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Renewable Systems Interconnection Study:

Advanced Grid Planning and Operations

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Sandia Contract 715908

Abstract

To facilitate more extensive adoption of renewable distributed electric generation, the U.S. Department of Energy launched the Renewable Systems Interconnection (RSI) study during the spring of 2007. The study addressed the technical and analytical challenges that must be addressed to enable high penetration levels of distributed renewable energy technologies. This RSI study addresses grid-integration issues as a necessary prerequisite for the long-term viability of the distributed renewable energy industry, in general, and the distributed PV industry, in particular.

Preface

Now is the time to plan for the integration of significant quantities of distributed renewable energy into the electricity grid. Concerns about climate change, the adoption of state-level renewable portfolio standards and incentives, and accelerated cost reductions are driving steep growth in U.S. renewable energy technologies. The number of distributed solar photovoltaic (PV) installations, in particular, is growing rapidly. As distributed PV and other renewable energy technologies mature, they can provide a significant share of our nation's electricity demand. However, as their market share grows, concerns about potential impacts on the stability and operation of the electricity grid may create barriers to their future expansion.

To facilitate more extensive adoption of renewable distributed electric generation, the U.S. Department of Energy launched the Renewable Systems Interconnection (RSI) study during the spring of 2007. This study addresses the technical and analytical challenges that must be addressed to enable high penetration levels of distributed renewable energy technologies. Because integration-related issues at the distribution system are likely to emerge first for PV technology, the RSI study focuses on this area. A key goal of the RSI study is to identify the research and development needed to build the foundation for a high-penetration renewable energy future while enhancing the operation of the electricity grid.

The RSI study consists of 15 reports that address a variety of issues related to distributed systems technology development; advanced distribution systems integration; system-level tests and demonstrations; technical and market analysis; resource assessment; and codes, standards, and regulatory implementation. The RSI reports are:

- *Renewable Systems Interconnection: Executive Summary*
- *Distributed Photovoltaic Systems Design and Technology Requirements*
- *Advanced Grid Planning and Operation*
- *Utility Models, Analysis, and Simulation Tools*
- *Cyber Security Analysis*
- *Power System Planning: Emerging Practices Suitable for Evaluating the Impact of High-Penetration Photovoltaics*
- *Distribution System Voltage Performance Analysis for High-Penetration Photovoltaics*
- *Enhanced Reliability of Photovoltaic Systems with Energy Storage and Controls*
- *Transmission System Performance Analysis for High-Penetration Photovoltaics*
- *Solar Resource Assessment*
- *Test and Demonstration Program Definition*
- *Photovoltaics Value Analysis*
- *Photovoltaics Business Models*

- *Production Cost Modeling for High Levels of Photovoltaic Penetration*
- *Rooftop Photovoltaics Market Penetration Scenarios*.

Addressing grid-integration issues is a necessary prerequisite for the long-term viability of the distributed renewable energy industry, in general, and the distributed PV industry, in particular. The RSI study is one step on this path. The Department of Energy is also working with stakeholders to develop a research and development plan aimed at making this vision a reality.

List of Acronyms

ΔV	voltage change
ANSI	American National Standards Institute
BPL	broadband over power line
CAES	compressed air energy storage
CERTS	Consortium for Electric Reliability Technology Solutions
AEP	American Electric Power
CHP	combined heat and power
CT	combustion turbine
DER	distributed energy resources
DG	distributed generators or generation
DOE	U.S. Department of Energy
DR	distributed resources
DUIT	Distributed Utility Integration Test
EEN	energy exceeding normal
EMS	energy management systems
EPRI	Electric Power Research Institute
FCC	Federal Communications Commission
HV	high voltage
I^2R	power flow losses
IA	IntelliGrid Architecture
ICE	internal combustion engine
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IGBT	insulated gate bipolar transistors
ISO	independent system operator
IUT	intelligent universal transformer
LCOE	levelized cost of energy
LTC	load tap changing
LV	low voltage
MCFC	molten carbonate fuel cells
MEM	Microgrid Energy Management
MV	medium voltage
NREL	National Renewable Energy Laboratory
NTUA	National Technical University of Athens
OMS	outage management system
PAFC	phosphoric acid fuel cells
PHEVs	plug-in hybrid electric vehicles
PURPA	Public Utility Regulatory Policies Act (1978)
PV	photovoltaics
PWM	pulse-width modulated
RSI	Renewable Systems Interconnection
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
SEIA	Solar Energy Industries Association

SMES	superconductive magnetic energy storage
SNL	Sandia National Laboratories
T&D	transmission and distribution
TC	Technical Committee (of the IEC)
UL	Underwriters Laboratories
VAC	volts alternating current
VAR	volt ampere reactive
WG	Working Goal (of the IEC TC)

Executive Summary

The electric grid enables PV generation by delivering available renewable power system output to the larger energy market. The grid simplifies the balancing of variations in supply and demand of individual distributed generators over a wide area. This service improves distributed generator economics and reduces the requirement for adding energy storage. A critical challenge—and the subject of this study—is that significant deployment of PV energy requires modernization of the distribution grid. Grid change needs depend on the level of deployment, the existing distribution configuration, and the PV system design. R&D is needed to define what future electric distribution will look like and how the existing distribution system can evolve to this new design.

This report looks at issues and options for increasing the penetration of renewable generation. The distribution grid was designed and built and is operating for centralized generation. With limited capacity for reversing power flows and without control and communication at the point of use, our existing distribution grid is not equipped to realize the full potential of distributed PV generation. Gradual—and not necessarily system-wide—evolution is needed and should be appropriate for the level of penetration at a substation or feeder level. Other opportunities to improve the distribution and use of electricity such as load management, advanced metering, and demand control are considered in this report, along with distributed renewable generation.

Two evolutions are envisioned. The first is distributed PV systems that operate interactively with available solar resources, varying conditions on the grid, and other local resources, including load control and future generation and storage resources. The second, and perhaps more challenging, evolution is that the distribution grid will need to be reinvented to interact with and in some cases control distributed generation and load demand. This will in turn make the grid more compatible with "grid-ready" distributed PV systems.

To support this vision, a strategy is needed to move from the relatively small PV energy market of "passively interacting" systems to a PV system that is an "active partner" in the grid. A key element of this strategy is that the PV system will help to meet system energy demand and control requirements at all grid levels, including transmission and independent system operators. Another element is recognition of the large existing capital investment in distribution, which will require a long-term and deliberate effort to change.

A key conclusion of this work is that significant coordination, planning, and related R&D will be required to ensure that the evolution is done intelligently. This "smart" evolution includes other necessary system changes, such as allowing for increasing distribution automation, automated load controls, and greater facilitation of features that enhance power quality and reliability. These features can be part of a 21st-century grid that is more reliable, has improved long-distance power transaction flexibility, and is ready for widespread PV energy systems.

Three areas are addressed in this report:

- Evolutionary change to enable high penetration
- 21st-century power distribution and PV compatibility
- The future for microgrids.

Evolutionary Change to Enable High Penetration

In the history of efforts to deploy and apply distribution generation, significant progress has been made with interconnection standards and with the recognition that changes must be made in power distribution design and operation in the future. This began with the Public Utility Regulatory Policies Act (PURPA) of 1978, which provided a framework and allowed cogeneration with the electric grid. Larger conventional types of distributed generators (DG) were installed on a case-by-case basis. With a wider variety of smaller generators, more uniform connection rules were developed. As penetration levels increase, however, traditional grid system operation and controls require change (with a few exceptions). In general, distributed resources passively interact with the grid.

With the growth and success of wind generation and aggregation into large wind farms at transmission and subtransmission levels, the operating rules have evolved to more active interaction with and support of the grid. As distribution-level distributed generation grows to higher penetration levels, two evolutions are seen. The first is that distribution generation begins to operate interactively with both the conditions on the grid and with other local resources, including load control and, in the future, other generation and storage resources. The second and perhaps more challenging evolution is that the distribution grid will need to be redesigned and rebuilt, perhaps reinvented, to be more compatible with the new requirements of distributed energy systems.

Table ES-1 shows this evolution of distributed energy (note that stand-alone operation, such as microgrids that are disconnected from the electric grid, is not included in this table).

Table ES-1. Evolution of Distribution Energy

Parameter of Interest	Fossil Fueled Cogeneration (PURPA) (1978 to mid-1990s)	Emerging Gas and Renewable DG (mid-1990s to present)	Maturing Renewable DG and Load Control (near future and beyond)
Penetration Level	Less than 2% of bulk generation energy	Less than 10%	Growing to 20% and greater
Deployment Strategy of Distributed PV	To provide initial legal and technical framework to allow grid connection of independent power producers	To facilitate a developing market for small to mid-sized passively interacting DG	DG becomes an active partner in helping to meet system energy demand and control requirements at all grid levels
Level of System Where Strategy Is Focused	Not addressed	Distribution system level	Distribution and bulk system levels
Level of PV Compliance with the Electric Power System	Location-specific requirements; main concerns are trip limits, safety, and protection	System-specific requirements for power quality, islanding protection, and passive system participation	Uniform requirements for power quality and active participation in power system operation
Electric Power System Changes To Enable Penetration	No special proactive design considerations	Some proactive design considerations, mostly minor changes such as slower reclosing	Significant protection, control, grounding, and communication design changes to implement high penetration

The transition to active distributed PV systems and a distribution system that is ready for integration of these systems will not be achieved abruptly. Such a sudden shift would disrupt existing power delivery and require too much new capital investment. Distributed generation is operating now in compliance with utility voltage limits, and high penetrations can be achieved with the use of adaptive, autonomous local control systems that operate under utility supervision, as well as with the use of rapid, inverter-based fault current limiting. Considerable time will be required, however, to fully integrate these distributed systems with automated distribution management systems (involving investments by both utilities and PV system manufacturers). A key conclusion of this work is that significant coordination, planning, and related R&D will be required to ensure that the evolution proceeds in an intelligent fashion and includes other necessary system changes, which could include increasing distribution automation, adding automated load controls, and building in features that enhance power quality and reliability. These features can be part of a 21st-century grid that is more reliable, has improved long-distance power transaction flexibility, and is more compatible with distributed PV generation.

Overarching the technical challenges of increasing penetration levels is the need for change in the traditional business case for generation and delivery of electric power. In looking to the future requirements for implementation of distributed resources, the research plan and agenda must promote both central and distributed power system concepts with a view to optimizing system efficiency and economics. It is critical that research is directed to creating opportunities on both sides of the meter that lead to a “market-driven response” for reinventing the electric grid.

