Distributed Renewable Energy Generation Impacts on Microgrid Operation and Reliability

Technical Report

Distributed Renewable Energy Generation Impacts on Microgrid Operation and Reliability

1004045

Interim Report, February 2002

EPRI Project Manager
T. Peterson

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Science and Technical Consulting

ORDERING INFORMATION

Requests for copies of this report should be directed to EPRI Orders and Conferences, 1355 Willow Way, Suite 278, Concord, CA 94520, (800) 313-3774, press 2 or internally, x5379 (925) 609-9169 (925) 609-1310 (fax).

CITATIONS

This report was prepared by

Science and Technical Consulting
4659 Los Gatos Ct.
Santa Rosa, CA 95403

Principal Investigator
B. Fies

This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Distributed Renewable Energy Generation Impacts on Microgrid Operation and Reliability:
EPRI, Palo Alto, CA: 2002. 1004045.

REPORT SUMMARY

Microgrids incorporating distributed generation, and particularly those incorporating renewable energy technologies, have the potential to improve electric power system efficiency and reliability while providing novel benefits to their owners, operators, and the system as a whole. This report focuses on the impact of renewable energy technologies on microgrids and on the larger question of the impact of distributed generation and microgrids on the electric power system.

Background

Distributed generation (DG) refers broadly to the use of on-site generators that can operate independently of a central-station power plant. DG may be owned by either a consumer or supplier of electricity and can operate either independently or interconnected with the grid. In the context of this report, renewable energy technologies can be considered a subset of DG fueled by renewable energy sources such as solar, wind, hydro, or biomass power. Microgrids extend the DG concept to encompass several DG resources linked together in an industrial park, commercial complex, residential neighborhood, or university campus. A microgrid would most often generate enough electricity to meet its own internal demand, though most microgrid concepts also call for connection to a utility for backup power. Interconnecting DG within the microgrid and interconnecting the microgrid to the utility grid ("macrogrid") are the major technical and regulatory challenges addressed in this report.

Objectives

- To summarize the current state of EPRI and industry understanding of the microgrid concept, related interconnection issues, regulatory requirements and standards, and modeling techniques useful in assessing the impact of distributed generators on the grid
- To provide insight into the impacts of solar, wind, biomass, small hydro power and other renewable energy generation technologies on the operation, reliability, power quality, environmental emissions, and economics of microgrid systems
- To identify barriers to implementing renewable DG in microgrids and recommend avenues for future research.

Approach

The project team integrated several recent reports and studies completed by EPRI and others to provide a broad understanding of relevant topics, progress, and challenges. Based on this survey of the field as it exists today, the team drew conclusions and recommended future courses of action that will help facilitate the use and acceptance of DG and microgrids.

Results

The report introduces the microgrid concept and summarizes its potential applications and properties, including capacity and reliability. It discusses general interconnection issues including concerns about system safety, stability and security, the functional requirements of DG, and communication and control protocols and standards. The report addresses relevant regulations and standards at the local, state, and federal levels in addition to the potential benefits of device certification procedures. System modeling is discussed as an important tool to simulate the impacts of DG devices; guidelines are included for choosing and applying simulation tools along with the results of three EPRI case studies that employed those tools. The report describes related environmental issues such as siting, emissions and controls, and the impacts of renewable technologies. It also touches on economic issues such as policy and tariff provisions and provides a case study outlining the potential economic feasibility of a microgrid project on the East Coast. Finally, the report suggests several areas for future action and research.

EPRI Perspective

Advances in renewable and other DG technologies plus restructuring of the electric utility industry are creating new needs and opportunities for solutions such as DG and microgrids. When effectively integrated into an electric power system, DG can be used to provide energy, capacity, power quality, and various ancillary services such as voltage regulation and emergency power supply. This report provides an introduction to the potential benefits and roadblocks to implementing DG and microgrid projects. It also points out the need for continued collective effort and education on the part of all stakeholders—manufacturers, equipment owners, utilities, regulators, customers—to develop new policies and better engineering tools for DG integration

Keywords

Microgrid
Distributed generation
Renewables
Interconnection

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

Distributed generation (DG) systems are commonly viewed as relatively small electricity generators scattered throughout a grid or as discrete remote systems operating independently of the grid. They include renewable energy technologies such as solar photovoltaics (PV), wind, biomass, and small hydroelectric in addition to more common DG units fueled by diesel or natural gas. Owners and operators benefit from the reliability, power quality, modularity, flexibility, security, economic, and environmental benefits that DG provides.

Local, state, and federal policies increasingly allow and even encourage interconnecting DG with the grid. Net metering programs in many states allow DG owners to feed short-term excess power they generate to the grid—colloquially called “running the meter backward”—effectively permitting them to use the grid as a 100%-efficient (and free) storage battery. It is important to note that net metering policies vary greatly among jurisdictions and that most do not allow customers to “sell” electricity back to the utility—that is, to receive payment should they generate more power than they consume. Some programs may offer payment or credit at rates less than the retail price, such as the avoided cost rate. Net metering is best understood as a cost-free method for storing energy that must be consumed within a relatively short time, typically on the order of one month.

The maturing “microgrid” concept may offer new applications and advantages to DG owners and operators. For example, one might envision a microgrid as a residential neighborhood, business park, or commercial district encompassing several on-site distributed generators networked together and interconnected to the grid at a single distribution-level point (Figure 1-1). Microgrids have the potential to improve the reliability of power delivery while reducing the cost of maintaining the wider power system.

A microgrid is electrically isolatable from the utility macrogrid and would often have sufficient cumulative capacity to meet the needs of those within in, although most microgrid concepts also specify a utility backup. Some microgrids could operate as full-time islands, while others could operate as part of the macrogrid during normal operation and only separate into an island during service interruptions. A microgrid could incorporate several different types of on-site generators—PV, wind, diesel, natural gas-fueled microturbines, fuel cells—whose output would need to be coordinated.

Microgrids pose several challenges to infrastructures built around existing distribution control and protection practices. Microgrid control structures would require frequency and voltage regulation as well as protection equipment at each generator and at the point of grid interconnect. A microgrid would need protocols for blackstart and system restoration following disruptions, and would likely demand a high degree of sophisticated automation. Microgrids incorporating significant amounts of intermittent generation—for example, a PV-equipped neighborhood whose net output varies substantially due to sun angle or transient cloud cover—pose additional challenges.

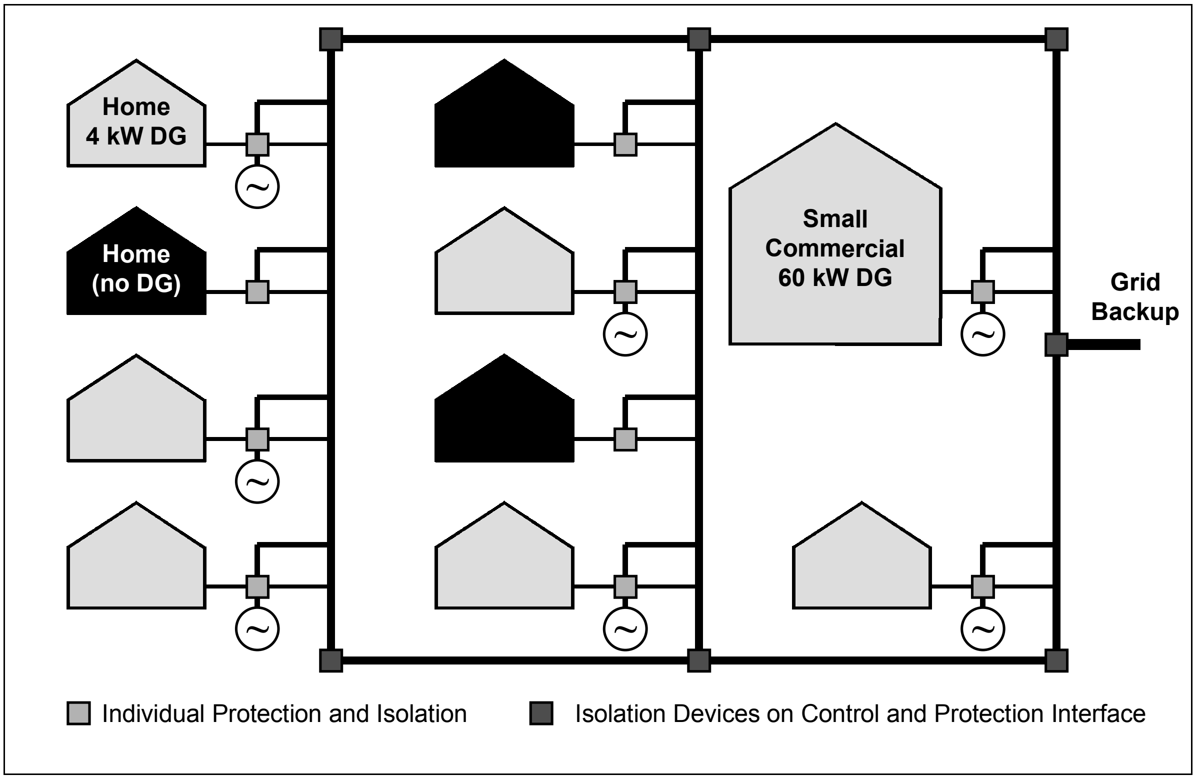

Figure 1-1
Schematic of a Simple Microgrid System

Purpose of This Report

This report summarizes the current state of EPRI and industry understanding of the microgrid concept, related interconnection issues, the status of regulatory requirements and standards, and modeling techniques useful in assessing the impact of distributed generators on the grid. Where possible, it provides insight into the impacts of solar, wind, biomass, small hydro power and other renewable energy generation technologies on the operation, reliability, power quality, environmental emissions, and economics of microgrid systems. Finally, the report attempts to identify barriers to implementing renewable DG in microgrids and recommend avenues for future research.

A brief note on terminology: throughout this report, the term "macrogrid" is used to refer to the greater electric power system—usually referred to simply as "the grid." "Macrogrid" is used to clarify the distinction between a microgrid and the larger grid with which it may interconnect.

2 THE MICROGRID CONCEPT

A typical microgrid would comprise a cluster of generators and loads capable of operating in a coordinated fashion autonomously or semi-autonomously from the macrogrid. It could also include energy storage devices. The cluster would most likely exist within a small, dense group of contiguous geographic sites, although its components could be dispersed and share electrical energy through a distribution network.

Generators and loads within a microgrid would be placed and coordinated to minimize the cost of serving electric (and, if combined heat and power (CHP) systems are employed, heat) demand given prevailing market conditions, while continuing to operate safely and maintaining power balance and quality. This pattern of power generation and consumption is distinctly different from existing power systems in that the sources and sinks within a microgrid can be maintained in a balanced and stable state without active external control or support.

The heart of the microgrid concept is the notion of a controllable interface between the microgrid and the macrogrid. This interface can separate the two sides electrically, but would connect them economically. Within the microgrid, the conditions and quality of service would be determined by its component customers, while flows across the dividing line would be motivated by the prevailing valuation of energy and other services available on either side at any instant. In its simplest form, the interface could be a simple barrier that permits the microgrid to island itself and resynchronize with the macrogrid as desired. It would allow the microgrid to appear to the larger macrogrid as a “good citizen”—that is, the microgrid would performs as a legitimate, well-behaved generator operating under grid rules.

Traditional power system planning and operation hinges on the assumption that the selection, deployment, and financing of generating assets is tightly coupled to changing requirements and that it rests in the hands of a centralized authority. The ongoing regulatory restructuring of the electric industry is one step in the evolution (or abandonment) of the centralized paradigm; the emergence of microgrids could represent a second step. Microgrids will develop their own independent operational standards and expansion plans that will significantly affect the overall growth of the power system, yet they will develop in accordance with their own independent needs and incentives.

One organization taking the lead in developing the microgrid concept is the Consortium for Electric Reliability Technology Solutions (CERTS), which is funded by the U.S. Department of Energy and managed by Lawrence Berkeley National Laboratory (LBNL). CERTS works to resolve technical barriers to the widespread adoption of distributed energy resources, particularly those barriers that individual equipment vendors are unlikely to tackle themselves. The consortium anticipates that improvements in small-scale generating technology, limits on continued expansion of the existing power system, the potential to apply CHP technologies that provide new services while improving efficiency, and improved customer control over service and reliability will help make DG microgrids competitive with central station generation.

Capacity and Reliability

Microgrid capacity and reliability are typically calculated probabilistically. It is generally not necessary for *each* power consumer within a microgrid to generate sufficient electricity to meet all of its individual energy needs. Rather, the microgrid *as a whole* must have sufficient capacity to meet the needs of those users likely to be drawing electricity at any given time. This concept of "load diversity" guarantees that the maximum power demand of a group of electric customers is always less than the sum of customer-specific peak demand. Load diversity can be expressed mathematically as the "coincidence factor," or the ratio of maximum coincident total power demand for a group of customers to the sum of the peak power demand of each customer in that group. As shown by the coincidence factor curve (Figure 2-1), as the number of microgrid customers increases, the *average* amount of electricity each customer must contribute to the system decreases.

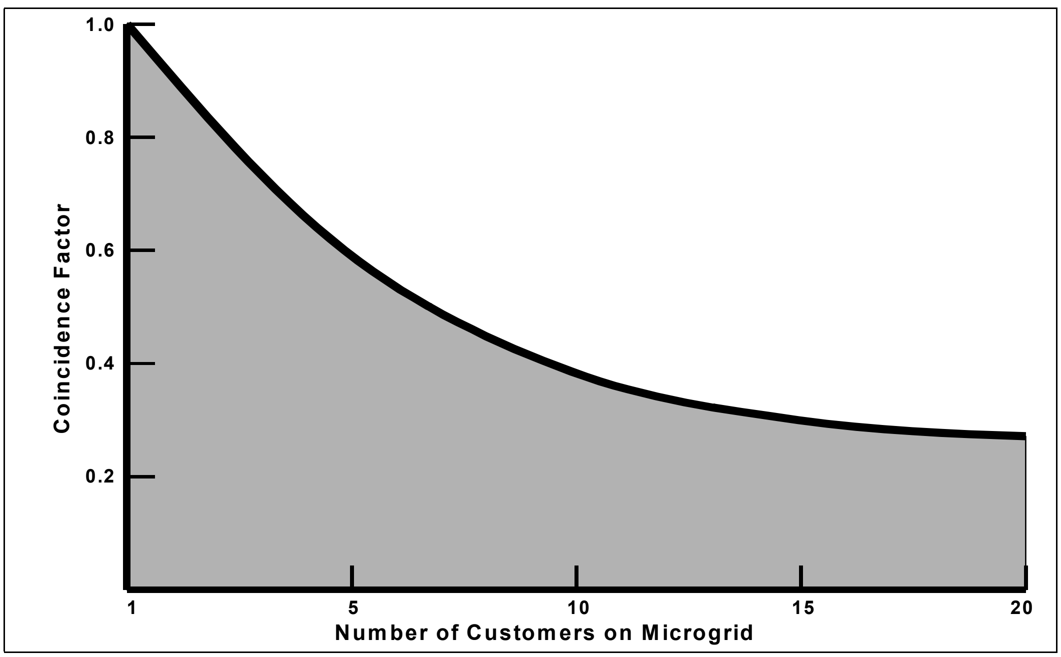

Figure 2-1
Coincidence Factor Curve

For example, the sample coincidence factor curve above indicates that, while 20 homes with a peak demand of 15 kW would ordinarily require a total generating capacity of 300 kW, when linked in a microgrid system the total demand of the same 20 homes could be satisfied by approximately one-third that amount, or 100 kW. Reliability might be ensured by calculating a rate at which equipment outages are likely to occur and determining an adequate reserve margin. System operators might provide for a reserve margin sufficient to cover the loss of two generators in the event that one breaks down unexpectedly while another is undergoing maintenance.

