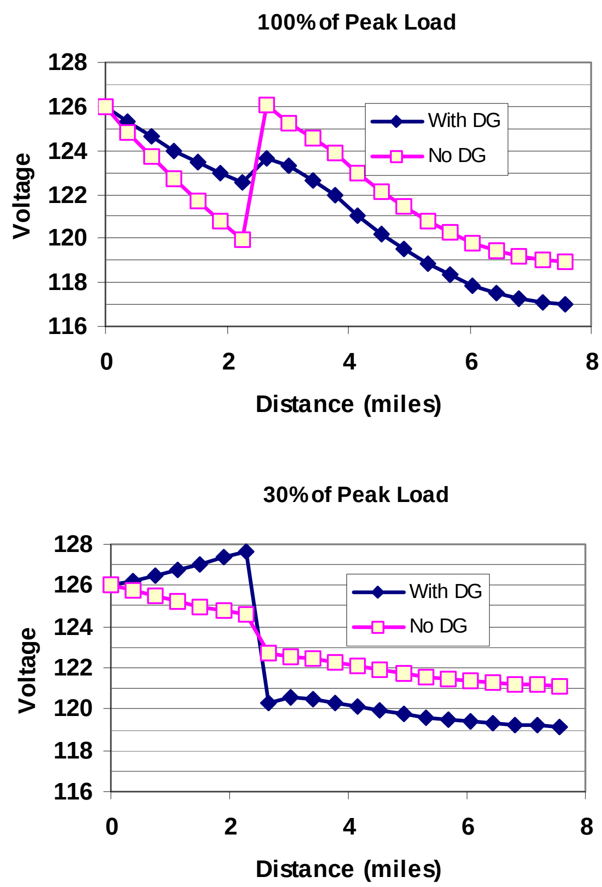


Figure 4-7: Interaction of reverse power flow with regulator LDC. 100% DG penetration, DG lumped immediately downstream of regulator.

For reliability, radial feeders are often configured as open loops. In the event of an outage in the upstream section of the feeder, or at the substation (e.g., breaker maintenance), the feeder may be fed in a reverse direction from the alternate source. An SVR's control must sense and regulate the voltage on the side opposite the source (i.e., on the downstream side from the standpoint of short-circuit current). If an SVR is used on such a loop scheme, the control logic must be shifted when the feeder is backfed from the alternate source. A common control feature on many SVRs is a "reverse power sensing" function which automatically reverses the SVR control logic if the real power flow reverses. This function assumes that the power flow is in the same direction as the short-circuit capacity. A DG can reverse the power flow locally at the SVR location, without providing a strong enough source to reverse the direction of short-circuit capacity. This can cause the SVR control to go unstable because voltage on the wrong side of the SVR is sensed. A sensing of voltage less than the setpoint will cause the tap to change such that this voltage is decreased instead of increased. Because the control will not be satisfied at this next tap point, the SVR will continue to be stepped in the same direction until the maximum boost position is reached. If the initial voltage is greater than the setpoint, the regulator will be driven to the maximum buck position. Figure 4-8 illustrates an unstable SVR situation, creating severe undervoltages on most of the feeder. In this example, DG export slightly less than the minimum feeder load was sufficient to fool the reverse power sensing function.

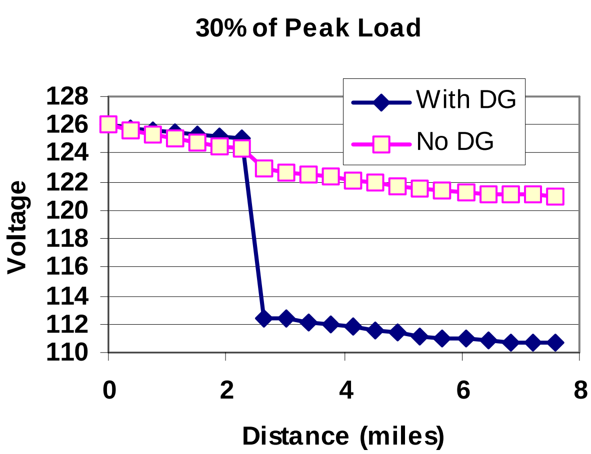


Figure 4-8: Voltage profile for voltage regulator control made unstable due to triggering of reverse power flow feature, due to DG export flow. Penetration 25%.

Voltage Regulation By DG

A DG designed for off-grid operation will usually have an automatic voltage regulator which varies generator excitation (if a rotating generator) in order to maintain a desired output voltage. Inverters for off-grid operation also provide an equivalent function. For operation of a DG interconnected with the grid, however, the normal practice is to operate with a constant power factor or constant reactive power output and no automatic voltage regulation. The current draft of P1547 allows automatic voltage regulation by the DG only when there is no detrimental effect on the utility system voltage performance.

A small DG, compared to the system short-circuit strength, would not usually be able to regulate voltage significantly without often running into its reactive power limits. A large DG, or a large group of small DGs with similar control strategies, can regulate the feeder voltage. This may, or may not, be beneficial to the overall feeder voltage regulation performance.

Regulation of the feeder voltage by the DG can be detrimental to system performance when the voltage regulated by the DG needs to be changed in order to provide acceptable voltage elsewhere in the system. Consider the downstream side of a step-voltage regulator (SVR) with load-drop compensation (LDC). The voltage at this location is raised by the SVR as a function of load current, in order that voltage at the remote end of the feeder does not drop below the desired band under heavy load conditions. A large DG with automatic voltage regulation located immediately downstream of the SVR can defeat the feeder voltage regulation strategy, causing serious voltage problems elsewhere on the feeder. Also, the SVR and DG will fight each other, possibly driving the SVR to its tap limit or the DG to its reactive limit because its voltage control objective cannot be met due to the opposing action of the other.

Figure 4-9 illustrate a DG regulating feeder voltage near the downstream side of an SVR, and the SVR is attempting to regulate the same voltage. The SVR is driven to its 10% voltage buck tap limit. The DG in this case is operating at a power factor slightly greater than 90%. Loads upstream of the SVR are driven to excess voltage. A similar collision can occur between a DG regulating voltage and feeder switched capacitor bank controls.

To be beneficial, the DG regulation setpoint needs to be carefully coordinated with the utility's voltage regulation strategy. Often, a fixed voltage setpoint is not desirable. The setpoint may need to be varied over the feeder load cycle, and also whenever the feeder is reconfigured. This may require providing feeder current measurements to the DG, or using communication between the DG control and the controls of SVRs, capacitor banks, and switchgear. With the proliferation of intelligent electronic devices (IEDs) in distribution systems, there is future potential for integrating DG as participants in the overall feeder voltage regulation design.

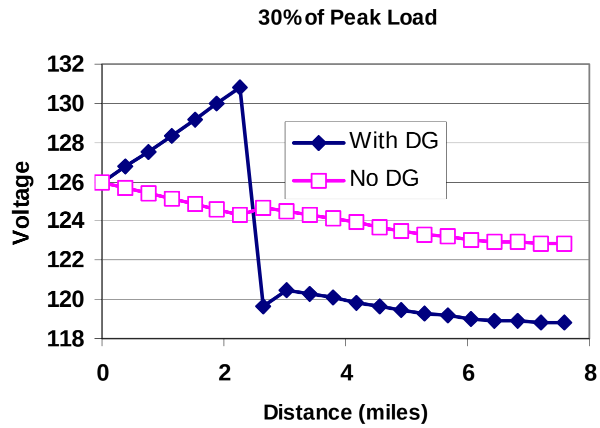


Figure 4-9: DG voltage regulator and feeder SVR attempting to regulate same point to different voltages. DG penetration 100% of peak feeder load.

4.2.2 Post-Disturbance Voltage Regulation

When DG penetration is sufficiently large to significantly affect feeder voltage profiles, the power quality effect of system disturbances can be compounded by subsequent periods of abnormal voltage.

Present interconnection standards generally require that DG trip for any fault on the utility system to which it is connected, and for any voltage or frequency disturbance outside of a defined magnitude-time characteristic. The purposes are to limit DG contribution to faults, minimize protection coordination problems, allow faults to clear, and avoid unintentional islanding. It is often very difficult to set DG relays so that faults on the interconnected feeder are discriminated from faults on other feeders or on the transmission system. Therefore, DG protection strongly tends toward overtripping. To avoid interference with reclosing, interconnection standards also restrict DGs from returning to operation on the system for a prescribed period such as five minutes.