Power Distribution and PV Compatibility

In the future, generation of distribution will be more automated and ready to interact with distributed PV and other distribution-connected energy resources. Distribution automation and smart grids will apply to all the elements of the distribution system:

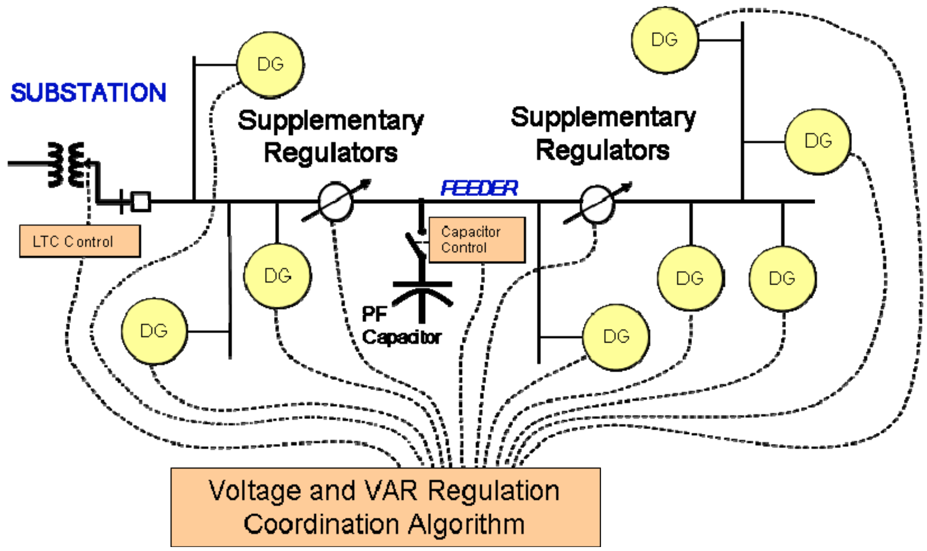
- Individual customers (meters and loads) and at the transformers or groups of customers (including intelligent universal transformers)
- Intelligent load-control devices on the distribution system
- Distributed generation and storage, including local energy control systems, rooftop solar, and eventually plug-in electric vehicles
- Intelligent switches, breakers, and reclosers on the feeder
- Substation data management
- Planning area data management.

There is general agreement that all of these elements, as well as related opportunities and challenges, must be considered together so as to best apply new technologies to meet today’s challenges for the distribution system. As a result, several efforts have emerged to address these issues:

- The Gridwise Consortium, led by the U.S. Department of Energy, Washington, D.C.
- The Intelligrid Consortium, led by the Electric Power Research Institute, Palo Alto, California
- The Avanti Distribution Circuit of the Future project, led by Southern California Edison, Rosemead, California
- The DisPower project, coordinated by ISET, Kassel, Germany

In addition to these projects, national laboratories, power companies, universities, and equipment manufacturers around the globe are undertaking numerous research activities. Overall, the ongoing development and implementation of distribution automation is a synergistic activity that is partially driven by the need to accommodate and to control distribution-level resources. There is no doubt that an automated distribution system will be more interactive with distributed PV systems than the current systems. This, in turn, will enable better utilization of resources and higher penetration. The requirements for high-penetration PV will generally include the following:

- **Interactive voltage regulation and volt ampere reactive (VAR) management.** Utility voltage-regulator and capacitor controls will be interactive with each other and the DG sources. A central controller, such as that depicted in Figure ES-1, will help manage the interactivity to ensure optimized voltage and reactive power conditions.



Note: LTC = load tap changing

Figure ES-1. Distributed controller results are aggregated to manage area power and system voltage profiles

- **Bulk system coordination of DG.** For market and bulk system control, DG will need to be controlled from a dispatch center. This will allow DG to participate and be aggregated into energy markets as well as to preserve system stability, power quality, and reliability at the bulk level.
- **Protective relaying schemes designed for DG.** The distribution and subtransmission systems will include more extensive use of directional relaying, communication-based transfer trips, pilot signal relaying, and impedance-based fault-protection schemes (like those used in transmission). These can work more effectively with multiple sources on the distribution system.
- **Advanced islanding control.** To improve the ability to detect unintentional islands, switchgear will need to be extensively automated and DG will need enhanced islanding detection capabilities. In addition, these systems should be able to reconfigure the grid/DG into reliability-enhancing "intentional islands."
- **Interactive service restoration.** Sectionalizing schemes for service restoration allow distributed PV and other DG to help pick up load during the restoration process, as shown in Figure ES-2. Once separated, these must deal effectively with overloads from cold-load pickup and the current inrush required to recharge the system.

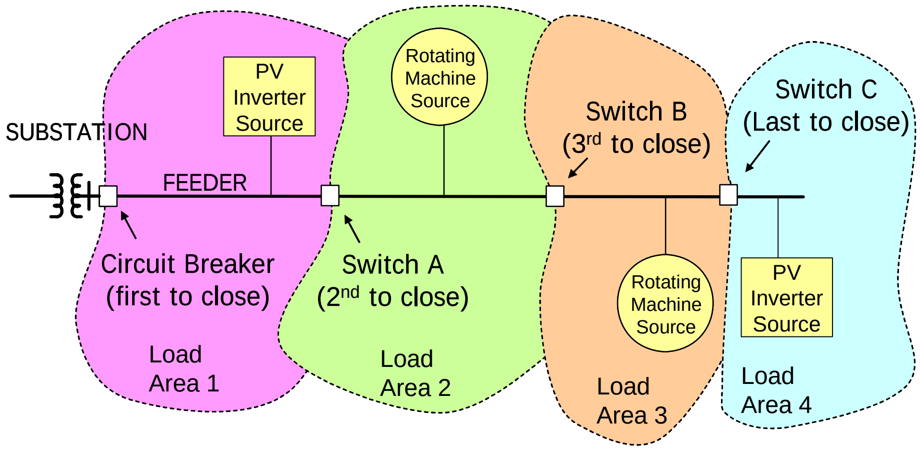


Figure ES-2. Illustration of cascaded restoration of DG

- **Improved grounding compatibility.** In both DG and distribution, new devices and architectures must be considered that address grounding incompatibilities among power system sensing, protection, and harmonic flows. Examples of these techniques are
  - Control or limit ground fault overvoltage via relaying techniques or ancillary devices instead of effectively grounded DG requirements
  - Harden the power system and loads to be less susceptible to ground fault overvoltage (increase voltage withstand ratings)
  - Change protective relaying for ground faults so a high penetration of grounding sources does not affect the ground fault relaying
  - Change feeder grounding scheme or load serving scheme back to a grounded three-wire system.
- **Employ distributed energy storage.** Energy storage of various forms will apply to correct temporary load/generation mismatches, regulate frequency, mitigate flicker, and assist advanced islanding functions and service restoration.

These system changes and technology upgrades not only represent an extensive investment on the part of government, electric utilities, and equipment manufacturers, but also a huge change in the way the power system is operated and designed. These changes will not be implemented overnight but rather over many decades. Furthermore, considerable engineering planning and development will be required to determine the balance of necessary features and capabilities against the cost and complexity of implementation. Nonetheless, these are the approaches needed to move to high-penetration PV, and the industry needs to begin work now on R&D that will make technologies, tools, and approaches available in a timely manner.

In moving forward, the best tactic is not to look at these changes as being done solely for the purpose of high-penetration DG implementation. Many changes also have synergy with other system operating goals that electric utilities and customers have had for decades. As a result, the incremental value or value-added aspects of investments must be identified and evaluated.

Future for Microgrids

There is considerable interest in developing microgrids with multiple generators at widely dispersed locations and with a variety of generation types, including various combinations of solar, wind, fuel cell, reciprocating engine, combustion turbine, and energy-storage devices. Using multiple generators at dispersed locations requires a significant change in the protection and control methodologies compared to those employed at a single generation plant. No longer will the standard radial protection and relaying approaches be appropriate, and the generators must communicate with each other in a manner that ensures adequate load sharing, system stability, proper frequency and voltage control, and optimal system performance in terms of efficiency and the cost of energy production.

Microgrids can be applied in a broad range of sizes and configurations. Figure ES-3 shows examples of possible microgrid subsets that could be derived on a typical radial distribution system. These subsets include a single customer, a group of customers, an entire feeder, or a complete substation with multiple feeders. A very large substation could serve more than 10,000 customers, have up to 100 MW of capacity, and employ eight or more feeders.

Challenges with microgrids are many. Regardless of their size, they must take on key control responsibilities while operating in the islanded state; otherwise, serious damage can result. These distributed generators must not adversely affect reliability, voltage regulation, or power quality on the bulk power system while the microgrid is interconnected.

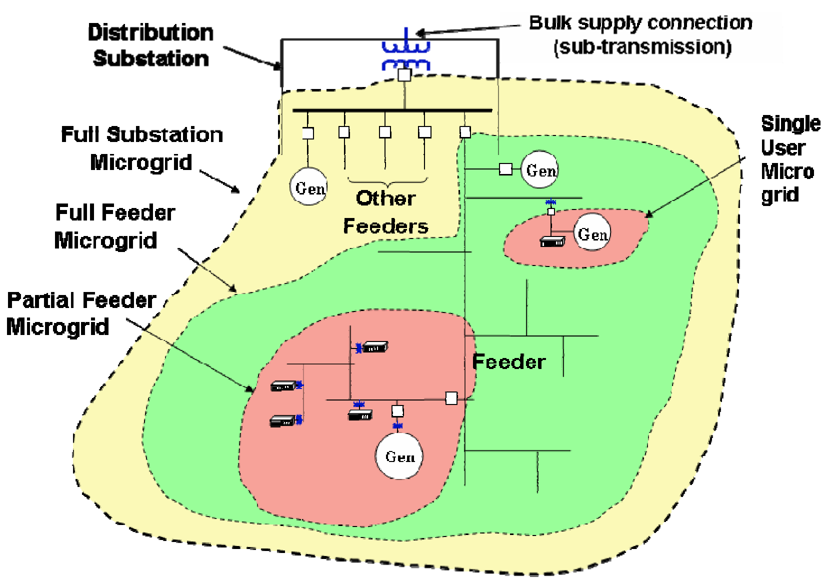
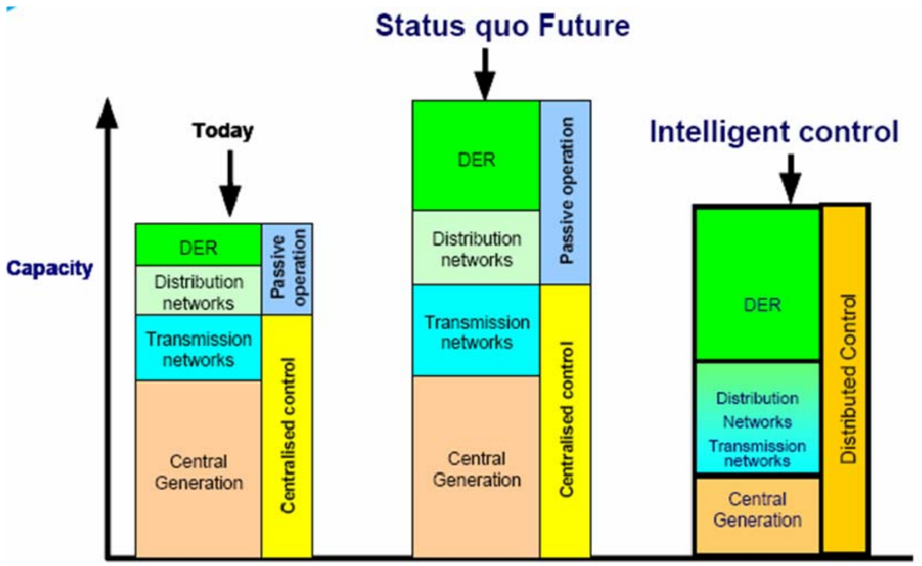


Figure ES-3. Concept of distribution microgrids of various sizes and levels, allowing reliability islands and grid tie operation

Advanced inverters/controllers and energy management systems (EMS) will need to be sophisticated enough that they can interface with emerging smart grid technology. As such, the advanced technologies must be capable of supporting communication protocols used by current energy management and utility distribution-level communication systems. Finally, these systems must meet the performance and reliability targets set forth by the AIIC/EMS Program, in which analysts use the levelized cost of energy (LCOE) as a metric. Figure ES-4 illustrates this shift from today's central control system to the intelligent control system of the future.