Potential Benefits

Distributed generation in general offers many advantages for both individual customers and electric power system operators. For customers, DG can result in lower costs, improved reliability, and the opportunity to satisfy on-site thermal energy requirements using CHP systems. For the macrogrid, DG can allow postponement of costly T&D system upgrades, better local voltage control and overall power quality, more reliable service, reduced transmission losses, and less congestion via peak load shaving.

Microgrids share these advantages and could prove useful in commercial, industrial, or residential settings. They are often discussed in the context of premium power parks, in which highly reliable, high-quality electric power would be generated for a high-tech manufacturing or data processing center for whom even a brief interruption or fluctuation in power could prove very expensive (Table 2-1). However, a microgrid could just as easily consist of a large housing complex, residential neighborhood, or university campus equipped with PV, wind, and other on-site generating technologies.

Table 2-1
Costs of Power Outages to Key Industries

Industry	Average Hourly Cost of Downtime
Cellular Communications	$41,000
Telephone Ticket Sales	$72,000
Airline Reservations	$90,000
Credit Card Operations	$2,580,000
Brokerage Operations	$6,480,000

Source: U.S. DOE, “Distributed Energy Resources”

Potential benefits of microgrids include improved power quality, reliability, security, and economic flexibility. In some circumstances, a microgrid could cost less than existing service because it would not be burdened with the cost of the external T&D system maintenance and upgrades. Modern advanced DG technologies, and particularly renewable energy technologies, generally have fewer emissions and less environmental impact than their central station counterparts (although the issue of *proximity* to atmospheric emissions, noise, and visual impact may be significant—a relatively clean and quiet electric generator next door may prove less attractive than a dirtier, noisier power plant in a remote location).

It is evident that for a microgrid to operate as intended, a diverse array of generation technologies would tend to prevent over-reliance on a particular resource or fuel supply. The benefits of, for example, having natural gas-fueled microturbines or fuel cells available to provide power on days when sun or wind are absent—or, conversely, to have renewable technologies available when fossil fuel prices may be undesirably high—are obvious. As the performance and economics of renewable technologies improves, their value in microgrid applications will increase. However, the question of what types, mixes, or amounts of distributed generation technologies might best meet the needs of different types of microgrid customers does not appear to have been studied to date.

3
GENERAL INTERCONNECTION ISSUES

The task of integrating distributed generation into a microgrid or large electric power system is a key challenge that raises many complex technical, safety, and policy issues. Utilities wish to ensure the safety of the public and their own personnel, protect equipment, meet customer power quality needs throughout their service territory, and maintain system stability. Besides safe operation, DG owners and operators want a minimum of interconnection engineering, simple approval procedures, maximum flexibility of use, and protection for their generator. Figure 3-1 depicts a typical parallel interconnection configuration between a distributed generator, the load it serves, and the electric power system.

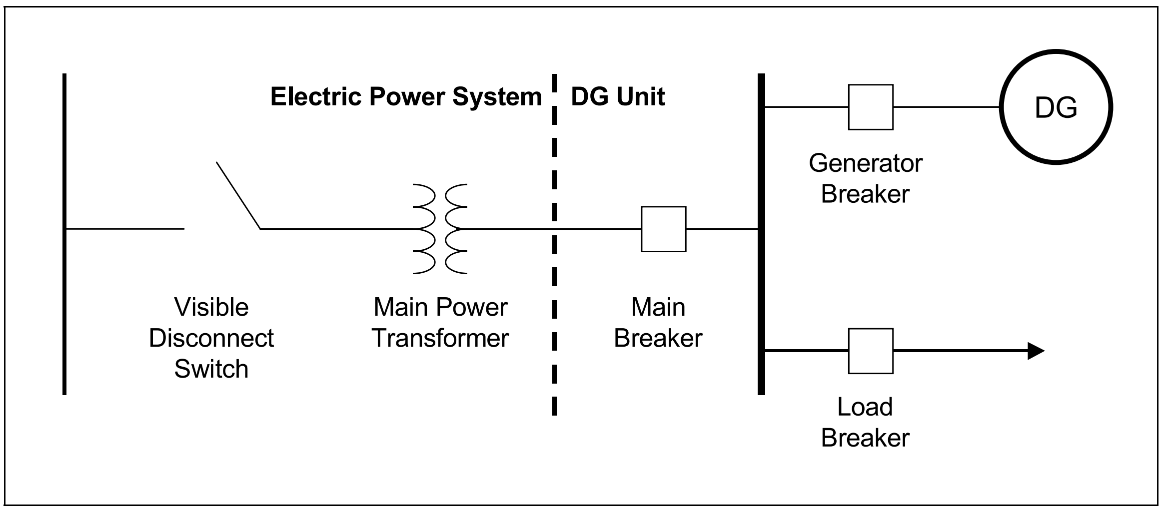

Figure 3-1
One-line Diagram of Typical Parallel Interconnection

Historically, these desires have often conflicted. Some DG owners charge that energy companies impose onerous and unnecessary testing, certification, and hardware requirements. Some energy companies fear DG is a loose cannon introducing uncertainties and imperiling their commitment to delivering reliable, high-quality power. In recent years, however, energy industry restructuring, technological advances, and new focus among policymakers are powering progress on several fronts. In most states, power markets are more accessible than they have ever been. State and federally sponsored rebates and tax breaks support the cost of distributed renewable energy technologies. Net metering programs in many states allow DG owners to feed short-term excess power they generate to the grid. At the same time, new certifications and procedures are codifying interconnection standards that at one time varied from state to state, utility to utility, sometimes even block to block. Interconnection remains a work in progress.

Interconnection Concerns

This section discusses the most common impacts of DG, including renewable energy technologies when applicable. Those impacts are: unintentional islanding, changes in radial feeder power flow, reverse power flow in distribution networks, loss of effective voltage regulation, ferroresonance voltage swings, harmonic injection and distortions, voltage fluctuation and flicker, and overcurrent-protective device coordination.

Unintentional Islanding

Unintentional islanding is perhaps the most significant and commonly raised concern with respect to microgrids and DG, primarily because it can endanger the safety of line workers and the public. Islanding is a situation in which DG and a portion of the utility system operate separately from the rest of the system. Some microgrids may be designed to operate as independent *intentional* islands. Unless that is the case, however, it is critical to include anti-islanding provisions in any DG system interface package.

When islanding occurs, a portion of the system becomes separated from the main system. The system operator no longer controls the frequency or voltage in that section. Because most DG devices are not configured to regulate voltage on the feeder, it is unlikely that adequate voltage would be maintained throughout the islanded section. Islanding may damage utility equipment and cause delays in restoring service because an island will typically drift out of phase with utility system voltage, and key switches and breakers may not be able to be reclosed until the island is first de-energized. Otherwise, if the main system is reconnected out-of-phase to the island, it may damage the DG unit, customer loads, and utility switchgear as well as instigating significant power quality disturbances for upstream customers. An unintentional island may also prevent the clearing of fault currents, leading to reliability degradation and possible conductor burn-outs.

A critical problem with unintentional islanding is the potential danger it creates. Line crews working on a section of line they believe to be de-energized may unexpectedly encounter line voltage and could be electrocuted. Similar danger extends to the public in situations with downed conductors or other live wires within reach that would have normally been de-energized by upstream utility switchgear had an island not developed.

Unintentional islanding can occur with synchronous generators, induction generators, or inverters. The main criterion enabling islanding is that real-time power generation roughly matches the real-time power requirements of a system. An island is therefore more likely to be created and sustained when generators have built-in real and reactive power control, which is the case with synchronous generators and some self-commutated inverters (induction generators and line-commutated inverters require an external source of excitation and do not have reactive power control. See Chapter 5 for a more detailed discussion of generator types and how they apply to renewable and other DG technologies.)

The most common way to prevent unintentional islanding is to use voltage and frequency relays on DG units, set to trip whenever voltage or frequency migrate outside a selected window. This form of islanding protection is called “passive” protection, and prevents islanding in most cases.

When a section of the distribution system and DG units separate from the rest of the system, the output of the DG unit will not match the power demand within the separated area, resulting in voltage and frequency changes that cause the relays to trip in a very short time. Relays might typically be set to a tight frequency range of ±1 Hz or less, while voltage would be allowed more latitude (±5 to 10%) to account for typical voltage regulation excursions on the feeder.

Changes in Radial Feeder Power Flows

Distributed generation can have a significant impact on power flows that occur on the transmission and distribution system. The degree of this impact will depend on many factors, including the size of the DG units, their location on the T&D system, the existing load and configuration on the system, and the time at which DG units are operated.

A common technical myth regarding DG is that it poses no real threat to system protection or voltage regulation as long as power flow is not reversed on the line. This is not true. DG can cause interaction problems with utility system equipment even in situations in which power flow on a feeder has only been reduced by DG, not completely reversed. For example, a distributed generator could confuse a line-drop-compensation controller by making it appear that the load is reduced on a given line section, resulting in lower-than-normal line voltage.

When DG output is sufficient to reverse the power flow on a feeder, the scope and severity of problems increase. On radial circuits, DG capacity large enough to create reverse power is also more likely to interact with under-frequency load-shedding schemes at substations. One example is a case in which there is sufficient DG penetration on a distribution circuit so that a fault on the transmission system momentarily de-energizes the transmission feed. In this case, the DG continues to island long enough to trip under-frequency relays in the substation, creating a sustained interruption for potentially thousands of customers who would have otherwise experienced only a momentary interruption.

Large penetration levels of DG will also increase the severity of cold-load pickup, which occurs after an extended outage causes the load to lose diversity. After an extended outage all electric water heaters, air conditioners, refrigerators, motors, and other appliances will cycle on simultaneously. Because of this loss of diversity, both inrush and full-load currents could be two to three times higher after the outage than before. If DG were supporting the pre-outage load and remained off-line post-outage—since most DG responds to loss of system voltage by shutting down until after normal voltage has been restored—those distributed generators may not be available to help support the feeder loading at the substation when it is needed.

Reverse Power Flow in Distribution Networks

Low-voltage secondary networks are distribution systems that are used in most major cities and would typically be used within a microgrid as well. The secondary network operates at customer voltage and is ganged together in a grid rather than the normal radial system. Several primary distribution circuits, such as 12.47-kV circuits, feed a secondary network. If any of the primary circuits fail, others will carry the load without causing an outage for any customers. To isolate failed circuits, secondary networks have network protectors between the primary and secondary network that will open when there is reverse power flow through them.

DG can cause unique problems on a secondary network. For example, if the DG is relatively large, reverse power flow through network transformers on low-voltage networks will trip protectors, leading to an outage (Figure 3-2). Also, when the network protector recloses, there is potential for significant damage under some conditions. Under light load, a DG unit may cause all of the network protectors that are feeding the load to trip, thereby creating an island. The network protector will try to close back in to the network. If this happens and the systems are no longer synchronized, the network protector can fail and cause significant damage.

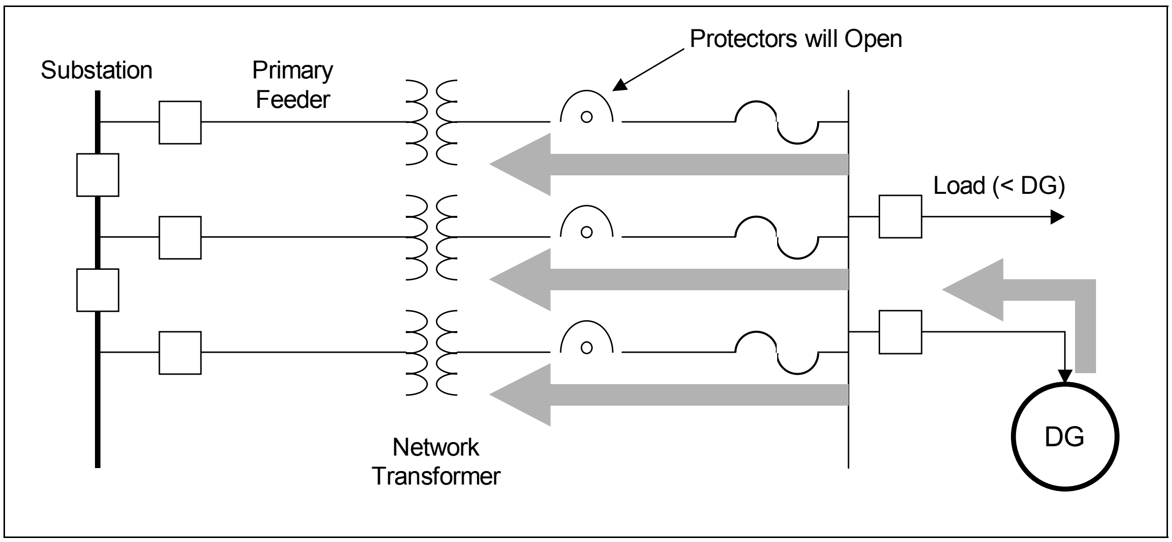

Figure 3-2
Low-Voltage Spot Network Compromised by DG (gray arrows indicate reverse power flow)

Loss of Effective Voltage Regulation

DG can influence the voltage regulation of electric power systems. It affects the flow of power on the distribution system and therefore changes voltage drops occurring across impedances in the system. Voltage levels at various points on the feeder also change. Whether these changes are significant, beneficial, or problematic depends on a number of factors. Typical critical considerations are the size of the DG relative to the power system at the point of application, the way in which the DG is operated and controlled, and the nature of upstream voltage regulation equipment.

The interaction of DG with regulating equipment provides another potential impact on voltage regulation. If a DG unit has varying output (as with PV or wind), it may change the system voltage or current flows enough to cause a regulator tap change or an operation of a switched capacitor. Likewise, a distributed generator that has feedback to control voltage may interact negatively with utility regulation equipment. Undesirable cycling of regulation devices and noticeable power quality problems may result.

Ferroresonance Voltage Swings

Ferroresonance is an uncommon, abnormal condition known to cause damaging system overvoltages. It is a special form of resonance that involves the magnetizing reactance of a transformer and the system capacitance. DG can cause a special type of ferroresonance during islanding conditions. It can occur with both induction and synchronous generators. According to transient simulations, this type of ferroresonance may cause arrester failures.

Harmonic Injection and Distortions

Several types of distributed generators can inject significant harmonics into the system. They may also serve as a system sink for harmonics. System harmonic currents flowing into DG may cause overheating of transformers, secondary neutrals, or in the generator. The level of system harmonics that flow into a generator is important since it affects harmonic limits. Harmonic limits for current do not differentiate based on the current's origin.

Voltage Fluctuation and Flicker

Light flicker is due to rapidly changing loads and generation that cause fluctuation in secondary voltage. Even a small change in voltage can cause noticeable lamp flicker. The degree of customer irritation depends on the frequency as well as the magnitude of the fluctuations. Most people will notice voltage changes of 1% and smaller that occur in the range of 1 to 33 changes per second (60 to 2,000 per minute). The greatest sensitivity occurs around 15 changes per second (900 per minute), which is equivalent to a frequency of 7 to 8 Hz.