Prior to the disturbance, the output of the DG will have biased the settings of voltage control devices such as LTCs, SVRs, and switched capacitor banks. System disturbances can cause all DG on a feeder to trip, leaving the system to operate with the voltage control devices set improperly for maintaining a good voltage profile. Provided the circuit is properly designed to support the load without the DG, the voltage control devices will bring the voltage back to the acceptable range. The recovery of voltage profile can take some time, however, as there is time delay built into the response of the tap changers and capacitor switching controls. Sudden return of the DG to the system can cause an additional voltage excursion.

Figure 4-10 shows voltage profiles on a feeder with a DG at the end and switched capacitor banks. Prior to a disturbance tripping the DG, the voltage support provided by the DG caused all capacitor banks to be switched off. After DG tripping, the voltage at the end of the feeder is very low. Then, the capacitor bank controls respond to the undervoltage and switch in reactive support. Finally, the DG returns suddenly while the capacitor banks are on, causing a serious overvoltage until the capacitor banks are switched off. (It should be noted that the example here has a high penetration of DG to illustrate the phenomenon.)

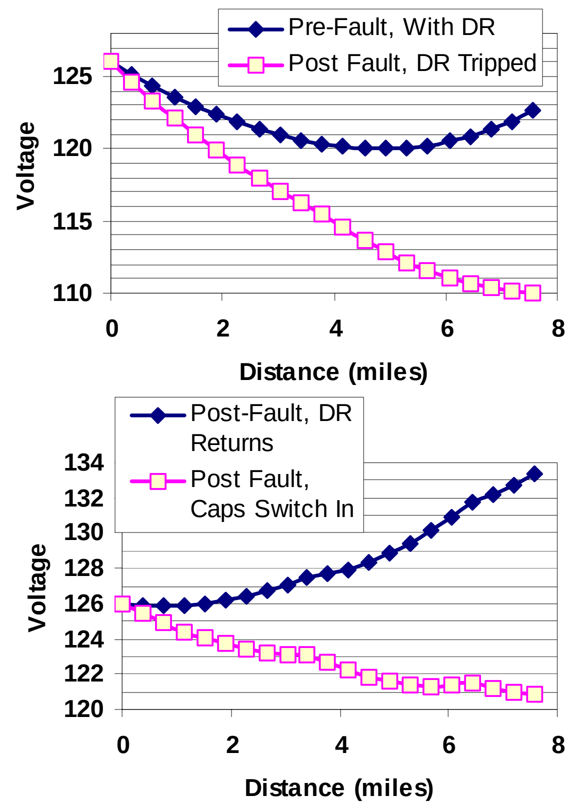


Figure 4-10: Extremes of voltage caused by DG tripping due to a fault. Penetration 100%, load at 100% of peak. Order of events: prefault, DG trips, caps switch in, then DG returns.

4.2.3 Flicker

Abrupt or repetitive variations in voltage can cause objectionable lamp flicker, even when the voltage remains within the acceptable range. In some cases, DG power output variations can be the cause of flicker voltage variations. There are two basic causes: DG synchronization and DG power source (prime mover) variations.

DG Synchronization Flicker

Closing in of a synchronous generator can cause a voltage disturbance if the machine's voltage, frequency, and phase angle are not sufficiently matched to the system. The disturbance can usually be avoided by appropriate synchronization controls and synchro-check relays. Induction generators cannot be synchronized like a synchronous generator, because the induction generator does not produce voltage prior to system connection. Voltage transients can be minimized, but not eliminated by bringing the induction generator to near synchronous speed before closing in its breaker. These startup transients for both types of rotating generator are one-shot, and a larger voltage deviation can usually be tolerated than for a repetitive variation.

DG Power Source Variations

DG power source variations can cause repetitive fluctuations in DG output, possibly leading to voltage flicker. Wind generators have a small variation in output when the turbine blades pass by the pylon. This small variation can be objectionable due to the fast repetition. Reciprocating engine prime movers can experience fluctuations due to misfiring. This is more likely to occur where low-quality fuel is used in the engine, such as landfill gas. Photovoltaic systems output will vary, at a slow rate, due to cloud passage.

DG Response to Load-Induced Flicker

Flicker is more likely to be produced by loads than by DG. Some types of DG will reduce load-induced voltage variations. Synchronous generators, and to a less extend induction generators, stiffen the system and minimize flicker. Inverters will not normally mitigate load-induced flicker, but special controls can be implemented to achieve this function.

4.2.4 Harmonic Distortion

Harmonic distortion can cause misoperation of sensitive loads, capacitor unit overload and nuisance fuse operation, rotor heating of generators and motors, and increased heating of current-carrying equipment such as transformers. Coupling of harmonics from power lines into parallel telephone lines can cause communications interference. Both rotating generator DG and inverter-interfaced DG can inject harmonics into the utility system, increasing distortion levels.

Load-Commutated Inverter Harmonics

Inverters convert dc to ac by sequentially switching the positive and negative side of the dc source to the ac phases. The switching action inherently produces distortion, which can be limited by various techniques in the inverter design.

Load-commutated inverters produce a stair-stepped current such as illustrated in Figure 3-12 for a 6-pulse converter (six thyristor switching units, sequentially fired every 30°). The harmonic content of such an inverter's current is high, typically 20%- 25% total harmonic distortion (THD). Ideally the harmonic orders are 5, 7, 11, 13, 17, 19, etc., or:

$$h = 6n \pm 1, \text{ where } n = 1, 2, 3\ldots$$

The harmonic magnitude decreases with harmonic order (multiple of 60 Hz), with typical values shown in Figure 4-11. The harmonics follow the ideal pattern only when the 60 Hz voltage is balanced. In a distribution system, voltages are rarely balanced and an inverter will produce current at all odd-order harmonics. This includes harmonics which are an odd multiple of three (i.e., 3rd, 9th, etc.). These odd-order harmonics are not zero sequence, however, as might commonly be assumed, and they are not blocked by delta or floating-wye transformer connections.

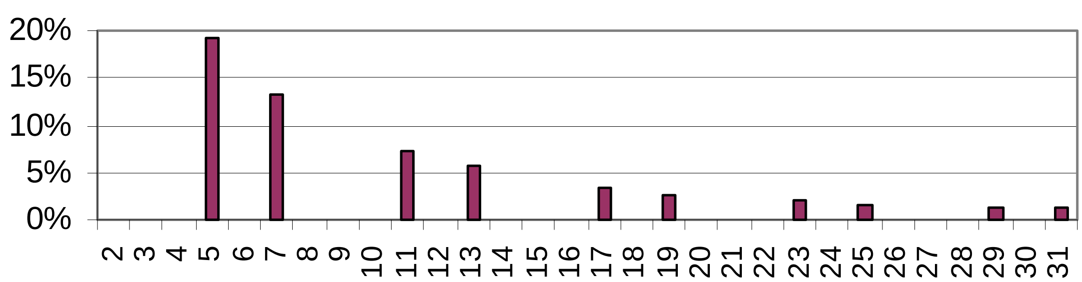


Figure 4-11: Harmonic currents produced by a typical 6-pulse load-commutated inverter.

Two 6-pulse converter bridges can be connected through separate delta and wye transformer windings so that the phase angle of each are offset by 30°. This forms a twelve-pulse converter which has a less distorted current output, with harmonic orders given by the following equation:

$$h = 12n \pm 1, \text{ where } n = 1, 2, 3\ldots$$

It is possible to connect even more converter bridges to form higher pulse-order converters and further reduce harmonic distortion. This is not a common practice for DG, however.

Load-commutated inverters usually require output filters in order to meet harmonic distortion requirements.

Voltage-Source Inverter Harmonics

Most inverter-interfaced DGs use voltage-source inverters. These devices create a 60 Hz source by switching on and off voltage pulses of varying widths. This is known as pulse-width modulation (PWM) and is illustrated in Figures 3-13 and 3-14. While the internal voltage produced by a PWM inverter is highly distorted, a series inductor smoothes the resulting current. The current distortion depends on the switching rate, the series inductance, and other design parameters. With a high switching rate, low distortion can be achieved, and these inverters can be designed to meet harmonic requirements without filters other than the series inductor. The dominant harmonics are clustered around the PWM switching frequency, and multiples of that frequency. Harmonics of high order (frequency), but with low magnitude, can be created. The high-order harmonics can potentially cause telecommunication system interference, due to the acute sensitivity of the communication circuits and the human ear to these frequencies.