Note: DER = distributed energy resources

Figure ES-4. Distributed controller must be integrated with overall distribution control systems to maximize system value

The master controller is the key to providing highly sophisticated microgrid operation that maximizes efficiency, quality, and reliability. Some of the capabilities identified for an intelligent microgrid master controller are currently being researched; others do not yet exist. The Galvin Electricity Initiative has documented the functional requirements for master controller software in *Master Controller Requirements Specifications for Perfect Power Systems, Revision 2-1*(EPRI, Palo Alto, CA, November 15, 2006). This document is available from the Galvin Electricity Initiative's Web site at www.galvinpower.org.

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1.0 Introduction

This report describes research and analysis on advanced grid planning and operations needed to facilitate large-scale integration of distributed photovoltaics (PV) into the distribution system. This work was aimed at answering a key question: What grid modernization strategies are needed to enable large-scale deployment of distributed renewable generation and integration with other load and generation resources?

These strategies will vary depending on the voltage with which new PV generation is connected in the power system, ranging from low-voltage (LV) power customers through medium-voltage (MV) distribution to high-voltage (HV) transmission. Strategy will also depend on the penetration level relative to the power system capacity at the point of connection. The rules, concerns, and potential paybacks all vary at different system levels and have been treated separately in the past, as illustrated in Table 1-.

Table 1-1. Distributed Power System Performance Expectations at Various Connection Points in the Electric System

<table>
<tr><th>Distributed Generator (DG) Expectations and Connections</th><th>Interconnection Rules</th><th>System Integration Concerns</th><th>Local and System Values or Payoff</th></tr>
<tr><td>Connection at LV End Use</td><td rowspan="2">Local connection requirements; e.g., Institute of Electrical and Electronics Engineers (IEEE) 1547and derivatives</td><td rowspan="2">Feeder-level issues such as power flows, protection, and voltage impacts; e.g., issues related to high penetration levels</td><td>Power, heat, load control, quality, and reliability</td></tr>
<tr><td>Connection at MV Distribution</td><td rowspan="2">Ancillary service support to utility transmission and distribution (T&D); e.g., reserve capacity, demand response, and deferral of expansions</td></tr>
<tr><td>Connection at HV Transmission</td><td>Special grid rules for <20-MW generators</td><td>Understanding system response for planning and analysis of scenarios</td></tr>
</table>

Therefore, a key issue for this analysis is how to bring together system understanding and the related R&D requirements for high-penetration renewable integration. With a view of the overall grid planning and operational challenges, the following other issues and questions are addressed in this study:

- What are the grid-reliability-driven boundary conditions that limit PV resources installed in a given location? And how can these limits expand by grid modernization, communication, and/or other demand-response technologies?
- How can distributed renewable generation increase significantly without affecting the safety, reliability, security, sustainability, and cost effectiveness (surety) of the T&D system?

- What research is needed to determine the operating, control, and physical changes required to allow T&D systems to accommodate high levels of renewable penetration?

The answers to these questions will depend strongly on the characteristics of the local distribution network, other modes of generation available locally, characteristics of the transmission grid, and the availability and market cost of power, among others. An approach to cover this variety of possible applications is to consider several scenarios that reflect regions and distribution systems with differing characteristics. Work in other areas of the U.S. Department of Energy (DOE) Renewable Systems Interconnection (RSI) study, such as identifying various market scenarios and evaluating impacts by simulating different distribution penetration conditions, will complement results in this report.

1.1 Scope

This report addresses the following RSI study area: "Definition of Grid Requirements for Increasing Distributed Energy Resources." For this work, the Electric Power Research Institute (EPRI) coordinated with the National Renewable Energy Laboratory (NREL), Sandia National Laboratories (SNL) and other participants to develop and share research and analysis on advanced grid planning and operations that will be needed to facilitate large-scale integration of distributed PV into the distribution system. The work specifically addresses the expected research needs and the potential pitfalls or gaps in grid planning and retooling to accommodate high penetration of distributed resources.

A key concept in defining and timing future research under this study area is the expected evolution of distributed resource penetration from an insignificant (appliance) level to levels where the grid is dependent on distributed generation for voltage support and eventually for energy production. As penetration levels evolve, so must grid planning and operation. The rules for operating with increased distributed resources penetration will change from the current requirements found in IEEE 1547. A step change in operating rules and requirements occurs with grid separation and intentional islanding or microgrid operation. In this separation, both the islanded distributed resources and the grid experience a paradigm shift in operating philosophy and requirements. The approach taken in this task was to consider this necessary evolution and identify needed grid advancements.

Overarching the technical challenges of increasing penetration levels is the need for change in the traditional business case for generation and delivery of electric power. To accommodate future requirements for implementing distributed resources, the research agenda must promote both central and distributed power system concepts while optimizing system efficiency and economics. It is critical that research is directed at creating opportunities on both sides of the meter—opportunities that lead to a "market-driven response" for reinventing the electric grid. This need to facilitate a market response will be considered in identifying a grid research agenda.

1.2 Approach

The following approach was taken in preparing this report:

- Identify what is needed for the distribution system to evolve from distributed resources operating at an appliance level to fully utilizing them as grid resources

- Consider the potential interactions and relative importance of all energy resources from central power plants and the distribution grid to energy efficiency, distributed PV and storage systems, and the plug-in hybrid electric vehicles (PHEVs) of the future.
- Aim to put all requirements and related research in the context of creating opportunities on both sides of the meter that lead to a market-driven response
- Outline the specific requirements that will be necessary for grid evolution as operating rules change from an insignificant level to the microgrids level
- Accomplish all of this while retaining safety, reliability, and power quality.

1.3 Report Organization

Section 2 addresses the current status of research on the addition of distribution-connected PV power systems and related energy resources. In Section 3, the overall approach to this study is described. Section 4 details the research results and the gaps between current and future R&D needs, which are outlined in Section 5. Recommendations for future R&D are given in Section 6 and conclusions are presented in Section 7. The appendices offer several descriptions of penetration levels and needs for future inverter and controller technologies.

2.0 Current Research Status

Today's electric distribution systems have evolved over many years in response to load growth and changes in technology. The largest single investment of the electric utility industry is in the distribution system.

2.1 Today's Radial Distribution System

Most common in today's distribution system are radial circuits fed from distribution substations designed to supply load based on customer demand while maintaining an adequate level of power quality and reliability. Figure 2-1 shows the topology of the current system.

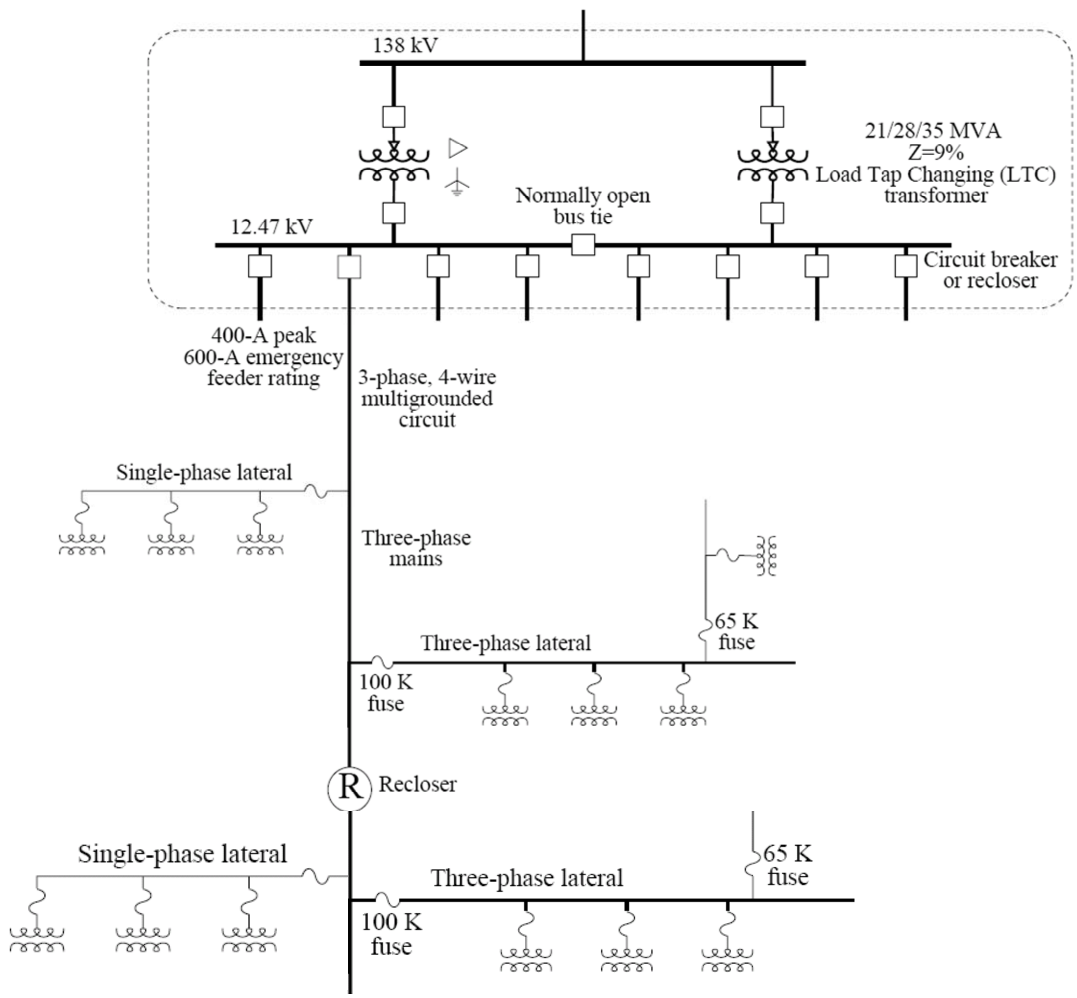

Figure 2-1. Typical distribution feeder topology [1]

Figure 2-1 shows how the system is designed to be fed from a single source. Protection is based on time-overcurrent relays and fuses that use nested time delays to clear faults by opening the closest protective device to a fault and minimize interruptions. It is designed to safely clear faults and get customers back in service as quickly as possible. In areas of high load density, network systems are common. These systems are fed by multiple transmission sources, thereby providing high reliability. Both of these systems have been designed to serve load, with little planning for generation connected at these levels.

Sectionalizing switches are manually controlled to restore load in unfaulted sections downstream from a failure. The system voltage is maintained in compliance with American National Standards Institute (ANSI) Standard C84-1, which specifies that service voltage be delivered within 5% of the system rated voltage. These systems are generally considered to be ready to support small PV installations without change, as long as the PV inverters meet appropriate IEEE, Underwriters Laboratories (UL), and Federal Communications Commission (FCC) standards and the overall penetration levels are very low.

The designs and technologies associated with today's distribution systems impose important limits on the ability to accommodate rooftop solar and other distributed generation, end-user load management, distributed system controls, automation, and future technologies such as PHEVs. The system characteristics that lead to these limitations include the following:

- Voltage control is achieved with devices (voltage regulators and capacitor banks) that have localized controls. These schemes work well for today's radial circuits but they do not handle circuit reconfigurations and voltage impacts of local generation well, resulting in limits on the ways in which circuits can be configured and imposing important limits on the penetration of distributed resources. This also limits the ability to control the voltage on distribution circuits for optimizing the energy efficiency of customer equipment.
- Minimal communication and metering infrastructure is in place to aid in restoration following faults on the system.
- No communication infrastructure exists to facilitate control and management of distributed resources that could include renewables, other distributed generation, and storage. Without communication and control, the penetration of distributed generation on most circuits will be limited. The distributed generation must disconnect in the event of any circuit problem, limiting reliability benefits that can be achieved with the distributed generators as well.
- There is no communication to customer facilities to allow customers and customer loads to react to electricity price changes, emergency conditions, or both. Customer-owned and distributed resources cannot participate in electricity markets, limiting the economic payback in many cases. Communications to the customer would also result in energy-use feedback that has been shown to help customers improve their energy efficiency.
- The infrastructure is limited in the capacity to support new electrical demand such as home electronics and PHEVs. These new loads have the potential to seriously affect distribution system energy delivery profiles. Communication and coordinated control will be needed to effectively serve this new demand.