Flicker prediction and measurement can be challenging. Several types of DG can cause flicker, including:

- Photovoltaics—changing solar incidence levels will cause power output fluctuations that, at their fastest, generally happen over 4 to 10 seconds.

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

- Induction Generators—If an induction generator does not have self-starting capability, starting an induction generator has the same impact as starting an induction motor: large inrush currents averaging about 5 times full-load current are drawn from the system. When the generator is large compared to the system (as might be the case in a microgrid, or even with a large DG interconnected with the macrogrid), system voltage will sag for several cycles during starting. This can result in objectionable light flicker.

- Internal Combustion Engines—The output of an internal combustion engine can change rapidly if it is misfiring. This can happen if the engine is operating on low-grade fuel, landfill gas, or an improper tune-up.

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

Overcurrent-protective Device Coordination

Deploying DG on an electric power system will influence the operation of various overcurrent-protective devices. Some common typical impacts resulting from the integration of DG include nuisance fuse blowing, false tripping operations by upstream breakers, recloser, sectionalizers, or fuses, failure of sectionalizers to operate when they should because DG keeps a line energized, and desensitization of breakers and reclosers due to unplanned DG currents.

Fuse/breaker coordination for faults downstream of a fuse can be affected if the fault current passing through the fuse is changed significantly by the addition of DG units on the distribution system. This occurs if fuses are coordinated with an upstream circuit breaker in a fuse-saving practice, in which the objective is for an upstream breaker to clear a fault prior to damage or melting of a fuse. When using the instantaneous trip setting, it takes 5 to 6 cycles for the upstream breaker to clear a fault. Therefore, the fuse is sized so that its maximum melt time is longer than 6 cycles, plus a margin. If the fault current increases due to the presence of DG, a fuse’s minimum melt time may be significantly shorter than 6 cycles and it will no longer coordinate with the circuit breaker.

The impact of DG on fault currents can be significant. A synchronous generator would typically inject 4 to 8 times its rated output current for 5 to 7 cycles during a fault. This drops off to approximately 2 to 5 times the rated current after 60 to 120 cycles into the event. Since a fuse operates within the first few cycles of an event, these decaying fault levels must be taken into account. If DG raises the level of fault current, affected fuses may no longer coordinate with the main feeder circuit breaker.

DG may also impact automatic sectionalizers. Many energy companies use automatic sectionalizers to isolate faulted sections of distribution circuits. They work by detecting fault current downstream of their location. When a fault is detected, they wait for a circuit breaker upstream of their location to de-energize the line, after which the sectionalizer contacts open. When the upstream breaker recloses, the sectionalizer will have removed the faulted section of the line from the circuit.

Distributed generators placed downstream of a sectionalizer may interfere with its operation by keeping the line energized longer than expected. Large DG units located downstream of a sectionalizer and feeding faults upstream of its location may also confuse a device’s protection logic. In this case, a sectionalizer operates on the indication that the faulted section of the line is downstream. DG must be coordinated with upstream sectionalizers to avoid such conditions.

Another coordination impact is possible when a very large generator near a substation causes sympathetic tripping of the feeder or line reclosers on its circuit, which happens when a fault occurs on adjacent feeders serviced by the same substation. The large local generator feeds the adjacent feeder's fault with sufficiently high current to activate the instantaneous overcurrent-protective device on the unfaulted feeder, triggering the sympathetic trip. This condition can be prevented by the addition of directional overcurrent relays or by adjusting standard overcurrent relays at the substation.

Functional Requirements of DG Interconnection

Most interconnection requirements stem from fundamental issues related to providing a compatible interface. These include safety, reliability, quality, and potentially damaging interactions. Some requirements originate with distribution system operators and take the form of interconnect agreements, permits, or public service commission rulings. Industry standards, such as those promulgated or being developed by IEEE, may be adopted in whole or in part through such rulings. Other requirements may be imposed by local inspection authorities fulfilling their obligation to protect the public and comply with building and electric codes.

The five basic functions that follow—electrical isolation via power transformer, controlled connection and disconnection, a visible and secure disconnect, short-circuit protection, and surge protection—are common to most interconnection policies or agreements.

Electrical Isolation

Grounding compatibility is required for safe and effective interconnection. This normally translates into a requirement for transformer electrical isolation and specific transformer winding configurations. Most connection standards do not specifically require an isolation transformer. However, in practice, it is often the most cost-effective way to get the job done. The cost of a dedicated interconnection transformer is relatively high, and its necessity may be debated for small or inverter-connected DG. IEEE Standard 929, which applies to inverter-connected PV, has been carefully worded to avoid requiring a dedicated transformer.

Controlled Connection, Disconnection, Paralleling

Controlled connection and disconnection is another functional requirement seen as key to meeting several operating criteria. Controlled connection is needed to synchronize and operate in parallel with the utility system. It is also needed to reconnect after a protective trip, usually with some time delay once normal voltage conditions have been restored. Controlled disconnection is needed to respond to abnormal conditions on the power line, such as loss of generation or unintentional islanding.

The cost of controlled connection and disconnection systems can be relatively high for small DG systems. Significant savings can be realized when inverters are used to make the connection. For example, when a DG unit is connected via electronic inverters, a DG system can cease to energize the grid or microgrid without actually disconnecting from it; a mechanical switch or contactor may not be required (although manual disconnect switches are commonly required by state or utility interconnection rules—see “Visible and Secure Disconnect” below). The fundamental challenge is to provide a means for system operators to verify the operation and setting of protection equipment.

Visible and Secure Disconnect

In most DG installations, local utilities—in compliance with the National Electric Safety Code (NESC), an accredited American National Standard developed and approved by IEEE—may require a manual disconnect switch. In fact, local inspection authorities, enforcing the National Electric Code (NEC), will likely require a disconnect switch even if the local utility does not. As described in NEC Article 705, such a device needs to be visible, accessible, and lockable by the system operator. Future standards and technological developments may make the disconnect switch a moot point. For example, advanced communications systems may allow system operators to control DG connection and disconnection remotely.

Short-circuit Protection

Short-circuit protection is required in all DG system types and does not generally add significant cost. If a DG unit is installed on the end-user side of the meter, NEC dictates short-circuit protection of the feeder or branch circuit that connects the generator. Specific requirements for emergency, standby, and grid-connected generators are provided in NEC Article 700. Normally, additional protection for internal generator faults will also be provided within the system in order to isolate a generator from damage.

For larger DG systems connected on the utility side of the meter, the NESC dictates that suitably rated short-circuit protection be installed. The short-circuit-current interrupting capability is usually determined by available short-circuit current at the point of common coupling. For ungrounded or impedance-grounded systems, ground-fault detection and the availability of qualified personnel are also normally required.

Surge Protection

The ability to withstand surges can be considered optional from the perspective of protecting a DG owner’s investment. However, utilities traditionally require an explicit and testable withstand capability for any protective system that may impact the larger electric power system. Immunity levels and test standards for protective relay equipment used in interconnection already exist.

Communication and Control

Communication between DG devices, equipment from the electric power system, and utility control centers may be needed to allow safe and efficient operation of the power system, particularly as DR penetration levels increase in the future. Accurate, real-time communication among DG equipment would be especially crucial within a microgrid, where the output of several DG devices and the load of several customers may need to be carefully coordinated. The general benefits of linking DG and other system equipment in a communication and control scheme include:

- Improved dispatch of DG to better match system demand.
- Better voltage regulation and control.
- Better use of DG to enhance reliability.
- More robust anti-islanding protection.
- Improved system stability and control, with less susceptibility to negative interactions between DG and the electric power system.
- Potential extension of open access market to DG units that choose to participate, plus better market signals to customer-owned DG.

Current Practices

Today, most small to mid-sized DG is not linked to a communication system, which has generally been required only for larger installations greater than 1 MW in size. However, most industry observers expect practices to change so that virtually every distributed resource will eventually be linked to a centralized or distributed control system. Such a communications infrastructure will be made possible by new technologies and may prove necessary for safe and successful DG operation in an environment in which very high DG penetration creates potential system interactions that cannot be solved by local autonomous control.

Communications technologies that energy companies currently use for control and operation of the power system include power line carriers, telephone-lease lines, twisted copper pairs, fiber optics, and radio-based techniques. These technologies have seen significant improvements in cost and performance in recent years. In addition, the widespread use of newer technologies such as wireless cellular and packet switching data networks, the Internet, and satellite technologies are creating substantial opportunities to improve both the use of DG and the power distribution system itself.

Utilities commonly employ system control and data acquisition (SCADA) procedures to the substation level. There is little command, control, and data acquisition carried out farther down to the feeder or customer level (although there are some notable exceptions such as feeder-level capacitor banks controlled by radio signals or remote meter-reading technologies).

The use of communications for feeder-level DG closely parallels the need for communications in distributed automation, which involves the control and monitoring of feeder devices such as line reclosers, voltage regulators, switches, capacitor banks, metering, and sensors. It is essentially SCADA accomplished at the customer level. With distributed automation it is possible to automatically perform functions such as load balancing, loss minimization, fault isolation, service restoration, and voltage support. The objectives of distributed automation are similar to the T&D support benefits often cited for DG, so the two areas enjoy some significant synergy.

Despite years of evaluation and several pilot projects, it remains unclear what the appropriate architecture for distributed automation systems at the feeder level should look like. Some believe that a distributed management and control hierarchy, in which each piece of feeder equipment has its own intelligence and is communicates with other system components while still functioning somewhat independently, is most appropriate. Others argue for a highly centralized control scheme in which feeder-level devices have little autonomy. Both approaches promise advantages and disadvantages. Research, development, and debate are continuing.

Data Collection and Control

The types of data collection and control functions that must be coordinated and executed determine the communication requirements of DG. The following areas emerge as key considerations:

- DR Unit Status and Telemetry—On/off status, output levels, alarm signals, breaker and switch positions, temperature data, protection status, voltage and current metering data, data log reports, availability status.
- Voice Communications—Between utility dispatch center and DG operator, requires minimal delay to achieve reasonable quality. Used to transmit verbal commands, check status, or conduct other activities that need a human interface on site.
- Slow Control Functions—Control functions requiring a slow response, including starting the unit, controlled slow shutdown of the unit, raising or lowering its output, and changing voltage regulation or power factor.
- Fast Control Functions—Functions requiring very fast responses on the order of less than 1 second, such as overcurrent protection, anti-islanding protection, and dynamic-response control. These are the most demanding communication requirements from the DG perspective of both reliability and response speed.
- Market Signals—These may be pricing signals sent by a utility to encourage independent units to operate at specific times and at specific power levels. Response times of several minutes or more would typically suffice.

The above areas encompass a wide performance range. For example, data collection may dictate the use of an Internet-based system that covers a broad geographic area, while other control functions may require high-speed point-to-point communication. Some approaches use dedicated links that a hard-wired between two devices, while others may involve networks with a meshed communication flow pattern allowing packets of information to traverse many possible paths. Another type of communication system involves broadcasting signals via radio or satellite to multiple control points simultaneously (Figure 3-3).

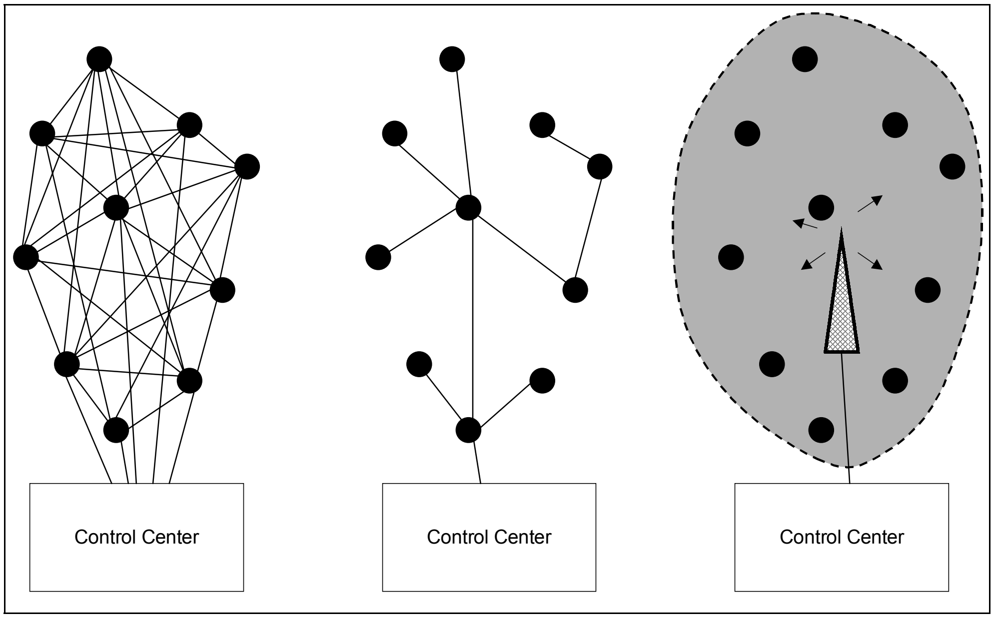

Figure 3-3
Examples of Communication Architectures: (left to right) a Packet Data Network Approach, a Radial Link Approach, and a Broadcast Approach.

Communication for Higher DG Penetration Levels

At higher DG penetration levels that might be experienced within a microgrid or incorporated into the macrogrid in the future, existing communication and control requirements may not be practical. While the impact of a single small rooftop PV system is insignificant, dozens of them in a microgrid or thousands of them in a city could pose complications. Impacts on power system stability, degradation of the reliability of DG anti-islanding algorithms, overcurrent-protection system interactions, and other factors may make it necessary to process system-control decisions from a central location such as a substation or at a utility central control center. A much more substantial communications infrastructure will be needed to support such control. Some of the additional functions that may be needed include frequency control, voltage and VAR control, damping of dynamic disturbances, improved anti-islanding control, DG phase and synchronization control, and DG control and dispatch for system support.

Key Characteristics of Communication Systems

The performance of a communication system is often defined in terms of its data rate, speed of propagation, reliability, security, and directional characteristics.

Data rate is the bits per second of information that can be transmitted over a communication channel, or its “baud rate.” It is important not to confuse data rate with command execution or data-propagation speed (see below). For example, Internet technologies can have very high data rates of well over a million bits per second, but the time required for information to propagate through a network may be delayed enough so that fast control functions that must be carried out within a few cycles are not possible. Baud rates vary from less than 100 bits/second for some carrier-carrier technologies up to many gigabits per second for fiber optic systems. Baud rates are analogous to bandwidth for analog systems.

The command or data-propagation speed is the rate at which a signal propagates through a communication system between two terminal points. For many purposes, the speed of light is nearly instantaneously fast, but a radio signal bounced off of a geostationary satellite can be delayed by as much as ¼ second, or about 15 cycles. For networks, the speed of signal propagation via wires is limited by its route through various servers, hubs, and other devices. The highest propagation speeds are obtained with direct point-to-point architecture: lease lines, direct fiber optic links, or microwave links.

The reliability of a communication system is essentially the likelihood that it will be available when needed. For critical control functions, 3 or 4 "nines" of reliability (that is, 99.9% or 99.99%) is desirable. However, estimates of reliability must also take into account the fact that a communication system could be disabled by the very phenomenon and at the very instant that it is most critically necessary—a lightning storm, for example. Communication channels that take paths different than the power lines they are used to protect or control are less likely to experience problems at the time of need.