Harmonics from Rotating Generators

While harmonic injection is most often thought of as being caused by power electronic equipment, rotating generators can also be a harmonic source. This is due to the imperfect distribution of the generator's windings, and is a function of the machine winding parameter known as pitch factor. Unless a 2/3 pitch factor is used in a three-phase, the generator will create zero-sequence third-harmonic voltages which need to be blocked by a suitable (e.g., delta-wye) transformer connection.

Harmonic Performance Standards

IEEE Standard 519 is the "IEEE Recommended Practices for Harmonic Control in Electric Power Systems", and is widely used in the industry. It is also the basis for harmonic performance requirements for DG in the current draft of P1547. IEEE 519 assumes harmonic sources are current sources, and places limits on the harmonic currents produced by load and generating devices. Voltage distortion, however, is considered the responsibility of the utility and recommended voltage distortion limits are provided. The basic assumption of this standard is that voltage distortion limits should be achievable in a typical system if the current distortion limits are followed.

The harmonic current limits for loads are a function of the size of the load, relative to system strength, with the largest loads held to a lower limit. Generating devices, however, are held to the most stringent requirement independent of size. Shown in Figure 4-12 are the harmonic current limits proposed for DG in P1547.

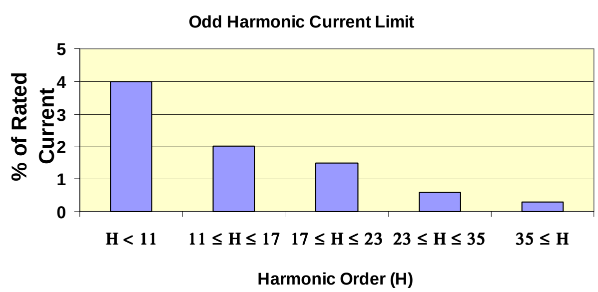


Figure 4-12: Harmonic currents limits proposed for P1547. Even harmonics are limited to 25% of odd harmonic values shown above. Total rated distortion (root-sum-square of all components) is limited to 5%.

Unless the DG penetration becomes large with respect to the system strength, harmonics from DGs will not usually be a major distribution system issue. The harmonic currents will generally be less than those created by loads in the system. Distortion, however, could be an issue if DG is used to used to support an intentionally-islanded system.

4.2.5 Network Issues

Secondary grid and spot network systems provide the most reliable power delivery. Multiple primary feeders serve a grid network, with each primary feeder serving the secondary grid at multiple locations through network transformers. In a spot network, multiple feeders serve a common secondary bus through network transformers. Each network transformer in a grid or spot network has a network protector, which is a special type of low-voltage switchgear controlled by a reverse power relay. If a network feeder experiences a fault, the protectors on the network transformers connected to the faulted feeder see reverse power flow into the faulted feeder and open in order to isolate the fault. Protectors are set sensitively so that they also sense reverse power as small as the network transformer excitation power. This is so that, if the primary feeder is opened at the substation (without a fault), the network protectors will also open to eliminate the backfeed and deenergize the feeder.

Connection of DG on a secondary grid or spot network creates inherent conflict with the fundamental assumptions used for network design and protection. These assumptions are that there are no sources on the network, other than the primary substation, and reverse power is indicative of a faulted or dropped feeder. DG provides a source of power and short-circuit capacity (inverters are possible exceptions) on the secondary system which can cause reverse power through a network transformer while its primary feeder is healthy and energized. If DG output exceeds the load on the network, all protectors may open and leave the network islanded.

The events which can cause undesired operation of network protectors include:

- Secondary loadflow patterns reversing power on one or more network transformer
- Sudden drop of load, leaving DG output in excess of local load demand.
- Faults on the transmission system or on another feeder.

Secondary Grid Loadflow Reversals

If DG output exceeds the demand of loads in close proximity to the DG's location on a secondary grid network, power flow through the nearest network transformers will be decreased. With greater DG output, the flow on some network transformers can be reversed, even though the total network demand is much greater than the DG output. This is because impedance from the DG back to the primary substation via paths through nearby network transformers may be less than the impedance across the secondary grid to remote loads.

Reversal of power will cause the network protectors to open. As long as only a few protectors are open and the DG continues to operate, this may not present an immediate problem. However, as load and DG output fluctuates, the network protectors may cycle frequently, leading to accelerated wear of the interrupting contacts and actuating mechanism. Operation with some protectors open decreases network security. Tripping of the DG, or loss of additional feeders can leave a portion of the network inadequately supported by the network transformers in service. In the time from DG tripping until the open protectors close in response, network voltages can sag and cable limiters (fuses) might also blow.

Sudden Load Drop

It is clearly undesirable to allow a DG to export more power than the demand at any given time on a grid or spot network. DG output would normally be restricted to a fraction of the minimum expected load. Minimum instantaneous load, however, can be much less than the minimum planned or estimated load. A large load, or a facility's secondary feeder serving substantial load, may trip, leaving a connected load demand less than the DG output. Also, a voltage disturbance such as a transmission fault may cause contactor dropout on large motors constituting a significant portion of the load. The consequences of network power demand dropping below DG output are serious because all network protectors can open, leaving the network islanded from the primary system. Most likely, the DG will not have the control functions enabled to successfully operate in the islanded mode within voltage and frequency limits. The DG will trip, leaving the secondary network outaged. Thus, the most reliable of all distribution system types is rendered unreliable due to a single contingency.

Even if the DG were to maintain stable operation of the islanded network, eventful failure of the network protectors can result. This is because the network protectors are typically neither designed or rated for isolating asynchronous systems. With the network islanded, the phase angle of the network will drift with respect to the primary system. Eventually, the primary system will lead the secondary phase angle by the amount required to initiate protector reclosing. If the relative phase angle is fixed or moving very slowly, the protectors may close and resynchronize the network with the primary system uneventfully. However, if the relative angles are changing more rapidly, the protector may reclose out of phase. This happens when the protector control senses the correct phase angle for closing and triggers the main contact mechanism to close. At this point, the reclosing is sealed in and will not stop or reverse if the relative phase angle changes. With a fast moving relative phase angle, the contacts may close at a time when the systems are out of phase. Very large currents can flow, well in excess of protector rating. The protector, if does not fail on the first out-of-phase reclose, may reopen and the process may continue several more times, increasing the risk of failure. This scenario, involving a DG, is believed to have resulted in a serious failure in the Midwest several years ago, leading to a vault explosion and fire when the network protector failed.

Power Reversal Due to External System Events

Load dropping is not the only plausible scenario for the islanding of a secondary network having DG connected. As illustrated in Figure 4-13, a fault on the transmission system or on an adjacent feeder can result in short-circuit contribution from the DG via all of the network transformers. If the real component of the fault contribution exceeds the net demand on the network (which may be reduced due to the low voltage during the fault), then it is possible for all network protectors to operate. As explained above, this is likely to lead to outage of the network or to network protector failure, as a result of an incident which would not have otherwise compromised the security of the network. This scenario requires that the DG have significant short-circuit capacity; an attribute of synchronous generators and to a lesser extent, induction generators. Most inverters do not have the short-circuit capacity to cause power reversal due to external faults.

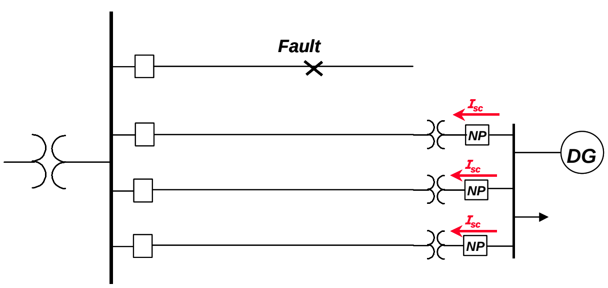


Figure 4-13: Simultaneous reverse power flow through all the spot network's protectors due to DG contribution to an adjacent feeder fault

Another scenario is power reversal due to utility system dynamic angle swings. Transmission system faults, and other events such as major generating unit tripping, triggers swings in the power system frequency and phase angle. A DG connected to a secondary network must necessarily follow these swings to maintain synchronism. For a reasonably designed inverter, tracking of these swings will normally be accomplished without significant change in DG power output. A synchronous generator, however, tracks the swings by speeding up and slowing down its mechanical inertia. As the system frequency advances, a component of power flows from the system into the machine (this may or may not be greater than the machine power output; thus the generator's power may potentially reverse). As the system frequency decreases, extra power flows out of the machine. This additional power can potentially cause the generator output to transiently exceed the local load and cause the network protectors to all trip.