At the same time, the distribution system infrastructure is aging, resulting in concerns for ongoing reliability. Utilities are struggling to find the required investment just to maintain the existing reliability, much less achieve higher levels of performance and reliability. New automation schemes are being implemented that can reconfigure circuits to improve reliability, but these schemes do not achieve the coordinated control needed to improve energy efficiency, manage demand, and reduce circuit losses.

The bottom line is that today's power distribution system was not designed with distribution-connected PV or, for that matter, general DG compatibility as an objective. In the past this was not an issue, but with larger amounts of PV now connecting to the system, complications arise in how this type of generation can be safely and reliably interconnected. Fortunately, because of the robustness of the existing design practices, the distribution system can handle a limited amount of PV without modification. This robustness of the existing design has allowed a move into a new era of interconnection—based on standards such as IEEE 1547-2003—without major design changes to the system. As the aggregations of PV continue to grow, however, changes in design and control practices will eventually be required at all levels of the power system.

To directly address the issues related to connecting large amounts of PV in the distribution system, practices in four key areas have been identified:

1. Voltage regulation
2. Overcurrent protection
3. Grounding
4. Switching and service restoration.

The following subsections discuss these issues and other factors related to the system design and its interaction with PV energy sources. Note that these issues also apply to other types of distributed generation and storage.

2.2 Voltage Regulation Practices

The voltage-regulation practices used on power distribution systems generally assume that there are no power sources on the system other than the substation. This means that all flow is outward from the substation source toward the ends of the feeders. To regulate this type of condition, utilities typically use LTC transformers at the substation, stepped voltage regulators on longer feeders, and switched capacitors. All these devices have control settings and functions that are generally coordinated for the system voltage drop profile that occurs with the substation set up as the sole source of power. The ideal condition is to hold all customers within the band of ±5% voltage (what is known as "ANSI Service Voltage Range A" or simply "ANSI Range A"). As soon as PV is added to the system, the basic assumption that there is no other source on the feeder collapses and voltage problems can ensue if the capacity of the added source is significant with respect to the distribution feeder capacity.

The size of the PV system, its location on the circuit, the impedance of the system, and the way the PV inverter operates (in "voltage-following" or "voltage-regulating" mode) will determine its impact on the system voltage. Under IEEE 1547 guidelines, the general practice for small PV inverters is that they will not attempt to directly regulate the voltage on the distribution system. This practice is called voltage following because the PV source simply injects the power into the system and it "follows" whatever voltage appears at its terminals (as opposed to attempting to hold a particular set point). An important concept is that even though the PV source is voltage following, it still affects the voltage on the distribution system. This is because the mere act of injecting power, even when the inverters are acting in a voltage-following mode, does change the power system voltage. Note that future approaches of allowing distributed generation to contribute to the voltage-regulation needs of the distribution system could be an important benefit. This can be accomplished with an integrated control system that provides for communications to avoid control conflicts.

As long as the distribution-connected PV penetration level is low, voltage-following inverters work fine. In such cases the feeder voltage will not change more than a few tenths of a percent—which is not considered significant—and the job of regulating that voltage can remain as the domain of utility equipment (LTC transformers and regulators) with no adverse impacts. On the other hand, if the PV penetration on the system becomes large, it can lead to significant voltage changes of several percent or larger. Such changes are considered significant and of concern. Under these conditions, utilities must watch for three main "steady-state" voltage-regulation issues:

1. Undesirable interactions with line drop compensators
2. Higher than desired voltage rise
3. Reverse-power tap changer runaway conditions

The first problem results from the fact that line drop compensation (a method of measuring current at a regulator terminal and calculating downstream voltage drop to a remote point on the feeder to compensate for the drop to that point) can be confused by the presence of distribution-connected PV or general DG forms. If a large PV unit is placed on the distribution line just after the regulator unit, and if that unit masks the regulator from seeing the current of the load, the regulator will not know how large the actual line current is and will not boost the voltage adequately to compensate for the voltage drop (see Figure 2-2). The generation that causes this effect could be of any type, including PV, wind, fuel cell, ice, and so on.

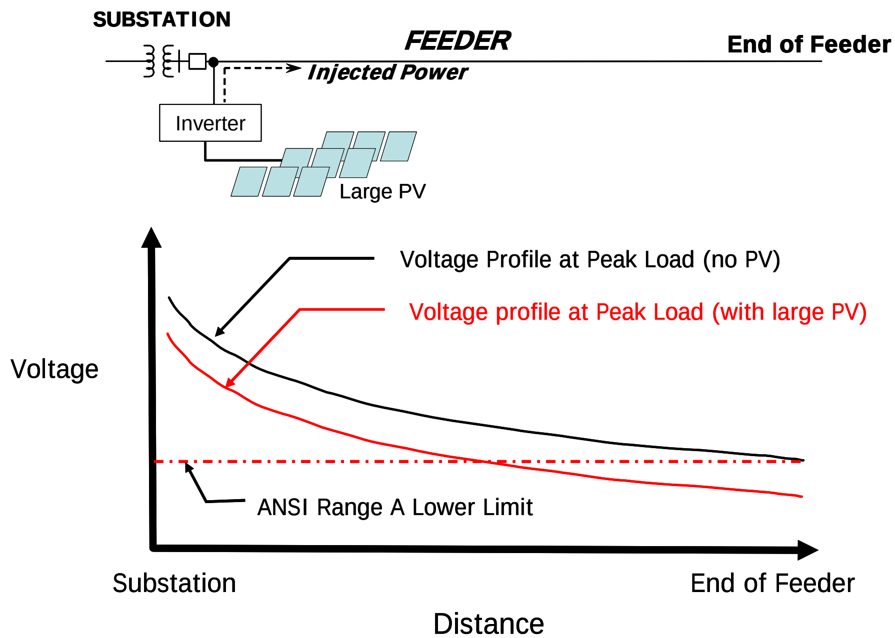

Figure 2-2. Line drop compensation-controlled voltage regulator allows undervoltage at the end of the feeder when the PV generator injects power

This can cause low voltage toward the end of the voltage-regulation zone and could affect a large number of customers. When this problem is significant, it usually results from the utility using line drop compensation control and large amounts of feeder connected generation (equivalent to more than 20% of the load) *concentrated at the front of the feeder* (or regulation zone). Scattered small PV sources (such as numerous small rooftop PV dispersed about a feeder) will not cause this particular issue, even if they aggregate up to very high penetration levels. There are ways to set voltage regulator controls to manage this problem where it occurs. In addition, some of the suggested design changes for future systems and equipment (discussed later in this report) can solve the problem in high-penetration scenarios.

In another type of voltage problem, the injected distribution-connected PV current can cause "forcing up" of the feeder voltage to a level above the upper ANSI C84.1 voltage regulation limit. This effect occurs because as the PV current passes into the system, it creates a voltage rise across the system impedance. The amount of voltage rise on a distribution circuit resulting from the PV (prior to any regulator adjustments) is roughly equivalent to the equation shown in Figure 2-3. The key parameters are the *R* and *X* of the power system looking into the injection point back to the nearest regulator, the magnitude of the current injected, and its phase angle of the PV source current with respect to the utility source voltage.

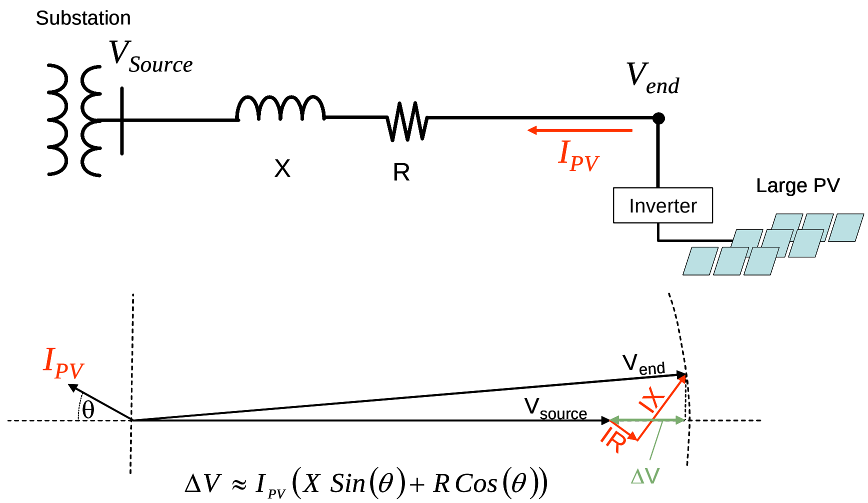

Figure 2-3. Approximate voltage rise resulting from injected current of PV system

For smaller and mid-size PV or PV aggregations and for nonexporting PV, this type of voltage rise on the primary would not normally be an issue. But for larger PV located near the end of the line (or the end of a regulation zone if multiple zones are used on the line), the rise could become significant, raising the voltage above ANSI limits. Figure 2-4 shows an example of a voltage rise condition for a very large PV injecting current into the system at the end of the line.

This problem can also occur on a secondary circuit even with smaller PV under the right (but rare) conditions. For PV inverters, the IEEE 1547-2003 abnormal voltage tripping window is too broad to protect against the issue because that window goes up to +10% and the ANSI Range A upper limit is +5%. Consequently, any situation with very high aggregate PV penetration near the end of the feeder or a single large PV concentrated near the end of a regulation zone would need to be evaluated for this effect. The use of active voltage regulating algorithms in PV inverters as well as interactive controls with LTC transformer regulator units and step regulators could mitigate the problem. As mentioned earlier, this is an important potential benefit of distributed generation and is discussed in 21st-century distribution layouts later. This type of issue, as illustrated here for PV, could arise with any form of DG if sufficient capacity is connected on the line.