Security is the ability of a system to avoid sending false information, such as a false trip signal. Factors that influence security include the type of data encryption and error correction employed, the communication medium itself (for example, its susceptibility to noise and electromagnetic interference), and cross checks used at the transmission and receiving points to verify message content.

Protocols and Standards

Standard communication protocols are need to ensure that various DG devices, power system equipment, and control centers can reliably communicate with each other. Common communications protocols used for SCADA applications today include DNP 3.0, IEC 870, and Modbus.

Utility Communications Architecture (UCA) 2.0, meant to be a future standard for inter-device communication, is being developed by EPRI, IEEE, and IEC. UCA meets the need for a standard, self-defining, object-oriented communication protocol. All major distribution automation and substation automation field devices are becoming compliant with the UCA standard as defined by IEEE UCA Technical Reports and by work in progress. The goal is to allow new DG devices to operate as "plug-and-play" components in an established, universal communication infrastructure.

While the UCA standard in progress is enjoying widespread support and adoption, a great deal of work is required before complete, standardized UCA DG object models can be implemented. Many stakeholders—including local distribution companies, independent system operators, manufacturers, regulators, DG operators and others—must cooperate and share resources to ensure the development of an inclusive communication scheme. The more stakeholders unite now to define a flexible communication infrastructure that best meets all their needs, the more costs can be shared and the system will be more robust and useful for all its participants.

4
REGULATORY REQUIREMENTS AND STANDARDS

More than 3,000 separate utilities are doing business in the United States today. Most have specific standards for customers who want to install their own power generation facilities. But many of those standards were designed for large (hundred-plus kilowatt) customer-owned and cogeneration systems. Compliance with such requirements may be both difficult and expensive for, say, an individual homeowner wanting to install a few-kilowatt PV system on a roof. In many cases, the cost of meeting local utility and permitting requirements can completely negate any savings that might be realized by a DG installation. Such disincentives have diminished in just the past few years, as utilities have better recognized the value of distributed generation on their systems, and regulators have in some cases required them to accommodate it.

Although the discussion that follows specifically concerns individual DG units interconnected with the utility grid, analogous issues pertain to deploying DG within a microgrid or to integrating a microgrid with the macrogrid.

Typical Utility Requirements

In the absence of universal, uniform standards, interconnection policies have differed from state to state and utility to utility. Nevertheless, surveys of leading energy companies and reviews of relevant existing standards yield some common requirements that share the objectives of ensuring safe and reliable operation, preventing service degradation to other electric customers, and maintaining the integrity of the larger utility macrogrid.

Virtually all utility standards state that for all but the smallest synchronous generators and self-commutated static power converters (“inverters”), anti-islanding protection is always required and is accomplished with under/overvoltage and under/overfrequency detection methods (see Chapter 5 for descriptions and more detailed discussions of synchronous generators, induction generators, and inverters). For induction machines of any size where self-excitation is possible, under/overvoltage and under/overfrequency protection is required.

For small DG units, undervoltage protection is used to verify that the generator is not connected to a de-energized line and prevents reconnection if it is already disconnected. It also disconnects the unit upon de-energization so that it is off line when the feeder recloses. Voltage and frequency protection functions can be based on either microprocessor, electronic, or electromechanical relays. They may comprise an internal control provided within a generator or added as a separate package later. For example, many static power converters come equipped with microprocessor-based voltage and frequency protection that is integrated with the converter unit. Whether an external “utility grade” package is needed typically depends on the size of the unit and specific utility requirements.

All utilities as well as local and national electrical codes require a fault-clearing device such as a fuse or circuit breaker for DG units. The purpose of the device depends on the size and type of DG unit. For small systems, an overcurrent protection device is intended mainly to protect the generator and its branch circuit wiring from faults within the DG installation fed by the utility source. In contrast, large DG units can generate high levels of fault current and can drive a fault current out onto the utility system. These units need protection against faults both within the DG installation and on the utility system. For larger synchronous generators, phase and ground overcurrent protection, usually accompanied by voltage restraint or control, is used. Differential fault protection of the generator and the step-up transformer is also common for larger systems.

Most utilities require that a negative sequence relay be used if there is a possibility of a DG unit producing single-phasing or significantly unbalanced currents. Single-phasing could occur if upstream protection devices are fuses; if one fuse were to blow, the downstream generator would be connected to an unbalanced system. Unbalanced operation can cause severe damage to three-phase rotating equipment.

Utility guidelines are commonly represented as the *minimum* standards to which DG must adhere. Most explicitly state that their guidelines are general in nature and the utility reserves the right to review and approve all interconnections. They make it clear that it is the responsibility of non-utility generators to protect their own equipment and facilities from overvoltages, line frequency disturbances, faults, lightning surges, and any other phenomena resulting from the interconnection or operation of the DG.

Government and Institutional Interaction

Interaction with a number of local, state, regional, or federal government agencies is a normal and necessary aspect of implementing a DG project, particularly if rebates or tax incentives for the use of renewable energy technologies is involved. Smaller installations for grid-independent applications that customers install for their own use—for example, a PV-powered water pumping station—may require minimal or no bureaucratic contact. Grid-connected applications usually require at least a construction permit and subsequent inspection.

Local

Permits required for DG installation depend on the location and type of installation. For example, a 2-kW grid-connected PV system to be installed on a residence usually requires a building permit from the local authority's engineering office. In addition, an inspection is needed to ensure that system installation adheres to required building and electrical codes. This process may become complicated if local inspectors are unfamiliar with DG devices. Although a permitting agency will have particular procedures and needs, there are several common approaches. A project description will be necessary, and should include details about location, equipment, operations, and likely environmental impact. At a minimum, a plot plan and area map of the site location should be provided. Basic information needed could include:

- Location—Information should include existing and proposed land uses, zoning, site size, nearby roads and access, nearby historic or archeological sites, sewer connections, pipeline connections, and nearby ecologically sensitive areas.

- Equipment—Information should include vendor and manufacturer specifications, make, model, maximum design/rated capacity, footprint, a description of ancillary equipment, control equipment, and any associated storage tanks.
- Operations—Information should include a description of the process, how the DG unit interacts with other facility operations, maximum and actual hours of operation, types of fuel, electrical load, steam load, anticipated maintenance schedule, and method and schedule for delivery of raw materials.
- Environmental Impacts—Information should include estimates of potential air quality emissions including toxic air contaminants for controlled and uncontrolled operations, quantities of hazardous or regulated substances present, drainage points, and potential sources of noise.

More permits are required for commercial or industrial ground installations rated in the tens of kilowatts or greater. In addition to construction permits, environmental approvals may be needed from local, state, and federal agencies. These may require up-front studies that will add time and cost to the approval process.

Covenants, restrictions, and zoning restrictions are other local issues that may arise. Such restrictions are normally not citywide, but may involve new or existing real estate developments, most addressing the installation of items such as PV arrays or solar heating systems on residential roofs. Recently, some utility PV programs have encountered restrictions on the types of structures that can be installed in residential backyards. Setback requirements typically govern the height and placement of wind turbine towers on private property. Other ordinances commonly address noise that may accompany DG technologies such as microturbines or even wind turbines.

State, Regional & Federal

Regulators at the state and regional levels can have significant impact on DG installation—especially financial. Many states have loan or grant programs that can provide partial support for various facility installations, particularly renewables. Many incentive programs are earmarked for commercial and industrial installation, but some also include funds for individual end-user projects.

Corporate, personal-income, and property taxes can impact the economics of DG installations. In some cases, a significant share of the cost of producing energy from a DG unit can be attributed to annual property taxes imposed on a facility. However, increasing numbers of states are passing tax relief or exemptions for some DG systems, again favoring renewables. Some states have also recognized the discouraging impact of state sales tax on renewable technologies and have acted to exempt such systems.

Federal programs managed by the U.S. DOE have primarily supported research, development, and early field installation of advanced DG technologies such as PV, wind, fuel cells, microturbines, and advanced reciprocating engines. In recent years, however, a number of federal efforts also support development of commercial products and industry commercialization activities. In addition, other federal organizations such as the Environmental Protection Agency, the Federal Emergency Management Agency, and the U.S. military issue requests-for-proposals or initiate other programs that involve installing DG systems.

Codes and Standards

Industry-wide codes, standards, and guidelines govern the installation and operation of DG devices. The most respected and universally recognized standards are those adopted by the Institute of Electrical and Electronic Engineers (IEEE) and Underwriters Laboratories (UL). Other organizations involved in the development and promulgation of relevant standards include the American Society of Civil Engineers (ASCE), the American National Standards Institute (ANSI), the American Society for Testing and Materials (ASTM), the Building Officials and Code Administrators International (BOCA), the International Association of Electrical Inspectors (IAEI), and the National Fire Protection Association (NFPA). Key requirements for DG devices include those codified in NEC Article 690, UL 1741, IEEE 929-2000, and the proposed IEEE 1547.

NEC Article 690

Article 690 of the National Electric Code, “Solar Photovoltaic Systems,” concerns design and installation requirements for PV systems, primarily related to safety. The National Fire Protection Association releases an updated version of the code every three years.

IEEE 929-2000

IEEE 929-2000 is the “IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic Systems,” which was approved in early 2000. The standard describes the interface, functions, and requirements necessary to interconnect a PV power system with the electric grid. It also describes acceptable and safe practices for accomplishing those functions.

UL 1741

Standard UL 1741, the “Standard for Safety for Static Inverters and Charge Controller for Use in Photovoltaic Power Systems,” is closely related to IEEE 929-2000. In fact, UL and IEEE worked closely to ensure that testing procedures described in UL 1741 ensure inverter compliance with the guidelines established in IEEE 929-2000. In addition, UL is reportedly working to broaden the scope of UL 1741 to apply to inverters used in a wide variety of applications beyond PV systems.

IEEE 1547

IEEE 1547 is the proposed “Standard for Distributed Resources Interconnected with Electric Power Systems.” Its passage is seen as a critical milestone for the DG industry. When approved, IEEE 1547 is expected to provide a uniform interconnection standard that states and energy companies throughout the United States and the world will use as the basis for their own interconnection practices. While the standard is being developed, details of its contents are confidential; however, the standard reportedly will not specify particular interconnection systems that must be employed. Rather, it will allow suppliers to pursue various approaches to meet its requirements.

In early discussions, the IEEE 1547 Working Group discussed the relationship between this standard and IEEE 929, which focuses primarily on photovoltaic systems. The group decided against directly incorporating IEEE 929 into IEEE 1547, but may address it within a “notes” section of the standard. Eventually, IEEE 1547 is expected to supercede IEEE 929.

As of early 2002, drafts of the proposed standard have fallen short of approval by the greater IEEE 1547 Working Group. Working group participants continue to recommend changes and labor toward consensus. Outstanding issues concern the scope of the standard, improved definitions, and the aggregate impacts of DG on the electric power system. Observers expect these issues to be resolved and the standard approved by mid-year.

Others

While the standards described above are by far the most critical with respect to deploying DG and renewable energy systems, several other industry standards and guidelines also pertain to the industry, particularly PV. They include:

- IEEE 928-1986: Recommended Criteria for Terrestrial Photovoltaic Power Systems. This standard for performance criteria applies to all terrestrial PV power systems regardless of size or application. Its principal purpose is to present an overall framework into within which all other terrestrial PV system performance ancillary standards can be developed.
- IEEE 937-2000: IEEE Recommended Practice for Installation and Maintenance of Lead-Acid Batteries for Photovoltaic Systems. This standard includes safety precautions and instrumentation considerations.
- IEEE 1013-2000: IEEE Recommended Practice for Sizing Lead-Acid Batteries for Photovoltaic Systems.
- IEEE 1144-1996: IEEE Recommended Practice for Sizing Nickel-Cadmium Batteries for Photovoltaic Systems.
- IEEE 1262-1995: IEEE Recommended Practice for Qualification of Photovoltaic Modules.
- IEEE 1374-1998: IEEE Guide for Terrestrial Photovoltaic Power System Safety
- IEEE P1561: Guide for Sizing Hybrid Stand-alone Energy Systems. This proposed guide provides methods and procedures for sizing the major components of hybrid systems that generally consist of a renewable energy technology integrated with a fossil-fueled generator and an energy storage subsystem. Methods include sizing each component according to design criteria including low cost, maximum performance, and expected operating environment.
- IEEE P1589: Draft Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems (proposed)

- IEEE P1608: Distributed Resource Applications (proposed)
- UL 1703: Photovoltaic Panels and Modules
- UL 2200: Engine Generators and Microturbines
- UL 2265: Fuel Cells
- UL 2264: Hydrogen Generators
- IEC 61400: Windpower Generators

Device Certification

An important strategic goal of DG manufacturers and vendors is type-testing certification: a process for certifying at the factory that every unit of a particular type of DG satisfies standards that are universally accepted and recognized, and that no additional testing, simulations, demonstrations, or time-consuming and expensive approvals for individual generators are required. Type-testing certification would ensure that DG devices conform to anti-islanding, abnormal voltage and frequency, overcurrents, and other safety and power quality requirements. It would represent major progress beyond the unit-by-unit, site-by-site field testing that is frequently required now. Although it would not eliminate the need for a field test of the final installation, type-testing certification would greatly simplify the acceptance process. The approach is most viable in applications where the final field installation and any ancillary hardware added in the field do not alter the factory-programmed functional response characteristics of the DG unit, which would generally be true only for smaller DG units less than approximately 300 kW in size. Larger DG will likely continue to be protected on a case-by-case basis. Ideally, individual states will work together with DG stakeholders to adopt consistent type-testing approaches for the widest possible range of DG types and sizes.

Although true “plug and play” capability is still some time distant for DG, many hope that the imminent promulgation of IEEE 1547 is a significant step in that direction. In the interim, actions such as UL’s recent certification that Capstone Turbine’s 30-kW and 60-kW microturbines are complaint with UL 1741 is viewed as an encouraging sign and a strong competitive advantage in the marketplace. Already, some utilities will accept UL certification in lieu of hardware and site verification.

5
MODELING DG DEVICES

To derive maximum benefit from DG and avoid possible adverse system impacts, system owners and distribution utilities will need the ability to simulate the effect of interconnected distributed resources on their power systems. Accurate modeling of DG can help determine any distribution system modifications that may be needed to accommodate the devices as well as develop a basis for strategic system operation. Such modeling is important at both the microgrid scale—assessing how individual DG devices will work within a microgrid—and at the macrogrid scale, where an interconnected microgrid might be considered as a single large distributed generator with its own characteristic impacts and behavior.

Currently, energy companies use a variety of simulation tools for distribution planning purposes. Most are used to analyze the impacts of customer load on the distribution system. Other simulation tools determine the optimal placement of field equipment, such as capacitor banks and voltage regulators, for efficient and reliable operation of the power system.

Most simulation tools are based on power flow algorithms that incorporate software models of the physical and electrical characteristics of a distribution power system. Traditionally, these power system models include the electric characteristics of capacitor banks, load tap changers, voltage regulators, customer loads, and other distribution equipment. Since most distribution systems, whether radial or networked, are constructed with the expectation of overall one-way flows of energy, these power flow algorithms assume one-way flow in which substations supply electricity and customers consume it.