Accommodating DG on Secondary Networks

It is possible to safely interconnect DG onto a secondary network without significantly compromising network security. However, the application needs to be carefully studied and designed on an individual basis. The study should include:

- Network flow patterns, and the possibility of network protector cycling
- Comparison of DG rating and maximum power output to the minimum network load, including load under unusual or contingency situations.
- Short-circuit flow into external faults.
- Stability studies, if needed to confirm that power swings will not cause the network to become isolated

The settings of network protectors may also be adjusted to avoid operation for low-magnitude, transient power reversals. The instantaneous setting of the protector relay can be set to a reverse power level higher than the DG can produce, and the time setting have longer delays at lower pickup. This may be accomplished in many cases without compromising the network protector function of quickly operating for feeder faults, and slower operation for a dropped feeder.

In general, inverter-interfaced DG will be much easier to integrate due to the lack of significant short-circuit contribution, no mechanical inertia, and the capability of shutting off an inverter nearly instantly without the delays of switchgear operation. One innovative, but complex, approach is to monitor power flow at each network protector, and either trip the inverter, or modulate its output, so that power reversal does not occur. This technique could only be accomplished with an inverter DG because the delays in changing the output, or switching out, a rotating generator are too long to avoid operation of the network protector relay.

4.2.6 Inadvertent Islanding

The possibility of a DG sustaining energization of some portion of a system, while that subsystem is disconnected from the remainder of the utility system, is a major concern to the utility industry. In practice, such occurrences would tend to be rare, but the potential implications are great.

Necessary Conditions

Opening of an upstream circuit breaker, recloser, sectionalizer, fuse, or other switching device is necessary to create an island which might be sustained by DG. In most cases, operation of these devices is triggered by a fault in the system. The current draft of P1547, and most other interconnection standards, require a DG to trip for a fault on the feeder to which it is connected. Thus, most of the time, the fault causing the interrupting device to operate will also remove the DG. This will not always be the case, however. Below are described a number of different ways that the switchgear might isolate a subsystem without the DG being tripped:

- The DG relaying may not be as sensitive as the feeder relaying. The DG relaying may not be as sophisticated at utility relaying (e.g., it may not have arcing fault detection as is now used in some digital feeder relays), or the relatively light short-circuit contribution of the DG compared to the system may make feeder fault detection by the DG extremely difficult to coordinate. In the case of inverter DG, which does not have a short-circuit current contribution, conventional overcurrent or impedance relaying is not effective. Undervoltage relaying is necessary to detect faults, which is not selective. To avoid excessive nuisance tripping, the DG operator may set the relaying with too little sensitivity to detect all faults detectable by the feeder overcurrent relaying.
- A single-phase fault occurs downstream of a three-phase breaker or recloser, and a single-phase DG is connected to the unfaulted phase and does not see the fault.
- A utility interrupting device trips before the DG detects the fault. This still leaves the DG connected to the fault. However, the DG fault current contribution will normally be much smaller than from the utility substation. The fault current may become small enough for a fault arc to spontaneously clear without the DG detecting the fault.

In addition to circuit interruption in response to a fault, a feeder or a portion of a feeder circuit can become islanded due to manual switching, broken conductor, or a fuse sneakout.

For a DG to sustain an islanded subsystem, the real and reactive power output of the DG must match the demand of that subsystem, at the time that the event occurs. Note that the relevant demand is not necessarily that of the entire feeder, but is the demand downstream of the interrupting device which isolates the subsystem. In other words, for a DG located downstream of a recloser, the DG power should be compared with the minimum load connected to the system downstream of that recloser.

To provide the reactive power equilibrium necessary for an islanded subsystem to persist, shunt capacitors are generally needed. This is because DGs are most often run at, or near, unity power factor, and most loads have a significant reactive power demand. Because the subsystem also has resistance and inductance components in the load, as well as the shunt capacitance, many equate the islanded system to a resonant circuit. When inductive and capacitance reactance are equal at fundamental frequency, i.e., real and reactive power are in equilibrium, the parallel R-L-C circuit resonates at fundamental frequency. In reality, however, loads are not as simple as a parallel resistance and inductance. Loads have a significant motor content, and motors have inertias and other parameters affecting their tendency to stay at the same frequency and voltage.

Exact real and reactive power equilibrium on a subsystem is improbable. If there is a mismatch, the subsystem voltage and frequency will go outside of the normal range, and cause the DG to be tripped on over- or under-frequency or voltage protections. The amount of time required for voltage or frequency excursion to trip the DG is a function of the mismatch, parameters of the circuit, as well as the trip points used. Without active voltage and frequency regulation controls providing stabilization, an island is very unlikely to remain in continuous operation for long. However, it may persist long enough to create the problems described later.

Normally, a DG connected with the utility system is not operated with voltage regulation or frequency governor control functions. If an island should occur, these regulation functions in the DG may correct for the initial power imbalance, and stabilize the island before the voltage or frequency reaches a trip point. Thus, inadvertent DG islanding is made much more possible by such control functions, and there use should be carefully evaluated unless the DG maximum capacity is considerably smaller than the minimum load on the subsystem with which it can potentially become isolated.

Consequences of Inadvertent Islanding

Inadvertent islanding of a portion of the utility system, energized by DG, can have a number of undesirable consequences, including the following:

- Islanding results in a part of the power system being energized out of the control of the utility. The utility remains responsible to the public for safety, yet the utility cannot deenergize the subsystem or control its voltage, frequency, or power quality.
- Maintenance and restoration can be impeded by a DG keeping a subsystem energized after the subsystem is dropped. Safety grounds should not be applied to a line testing hot, and considerable time can be lost in locating the source of energization and isolating it.
- The greatest area of concern is circuit reclosing. Automatic circuit reclosing is used by most utilities to improve system reliability. If DG keeps the system downstream of a recloser or reclosing circuit breaker energized, the subsystem is likely to slip out of phase with the main system. Reclosing out of phase is widely understood to be potentially damaging to the DG. However, it can also cause widespread nuisance outages and damage of utility and customer equipment as well. These potential consequences of out-of-phase reclosing are described in the box on this page.

Active Anti-Islanding Schemes

If real and reactive power generation by DG and load demand are precisely balanced in a subsystem, it is theoretically possible for an inadvertent island to run on forever. To avoid this possibility, and to also accelerate the tripping of DG when the load and generation are less precisely balanced, a number of active anti-islanding schemes have been developed. In general, these schemes seek to destabilize the island.

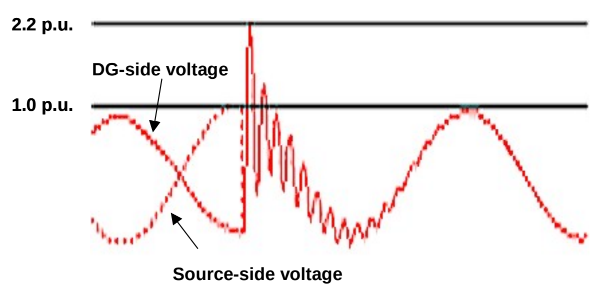
One approach varies the DG prime mover power output in a programmed, open loop manner, and looks to see if the local frequency changes significantly. A system of this type can be difficult to apply and coordinate if there are multiple DGs on a subsystem, each making their own variations. Also, excessive modulation of the DG can cause system problems such as flicker even when an island does not exist.

Other approaches use a positive feedback scheme to accelerate any perturbations from the equilibrium condition, with the intent of driving an islanded system quickly to the voltage or frequency protection setpoints. Two such schemes, intended for use in inverter-interfaced DG, have been described in a widely-

Will reclosing on an island harm the utility system?