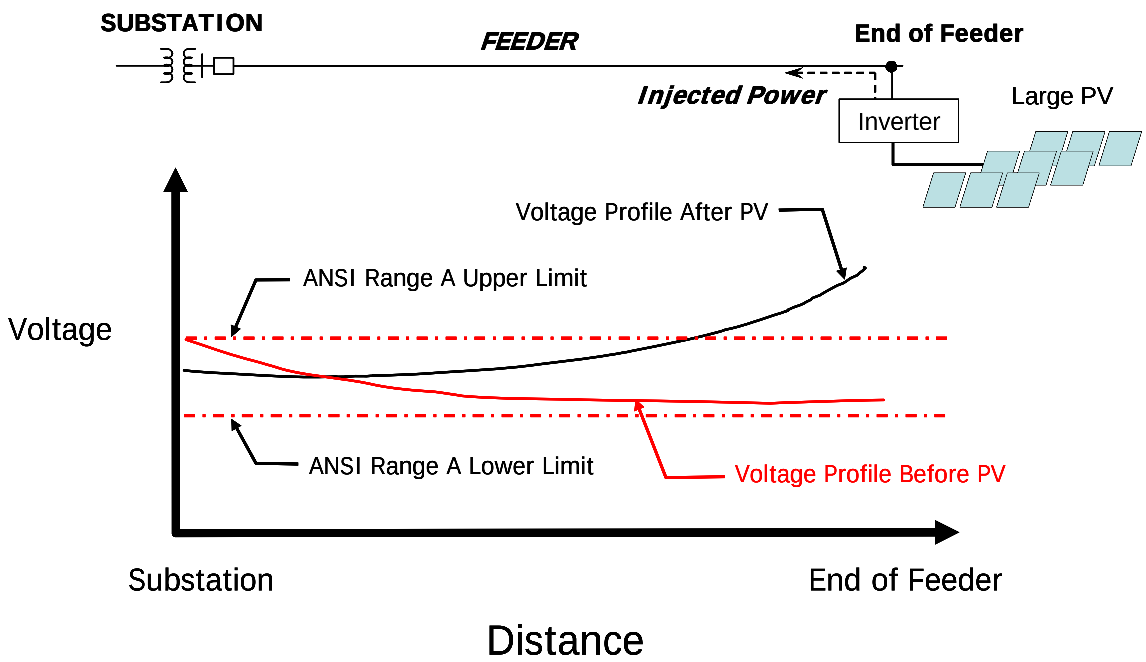

Figure 2-4. Tail end of regulation zone forced to high voltage because of large exporting PV system located near the end of the feeder or regulation zone

A "runaway tap changer," caused by reverse-power-induced controller confusion is another potential issue with large amounts of distribution-connected PV. This problem can lead to low or high voltage conditions well outside ANSI limits. The tap changer "runs away" (moves to the limit of its highest or lowest allowed position) because the PV energy injection into the system forces reverse power through a regulator that has a controller set to change its "regulating side" if reverse power is detected. Some regulators have a controller that detects reverse power flow and shifts from regulating the "normal output side" to regulating the "normal input side."

This feature is used so that if an autoloop feature on a distribution system operates, that regulator can regulate voltage in the reverse direction. The problem is that if PV (or other forms of DG) is present in sufficient quantity, this may cause reverse power when the autoloop has not actually operated. Under this condition, the substation source will still be connected to the normal input side of the regulator and the PV source, which is voltage following, will be injecting power into normal output side of the regulator (see Figure 2-5). Under this condition, the regulator switches to the reverse mode and will attempt to regulate the voltage on the section of feeder closest to the substation (the normal input side of the regulator). At that side where the system is still connected to the substation (a strong source), however, tap changes at the feeder regulator will not be able accomplish a "voltage solution" for the controller. Meanwhile, on the PV side of the regulator as the tap changer moves (to attempt to regulate the other side), the voltage will change on that side a bit more each time the tap changer moves. As the controller attempts to force a voltage solution (meaning measured voltage = set voltage), it will simply run up to the tap position limit, never reaching a solution.

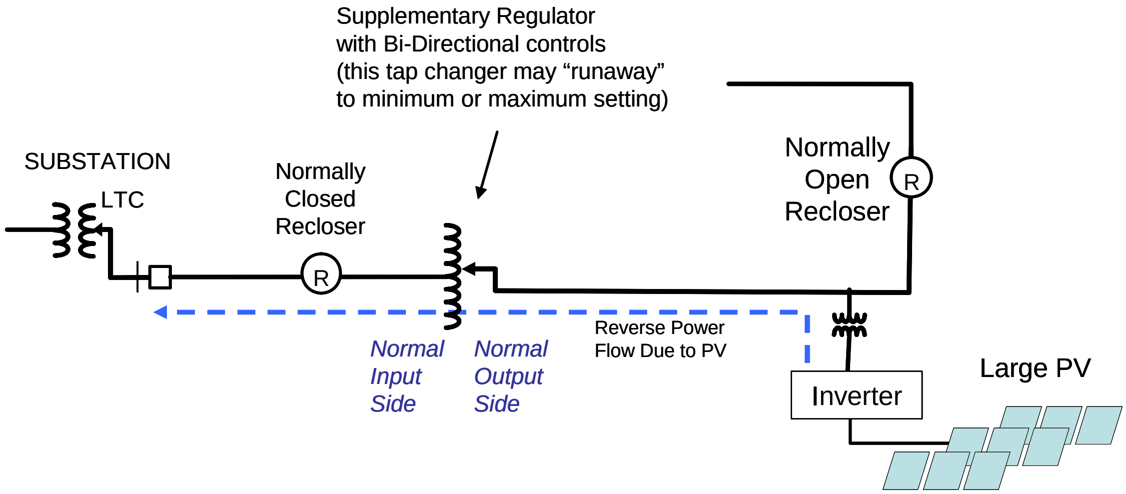

Figure 2-5. Runaway tap changer on an autoloop supplementary regulator results from reverse power detection

In this condition, the voltage on the PV side of the regulator could rise to a high or low level outside ANSI limits. There could also be various cycling events, depending on power fluctuations from the PV source(s). Whether the tap changer runs away in the upward or downward direction depends on the initial tap change direction requested from the controller. Obviously this issue will never be a problem with nonexporting PV. But any large aggregation of PV or a single large PV that does export enough current to reverse the flow through such regulators can cause this problem. Although the focus of this discussion is PV, any form of DG could cause this problem under the right conditions.

The penetration level where this becomes an issue will depend on many factors. The level could, however, be somewhat lower than those causing the other voltage problems discussed so far. Solutions to the problem exist, including special controls and settings to alleviate it, but these have drawbacks such as trading off voltage regulation quality in autoloop mode for distributed-connected PV compatibility. An advanced 21st-century distribution voltage control architecture like the one discussed later can solve the problem by allowing full voltage quality under all modes and total compatibility with distributed-connected PV as well as with other forms of DG.

2.3 Output-Related Voltage Fluctuations

In addition to the problems previously discussed, varying output of PV sources can cause cyclic voltage excursions on the feeder that lead to hunting of tap changers or capacitor-switching devices. These voltage excursion conditions, even if they do not go outside ANSI voltage limits (and depending on severity as well as rate of change), can become noticeable to customers as light flicker or variable motor speed performance. Such variations can also cause increased wear of tap changers and capacitor switches (resulting from the many cyclic operations of the switches to attempt to hold voltage at the best level). In addition, capacitors that switch on and off can—when cycled more than normal—contribute a higher number of switching surges to the system, degrading power quality and causing interference to sensitive loads.

Distribution-connected PV and wind energy sources in particular can fluctuate considerably and, with high penetration, can lead to noticeable problems, such as the ramp up or down caused by moving clouds and illustrated in Figure 2-6. Below 20% penetration on a feeder voltage-drop capacity basis, these factors are probably not significant. Above 20% penetration, though, especially where the PV is lumped at a single site on a weak feeder, the impacts could be significant. For any rapidly varying energy source that varies more rapidly than the time-delayed responses of voltage regulators, it is critical to make sure that the assessment voltage change includes the entire impedance of the system and not just the impedance back to the nearest regulator station. The voltage change (ΔV) of the distribution system is more sensitive to short-term fluctuations than it is to long-term fluctuations (the "flicker" voltage drop sensitivity is different from the steady-state voltage drop sensitivity).

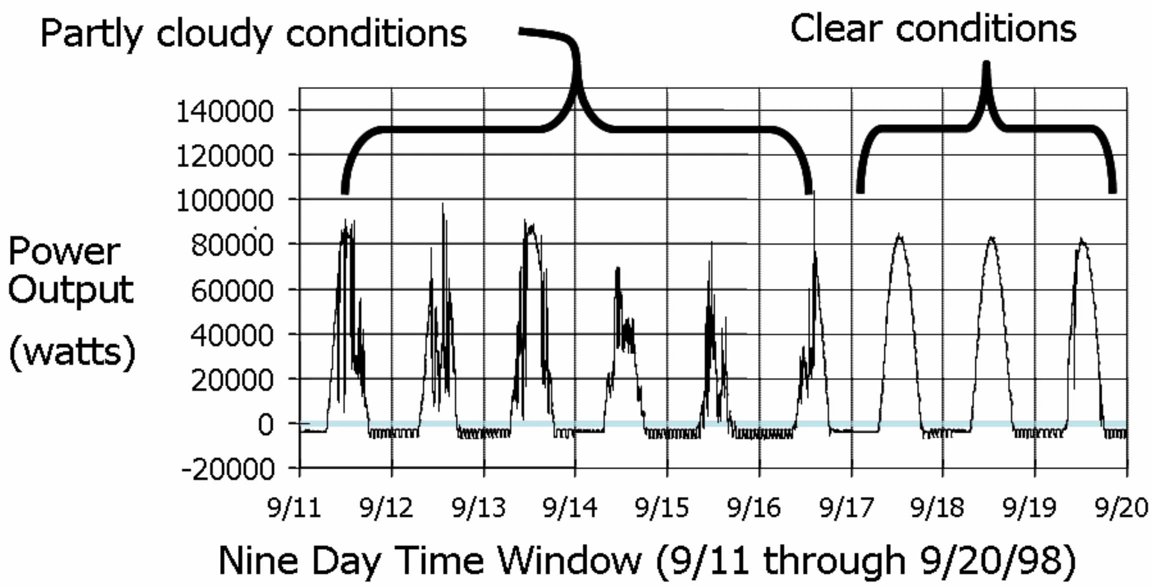

Figure 2-6. PV power fluctuations at a 100-kW PV site near Albany, New York

A traditional method for assessing light flicker in the utility industry has been the IEEE 519-1992 (GE) flicker curve (see Figure 2-7). This flicker curve provides a measure of the sensitivity of the human eye to incandescent light output fluctuations that result from square envelope voltage changes. Many utilities use it to evaluate flicker caused by motor starts and other load pulsations that have a square or fast drop saw-tooth voltage envelope. Applying this method to the "smoother" (rounder) voltage envelope variations of flicker related to PV or wind power proves to be an unnecessarily conservative approach to evaluating PV or wind flicker because those voltage envelope shapes are less noticeable to the eye. The newer International Electrotechnical Commission (IEC) flicker standard (IEC 868 and IEC 61000-3-7), which uses mathematical functions to describe the flicker effects of any waveform envelope, is the best method for assessing PV-induced voltage flicker. Generally, because PV fluctuations are smooth and slow over many tens of seconds, it takes a fair amount of voltage change caused by PV for it to be observable on the system. As a result, the industry today has not really encountered many flicker problems caused by PV because penetration levels have been generally low to date. Flicker might become an issue for PV on the distribution system at a penetration level well above 20%. Flicker-filtering inverters that include reactive voltage compensation could be one way to allow high penetration of PV without any adverse impacts.