With the addition of DG to power systems, two simulation tool issues arise. First, power flow algorithms must include DG devices at or near customer sites as possible sources of energy. Energy can no longer be assumed to flow one way from substation to customer, but must account for possible flow from customer to substation. Second, to date only rough estimates of the electrical characteristics of DG devices have been readily available, making any model necessarily inaccurate. Much work is now underway on several fronts to develop new modeling tools to account for two-way power flow and the characteristics of a wide variety of DG devices.

As DG becomes more ubiquitous, simulations will also be required during real-time operation to manage the devices effectively, efficiently, and safely. Simulation tools could use information gathered from the distribution system, analyze current operational costs, and develop optimal settings for distribution devices. More advanced simulation tools could rely on real-time data from DG devices and other power system equipment to determine actual conditions and either recommend or impose optimal settings for DG devices and other field equipment. Such simulation applications could also be used to ensure that utilities meet their marketplace contractual commitments for buying and selling DG energy and ancillary services at the distribution level.

To begin modeling the system impacts of DG on a microgrid or macrogrid, it is necessary to understand the electrical characteristics of DG devices. The following discussion summarizes key considerations with respect to DG devices in general and some renewable energy technologies in particular. From that discussion, some general conclusions may be reached to support the development of system modeling.

DG Prime Energy Technologies

Distributed generation comes in many forms, including PV and fuel cells with inverter circuitry, wind-powered induction generators, and gas turbine-driven synchronous generators. The analysis, installation, and operation of such generators in distribution systems are relatively new engineering topics.

Table 5-1
Comparison of Selected DG Prime Energy Sources

	Prime Energy Source	Prime Power Output	Common Power Converter
Renewable Energy Technologies	Photovoltaic	Direct current	Inverter (static power converter, no inertia)
	Wind Turbine	Mechanical energy (rotating shaft)	Induction generator (single-speed) or high-frequency alternator with inverter (variable-speed)
	Small hydroelectric	Mechanical energy (rotating shaft)	Induction or synchronous generator
	Solar Thermal	Mechanical energy (rotating shaft)	Induction or synchronous generator
Other Generation Technologies	Reciprocating Engine	Mechanical energy (rotating shaft)	Induction or synchronous generator
	Combustion Turbine	Mechanical energy (rotating shaft)	Induction or synchronous generator
	Microturbine	Mechanical energy (rotating shaft)	Induction generator or high-frequency alternator with inverter
	Fuel Cell	Direct current	Inverter (static power converter, no inertia)

Despite the wide range of prime energy sources described in Table 5-1, there are only three basic power converters used as the final interface to the utility system: induction generators, synchronous generators, and static power converters (or inverters). To some extent, the interaction of a DG unit with the utility system will be dominated by the characteristics of the power converter used for this final interface.

However, understanding the characteristics of the prime energy source is also crucial since each has its own set of typical response times and output fluctuations. For example, wind and PV sources can experience rapid changes in output (from 10% to more than 100% of rated system capacity) in a matter of seconds due to changing wind or cloud cover. These fluctuations can occur for prolonged periods of time depending on weather conditions. Their impacts can be very different than similar fluctuations in conventional generation technologies. For example, reciprocating engines may experience fluctuations such as those caused by engine misfiring that can impact a utility system more than solar or wind fluctuations would. A random oscillation in output of 100 kW from a solar array may not be noticeable because it happens over a 5- to 10-second period. However, a 50-kW output oscillation from a reciprocating engine occurring at a rate of 4 to 8 Hz (the most sensitive region of the flicker curve) could create noticeable flicker on a distribution feeder. Understanding the characteristic fluctuations and responses of the prime energy source to various loading conditions is crucial to the various steady-state and dynamic response calculations needed to evaluate DG impacts on utility systems.

Synchronous vs. Induction Generators

A synchronous generator is a rotating alternating current machine that operates at a constant speed up to full load. It utilizes a separate dc excitation system to produce the magnetic flux needed to generate voltage and current. Synchronous DG machines such as reciprocating engines, gas turbines, or small hydroelectric generators are similar to their utility-scale counterparts. Synchronous generators require a complex control system to both synchronize with utility power and to regulate field excitation.

Among the characteristics important to consider when analyzing the system impacts of synchronous generators is their ability to sustain fault currents of up to 500% of rated load current for several seconds, depending upon the nature of their excitation systems. Directly connected rotating machines do not normally inject significant harmonic currents (multiples of 60 Hz) into the distribution system. In fact, such machines present a relatively low impedance to harmonics (the subtransient reactance) and can serve as a sink. Synchronous generators can operate over a wide range of power factor depending upon the magnitude of field current or dc excitation. Changes in excitation determine the terminal voltage and the reactive power of the generator.

An induction generator is a rotating ac machine that operates *above* synchronous speed over its range of power output. The faster it is driven above synchronous speed by a prime mover, the more electricity it generates. Excitation is provided in the form of external reactive power; thus, induction generators normally lose their ability to produce voltage and power when isolated from the utility or other power source.

Under special conditions, induction generators can continue to operate after isolated from an external power source. Self-excitation can occur if sufficient capacitance is connected in parallel with the generator to provide excitation current. Overhead line capacitors as well as line and cable capacitance on the circuit can cause self-excitation of an induction generator. Self-excitation can be very unstable and may result in system overvoltages. Induction generator excitation under isolated conditions can also be provided by other paralleled synchronous generators serving the same isolated load. The probability of this condition happening increases as the concentration of generators increases on the circuit.

Induction generators characteristically operate at a low power factor under lightly loaded conditions and always appear as inductive loads to the system, since reactive power is being provided for excitation. As more induction generators are interconnected to a system, the grid must provide increasing amounts of reactive power.

An induction generator can contribute momentary fault current of five to eight times the rated current, which decays over a short time period of two to three cycles. Like synchronous generators, induction generators are not a major source of harmonics, although an induction machine operating at a slip frequency can produce non-characteristic harmonics due to rotor asymmetries. An induction generator is typically less expensive than a similarly sized synchronous machine and does not require the synchronizing equipment and control that a synchronous generator does.

Photovoltaic Inverters

PV power is produced as direct current that must be converted to suitable alternative current via a static power converter, or inverter. Static power converters for PV systems have some special characteristics that must be addressed. One consideration is “peak power tracking” of the array. PV cells have a voltage/current characteristic curve that is relatively flat—that is, it decays little in current—up to approximately 80% of the voltage output at zero current (open-circuit voltage). Then a knee is reached where the current declines more steeply (see Figure 5-1). This is the maximum power point, where the product of the voltage and current from the PV array has its highest value.

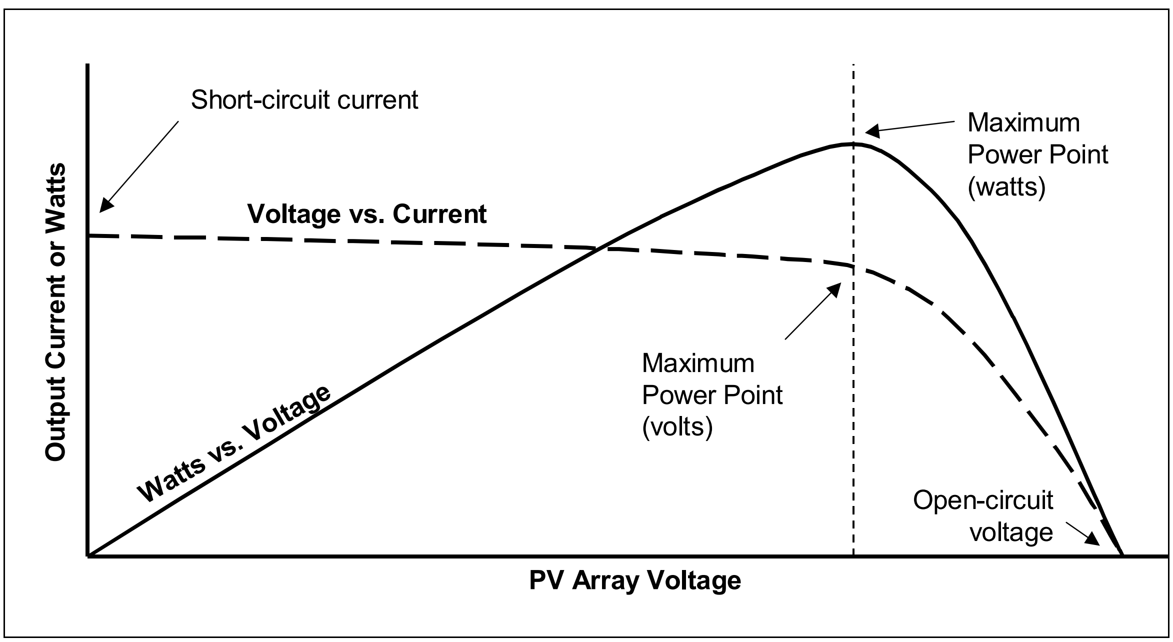

Figure 5-1
Current and Power as a Function of Voltage for Typical PV Array

More-advanced inverters, designed for PV, attempt to operate a solar array at this point to maximize power transfer from the array. They actually alter the dc bus voltage by adjusting loading on the array until maximum power is achieved. This function is complicated by the fact that the maximum power point for a given PV array is not fixed, but rather varies depending, for example, on ambient temperature and solar intensity. Ideally, an inverter should track the maximum power point and not just be set at a fixed dc bus voltage level.

Over the years, a wide variety of inverter technologies have been applied to PV. Inverters may be line commutated or self commutated, depending on the type of power electronic switching device and switching control scheme employed. A line-commutated inverter uses the ac line voltage of the larger system to control the thyristor switching. Such an inverter cannot normally establish a voltage independent of an external source. In this respect it acts much like an induction generator. And, as with an induction generator, it is possible to self-excite line-commutated inverters if sufficient line capacitance exists under isolated conditions. A self-commutated inverter uses its own internal circuitry to control thyristor switching. This type of static inverter can produce voltage and current independently of an external power source, and therefore acts much like a synchronous generator.

The fault current capability of static inverters depends on the inverter design and the dc power source feeding the inverter. Because of the low thermal tolerances of semiconductors, many of these devices have an overcurrent capability of only 120% of rated current. Also, inverters inherently produce harmonic distortion, which could affect the power quality of other customers.

Common power electronic components used for inverters include silicon control rectifiers (SCR), insulated gate bipolar transistors (IGBT), and power-MOSFET (metal oxide semiconductor field effect transistors). While SCR inverters were popular in the 1970s and 1980s, the high distortion levels they produced plus the fact that they are line commutated made them less than ideal candidates. IGBT inverters and power-MOSFET inverters are self-commutating and can produce extremely low distortion wave shapes using pulse-width modulation techniques. As a result, pulse-width modulation inverters based on IGBTs dominate today’s market.

Wind Turbines

Wind turbines are rotational devices that convert the kinetic energy of the wind into electricity. This has generally been accomplished in two ways: induction generators and variable-frequency alternators coupled to static power converters.

Induction generators have historically been the most popular power conversion interface due to their low cost and simplicity. One drawback of the induction approach is that it forces a wind turbine to rotate at a uniform speed that may not be the most efficient speed for the turbine blades to operate at. Induction machines also require reactive power (VAR). The larger the machine, the greater is the potential for voltage problems due to its greater need for reactive power. It is possible to compensate with capacitors; however, this creates the danger of unstable self-excitation.

A state-of-the-art approach, not yet commonly deployed in the field, is the use of a static power converter with a variable-speed turbine design. These wind turbines, like synchronous generators, can supply reactive power to the power system rather than consume reactive power like an induction generator. Variable-speed turbine generators use an alternator that produces variable frequency ac current. This variable ac energy is then rectified and fed directly into a static power converter that produces low-distortion 60-Hz power suitable for grid use. This approach allows the alternator to run at virtually any speed, liberating the rotor blades to operate at rotational speeds most efficient for a given wind velocity. Advanced variable-speed wind turbines can start up at lower wind speeds and supply a more constant output during high winds after they attain rated capacity. Together with improvements in design and materials, the ability to operate at variable speeds gives these turbines significantly greater efficiency than their single-speed induction counterparts.

Small Hydro Induction Generators

For the purposes of modeling, a small hydro induction generator can be treated as a motor of the same size. In some software simulation tools, an induction generator can be modeled as an equivalent synchronous generator.

Choosing and Applying Simulation Tools

The simulation tools described below are software products in widespread use. These programs are among those employed in EPRI's recent "Integration of Distributed Resources in Electric Utility Distribution Systems" studies. Table 5-2 provides a list of other available software tools for distribution and advanced power system analysis.

Electromagnetic Transients Program (EMTP)

EMTP is a versatile computer program that utilities worldwide use to analyze high-speed power system transients. It was conceived in the 1960s by H.W. Dommel as a Ph.D. dissertation and developed in the 1970s by the Bonneville Power Administration (BPA). It has subsequently been maintained and improved by the EMTP Development Coordination Group composed of EPRI, BPA, the Canadian Electrical Association, Hydro Quebec, Ontario Hydro, the U.S. Bureau of Reclamation, and the Western Area Power Administration.

EMTP is used to simulate electromagnetic, electromechanical, and control system transients on multiphase electric power systems. It was first developed as a digital computer counterpart to the analog Transient Network Analyzer. The program allows users to build up complex multiphase models of a power system from among such components as overhead lines, transformers, circuit breakers, surge arresters, rotating machines, and switching devices. EMTP allows users to simulate and output multiphase voltages and currents resulting from faults or other system transients exactly as they would be seen on an oscilloscope.

Real-time Digital Simulator (RTDS)

The RTDS system is state-of-the-art equipment for real-time digital simulation of power systems and their components. The digital approach to modeling provides accuracy in component modeling and flexibility in component interconnection for representation of a power system.

RTDS simulates the power system and its components using EMTDC software, which is similar to EMTP. The modeled system is created using a graphics interface, with power system components represented by convenient icons. As with EMTP, the RTDS system computes the time domain solution of bus voltages and branch currents, but in a computation period of only 50 to 100 microseconds. The simulation proceeds indefinitely, with output quantities fed to digital-to-analog converters, which allow signals to be conveniently measured using conventional meters. The simulation can also be modified “on the fly” with user-defined control inputs—for example, closing or opening switches to connect or disconnect components in the simulated power system. The signals can also be applied, via current and voltage amplifiers, to relay equipment to test their performance.

EPRI Power System Analysis Package (PSAPAC)

The Extended Transient Midterm Stability Program (ETMSP), Multi-area Small Signal Stability Program (MASS), and the Interactive Power Flow Program (IPFLOW) are production-grade programs incorporated into the EPRI Power System Analysis Package (PSAPAC) developed at Ontario Hydro. ETMSP and MASS form a consistent set of tools for transient and small signal power system stability analysis. The dynamic models used in the programs are identical and load flow data can be presented in a variety of formats.

Both ETMSP and MASS are capable of analyzing large systems with more than 1,000 generators and 12,000 electrical network buses. Models of other dynamic devices that can significantly affect power system stability are also available to program users. The programs are intended to be used in a complementary fashion for power system stability studies both in planning and operation.

ETMSP is designed to simulate the time response of a power system to large disturbances, including a sever fault. It is the normal workhorse for the planning purposes and resolving operating stability issues. MASS is designed to study system stability during small disturbances, and is generally used for detailed control design and investigation of local small signal stability problems. MASS is also used to find the frequency response of interconnected equipment for control design.