It is well understood that reclosing on an out-of-phase islanded system, that is supported by a rotating generator, may damage the generator. However, it is not widely recognized that out-of-phase reclosing can also harm the utility equipment, and other customers' equipment. The potential harm and disruption can come about in the following ways:

- ***Transient Overvoltages** – Severe overvoltages can occur if the utility system recloses into the DG-supported subsystem when the two are at voltage peaks, and are near 180° out of phase. For example, the utility may be at +1 p.u. at this instant, while the island is at –1 p.u. After reclosing, the voltage on the island has to make a two per-unit jump. Because the capacitance and inductance in the circuit make a resonant system. The voltage will overshoot the new value and oscillate. Ideally, the phase-neutral voltage can reach 3 p.u.. The damping of circuit resistance and loads, however, will reduce the peak overvoltage some. Shown below are the island and utility voltages for a simulation of such an event. The overvoltage transients are much longer in duration than lightning overvoltages, and there is substantial risk that surge arresters and customer equipment may be destroyed.*



- ***High Inrush Currents** – Out-of-phase reclose also can result in magnetic and motor inrush currents much higher than normal energization. This inrush will occur simultaneously for all operating transformers and motors connected to the island. As a result, fuses may blow and customer circuit breakers may operate, causing outages.*
- ***Transient Electromechanical Torques** – The jump in voltage phase caused by an out-of-phase reclose will cause motors to also jump in their angular position. This applies large mechanical torques on the motor and their mechanical loads. Damage is possible, particularly for large motors.*

circulated report issued by the Sandia National Laboratory. These schemes, which can be used separately or in conjunction with each other, are referred to as the Sandia Voltage Shift and the Sandia Frequency Shift schemes. The voltage shift scheme looks at changes in the voltage magnitude. If the voltage is increasing, the DG current output is increased. In an islanded system where the load is resistive, the increased current drives the voltage higher. Likewise, the frequency shift scheme senses frequency changes and advances the phase angle of the DG output current for frequency increases, and retards the angle for frequency decreases. In an islanded system, this will tend further increase the frequency deviation. Implicit to these schemes is the assumption that, if the DG is not islanded, the strength of the system is such that these changes do not continue. If the DG is islanded, the deviation quickly accelerates to the trip point. One concern with this type of scheme is that it may create a destabilizing effect to the entire power grid if DG with this type of scheme has widespread system penetration.

Coordination with Reclosing

As described previously, it is essential that a DG cease to energize the system prior to reclosing of any upstream switchgear, unless it can be expected that the voltage phase angle will not drift sufficiently during the open time for an out-of-phase condition to develop.

The "cease to energize" requirement has different practical implications for the different types of DG. For a synchronous generator, this means circuit interruption, usually with mechanical switchgear taking a number of cycles to open. (Static switching could be used, but this is very expensive and lossy.) For an inverter, cessation of energization can be accomplished by ceasing to gate the inverter thyristors or transistors, which is nearly instantaneous.

Utility reclosing delays can vary from "instantaneous" to minutes. Instantaneous, in this context, means no intentional delay. Breaker or recloser operating times make the fastest reclose times approximately 200 milliseconds (twelve cycles). Where short or instantaneous reclosing delays are used, the potential for reclosing into an energized island is increased. The probability is also very much a function of the load on the subsystem downstream of the reclosing device, relative to the rating and output of all the DGs together. Where the aggregate DG rating is a substantial fraction of the minimum subsystem load, it may not be sufficient to rely on collapse of the subsystem voltage due to power mismatch in order to coordinate with reclosing. This is more likely to be an issue where most or all of the DG is composed of synchronous generators, which have inertia, short-circuit capacity, and are generally tripped off with mechanical switchgear requiring many cycles to operate. Even where the DG uses inverters with active anti-islanding techniques, coordination with instantaneous reclosing can also be unreliable.

Where this a risk of DG maintaining an energized subsystem throughout the shortest reclosing cycle, other measures may need to be taken. Suitable measures include:

- Increased reclosing delay, which may also decrease power quality for customers on the circuit.
- Voltage-supervised reclose, where reclosing is blocked if there is voltage on the downstream side of the switching device. This will require installation of a potential transformer where the recloser control can be adapted, and is not practical to implement on older electromechanical reclosers.
- Transfer trip of the DG. This requires a communication link between the switchgear and the DG. Where a feeder can be reconfigured, the trip signal may need to be communicated from several different switchgears.

5. IMPACT OF DG ON SYSTEM RELIABILITY

Enhancement of reliability is widely claimed by DG proponents as a significant benefit compared to conventional centralized generation. On the surface, it would appear that generating power close to the load would inherently provide greater reliability. This, however, glosses over the complexities of an interconnected power system and may be a greatly overstated claim in the present context. The pivotal issues are:

- Can the DGs be relied upon to be supporting the system under the critical conditions?
- Do interconnection requirements which force the DGs to trip generate system problems?
- Will the dynamic characteristics of DG integrate with the power system so that the system will remain stable through disturbances?

At low levels of penetration, DG is not likely to adversely affect system reliability, but it also will do little to support the system, either. At higher levels of penetration, the system behavior of DG can adversely affect reliability. Whether the net impact of DG on system reliability is positive or negative depends on how the DG is interconnected, controlled, and protected. Current interconnection requirements, such as the present draft of P1547 and most state requirements, do not address the DG performance requirements necessary for DG to provide system reliability benefit.

5.1 Power Reliability for the Facility with DG

DG can provide a substantial increase in power reliability if it is a suitable backup source. Not all DG has this functional capability, however. The DG must be capable of operating independently from the utility system, and carrying a customer's full load or a critical subset of the load. Even where the DG rating is greater than the load, the DG may not be a suitable backup source because of one or more of the following:

- Some inverters, such as load commutated inverters, and induction generators are not capable of operating without an external source of short-circuit capacity. These inverters and induction generators are incapable of off-grid operation. Most other DG types, including voltage-source inverters and synchronous generators, require a shift in control mode to operate independent of the utility system. If the appropriate controls are not provided, a DG will not be an appropriate backup source.
- Most loads have short-duration high-current transients due to motor starting, etc. If a DG cannot handle these transients without excessive voltage dip or frequency changes, it may not be a suitable backup source. Loads may also have other characteristics incompatible with a particular DG design, such as phase imbalance or harmonic load current distortion.
- If a DG cannot supply much short-circuit current, the customer facility's circuit protection may not be effective or coordinated.

Where a DG is sufficiently rated and capable of carrying the load, it will allow the customer to avoid extended interruptions due to outage of the utility service. However, the customer will usually not be able to avoid momentary outages or deep voltage sags during utility faults. In the event of a utility-side fault, the DG remains connected until switchgear operates to isolate the load and DG from the system. Mechanical switchgear is normally used, requiring a number of cycles to operate. The DG will not generally be able to hold up the facility voltage while connected to the faulted utility system; and if it was, the large short circuit current contribution from the DG into the fault would probably be unacceptable. As a result, facility voltage will sag until separation takes place. If static switches were used instead of mechanical breakers, the voltage sag could be limited to a sub-cycle duration, but such switches are very expensive and consume considerable operating losses. When a facility is separated from the faulted system, the voltage will recover. However, there will be simultaneous inrush to all of the operating motors, transformers, and electronic power supplies. If the DG is not capable of withstanding this inrush, it may be necessary to trip a portion of the facility load and restore the loads more gradually.

5.2 DG Benefits to System Reliability

Customer outages are due to inadequate generating capacity, or failures or inadequacy of the power delivery system. In a typical distribution system, the vast majority of customer outages are due to distribution system problems. On a non-looped radial feeder, outage of a feeder section results in an outage for all downstream customers. DG on the system will not restore service to any customers, except for perhaps the customers having DGs within their facilities, unless the DGs have the capacity and appropriate controls to independently power the system downstream of the outaged section. This would be an intentional island, and the DGs must have the regulating capabilities necessary to maintain adequate voltage and frequency. Where multiple DGs are within the island, there must be means to achieve load sharing. Simply installing DG according to the standard interconnection requirements will not achieve this goal. Careful study, engineering, and coordination is necessary to make such an islanding scheme work.

Most distribution outages are caused by faults and equipment failures other than overloads. However, a relatively small subset of distribution outages are the result of loading or lack of capacity. In these situations, the offset of load demand by DG output may eliminate the root cause of some distribution outages.