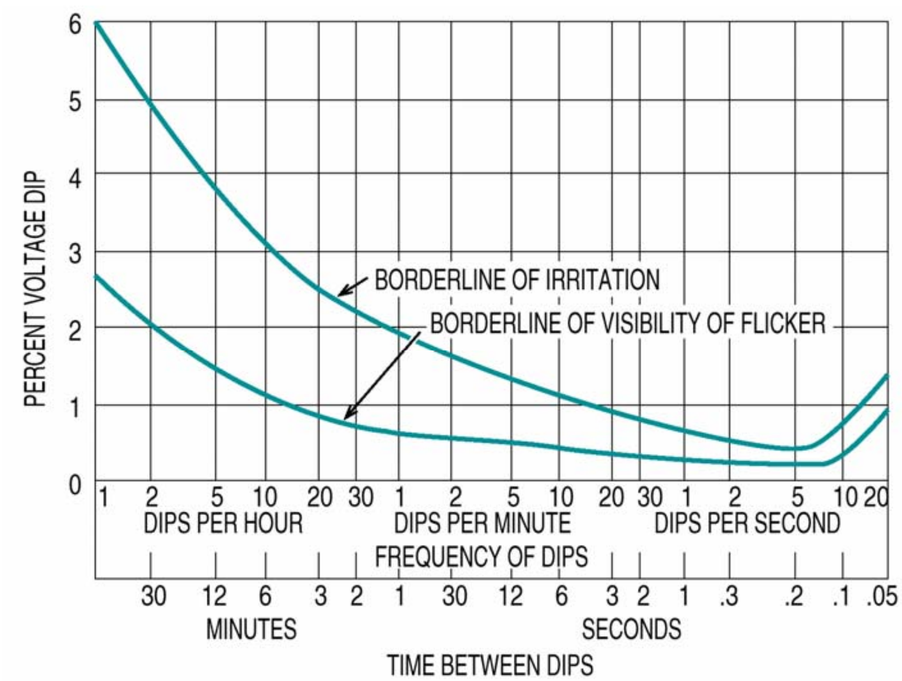

Figure 2-7. Voltage flicker curve (IEEE 519-1992)

2.4 Overcurrent Protection Practices

Overcurrent protection is a critical part of the design and operation of power systems. Proper overcurrent protection allows temporary faults to be quickly cleared from the system and permanent faults (failed cable sections or failed equipment) to be isolated in a manner that ideally minimizes the number of customers affected as well as the extent of any damage. Overcurrent protection involves coordinated operation of many devices, including circuit breakers, relays, reclosers, sectionalizing switches, and various types of fuses. All these devices are coordinated based on the various time-current response curves, relay pickup settings (where applicable), and fuse melting/damage curves. The practices and equipment used today have evolved over more than 100 years of engineering and field experience on power systems and were developed without distribution-connected DG or PV energy sources in mind.

For essentially all radial distribution systems, protection is predicated on the principle that power (and fault current) flows from the substation out to the loads. There are no other sources of fault current. The presence of distribution-connected PV introduces new sources of fault currents that can change the direction of flow, introduce new fault-current paths, increase fault-current magnitudes, and redirect ground fault currents in ways that can be problematic for certain types of overcurrent protection schemes. In addition, the time it takes to clear PV fault sources from the line may be somewhat longer than that for the utility source alone. Table 2-1 summarizes the possible fault-current-related issues posed to power distribution systems by PV as well as by other DG forms. All these issues are usually insignificant in low-penetration PV or DG environments, but at high penetration levels, they can require serious design upgrades to the power system to avoid problems.

Table 2-1. How Fault Contributions from PV and/or General DG Equipment Influence the System

Description of Fault Contribution Condition	Issues Related to Condition
Increased Fault Magnitudes on the System Contributed by PV or General DG Faults	1. Can cause fault levels to exceed interrupting device rating 2. Can change fuse and circuit breaker coordination parameters 3. Can increase conductor damage and/or distribution transformer tank rupture risk for faults (because of higher magnitude).
Changes in Direction of Fault-Current Flows or Additional New Flows not Present Before Addition of PV or General DG	1. Can cause sympathetic trip of reclosers or circuit breakers 2. Can desensitize ground fault relaying protection 3. Can cause network protectors to operate unnecessarily 4. Can confuse automatic sectionalizing switch schemes.
Increased Time to Clear All the Various PV and DG Contributions Compared to Utility Source Alone	1. Can increase conductor or equipment damage during fault (caused by longer durations of arcing or current flow) 2. Can cause less-efficient temporary fault clearing, defeating reclosing objective.

Rotating synchronous generators are the worst offenders among distribution-connected energy sources with regards to injected fault currents. These generators inject more than twice as much fault current per unit of rated capacity—the fault-current contribution can be four to eight times the rated current—as do solid-state inverter devices. Internal combustion engines (ICEs) and combustion turbines (CTs), which typically use rotary converters, are the largest fault-current injectors per unit of rated capacity. Inverter-interfaced power sources such as PV, fuel cells, and some microturbines are more benign forms of DG than their synchronous rotating generator cousins. At high levels of distribution-connected PV penetration, though, even relatively benign inverter technology can lead to problems. In a future world where large PV arrays on the distribution system may reach 50% or even nearly 100% of the local system capacity, the effects of fault contributions from PV must be considered. An important consideration with inverter technology is that the industry has done an inadequate job of documenting the duration and magnitude contributions for such inverters. These need to be better defined in the future so that power system engineers can analyze fault-current impacts. It is important to note that the inverter interface provides the opportunity for local fault-current limiting that could effectively prevent inverters from significantly contributing to faults, even at high penetration levels. This will rely on fast fault detection. Avoiding unnecessary tripping of the local generation will also be important because this can lead to voltage regulation issues (note the voltage sag ride through requirements for wind farms to avoid unnecessary loss of generation during remote fault conditions).

2.4.1 Sympathetic Tripping

Sympathetic tripping is but one of many ways in which distribution-connected PV or other forms of DG-caused fault current contributions can lead to problems on the distribution system that ultimately reduce system reliability. Sympathetic tripping, which is illustrated in Figure 2-8, can be described as the unnecessary tripping of a circuit breaker or recloser resulting from a fault located on an entirely different part of the power distribution system (such as an adjacent feeder). As the figure shows, the current flowing to that fault is not only from the 115-kV utility energy source but also from the various DG and distribution-connected PV sources. These distribution-connected fault-current source contributions will pass through the recloser and the circuit breaker of the feeder on which PV and/or DG is located and may trip those devices unnecessarily. The problem can be avoided with more advanced protection schemes than are currently used on distribution circuits, such as the use of directional overcurrent trip blocking and/or special transfer tripping schemes.

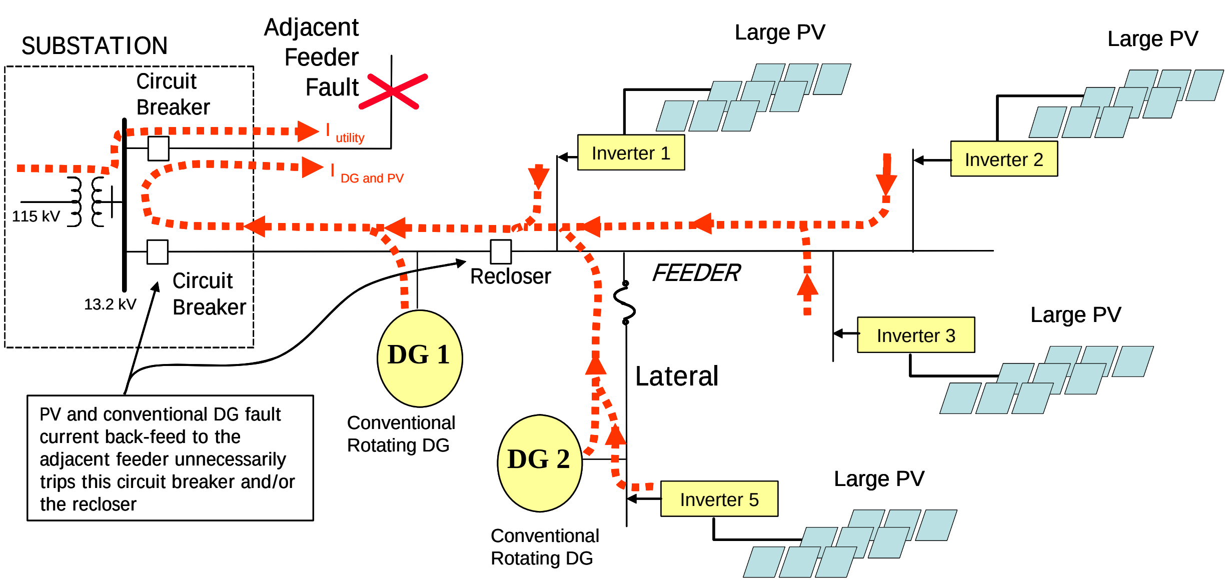

Figure 2-8. Example of how high penetration of DG can cause nuisance trips

The sympathetic tripping problem is fortunately a problem only for higher penetration environments where lots of distribution-connected PV and/or DG are present. This is because the instantaneous and time-delayed tripping pickup settings of most feeder circuit breakers and reclosers are typically set at the level of hundreds or even thousands of amperes. With such high tripping thresholds it takes a very high level of distribution-connected PV and/or DG penetration for this problem to occur. As an example, with the assumption that—on a typical three-phase 12.47-kV distribution feeder—each megawatt of rotating synchronous DG injects roughly 200 to 400 A of fault current and each megawatt of PV injects no more than 100 to 200 A of fault current (very conservative), it is clear it will take several megawatts of generation before the tripping threshold of even the more sensitive protection points is reached. Consequently, this is unlikely to be an issue for inverter-connected DG with any reasonable fault-current-contribution controlling technology.

2.4.2 Fuse Coordination Example

Another example of the impact of distribution-connected PV and/or DG on the overcurrent protection system is how fault contributions affect fuse and circuit breaker coordination. To understand this effect, an explanation of typical utility “fuse-saving” practices is necessary. Fuse saving means that when a lateral fault occurs, the fuse-melting time for the expected fault level is coordinated with the substation feeder circuit breaker’s instantaneous (fast) tripping setting, causing the circuit breaker to trip before the fuse is damaged or melts. This allows the breaker to open and fully de-energize any temporary fault on the lateral, then reclose a moment later. If the fault is cleared successfully, the net result is that this technique saves the fuse and prevents a long interruption on the lateral (it would take an hour or more for a line crew to be sent to replace the fuse if it were allowed to blow). On the other hand, if the fault is permanent, after a few attempts to clear it using the fast trip setting, the circuit breaker automatically switches to a “time-delayed” tripping setting that allows the fuse to blow before the breaker opens. This practice improves reliability and reduces repair costs for utility companies.

The whole concept of fuse saving can be adversely affected if the fault current at the fuse should rise to a level where it melts (blows) before the circuit breaker clears the fault (the higher the fault level, the faster the fuse melts). If distribution-connected PV and/or other types of DG are added to the system and fault levels go up sufficiently, fuse-saving coordination may be in jeopardy. Figure 2-9 is an example showing how these energy sources can change the fault level at the fuse when placed on the system. Because the fastest total fault-clearing time on most distribution feeder circuit breakers is about five cycles, as soon as the fault levels are increased enough that the fuse damage time is reduced to nearly this number of cycles, the coordination will be in jeopardy.