ASPEN DistriView™ Fault Analysis Program

ASPEN DistriView™ is a graphical power system analysis program available from Advanced Systems for Power Engineering, Inc. The program can be used to model distribution systems and is useful for such purposes as performing voltage profile studies, relay and fuse coordination, and fault analysis studies. Three-phase or sequence component data can be entered for various types of distribution system components and protection equipment. Numerous fuse and relay models are included with the program, which does not perform dynamic studies but is useful for steady-state calculations.

Table 5-2
Available Software Tools for Modeling DG Impacts

Product	Company	Contact
Distribution Analysis Products		
CH-Analysis for Electric	Cook Hurlbert	www.cook-hurlbert.com
CYMEDist	CYME	www.cyme.com
DESS	Dromey Design	www.dromeydesign.com
DEWorkstation	EPRI	www.EPRI.com
DistriView	ASPEN	www.aspeninc.com
EDSA	EDSA	www.edsa.com
FeederAll	ABB	www.abb.com
WindMill	Millsoft	www.milsoft.com
PSS/Adept	Power Technologies	www.pti-us.com
SynerGEE Electric	Stoner Associates	www.stoner.com
V-Flow	Cooper Power Systems	www.cooperpowersystems.com
Power System Programs for More Advanced Analysis		
ATP	ATP North America Users Group	www.ee.mtu.edu/atp
EMTP	EPRI	www.EPRI.com
PSCAD/EMTDC	Manitoba HVDC Research Centre	www.ee.umanitoba.ca/~hvdc
Harmflo	EPRI	www.EPRI.com
PSS/E	Power Technologies	www.pti-us.com
ETMSP	EPRI	www.EPRI.com
PSLF	General Electric	www.ps.ge.com

Information Required for Accurate Simulation

Based on the types of date such simulation tools require, Table 5-3 lists data that would ideally be known about each type of DG incorporated into a microgrid or interconnected with the utility macrogrid:

Table 5-3
Representative DG Data Needed by Simulation Tools

kW (kVA) range	Harmonics characteristics	Operation cost, peak, off-peak
Power factor range	Phasing characteristics	Modes of operation: kW generation, kVAR generation, absorption
Voltage levels	Reactions to power quality: spikes, dips, surges, imbalance, voltage & frequency deviation	Electric connectivity diagram (transformer, switches)
Connection schemes	Synchronization characteristics	Voltage & frequency dependencies
Protection requirements	Measurements available for monitoring	Reaction on non-synchronic switching
Dynamic characteristics, including time constants needed for stability analysis	Types of automated control available	Interaction with feeder capacitors
Energy storage capacity	Operational limits: kW, kVAR, volts	
Inertia characteristics		

Much of this information, particularly for newer DG technologies, is not well understood or has not been released by equipment manufacturers. In surveys conducted by EPRI to try to determine these characteristics for some DG devices, several vendors expressed reluctance to reveal detailed operational data, fearing loss of a competitive edge. Many vendors do not yet appear to perceive a benefit to supporting system simulation tools because DG technologies are not yet widespread. Of course, the future penetration of DG technologies may well be limited by a lack of sufficiently accurate, sophisticated system simulations. This remains an area in which further work is needed.

However, DG will not become economically or practically viable if every installation demands an in-depth analysis. For most situations, it is sufficient to screen the size and characteristics of a DG device and the distribution circuit on which it will be located. This screening can in some cases be done by hand. If initial screening uncovers issues of concern, more sophisticated software simulations may be needed. Most voltage regulation, flicker, and overcurrent coordination issues can be analyzed with standard distribution analysis tools. Other issues, including islanding, harmonics, ferroresonance, and stability, may require more complex analysis. Advanced tools, such as those that would be needed to determine optimal placement of DG within a distribution system, are not yet available.

Case Study: DG on Urban, Suburban, and Rural Feeders

In 1998 and 1999, EPRI simulated the effects of integrating distributed resources in electric utility distribution systems for urban, suburban, and rural feeders. Study findings were presented in EPRI technical reports TR-111490 and TR-112737. Briefly, the objectives of the project were to develop DG models for use in utility system simulation tools, to perform case studies on urban, suburban, and rural distribution feeders, and to derive general results with respect to the impacts of DG based on the three case studies. The reports emphasize that they are meant to provide general guidelines for distribution system design engineers considering similar case studies, and that each feeder system and situation is unique.

Actual distribution feeders were chosen to serve as the case study models. The Oakland circuit in Pittsburgh, Pennsylvania was selected to provide the urban case; the Pine Creek feeder near Pittsburgh provided the suburban case; and the Brandonville circuit in West Virginia provided the rural case. Existing simulation tools including ASPEN DistriView, ETMSP, and EMTP, were used in each case.

In general, the studies confirmed that as DG units are added to distribution systems, coordination of DG voltage control elements with standard distribution system regulators becomes very important. Depending on the type of DG and its control configuration, several modes of interaction are possible. In addition, the presence of DG units was found to directly affect voltage profiles along a feeder by changing the direction and magnitude of active/reactive power flows. The studies concluded that directionality of line compensation elements must be considered for generation and load levels that result in a net export of power to the system through a distribution transformer.

Although the studies found that steady-state stability is unlikely to impose limitations on most DG applications, large machines with high synchronous reactances connected at low voltage levels pose potential problems. Assuming such machines cannot be relocated to a stronger point on the distribution system—for example, closer to a substation—the only reasonable-cost solution is to equip the unit with a high-gain automatic voltage regulator and high-initial-response excitation system.

Table 5-4 lists DG penetration limits—that is, the percentage of DG that could safely and reasonably be added to existing generating capacity—that satisfy several specific limiting conditions. Again, these results apply only to these particular distribution systems and, in the original reports, are accompanied by extensive explanatory notes that are not included here. However, they are indicative of both the type of detail that such studies can yield and the order-of-magnitude DG penetration levels that may be possible in some circumstances.

Table 5-4
Selected DG Penetration Limits on Case Study Distribution Feeder Circuits

DG Type	Limiting Contingency	Urban Oakland (13 MW)	Suburban Pine Creek (13 MW)	Rural Brandonville (2.9 MW)
Any Generator Type	Voltage drop on loss of all units <5% on backbone	140%	49%	83%
	Voltage drop on loss of all units <5% on lateral	10%	10%	14%
	Fault at DG not tripped by feeder protection	21%	23%	N/A
	Fault at DG not tripped by feeder recloser	N/A	18%	8%
	Fault at DG not tripped by adjacent DG	108%	41%	15%
PV	Voltage flicker <1%, 500-kVA units on backbone	200%	26%	22%
	Voltage flicker <1%, 100-kVA units on backbone	1,000%	130%	110%
	Voltage flicker <1%, 500-kVA units on lateral	0%	0%	0%
	Voltage flicker <1%, 100-kVA units on lateral	5%	5%	3%
	Voltage flicker <1%, 10-kVA units on lateral	50%	50%	30%
Line-Commutated Inverter	Harmonic voltage <3%, 500-kVA units on backbone	100%	31%	60%
	Harmonic voltage <3%, 100-kVA units on backbone	100%	31%	60%
	Harmonic voltage <3%, 500-kVA units on lateral	5%	5%	25%
	Harmonic voltage <3%, 100-kVA units on lateral	5%	5%	25%
Pulse-Width Modulated Inverter	Harmonic voltage <3%, 500-kVA units on backbone	37%	3,900%	1,100%
	Harmonic voltage <3%, 100-kVA units on backbone	190%	20,000%	5,600%
	Harmonic voltage <3%, 500-kVA units on lateral	11%	4%	120%
	Harmonic voltage <3%, 100-kVA units on lateral	54%	21%	620%
	Voltage drop <10% on reversal of full reactive output, single unit on backbone	52%	28%	50%
	Voltage drop <10% on reversal of full reactive output, single unit on lateral	4%	4%	20%
Wind Turbine	Flicker <1%, 500-kVA stall-controlled, on backbone	520%	67%	56%
	Flicker <1%, 100-kVA stall-controlled, on backbone	2,600%	340%	280%
	Flicker <1%, 500-kVA stall-controlled, on lateral	0%	0%	0%
	Flicker <1%, 100-kVA stall-controlled, on lateral	13%	13%	7%
	Flicker <1%, 500-kVA inverter-connected, backbone	6,200%	790%	670%
	Flicker <1%, 100-kVA inverter-connected, backbone	31,000%	4,000%	3,300%
	Flicker <1%, 500-kVA inverter-connected, lateral	30%	30%	17%
	Flicker <1%, 100-kVA inverter-connected, lateral	150%	150%	87%
Induction Generator	Self-excitation overvoltage on islanding	100%	100%	100%
	Voltage drop <3% on startup, one unit on backbone	10%	6%	10%
	Voltage drop <3% on startup, one unit on lateral	1%	1%	5%

6 ENVIRONMENTAL ISSUES

One of the benefits often attributed to distributed generation technologies is their relatively benign environmental impact. Renewable DG technologies in particular are invariably “greener” than their fossil-fueled or central-station counterparts. However, DG does present environmental issues that must be considered, among them siting, emissions, and its effects on a community in terms of sound, appearance, and overall character. Such issues are likely to become more important as distributed generators are integrated into microgrids, which may tend to concentrate DG’s environmental impacts into a small geographic area.

Siting Considerations

As mentioned in Chapter 4, the placement of a DG facility involves assessing environmental and related impacts including noise restrictions and ordinances, land use or zoning restrictions, and visual restrictions. Compliance with local and regional air quality regulations may also have significant consequences for operations and maintenance, as may water discharge and hazardous waste handling. Key areas of concern include sound and vibration, ventilation and exhaust, and fuel supply.

Sound and Vibration

Sound and vibration must be considered when evaluating a type of DG and how it interacts with its surroundings. Vibration involves the physical coupling of movement caused by a prime mover with its attached structure. Problems with sound and vibration are typically associated with DG engine technologies: gas turbines, diesel generators, etc. Fuel cells are generally quiet and free of vibration, although some types require loud compressors to pressurize their fuel supply. Microturbines emit sound but produce virtually no vibration. Among renewable energy technologies, PV is notable for its complete silence of operation. Wind turbines do produce sound as their blades move through the air; newer designs and materials have greatly reduced their noise emissions in recent years. The sound and vibration emitted by small hydro installations varies depending on their type. In general, small hydro plants are located distant from dense residential or commercial development so that sound and vibration are likely to prove less of a nuisance.

Ventilation and Exhaust

Proper equipment ventilation and cooling ensures reliable operation and reduced maintenance cost. In cases where limited space is available for DG installation, special attention must be paid to intake airflow paths and exhaust flows. Batteries—such as might be used as an energy storage device with a PV system—are particularly sensitive to temperature. Turbines require larger inlet and exhaust space for ducting than engines but, since they radiate less energy, require less ventilation space.

Fuel Supply

A non-renewable DG facility's fuel supply system may involve construction costs including installation, land survey, maintaining necessary easements, and right-of-way costs. Pipeline construction or negotiations with a local gas utility for higher-pressure gas may also be involved. One of the advantages of solar and wind technologies, particularly in an urban or suburban microgrid setting, is that they avoid such potentially costly and complex fuel supply issues.

Emissions and Controls

The U.S. Environmental Protection Agency (EPA) evaluates ambient air quality standards via a "criteria document" that summarizes scientific evidence for all environmental and health-related issues concerning specific air-borne pollutants. Based on this report, standards are created to limit the amount of each pollutant released into the atmosphere. The six "criteria pollutants" defined by the EPA are ozone (O_3), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), sulfur dioxide (SO_2), and lead (Pb). Areas of the country where air pollution levels exceed the national standard are designated as "non-attainment" and are subject to more stringent regulations.

Although not categorized as a criteria pollutant, unburned hydrocarbons (UHCs) are regulated because they are known to be a precursor to the formation of ground-level ozone. UHCs are elements of unburned fuel that form as a result of low combustion temperature or an overly rich fuel-air mixture. They can be categorized as total hydrocarbons or total organic compounds, non-methane hydrocarbons, volatile organic compounds, or reactive organic gases. Table 6-1 presents a comparison of emission outputs from selected non-renewable DG devices. Emission factors are measured at the "tail pipe" and are intended for general comparison only. They do not include further possible reductions with post-combustion treatment of exhaust gas.

Table 6-1
Comparison of Emissions for Non-Renewable DG Technologies

	Fuel	NO_x lb/MWh [kg/MWh]	CO lb/MWh [kg/MWh]	VOC lb/MWh [kg/MWh]	PM lb/MWh [kg/MWh]	SO_2 lb/MWh [kg/MWh]	CO_2 lb/MWh [kg/MWh]
Conventional Steam Turbine	Natural Gas	1.77 [0.80]	0.15 [0.068]	0.0088 [0.0040]	0.22 [0.10]	Negligible	1,100–1,200 [500–545]
Diesel (gm/hphr)	Diesel Fuel	3–33 [1.4–15] (1-11)	8.6 [3.9] (2.8)	0.5 [0.23] (0.16)	0.66–3.3 [0.3–1.5] (0.22-1.1)	1.1–3.8 [0.5–1.7] (0.35-1.2)	1,600 [730]
Gas Turbine (ppmv)	Natural Gas	0.3–4.0 [0.14–1.8] (9-100)	0.3–1.5 [0.14–0.68] (15-50)	0.13–0.4 [0.059–0.18] (9-25)	Negligible	Negligible	1,200 [545]
Microturbine (ppmv)	Natural Gas	0.4–2.2 [0.18–1.0] (9–50)	0.08–1.5 [0.036–0.68] (3–50)	0.04–0.16 [0.018–0.073] (3–9)	Negligible	Negligible	1,500 [680]
Fuel Cell	Natural Gas	<0.02 [<0.01]	<0.025 [<0.011]	<0.0004 [<0.0002]	Negligible	Negligible	700–1,200 [320–545]

(Source: Distributed Generation Implementation Guidelines: Siting, Environmental Permitting, and Licensing, EPRI TR-111545, based on representative manufacturers' product specifications.)

Note that, when fueled by pure hydrogen, the only emissions produced by a fuel cell are water vapor and heat. However, most fuel cell systems in or nearing commercial production are designed to operate on reformed hydrocarbon fuels, generally natural gas. This fuel processing system does produce CO_2 and low levels of other emissions. The value of renewable solar, wind, and hydro technologies in eliminating emission concerns is evident.

Greenhouse Gases

Several greenhouse gases are known to contribute to humanity's effect on the radiation balance in the atmosphere and, hence, on global temperature and potential climate change. The greenhouse gases of concern include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and certain chlorofluorocarbons (CFC) that react with and deplete the ozone layer. The estimated lifetimes of these gases in the atmosphere before they oxidize to carbon dioxide and the infrared absorbing strengths vary.

Renewable generation technologies typically produce no direct emissions of fossil fuel carbon dioxide, methane, or other greenhouse gases, and can be used to offset greenhouse gas emissions by the fossil fuel-fired component of the system generation mix. Consequently, renewable energy can be considered to be a greenhouse gas emissions reduction technology as well as a renewable energy power technology. In addition, should a greenhouse gas emissions reduction mandate be enacted in the future, renewables would become an important component of a greenhouse gas emissions reduction strategy and would likely play a key role in carbon dioxide emissions trading.