On a looped distribution system, the system can be reconfigured to restore customer service during a feeder outage. Feeder loading, however, can limit reconfiguration options. By offsetting a portion of feeder loading, it may be possible to pick up a larger portion of an outaged feeder from the alternate source. Thus, DG can contribute positively to system reliability in this circumstance.

At the substation and transmission level, loading and capacity problems play a larger role in outages because there are usually multiple power paths. Outage of an element may not cause any customer service outages, unless the remaining system elements cannot handle the resulting load flow. Vulnerability of the bulk transmission system to dynamic and transient stability related problems is generally increased with transmission system loading. Reduction of net load served by the transmission system, due to DG production local to the load, inherently provides a transmission system reliability benefit.

Inadequate generating capacity is very rarely the cause of customer outages. When undercapacity occurs, however, it can have very widespread impact. The rolling blackouts in California in 2001 were a recent, and severe, example of outages due to power supply inadequacy. Because DG represents additional generation capacity resource, the DG impact is inherently positive on this aspect of reliability. Over time in the de-regulated power market, however, increased DG capacity will inherently mean less central generation will be built and the system will become reliant on the DG capacity. While production of power by a large number of smaller generation sources is statistically more reliable from a unit outage analysis standpoint, there may be other factors which will differentiate DG from utility-owned, or independent power producer owned, large central generation reliability. For example, the DG will probably not be under the same degree of control from system operators as large market players which can be dispatched to serve anticipated load.

5.3 Potential Adverse Impacts of DG on Reliability

There is considerable uncertainty whether widespread DG penetration will prove to be a net benefit to system reliability. The presence of DG can potentially cause or expand outages. Current interconnection standards are focused on avoiding DG contribution to faults and support of undesired system islands. Measures intended to meet these goals make it likely that widespread DG tripping may occur during system events, leaving the system with less support.

5.3.1 Adverse Distribution System Reliability Impacts

Listed below are a partial list of the potential negative impacts of DG penetration on distribution system reliability:

- **Slowed system restoration**. According to some interpretations, OSHA rules require lockout of all sources of energization prior to dead-line work. If there are DGs connected to an outaged system, crews might need to visit each DG location and lockout the interconnection prior to beginning line work. The alternative is to perform the work with hot-line practices, which also will slow restoration efforts.
- **Nuisance outages**. As described in the previous section of this report, short-circuit current contribution from DG can lead to nuisance fuse blowing or sectionalizer operation.
- **DG over-tripping**. Interconnection rules, such as the current draft of P1547 and most state interconnection rules, require that DG trip for distribution system faults. Also, tripping is required for voltages and frequencies outside of a defined time-magnitude range. It is extremely difficult to coordinate DG relays such that it trips for all faults on the circuit to which it is connected, but not for faults elsewhere in the system. As a result, it should be considered likely that all DG on a feeder may trip for a severe fault on an adjacent feeder, or even for a transmission system fault. If the DG penetration is significant, the sudden simultaneous loss of the DG can lead

DG Voltage Trip Requirements per P1547 (Draft 7)

Voltage	Time to Clear
V < 50%	0.16 s
50% ≤ V < 88%	2.0 s
110% ≤ V < 120%	1.0 s
V ≥ 120%	0.16 s

to severe voltage and current deviations. In severe cases, this can lead to voltage collapse and outages. This is illustrated by simulation results in Figure 5-1.

- **Network system outage**. Previously in this report, it was described how DG interconnected to a secondary network can cause all network protectors to open, isolating the network from the primary system. Because the DG is not likely to be able to support the network load, such isolation events may result in outage of the network. This reliability impact is particularly profound, as network outages are otherwise very unlikely.

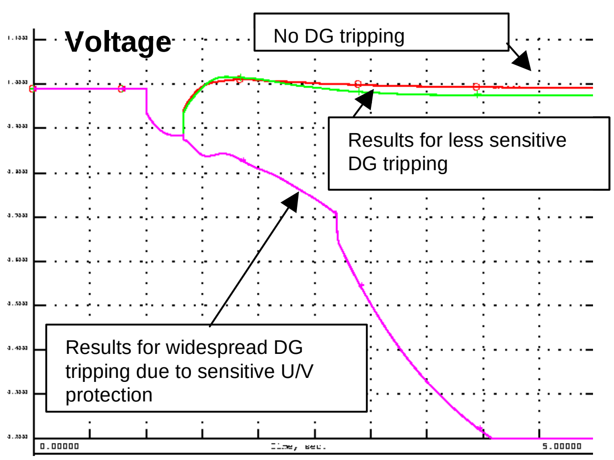


Figure 5-1: Simulation of post-fault dynamic voltage behavior in a distribution system with DG capacity equal to 45% of load. Comparison of DG trip sensitivities.

5.3.2 Adverse Bulk System Reliability Impacts

Large-scale penetration of DG across the bulk power system will affect system steady-state and dynamic behavior. Generally, DG will be near the load and will decrease transmission system loading. In systems constrained by steady-state considerations, such as thermal loading or voltage limitations, the DG will tend to improve system performance. Decreased transmission system loading, due to the DG output, will also benefit system stability. However, certain DG characteristics can create an adverse impact on the bulk system.

The DG characteristics most likely to have an adverse impact on bulk system stability are those which have been intentionally added to the DG for the purpose of islanding protection. These characteristics are:

1. Sensitive over- and under-voltage and over- and under-frequency trip points explicitly required by most interconnection standards (including the current drafts of P1547, and most state requirements), and
2. Active positive-feedback destabilization schemes used in many DG implementations to accelerate voltage and frequency in an inadvertently-islanded distribution system to the trip points.

Trip Sensitivity

The tendency for DG to trip for system voltage deviations can aggravate bulk power system disturbances. Transmission faults, which themselves initiate power swings in the system, can also depress distribution-level voltages over a wide area. The fault voltage dip can potentially result in widespread, simultaneous DG tripping. In addition to the undervoltage caused by the fault initiating a dynamic event, the voltage swings following the fault can also result in DG tripping. The tripping of the DGs removes a power resource near to the load, and thus will increase transmission system loading at a most inopportune time. If the DG penetration is significant throughout the system, the bulk system disturbance can be aggravate the system dynamic oscillations.

Figure 5-2 shows results from a simulation of the western U.S. transmission system interconnection, including addition of DG capacity equal to 20% of the peak load. The DG is assumed to be distributed over the entire system at all load buses. A severe fault is simulated at a weak point in the system, resulting in a severe dynamic disturbance. Three different voltage results are shown: one with no DG tripping, one with DG tripping when the local voltage reaches 75%, and one tripping when the local voltage reaches 90%. (Note: the interconnection standards specify the voltage level for which DGs must trip, but do not indicate where they can trip. Thus, the 90% voltage trip scenario is extreme, but plausible.) For the simulation where the DG tripping is most sensitive, system instability results. In this case, a major blackout of the entire U.S. west of the Rockies could hypothetically result in a future scenario of moderate DG penetration and excessive trip sensitivity.

In each of the three system interconnection in the U.S., frequency is very tightly regulated, and very rarely deviates outside of the range of 60.00 ±0.03 Hz. Larger frequency deviations at a DG are usually a very good indication, therefore, of local system islanding. However, major bulk system events can infrequently cause frequency deviations outside of this range. An underfrequency is the result of inadequate generation compared to load demand, and a breakup of the bulk interconnection can leave a region short of generation. Tripping of DGs in a system during such an underfrequency will only compound the generation shortage. As a result, this aspect of DG anti-islanding protection can result in an increased risk of complete system blackout during severe bulk system capacity/demand imbalance events.

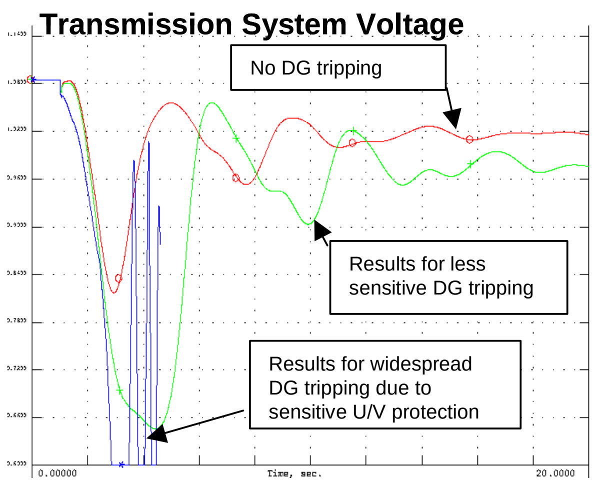


Figure 5-2: Simulation of a transmission disturbance aggravated by DG trip sensitivity. System instability occurs for the most sensitive tripping.