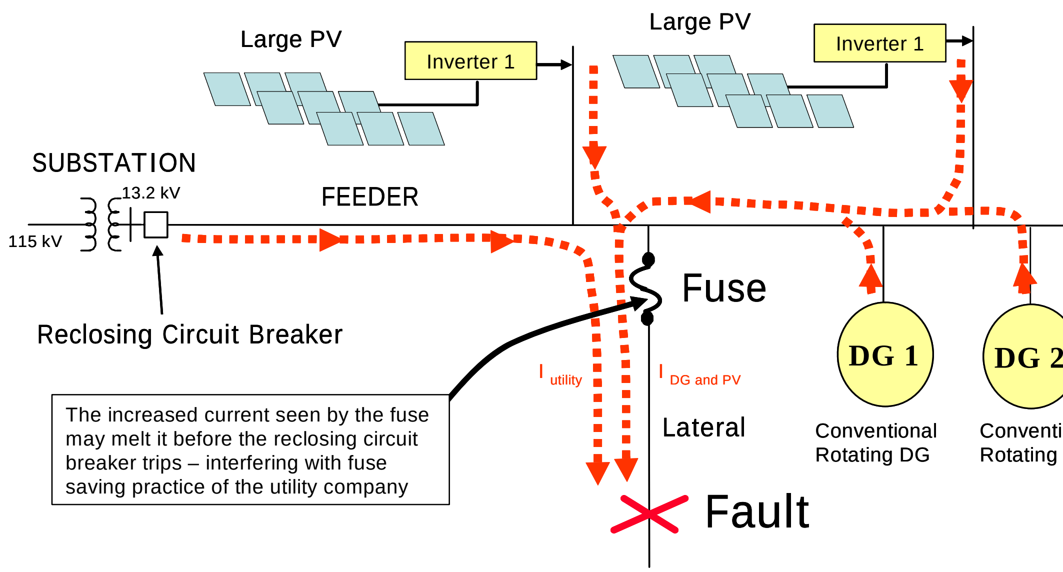

Figure 2-9. How fault contributions from other feeder energy sources such as PV can interfere with fuse and circuit breaker coordination in fuse-saving schemes

The fuse-coordination and sympathetic-tripping examples discussed here are but a few of the fault-current issues of concern. Other problems caused by fault-current contributions include operation of network protectors, confusion of sectionalizing switch fault-sensing circuits, improper logging of faulted circuit indicator devices, and exceeded breaker interrupting ratings. All of these fault-current-related issues are essentially problems associated with high-penetration distribution-connected PV and/or conventional DG environments (either through aggregation of many small energy source sites or a few large sites). Low-penetration environments rarely, if ever, need to worry about any of these issues (PV penetrations to date have not approached levels where these fault current contribution issues would be significant).

A big plus for PV technology is that it is inverter-interfaced. This means that it will have a more benign impact than standard rotating machinery. Nonetheless, as penetration levels rise, these issues will need to be dealt with more frequently with all types of DG, including PV. They can be overcome on a case-by-case basis by using existing designs, by implementing more advanced inverter algorithms that accomplish very fast fault-current limiting, or by upgrading the distribution system to a 21st-century design and operating strategy with better communication and DG-compatible relaying/protection approaches.

2.4.3 Islanding

Islanding is one of the most important interaction issues between distribution-connected energy sources and the power system. Islanding is a condition where one part of the power system breaks free from the main system and operates as a separate entity, energized by one or more distributed energy source units (PV or other forms of DG). There are two forms of islanding: “intentional” and “unintentional.” Intentional islands are purposely established zones that are carefully engineered for reliability and power quality purposes. They are intended to keep the power running on one portion of the system or at one customer location when the main power system is disabled. Intentional islands can be safe and offer high-grade power to critical customers or critical system areas when the proper local generation, control, switching, and protection technology is implemented. On the other hand, if an unintentional island is established by accident, as when a recloser opens and isolates a section of the power system with an energy source, dangerous conditions could arise (see Figure 2-10) . For a variety of technical reasons, unintentional islanding can be dangerous even if it lasts for just a few seconds, so these islands should be disabled them as quickly as possible.

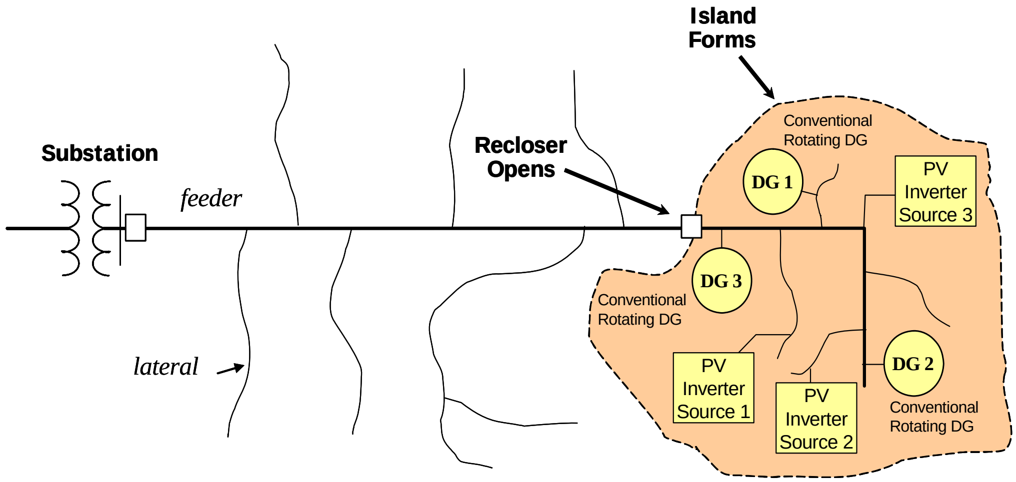

Figure 2-10. Example of an island composed of conventional rotating machine energy sources and PV inverter sources

Unintentional islands are a threat to proper utility system operation for a number of reasons:

- If an unintentional island forms and lasts long enough, the upstream utility system may attempt to reclose into it with an out-of-phase condition, which can damage switchgear, power generation equipment, and customer loads.
- An unintentional island may increase public exposure to unsafe, energized downed conductors (see Figure 2-11).
- Line crews working on power restoration following storms or other events may encounter unintentional energized islands, making their job more hazardous and slowing down the power restoration process.
- Unintentional islands do not usually have their generators set up with the proper controls to maintain adequate voltage and frequency conditions to the customer loads. Because PV inverters are currently set for voltage following, they do not help control the voltage during islanding conditions. In future scenarios where islanding is part of the system design, inverter controls will be used in a voltage-control mode to prevent unacceptable voltage conditions in the local island.
- Transient overvoltages caused by ferroresonance and ground fault conditions are more likely when an unintentional island forms—for example, the unit might be isolated with a large capacitor bank that could trigger a resonance with energy sources on the island.

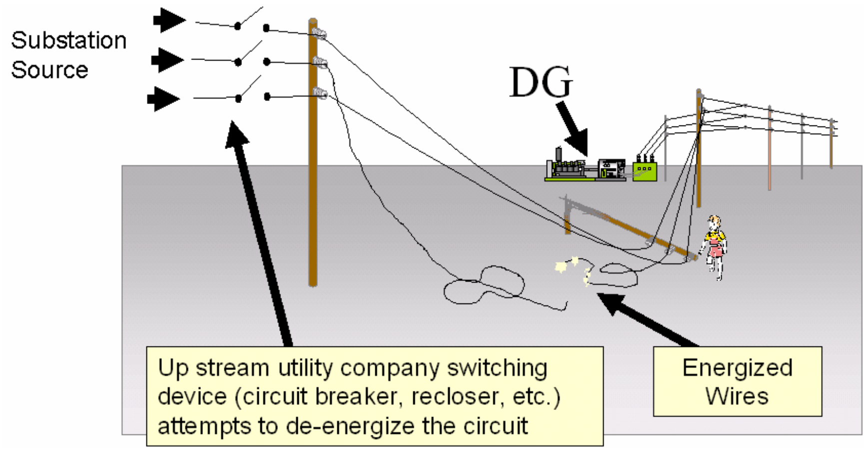

Figure 2-11. Increased danger to the public means that the industry must be careful with islanding issues

Because of the dangers of unintentional islands, the IEEE 1547-2003 standard and utility interconnection guidelines all require standard DG and PV connecting to the system to have anti-islanding protection at either the facility's public power system interface point (called the "point of common coupling") or where the DG or PV source itself interfaces to the customer's electric system. Anti-islanding protection is composed of relays or electronic circuits that sense that an island has occurred and trip the generator (separate it) from the public power system in a very short time (usually within 2 s or less). Islanding would be allowed with any part of the public utility system only if the utility agreed to it and if very careful engineering design, protection, and control procedures were implemented.

The key principle of anti-islanding protection is that at the instant a generator becomes islanded with a portion of the power system, it usually will be operating at a different power output level than the load on the island at the moment it is created. This mismatch between the generator output and load causes the frequency and voltage to deviate significantly. The islanding protection algorithm constantly monitors the state of voltage and frequency conditions at the DG terminals. If these parameters deviate from an acceptable window for even a brief period of time, the unit will trip off within seconds or even tenths of seconds, depending on the severity of the voltage or frequency digression. This type of islanding protection, called "passive" protection, is used on many rotating machine type systems.

Although this type of passive islanding protection functions effectively in many circumstances, especially with smaller rotating DG, it is not 100% reliable. If, for example, the load and generation are relatively closely matched at the instant of island formation (say within ±20% of each other), the frequency and voltage digressions will not be sufficiently severe to digress outside the acceptable window and trip the unit.

Today's electronic inverters for PV, fuel cells, and other devices are using a more sophisticated anti-islanding protection system that includes passive protection as well as what the inverter industry has termed "active" protection. Active protection means that if it becomes islanded, the inverter unit intentionally drifts in voltage and frequency away from the normal window because it has lost the utility system reference on which to phase lock and the unit has a bit of instability programmed into it. With this approach, once the inverter is alone as the sole source on the island, it will drift out of the acceptable voltage and frequency window and trip off. Other forms of active islanding detection include various forms of push/pull impedance-detection techniques. PV system inverters today are generally UL 1741 nonislanding certified, which means that they pass a test that successfully demonstrates their active and passive anti-islanding protection methods under a range of conditions expected on the feeder.

The current industry-accepted anti-islanding test works well for low penetrations of a few inverters with respect to local system load. Under high penetration levels with numerous inverters and with other forms of DG that share the same feeder, however, it is not clear that the active anti-islanding techniques used in inverters today will adequately detect island formation and disable it within a suitable time frame [2]. If these active anti-islanding algorithms start to break down as DG penetration increases, there will be increasing incidences of unintentional islands. A more advanced system of islanding protection—based in part on increased use of direct communication between elements of the inverter feeder switchgear—is needed to facilitate high-penetration DG scenarios and avoid such islands. Improved active anti-islanding algorithms are also needed. The future system will take advantage of islanding as a reliability-improvement tool (as described previously), but the current system design cannot effectively support this approach.

2.4.4 Grounding and Ground Fault Overvoltages

System grounding is a key area of difficulty in terms of the compatibility of the power distribution system design with distribution-connected PV and other DG types. Distribution systems can be categorized into several types by the nature of their grounding design:

- Three-wire ungrounded
- Three-wire unigrounded
- Four-wire unigrounded neutral
- Four-wire multigrounded neutral.

By far the predominant type of system in the United States today is the four-wire multigrounded neutral system. This system has excellent features related to cost, equipment layouts, and performance for the types of suburban and rural environments found in the United States. It is particularly suited to the low-load-density areas found throughout the country. The four-wire multigrounded neutral system allows small rural loads to be served cost effectively with just one insulated phase wire and one multigrounded neutral wire. This approach is more cost effective than three-wire ungrounded or unigrounded systems that require at least two insulated wires and commensurate equipment to bring single-phase power to a site. It also provides some fusing and protection advantages over the three-wire ungrounded or unigrounded distribution system. For these reasons it was chosen back in the 1930s as the standard U.S. system that was implemented for the rural electrification program. In the United States today, more than 70% of the circuit miles of distribution systems in suburban and rural areas are four-wire multigrounded neutral systems. Most of today’s PV inverters will connect to this type of distribution system.

Although the four-wire multigrounded neutral system offers advantages over classical three-wire systems for types of load-density patterns found in the United States, it is not a good design for the application of distributed energy sources such as PV. The four-wire system protection works best when the main substation source is the predominant “grounding source” on the circuit. This causes zero-sequence currents associated with ground faults to originate and flow back to that location. Placing energy sources that act as a grounding source (such as PV) on a four-wire multigrounded neutral system creates a problem in that zero-sequence flows start to originate from and return to these other grounding sources. Grounding energy sources can become significant in size in relation to the main substation grounding source. In this case, zero-sequence current can be diverted and zero-sequence current flows can be changed sufficiently to keep the relays and protective devices that measure this current (such as feeder ground fault-detection relays located at substations) from sensing adequate current and tripping or coordinating properly with the protection scheme on the feeder. For small and even medium amounts of PV interfacing to the system, the effect is either insignificant or can be controlled by using grounding reactors and relaying adjustments made to mitigate the issue. At high penetration levels on the system, though, the effects can become complex and difficult to mitigate without major power system upgrades.