The carbon dioxide emissions reduction potential of a renewable energy power plant is a function of the fuel mix of the existing generation system. The effective carbon dioxide emissions reduction *cost* is a function the CO_2 emission rate and the difference between the average generation costs of the base system and the renewable energy power plant. A full discussion of greenhouse reduction strategies, including specific examples illustrating the comparative greenhouse gas emission control costs associated with various renewable technologies, is included in EPRI's *Renewable Energy Technical Assessment Guide—TAG-RE: 2001* (1004034).

Renewable Technology Impacts

Photovoltaics

Although PV emits no gases or sounds in operation and generally presents less environmental impact per deployed megawatt than any other known generation technology, it is not completely free from impacts and potential hazards. Most notably, some impacts may be expected during system manufacture involving the safe handling of potentially dangerous materials. Other issues concern the ultimate disposal or recycling of PV devices. And, as mentioned in Chapter 4, some local ordinances or homeowners' associations have objected to rooftop PV devices on the grounds that they change the appearance or character of a neighborhood.

Wind

Relevant environmental and social issues include public acceptance, permitting, land use, soil erosion, visual and noise impacts, and impacts on resident and migratory bird and animal populations.

Bird interaction with wind facilities has been a key issue for the wind industry since the late 1980s, when bird carcasses were reported at the Altamont Pass wind resource area in northern California. In 1999, the National Wind Coordinating Committee published a definitive report, *Studying Wind/Bird Interactions: A Guidance Document*. The report provides extensive information on designing and conducting field avian studies to better understand the risk that wind facilities present to avian populations. The current industry trend toward larger wind turbines is also considered beneficial to reducing the risk of bird death or injury, since larger machines are built farther above the ground and rotate more slowly.

The noise generated by operating wind facilities is different in both level and character from the noise generated by conventional power plants. It is generally a low-level noise with both mechanical and aerodynamic components. Although no federal and few state noise standards exist, the EPA has promulgated noise guidelines. Many local governments have enacted local noise ordinances that must also be considered when siting wind facilities.

The visual impact of a wind project depends on the relative elevation of the site and the surrounding terrain, the presence of trees and other vegetation, and the number, spacing, placement, tower structure, height, and color of the turbines. Community attitudes toward wind projects can range from welcoming to hostile depending on local public policy goals and preferences. Often, careful efforts to educate the public about the nature and benefits of wind power can have a large impact on a project's acceptance.

Small Hydro

There are many different types of low-impact hydropower technologies, including in-stream turbines and other devices that recover kinetic energy from river, tidal, and ocean currents. In addition, there are several other technologies that involve retrofitting existing dams and conventional hydro plants, including retrofitting fish- and wildlife-friendly turbines at the more than 70,000 existing hydro and non-hydroelectric dams in the United States. Their environmental impacts will vary depending on their size, setting, and technology. In general, small hydropower projects produce no atmospheric emissions, little noise and visual impact, and minimal harm to fish and other aquatic species.

Biomass

Biomass energy is derived from living plants and animal wastes and therefore is a form of stored solar energy: sunlight captured as energy stored in the material of living plants. As long as the biomass is grown and harvested in a renewable, sustainable way it is a renewable resource that today can be used to generate power. Today, biomass power accounts for about two-thirds of the non-hydro renewable power generated in the United States.

Biomass power uses combustion technology, and hence is perceived by some as "not green." Historically, wood combustion processes were dirty, with uncontrolled emissions of smoke and haze, including soot, ash, carbon monoxide, nitrogen oxides, and hydrocarbons. Local and regional air quality problems still exist today as a result of high concentrations of fireplaces, campfires, and open burning of residues. Starting about 50 years ago, modern furnaces and boilers were developed for both wood and coal. Today, these combustion systems can operate with emissions controlled to virtually any level demanded by permit requirements. Current developments include gasification technologies (again, for both biomass and coal). Gasifiers not only provide higher efficiency power generation through integration with combined (gas and steam turbine) cycles; they also allow, and demand, a much deeper level of emissions control than the direct combustion technologies.

Most biomass fuels are significantly lower in potential air pollutants than most coals. Biomass has virtually no sulfur (often less than 1% that of coal), low nitrogen (less than 20% that in coal), and low ash content. Exceptions exist, but can be identified and controlled. For example, construction and demolition wastes, which are sometimes mixed with other wood wastes and used as biomass fuel, can have very high sulfur contents due to the gypsum (calcium sulfate) in wallboard. Treated lumber can contain trace amounts of toxic elements; one modern treatment contains a mixture of copper, chromium, and arsenic, which can cause the combustion ash to be classified as a toxic waste. Crops with high protein levels or grown with high fertilizer levels can have relatively high nitrogen contents. Overall, biomass is usually far superior to coal in terms of its concentrations of sulfur, nitrogen, ash, and metals. Compared to natural gas, however, biomass cannot claim any inherent advantage in terms of emissions, except for greenhouse gas emissions.

Another perception problem for biomass power is the use of forests, although forests are now expanding in the United States by about 3% per year. Biomass fuel used for energy today is essentially all from wood wastes and residues, the majority of which originate in forest operations conducted for other purposes. In some cases, biomass fuel is provided from forest management (thinning) operations that are conducted for the specific purpose of improving forest health and value.

7
ECONOMIC ISSUES

The pace, extent, and geographic pattern of regulatory reform intended to increase market competition is by far the most significant driver influencing future DG roles and potential. Industry restructuring in response to deregulation will motivate the various business models adopted by individual end-users, retail companies, distribution companies, and generation companies to incorporate DG into their strategic planning.

Policy and Tariff Provisions

It is not yet clear how distribution system planning will be accomplished in the restructured energy industry, nor how least-cost planning can or will be employed in the context of a competitive electric market. Energy companies raise important issues that must be addressed in DG policy formulation, including: What methods will be used to evaluate DG versus other distribution capacity alternatives? Will peaking, baseload, or load-following units predominate, and how will their operation be coordinated with the grid? What level of capacity assurance should distribution planners use to prevent either over- or under-capacity of the distribution circuit? What will be the rules for backup service? Who will control the ancillary services market and will DG units and microgrids be required to participate, particularly to meet local needs? These are currently questions without widely agreed-upon answers.

Utilities view customer-sited DG as necessarily causing bypass of the distribution system to at least some extent, resulting in the stranding of distribution assets both at the substation and the distribution feeder levels. Utilities may request reasonable cost recovery from their state utility commissions if that occurs, although in general the rate of DG deployment is expected to lag significantly behind overall system load growth. Standby charges on DG provide a means for utilities to recover past investments in distribution facilities and be compensated for providing backup services to DG operators when needed.

Many utilities feel that DG can be addressed adequately through present regulatory structures. For example, in a recent response to an order instituting rulemaking (OIR) issued by the California Public Utilities Commission (CPUC), PG&E expressed concern that “DG should not be artificially subsidized” and that the commission should be mindful of the “true costs” to all parties. They acknowledge that both utility and customer use of DG can help lower energy costs.

In several states, discussion about DG policies has focused on the possible allocation of exit fees. A load could be subject to a surcharge known as a “competitive transition charge” or “exit fee” that would be paid if an existing load is served by any party other than the local distribution company. The reasoning behind this concept is that customers might otherwise avoid paying their share of the costs for the existing utility infrastructure by switching to self-generation. On the other hand, similar types of system bypass have always been available to customers without the imposition of exit fees, and many state legislators may resist imposing them now.

Microgrid Economic Issues

As uncertain as the policy and economic landscape is for DG in general right now, it is even more so for microgrids—a concept with which many legislators and regulators are currently unfamiliar. However, some early work by the U.S. DOE and others suggests circumstances in which customers might find a microgrid to be a practical, economical, and attractive option.

CERTS Customer Adoption Model

In a report summarizing fiscal year 2000 work funded by the U.S. DOE, the Consortium for Electric Reliability Technology Solutions (CERTS) developed customer adoption models that analyzed typical load curves for four customer types: a grocery, a restaurant, an office, and a mall. By combining data from those four types, CERTS was also able to simulate a microgrid system. The results are summarized here less because of their value as a useful assessment of actual microgrid viability than as an illustration of one approach to the problem.

The study made simple assumptions about DG unit costs and made no allowance for the potential benefits of improved reliability, power quality, or CHP applications. Model customers were allowed to buy and sell power under several different scenarios. Under these assumptions, typical customers adopted some on-site generation under all scenarios.

The study found that typical annual electricity cost savings for the customers were approximately 20 to 25%. Model customers typically provided a significant share of their own energy requirements, often over 90%, while installed capacity tended to provide only some 50 to 70% of peak load. In other words, on-site generation tended to fill a baseload role; in none of the scenarios did customers meet their own peak load sufficiently to disconnect entirely from the grid.

When the four representative consumers' load profiles were combined to act as a microgrid, CERTS found that monthly load variation was dampened while differences between minimum and peak loads within a month became more prominent. For example, during January (Figure 7-1) the ratio of minimum to maximum load on a microgrid was 0.50, slightly flatter than the January load profiles for the simulated office and mall but much more variable than that of the grocery and restaurant. The August load profile (Figure 7-2) had a minimum-to-maximum load ration of 0.55, which was again flatter than the corresponding profiles for the office and the mall but less flat than those of the grocery and restaurant. On the other hand, while the grocery and mall experienced significant month-to-month variation in the shape of their load profiles, the microgrid enables customers to eliminate much of this variability. The resulting month-to-month load profile stability would help determine how DG technologies are selected.

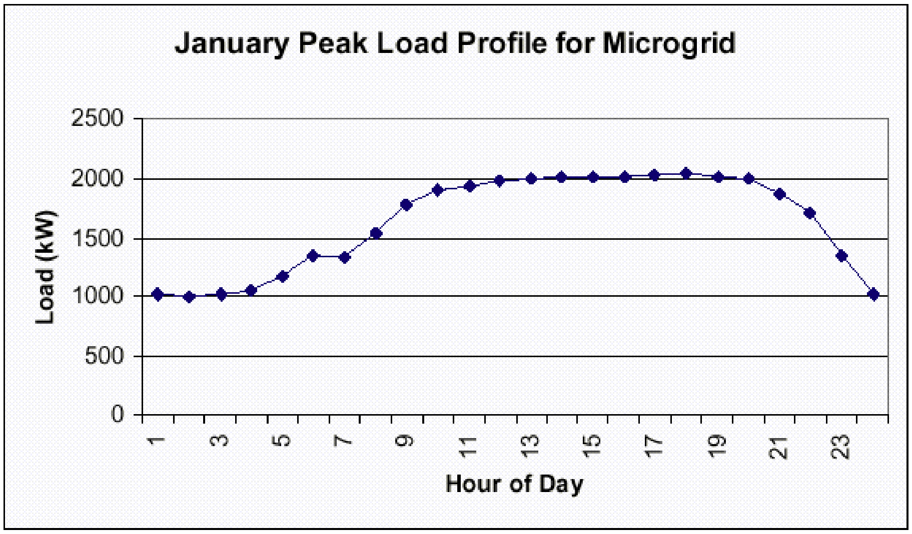

Figure 7-1
January Peak Load Profile for Simulated Microgrid (Source: CERTS)

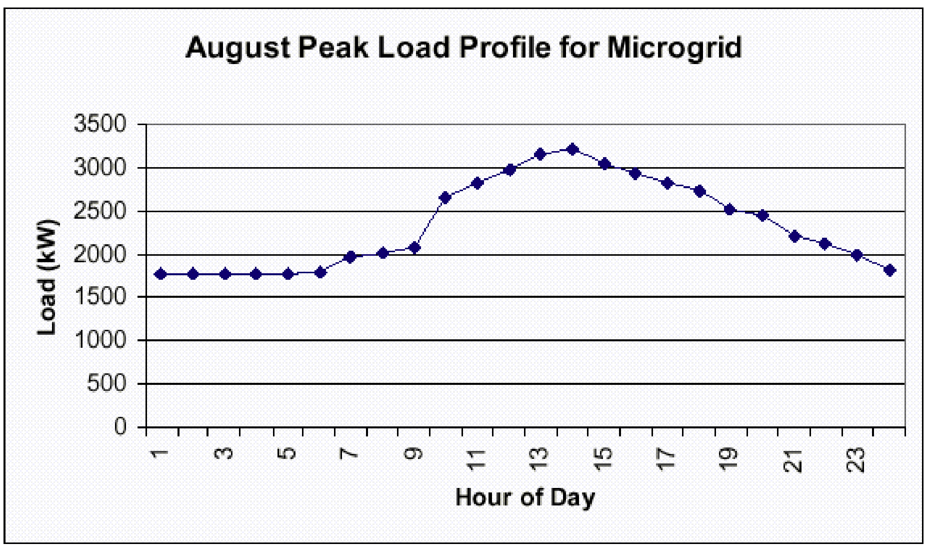

Figure 7-2
August Peak Load Profile for Simulated Microgrid (Source: CERTS)

Loads and generators within a microgrid not only appear as components of the microgrid's overall buying and selling pattern, concludes the CERTS report, but may also form complex economic relationships among themselves—for example, through bilateral or multilateral contracts for electricity, fuels, ancillary services, and heat for CHP applications.

Case Study: Block Island

Block Island is a community located approximately 10 miles off the coast of Rhode Island. The island is a resort and vacation destination, and its permanent population of approximately 800 grows to about 1,700 residents in the summer plus another several thousand visitors. Until recently, Block Island obtained its electricity from diesel generators, with some heating needs met by propane. The cost of transporting fuel from the mainland gave Block Island one of the highest electricity costs on the East Coast, as much as three times higher than mainland rates during the summer peak season.

Because the diesel generators were not in compliance with the Clean Air Act, Block Island Power Company (BIPCO) faced the prospect of either buying cleaner diesel generators or laying a submarine cable to carry electricity from the mainland. Both options would have driven electric rates even higher. A study by the U.S. DOE and the National Renewable Energy Laboratory (NREL) suggested that a DG microgrid combined with aggressive conservation measures could provide an economically viable alternative. The study proposed several measures:

- Wind Power—Install two 500-kW wind turbines to provide 1 MW (peak capacity) wind power.
- Photovoltaics—Install 50 20-kW PV systems at or near demand service customer premises to total 1 MW peak capacity.
- CHP—Install six 250-kW cogeneration systems to supply hot water to total 1.5 MW of CHP for demand service customers.
- Energy Efficiency—Replace 20,000 incandescent light bulbs with fluorescent lights in homes, hotels and restaurants; replace existing refrigerators with high-efficiency units for all year-round residential customers.
- Diesel Generators—Operate the existing diesel generators to provide 15% of the power sold as well as emergency peaking power.
- Future Plans (2004)—Install 1-kW cogeneration fuel cell systems in year-round customer residences to provide electricity and replace water heaters; reduce the use of existing diesel generators to 5%.

Overall, the study proposed generating 8.3 million kWh per year to meet customer demand of 7.7 million kWh, distributed as described in Table 7-1:

Table 7-1
Projected Block Island Microgrid Energy Mix (2004)

Efficiency (equivalent)	Wind Power	Commercial Cogen.	Residential Cogen.	PV	Diesel Backup	Total
25%	19%	29%	8%	21%	5%	107%

Since wind and PV are non-dispatchable, the match between supply and demand on a fine time scale is an important consideration. Initial estimates of demand measured over the course of a day and for each month of the year indicated a good match.