Positive Feedback Island Destabilization Schemes

Active anti-islanding functions seek to destabilize an unintended distribution system island. Although tremendously large, each of the three U.S. system interconnections is an island. If the future brings widespread proliferation of DG with these positive-feedback schemes, there is concern that the DG may interact with the bulk grid to decrease its stability.

It should be noted that very little modulation of real and reactive power, as a function of frequency, can have a substantial influence on system oscillatory damping. Many large generating units have power system stabilizers, which modulate the generator excitation in response to frequency such that generator reactive output increases in phase with frequency. This is exactly opposite of the change in reactive power made by a DG using the Sandia Frequency Shift Scheme described earlier.

This question of DG interaction with bulk system stability, for potential widespread DG penetration, is presently being investigated by GE under contract with the U.S. Department of Energy via the National Renewable Energy Laboratory. The results of this research will be openly provided to the industry over the next two years.

6. TRENDS AND POSSIBLE FUTURES FOR DG

The present applications of DG are primarily focused on providing power to the facility where the DG is located. There is also present consideration of using DG, or aggregate groups of DG, as power sources participating in the open power markets now developing.

New business opportunities, changes in regulatory environment, national energy policy, technology advances, including technology advances in non-power system disciplines such as transportation and communication, will drive changes in engineering practice and power technologies. These changes may make DG attractive for new uses.

This section presents discussion of some emerging trends in DG - as they relate to possible changes in distribution system design, planning and operation.

6.2 DG for Distribution Support

In general, DG is operated at the will of its owner, to meet the owner's needs, and is not under the control of the distribution utility except for limitations set by the tariff or interconnection standards. While such DG may reduce the net distribution system loading much or most of the time, it may not always be prudent to base system planning on this reduced net loading. This is because the DG capacity may not always be available when needed.

If the DG is controlled by the utility or system operator, its power capacity and regulation capability may be used for the benefit of the system. The DG could be installed and owned by the utility, or could be independently and contracted to the utility for capacity and performance.

Firm-capacity DG can be an effective planning tool to reduce T&D system infrastructure requirements. This may an attractive option stopgap measure where there is inadequate transmission or substation capacity to feed an area, and system upgrades cannot be completed sufficiently fast. Usually, the system will need the DG capacity only during load peaks.

DG real and reactive power output, if controlled or coordinated by the utility, can also be used to improve system performance. Many of the voltage regulation issues discussed in Section 4 are the potential result of uncoordinated DG operation. If the DG control is worked into the feeder voltage regulation design, and the DG can be relied upon to provide the expected support, there is significant potential to improve system voltage regulation.

6.3 Microgrids

The evolution of present day power systems has resulted in large-scale networked grids with central station generation feeding largely passive distribution systems. Economies of scale in many aspects of power generation and distribution have driven this evolution. The possible emergence of DG as significant factor in power systems of the future is, in a sense, a classic backswing of the pendulum, similar to that observed in many other disciplines (for example, as noted with regard to personal computing in the introduction).

One of the technical realities that brought distribution system practice to its present form is that high speed communication and computation has been expensive. Expensive to the degree that widespread use has limited to applications where relatively large amounts of power handling are needed to justify sophisticated active communication and control. Bulk power system operation, via energy management centers (e.g. pools or RTOs), rely on a network of communication and control that functionally parallels the bulk power system. Transmission, substations and central station generation are tied together: a central nervous system communicating with a brain, controlling a body --- down to the hands, but not the fingers.

The ever decreasing cost of communication bandwidth and computing firepower present an opportunity take better advantage of some of the potential benefits of DG, while reducing some of the disadvantages.

'Microgrid' is a recently coined term describing small autonomous (or semi-autonomous) power systems with their own distributed load and generation. In many regards this concept is nothing new: industrial customers with self generation and small isolated communities have always had such systems.

What is different today, is that microgrids are most often discussed in the context of the (possible) evolution of a conventional distribution system with embedded DGs. Microgrid may refer to a system that is, or is not, synchronously connected to the host (bulk power system) grid.

Many of the operational and reliability disadvantages outlined in Sections 4 and 5 relate to fact that individual DGs are unaware of the state, and therefore the requirements, of the power system beyond information that can be locally measured. Concerns about avoiding inadvertent islanding (section 4.4.6, 4.6, 5.7), system restoration, and voltage regulation are all primarily due to the fact that the system and the DGs are mutually unaware of each other.

The addition of a layer of communication and (appropriate) control to a distribution system with multiple loads and DGs could alleviate many of these problems (call out). Such a communications and control system could perform a range of function required to make the microgrid viable, e.g.:

- Provide the DGs with voltage regulation set points that meet the requirements of the entire subsystem
- Inform the DGs when an island has occurred, with several possible responses, including: (1) trip, (2) regulate voltage and frequency to sustain the islanded microgrid
- Coordinate the DG dispatch and possibly loads, such that contractually set level of power exchange with the host grid is maintained
- Allow safe resynchronization and recloser operation by controlling DGs to minimize angular separation across substation circuit breakers, and reclosers, and other switches
- Facilitate restoration of service, by coordinating cold load pickup and DG startup

There could be economic benefits for all the stakeholders, including the distribution service provider. Consider one possible scenario illustrated in Figure 6-1:

For this scenario, suppose that the distribution system in the figure has a substation capable of serving a peak of 20 MW load. If the peak load were projected to grow above that level, today the distribution service provider would be obliged to invest to increase the capability of the substation. This would be the case, regardless of whether the presence of DG imbedded in the system, since the DGs could not be 'counted on' to be on-line at the peak. However, with a microgrid, the DGs and the loads become active participants in the system operation. The DGs and loads would be controlled (and contractually obliged) so as to limit the substation load to 20 MW or less. The distribution service provider realizes a saving in capital expenditure. The individual DGs (and loads) may

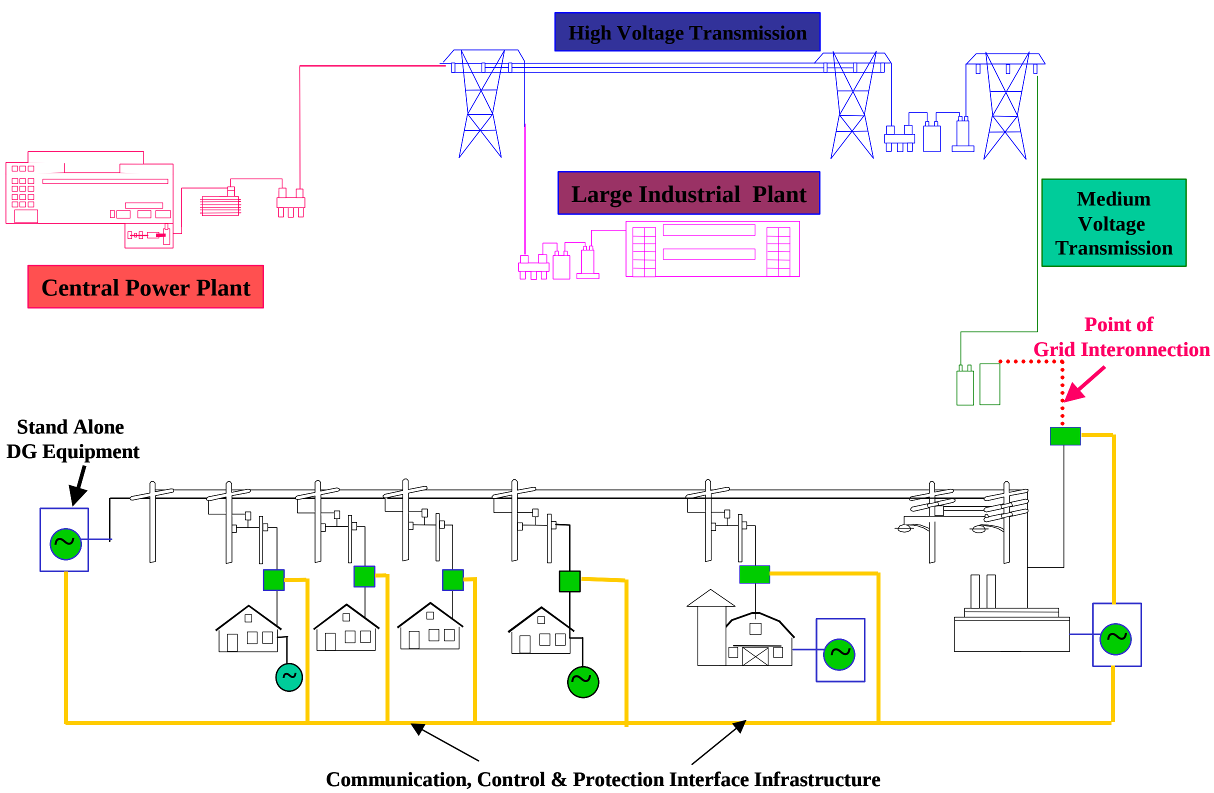


Figure 6-1: Conceptual scheme of a microgrid.