As shown in Table 7-2, the capital cost of the Block Island project would total approximately $8 million, or about $2 million per year over the four-year installation period. These costs are comparable to those involved with installing a submarine cable. There are no fuel costs associated with cogeneration because BIPCO would purchase fuel for the cogeneration units, run the cogeneration units to generate both heat and electricity, and then sell the resulting output to its customers, thereby offsetting its fuel cost. There are O&M costs associated with cogeneration as well as the other DG technologies.

The NREL study concluded that a microgrid system composed of clean distributed resources had the potential to be a technically and economically feasible alternative for BIPCO and island residents. Although actual work has not to date proceeded as the study suggested, the U.S. DOE did grant Rhode Island $400,000 to develop diesel replacement projects—including PV, wind, and solar hot water—to further investigate whether the DG microgrid approach would meet the needs of Block Island.

Table 7-2
Estimated First-Year System Costs for Block Island Project (1999 $)

	Efficiency	Wind Power	Comm. Cogen.	Res. Cogen.	PV	Diesel Backup	Total
Capital Cost	$500,000	$1M	$2M	$500,000	$4M		$8M
Size (MW)		1.0	1.5	0.3	1.0		
Life (years)	10	15	15	15	30		
Elec. Prod. (GWh/y)	2.0	1.5	2.2	0.6	1.6	0.4	8.3
O&M Cost ($/kWh)		$0.02	$0.05	$0.05	$0.01	$0.02	
Fuel Cost ($/kWh)						$0.08	
Annualize Factor	0.1343	0.1013	0.1013	0.1013	0.0707		
Annual Costs							
Cap. Cost ($/yr)	$67,132	$101,288	$202,575	$50,644	$282,865		$704,503
Property Tax ($/yr)		$5,000	$10,000	$2,500	$20,000		$37,500
Insurance ($/yr)		$7,500	$15,000	$3,750	$30,000		$56,250
O&M Cost ($/yr)		$29,692	$111,526	$32,073	$15,768	$7,671	$196,730
Fuel Cost ($/kWh)						$30,685	$30,685

Annual Cost	$1,025,668
Base Cost	$929,000
Total Cost	**$1,955,019**

8 FUTURE NEEDS AND RESEARCH

Gaps in both knowledge and technical capability must be filled to fully realize the potential for integrating microgrids and renewable distributed generation into the electric power system. This is especially true with respect to technical and operational considerations associated with large penetration of DG onto the system. Gaps include areas in which technology is not fully developed, standards have not yet been accepted, field experience is lacking, or methods of analysis and implementation are not available. They can be found in all three key areas of integration: interconnection, system design, and communication.

Interconnection Needs

Fundamentally, interconnection depends on hardware: control relays, transformer interfaces, disconnect switches, power converters, and other site-specific DG equipment. Consequently, there is much work to be done in developing standards, specifications, testing, and certifications to support that hardware. Test protocols are needed; field and laboratory experience will make these protocols practical and effective.

Near the top of the priority list is the anticipated promulgation of IEEE 1547, as described in Chapter 4. Unified national standards such as IEEE 1547 will help facilitate more efficient use of engineering resources in interconnecting DG to utility systems. However, the IEEE standard alone is not necessarily sufficient to unify and streamline interconnection practices. Other DG implementation issues beyond the scope of the standard will remain for regulatory bodies, utilities, DG manufacturers, and other DG stakeholders to resolve.

A universally accepted process for type-testing certification is a goal that appears achievable. As was also described in Chapter 4, type-testing certification is a process through which DG devices are factory-certified to conform to anti-islanding response, abnormal voltage and frequency, overcurrents, and other safety and power quality requirements. IEEE 1547 will greatly hasten progress toward type-testing certification, as will the precedent set by utilities willing to accept devices certified to be compliant with UL 1741, as is observed now with Capstone microturbines.

Field Experience

There is little question that the energy industry is still in the early-to-mid stages of the learning curve with respect to DG interconnection issues (and essentially at the bottom of the curve with respect to microgrids). The industry needs more field experience to learn how to optimize interconnection practices—practices that may seem appropriate in theory or on the bench but which may be found to have drawbacks as more units are installed in the field. After many years of growing DG penetration and further evolution in technology, it is likely that field experience will lead to increasingly optimized interconnection approaches that are both less costly and offer greater benefits for the power system.

Power System Design

Future high penetration of DG may lead to significant changes in the design and operational needs of power systems. Ideally, designs for new and upgraded distribution circuits will be more DG compatible so that DG is less likely to negatively impact the system. For example, suggested changes could include a longer reclosing “dead time” to give anti-islanding protection more time to work properly and reduce the risk of reclosing into an out-of-phase island. Selection of DG-compatible distribution transformers installed at the customer secondary level would help reduce adverse voltage impacts and ensure effective grounding of DG sources. Placement and programming of voltage regulation equipment to work more effectively with DG could help avoid many potential voltage problems. Overcurrent protection schemes that are less sensitive to the fault current contributions of DG and that can discriminate for directional power flow could greatly simplify the deployment of large amounts of DG on a system.

Distribution automation, as discussed in Chapter 3, is gradually growing throughout the distribution system. Planners and engineers considering automation projects should study the appropriate control and communication architectures that allow improved power system performance and high penetration of DG. The industry needs to move forward aggressively to determine how DG and distribution automation—two innovations that are emerging simultaneously—can work together to provide the best possible performance and service.

Standardized communication protocols are critical to ensuring that DG devices can interface with the communication network that will eventually be established at all levels of the power system. Communication protocols for distribution automation, SCADA, and DG must be compatible to allow equipment interaction at all system levels and to allow data transfer where needed. The industry and interested stakeholders must continue their strong efforts to develop UCA and gain full acceptance of this standard. In particular, communication object models need to be developed and validated that allow DG devices to be recognized by UCA and legacy architectures so that a migration to UCA can occur over time.

The list of these and other recommended design changes is long; many could be implemented with relatively small to moderate cost and would offer substantial performance improvement for the investment. Any planning-based design changes that are implemented would of course need to balance the needs of DG, the benefits received from DG, and any adverse impacts that may occur in other areas as a result of the changes.

Feeder Study Recommendations

EPRI’s work in modeling DG urban, suburban, and rural feeders yielded several recommendations for the direction of future investigation, starting with the need to study more real-world feeder circuits to formulate DG penetration limits for different configurations and extract some general guidelines from those analyses. Such new studies could be used to validate simple analytical formulas that could be used by utility planners.

With respect to protection, the impact of DG on the operation of reverse power relays used in street networks requires further study, as does the impact of DG on looped systems that can be reconfigured using remotely controlled switches.

Harmonic levels in feeders could be monitored to validate the models used in detailed simulations. In addition, energy companies and industry literature should be reviewed to verify whether the limits used in constructing the simulations—for example, a 5% voltage dip due to loss of generation, a 10% voltage dip due to loss of excitation or malfunction of an inverter control, or a 3% voltage dip accompanying the starting of an induction generator—are appropriate. More research is needed on PV and wind systems to see exactly how rapidly power levels can fluctuate due to cloud movement or how flicker can be induced by tower shadow or sporadic wind variations.

In general, the software tools used to study power system behavior must become more powerful and sophisticated. The industry would benefit from new or improved screening tools, DG database management systems, good dynamic models of DG, and advanced DG load flow, stability, and planning tools.

Education

One of the largest gaps facing microgrids and DG is the need to train and educate key stakeholders, including regulators, utility managers, engineers and planners, DG manufacturers, equipment integrators, installers, owners and operators, and electric customers. Inadequate education and understanding has in the past led to confusion, delays, mistrust, and poor DG implementations. The industry would greatly benefit from both training and cross training, in which one stakeholder learns from the experience and expertise of another. For example, utility engineers could receive training on DG technologies from manufacturers while DG manufacturers receive training on utility system design and operation. Certification classes for engineers, electricians, and technicians would help build a base of expertise within the industry to support DG design and construction efforts.

The energy industry enters the 21st century facing a new, evolving, dynamic operating environment that will almost certainly include distributed generation and microgrids. The industry should move to develop the technologies, methodologies, standards, and practices needed to fill capability voids and successfully integrate them into the system.

9
REFERENCES

CERTS Customer Adoption Model, Consortium for Electric Reliability Technology Solutions, Prepared for the Transmission Reliability Program, Office of Power Technologies, U.S. Department of Energy by Lawrence Berkeley National Laboratory, Berkeley, California: March 2001. LBNL-47772.

Customer Adoption of Small-Scale On-Site Power Generation, Lawrence Berkeley National Laboratory, Berkeley, California: May 2001. LBNL-47896.

Developing a Data Set for Modeling Distributed Resource Devices in Electric Power System Simulations, EPRI, Palo Alto, California: December 2000. 1000418.

Distributed Generation Implementation Guidelines: Siting, Environmental Permitting, and Licensing, EPRI, Palo Alto, California: December 1998. TR-111545.

Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems, EPRI, Palo Alto, California: December 2000. 1000419.

Generator Interconnect Supplement to Consumers Energy Generator Interconnection Requirements, Consumers Energy, Jackson, Michigan: May 2001.

Generic Analytical Models for Assessing Distribution System Design Implications of Distributed Generation and Storage, EPRI, Palo Alto, California: December 1999. TR-114156.

Greenhouse Gas Reduction with Renewables, EPRI, Palo Alto, California: December 2000. TR-113785.

Herig, Christy, *Distributed Generation in Minigrids*, National Renewable Energy Laboratory, Golden, Colorado: September 1999. DOE/GO-10098-657.

Hoff, Thomas E., *A Preliminary Analysis of Block Island Power Company's Use of Clean Distributed Resources to Provide Power to its Customers*, Clean Power Research, prepared for the National Renewable Energy Laboratory, Golden, Colorado: August 1998.

Hoff, Thomas E., and Herig, Christy, *The Market for Photovoltaics in New Homes Using Microgrids*, National Renewable Energy Laboratory, Golden, Colorado: January 2000.

Hoff, Thomas E., Wenger, Howard J., Herig, Christy, and Shaw, Robert W.*, Distributed Generation and Micro-Grids*, paper presented at the 18th USAEE/IAEE Conference, San Francisco, California: September 1997.

Integrated Assessment of Dispersed Energy Resources Deployment, Consortium for Electric Reliability Technology Solutions, Prepared for the Transmission Reliability Program, Office of Power Technologies, U.S. Department of Energy by Lawrence Berkeley National Laboratory, Berkeley, California: June 2000. LBNL-46082.

Integration of Distributed Resources in Electric Utility Systems: Current Interconnection Practice and Unified Approach, EPRI, Palo Alto, California: November 1998. TR-111489.

Integration of Distributed Resources in Electric Utility Distribution Systems: Distribution System Behavior Analysis for Suburban Feeders, EPRI, Palo Alto, California: November 1998. TR-111490.

Integration of Distributed Resources in Electric Utility Distribution Systems: Distribution System Behavior Analysis for Urban and Rural Feeders, EPRI, Palo Alto, California: November 1999. TR-112737.

Integration of Distributed Resources in Electric Utility Systems: Functional Definition for Communication and Control Requirements, EPRI, Palo Alto, California: November 1998. TR-111491.

Photovoltaic-Based Projects and Ventures: Development Guidelines, EPRI, Palo Alto, California: March 1999. TR-111892.

PV Standards, Codes, and Accepted Industry Practice, Florida Solar Energy Center website, University of Central Florida, www.fsec.ucf.edu/pvt/resources: January 2002.

Renewable Energy Technical Assessment Guide—TAG-RE: 2001, EPRI, Palo Alto, California: December 2001. 1004034.

Review of Utility Interconnection, Tariff and Contract Provisions for Distributed Generation, National Association of Regulatory Utility Commissioners (NARUC), Washington, D.C.: January 2000.

Scenarios for Distributed Technology Applications with Steady-State and Dynamic Models of Loads and Micro-Sources, Power System Engineering Research Center (PSERC), University of Wisconsin, Madison, Wisconsin: April 2000.

Technology Assessment of Interconnection Products for Distributed Resources: Research and Development Recommendations, EPRIsolutions, Palo Alto, California: December 2000. 1000775.

Target:

Renewable Technology Options and Green Power Marketing

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

EPRI. Electrify the World

Printed on recycled paper in the United States of America

1004045

SINGLE USER LICENSE AGREEMENT

THIS IS A LEGALLY BINDING AGREEMENT BETWEEN YOU AND THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). PLEASE READ IT CAREFULLY BEFORE REMOVING THE WRAPPING MATERIAL.

BY OPENING THIS SEALED PACKAGE YOU ARE AGREEING TO THE TERMS OF THIS AGREEMENT. IF YOU DO NOT AGREE TO THE TERMS OF THIS AGREEMENT, PROMPTLY RETURN THE UNOPENED PACKAGE TO EPRI AND THE PURCHASE PRICE WILL BE REFUNDED.

1. GRANT OF LICENSE

EPRI grants you the nonexclusive and nontransferable right during the term of this agreement to use this package only for your own benefit and the benefit of your organization. This means that the following may use this package: (I) your company (at any site owned or operated by your company); (II) its subsidiaries or other related entities; and (III) a consultant to your company or related entities, if the consultant has entered into a contract agreeing not to disclose the package outside of its organization or to use the package for its own benefit or the benefit of any party other than your company.

This shrink-wrap license agreement is subordinate to the terms of the Master Utility License Agreement between most U.S. EPRI member utilities and EPRI. Any EPRI member utility that does not have a Master Utility License Agreement may get one on request.

2. COPYRIGHT

This package, including the information contained in it, is either licensed to EPRI or owned by EPRI and is protected by United States and international copyright laws. You may not, without the prior written permission of EPRI, reproduce, translate or modify this package, in any form, in whole or in part, or prepare any derivative work based on this package.

3. RESTRICTIONS

You may not rent, lease, license, disclose or give this package to any person or organization, or use the information contained in this package, for the benefit of any third party or for any purpose other than as specified above unless such use is with the prior written permission of EPRI. You agree to take all reasonable steps to prevent unauthorized disclosure or use of this package. Except as specified above, this agreement does not grant you any right to patents, copyrights, trade secrets, trade names, trademarks or any other intellectual property, rights or licenses in respect of this package.

4. TERM AND TERMINATION

This license and this agreement are effective until terminated. You may terminate them at any time by destroying this package. EPRI has the right to terminate the license and this agreement immediately if you fail to comply with any term or condition of this agreement. Upon any termination you may destroy this package, but all obligations of nondisclosure will remain in effect.

5. DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, NOR ANY PERSON OR ORGANIZATION ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS OR SIMILAR ITEM DISCLOSED IN THIS PACKAGE, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS PACKAGE IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS PACKAGE OR ANY INFORMATION, APPARATUS, METHOD, PROCESS OR SIMILAR ITEM DISCLOSED IN THIS PACKAGE.

6. EXPORT

The laws and regulations of the United States restrict the export and re-export of any portion of this package, and you agree not to export or re-export this package or any related technical data in any form without the appropriate United States and foreign government approvals.

7. CHOICE OF LAW

This agreement will be governed by the laws of the State of California as applied to transactions taking place entirely in California between California residents.

8. INTEGRATION

You have read and understand this agreement, and acknowledge that it is the final, complete and exclusive agreement between you and EPRI concerning its subject matter, superseding any prior related understanding or agreement. No waiver, variation or different terms of this agreement will be enforceable against EPRI unless EPRI gives its prior written consent, signed by an officer of EPRI.

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com