realize significant economic benefits by selling power (reducing demand) at times of peak demand – i.e. responding to the actual locational market pricing rather than the market distorting behavior that accompanies net metering. Total capital invested in the system (distribution, DG and load infrastructure) all become responsive to market and performance requirements. The control and communication infrastructure would be a revenue generating service provided to the participating DGs and loads. This could be a service provided by the distribution service provider.

Microgrids provide a possible future by which traditional wires companies might avoid some of the worst aspects of DG: i.e. carrying all the infrastructure cost and reliability responsibility while realizing none of the revenues. At best they present an economic means of providing service, minimizing capital expenditures and providing better reliability

It is tempting to dismiss this concept as too complex and too expensive, but who would have guessed, even a few years ago, that the internet and cell phones could get this cheap, this fast. These are not particularly challenging communication or computation problems.

One technology issue that needs to be addressed is fault detection and clearing for very low short circuit current level systems. Conventional overcurrent based schemes will be inadequate if micrograms are dominated by inverter based DGs. Some researchers have suggested that intelligent ground current and unbalance detection schemes may be the answer to this challenge. It is clear at the moment, that there is no obvious and simple solution to this challenge.

The economics, technology and engineering practice for micrograms are not quite there yet, and like all such possibilities, may come to nothing. But micrograms do pass a first sanity test.

6.4 Integrated Energy Systems

The evolution of electric power infrastructure has to be viewed in the broader context of total energy requirements (and policy). The development of DG is being paralleled by development of other distributed technologies related to energy. These technologies have the potential to significantly impact advances in DG. The following are brief discussions of some key technology developments and why they may impact DG in the future.

6.4.1 Integrating Electrical and Thermal Demand

Presently, distributed generation is often applied where waste heat is recovered for heating or cooling purposes. The conventional approach for CHP and CCHP has been to size the generation for the thernal demand, thus dictating the electrical capacity. An emerging trend is to consider the total electrical and thernal requirements for a facility, and then perform an optimal design to meet both the thermal and electrical needs at the least cost using DG and waste heat, non-power generating furnaces and boilers, grid power, and even storage of electrical or thermal energy.

6.4.2 Chillers and Cold Storage.

As noted earlier, the overall efficiency of DG can be greatly improved with systems that utilize the waste heat from generation. Many applications have much stronger needs for cooling than heating. Yet the combined cooling heating power (CCHP) systems discussed above are relatively complex, expensive and inefficient. There is a great deal of research being directed at improving chiller technology to address these limitations. Another approach is cold storage. This is already done using refrigeration run by power purchased from the grid at night. Use of integrated DG/cold storage systems have the potential provide load leveling and better DG asset utilization benefits. This approach is receiving considerable attention.

6.4.3 Electric Storage

Electric energy storage, can offset some of the disadvantages of non-dispatchable sources. Conventional techniques, including electro-chemical (lead acid, NaS, etc.) batteries, magnetic (SMES), and mechanical (compressed air, pumped hydro), are in various stages of development, from mature to prototype. The economics of all the proven technologies is very rarely attractive for distributed applications. Research on most of these techniques continues. One technology that seems to hold particular promise are so-called 'flow batteries'. Flow batteries (sometimes called reversal fuel cells) use an electrolyte that can be pumped through structure similar to the fuel cell shown in Figure 3-3. Like a battery, the process is reversible, but like a fuel cell the 'fuel' (electrolyte) can be stored separately, in either state. This means that *energy* capability of the battery can be scaled up very inexpensively. This means that batteries of many hours or even days of capacity might (possibly) be economically achievable. Such economies are extremely unlikely in more conventional chemical batteries. And unlike pumped hydro and compressed air, these batteries could be located at or near the loads. If this technology successfully matures, the potential impacts on distribution systems as part of DR are huge.

7. CONCLUSIONS

The future of DG is not clear. The electric power industry may presently be experiencing the beginnings of a new age where distributed generation replaces centralized large-scale generation and long-distance transmission. Or, the current interest in DG may be a fleeting response to the proliferation of DG hype. Most likely, both DG and central generation and transmission systems will both play significant roles in the future. The final reality will be governed by economics; economics affected by regulations and government policy as well as the costs of fuel and generation equipment. Presently, DG is economically favorable only in niche applications. It will move to the mainstream only if its capital and operating costs decrease, or if centralized generation becomes relatively more expensive, unobtainable (due to plant siting issues) or undeliverable because transmission capacity cannot be installed.

7.1 DG Integration

Interconnection of DG to distribution systems is inconsistent with the fundamental assumptions made in the design of most systems. While DG interconnection introduces a range of operating, power quality, protection, and even safety issues, it is not acceptable to simply prohibit all such interconnections. Distribution utilities must, from a political and regulatory standpoint, make a legitimate effort to accommodate these interconnections. Only in the most exceptional cases can a utility be justified in prohibiting a specific interconnection plan, such as if the DG is simply far too large compared to the capacity and short-circuit strength of the intended interconnection point. Utilities need fair, and efficiently executed, policies for evaluating DG interconnections and consistently specifying technical and commercial interconnection requirements.

The proposed IEEE Standard P1547 provides the beginnings of a uniform interconnection requirement. This standard is likely to be adopted by many state regulatory agencies, and thus be mandatory. However, P1547 provides “necessary” but not always “sufficient” requirements. The purpose statement in this standard indicates that the requirements of P1547 are “sufficient for most installations”, but in a footnote further qualifies this with a statement that additional requirements may be necessary for some limited situations. Thus, there will be the need for utilities or local regulatory authorities to determine when standard interconnection requirements are sufficient, and when additional requirements are necessary. In general, additional requirements will be needed for significant DG penetration due to either the given DG to be interconnected, or the combined effect of all DG on a system or subsystem.

Technical issues discussed in this report are almost all dependent on DG penetration. Many issues do not arise at all, or are completely insignificant, with very low penetration levels. Very low DG penetration, or no penetration at all, is the present case on the vast majority of all distribution feeders today. Only in exceptional cases have the penetration levels risen to where significant system issues present themselves. This is why many issues have been speculated in engineering studies, but not yet observed in practice. However, the current trajectory of DG installations and the projects of accelerated growth of this industry segment indicate the technically significant penetrations are expected to be much more common in the near future. It is prudent for utilities to establish practices and policies now which will accommodate the situations expected in the not-too-distant future.

7.2 Future Integrated Systems

The full value of DG to a utility system cannot be realized with the current approach to DG integration. Because of concerns of DG continuing to supply an unintended island, most current interconnection requirements (including P1547) require a DG to be removed for almost any system disturbance. Thus, the DG capacity may not be useful as a system resource from the standpoint of transmission and distribution system capacity planning.

DG can, however, be a resource which reduces system infrastructure requirements if it can be guaranteed to be present when needed. Partly, this is a commercial issue which can be addressed in interconnection contracts. It is also a technical issue, as the conflicting requirement of ensuring that the DG does not support an unintended island and the requirement for continued system support during and following disturbances need to be both resolved.

A DG which is controlled autonomously, and only considering the needs of the local facility, may not contribute positively to the security and performance of the distribution system. Integrating the DG control with the power system control and protection offers substantial benefits to the distribution system in terms of demand reduction, voltage support, and improved protection along with providing the DG owner with a system much less vulnerable to spurious trips, and possible economic rewards for ancillary services (e.g., voltage support) provided to the system.