It might seem that the simple solution to having too many grounding sources on the power distribution system would be to connect PV and other DG sources to the distribution system in a “nongrounding” fashion (through a delta winding on the high side of the DG interface transformer). Ideally, this would allow the PV and DG sources to feed only in the balanced positive-sequence current component (ignoring the zero-sequence neutral current). This does solve the issue of PV grounding sources interfering with the main substation ground fault protection; however, an even more severe new issue—ground fault overvoltage—can arise. Ground fault overvoltage is a condition where, during a line-to-ground fault, the voltage on the unfaulted phases rises to a much higher value than normal because of neutral shift. For example, an ungrounded energy source, such as one that feeds in through a delta transformer winding, can cause a serious phase-to-neutral ground fault overvoltage of as much as 182% of the nominal level (see Figure 2-12). Note that there are other arrangements that also can act as ungrounded sources.

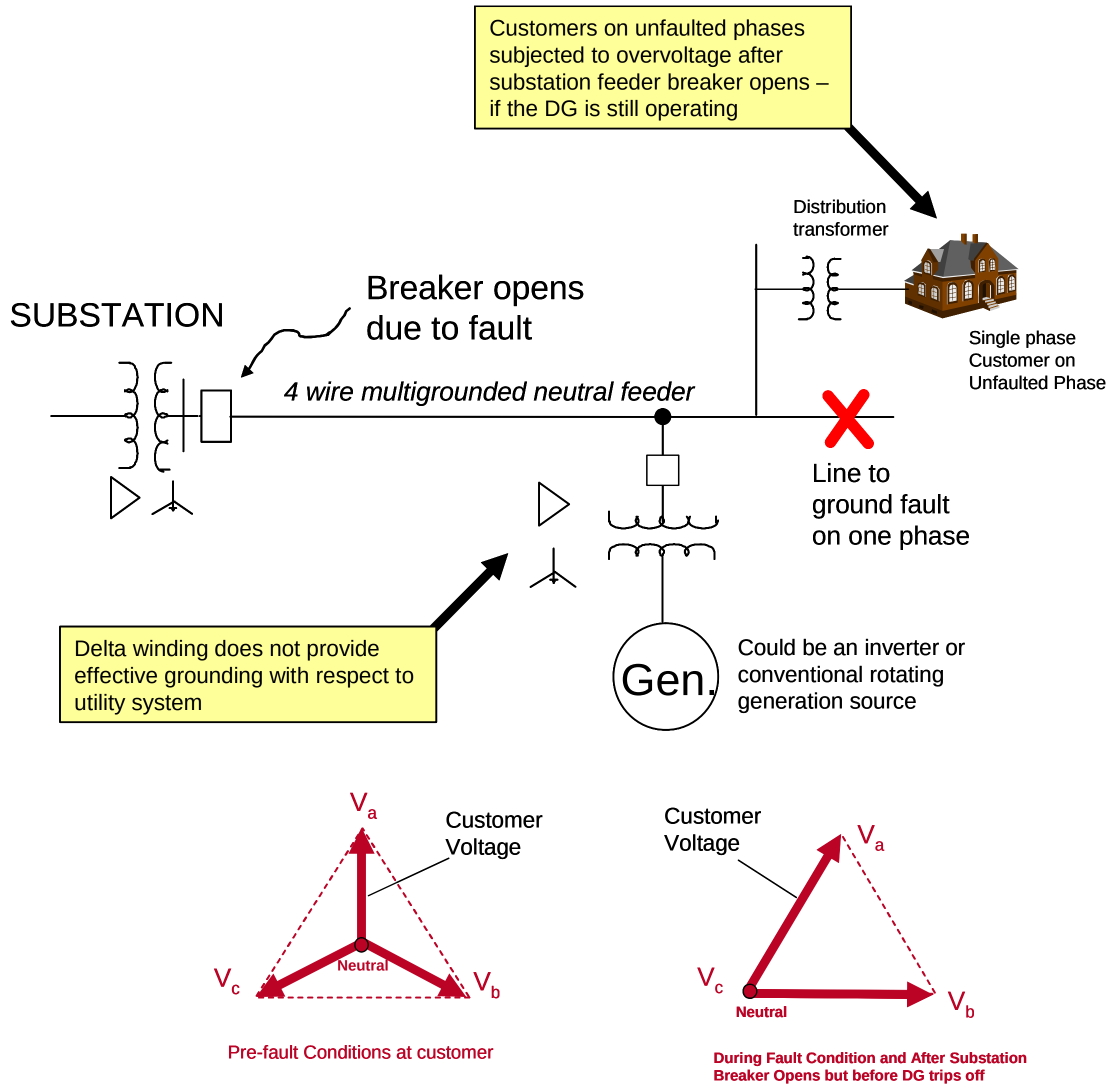

Figure 2-12. Delta windings on the high side of distributed energy source interface transformers act as one possible form of an ungrounded source and can cause ground fault overvoltage damage

"Effective grounding" describes a method that ensures that the impedance of the generator neutral grounding (zero sequence) with respect to the positive sequence impedance of the system is not so high that overly severe ground fault overvoltages (caused by neutral shifts) occur during ground faults. Effective grounding does not entirely eliminate the overvoltage that occurs on unfaulted phases during a ground fault, but it is good enough to limit overvoltages to a safer level of about 125% to 135% (for comparison, an ungrounded situation would be about 165% to 182% of nominal).

As PV penetration levels grow, so will the issue of ground compatibility. This issue arises from the conflict where, on the one hand, ground fault overvoltage is undesirable and an effective grounding approach is preferred, and, on the other hand, too many effectively grounded sources pose the challenge of uncoordinated ground fault protection. This issue of grounding incompatibility for high-penetration PV applications can be managed in a number of ways within the framework of the existing power distribution system design (such as careful timing of utility source and PV inverter separations from the system, changes to relay pickup settings, and other methods). In the long run, though, the most effective method is a comprehensive power distribution design and grounding philosophy change that is part of the 21st-century distribution system discussed later. This can make the system fully compatible at all levels of PV penetration without complex measures or quasi-effective modifications.

2.4.5 Other Transient Overvoltage Conditions

Two other types of overvoltage can occur on power systems: ferroresonance and load-rejection overvoltage. These conditions can occur individually, together, or in various combinations with ground fault overvoltage, depending on the design characteristics of the power system and the situations under which they arise. Under some conditions, these voltages can become severe enough to damage power system equipment and customer loads.

Figure 2-13 illustrates simulated overvoltages that occur with a synchronous rotating machine as a result of the formation of a sudden generation island with capacitors and low load during a ground fault. This combination of the three types of overvoltage would last until a protective device clears the conventional rotating DG from the system. Even a few cycles of high voltage can damage sensitive loads and utility equipment such as lightning arresters, so the ability to sense an overvoltage and then trip the unit in as short as 10 cycles (as required by IEEE 1547) is no guarantee that the overvoltage will not cause damage. Fortunately, PV inverters are much less likely to experience these conditions, which are primarily associated with rotating power generation equipment.

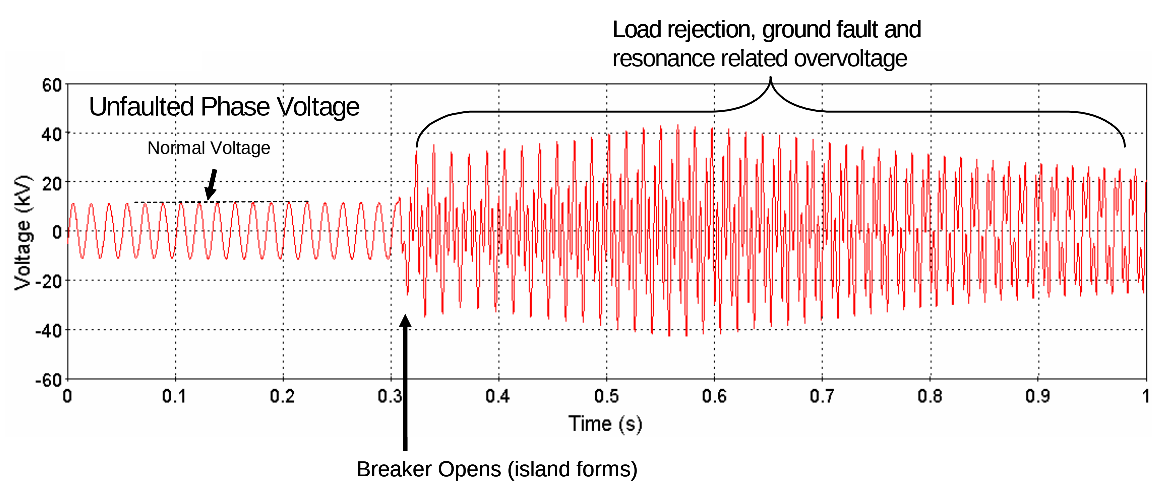

Figure 2-13. Examples of simulation of ground fault overvoltage, load rejection, and resonance-related overvoltage

The key to avoiding DG-related ferroresonance is to avoid the conditions in which it arises:

- An energized island
- Generator power significantly greater than load on the island

- Enough capacitance (30% to 400% of unit rating)
- A transformer group usually must be present (to provide additional inductance in addition to the machine's inductance).

Careful design of the DG protection and control scheme to avoid the listed conditions is warranted. As stated earlier, ferroresonance and load-rejection overvoltages are primarily associated with induction and synchronous rotating generators. System modeling and research study must be conducted to clarify whether this can be a serious issue for PV inverters or other types of inverters. Generally, the physics of modern pulse-width modulated (PWM) inverters are entirely different than the physics that govern rotating machines, and the PWM inverters probably will not support a resonant condition as easily as rotating equipment. On the other hand, it is a new area worth investigating because there has not been much high-penetration PV installed to date. In addition, past experience has shown that older line-commutated inverters can become self-excited in a quasi-resonant state.

2.5 Subtransmission Issues

So far the discussion has focused on distribution systems because these are the most directly affected by distribution-connected PV and other DG resources. As the following material shows, however, subtransmission circuits can be significantly affected in high-penetration PV or more general DG scenarios.

Subtransmission circuits feeding substations have much larger capacity (typically 4 to15 times greater) than the distribution substations themselves. As a result, the conventional wisdom is that detailed technical PV integration issues such as islanding, ground fault overvoltage, fault-current effects, and so forth need only need be considered on the power distribution system level. Unfortunately, though, once higher penetration levels are reached, the picture changes significantly and these factors do come into play at the subtransmission level. In fact, they may become some of the most costly and difficult technical problems to solve as the industry moves toward much higher levels of DG and PV resource usage..

At high PV penetration levels on the distribution system, subtransmission lines, especially weaker voltage classes such as 46 kV and 69 kV, can experience significant technical problems because of PV currents feeding from the distribution system back up into the subtransmission system. One of the biggest issues is ground fault overvoltage on the subtransmission lines. This can occur because substation transformers are usually delta on the high side and grounded-wye on the distribution side. Even though the PV located on the distribution system is usually effectively grounded with respect to that system, it will not be effectively grounded with respect to the subtransmission system after passing through that delta winding of the substation transformer.

Because subtransmission lightning arrester ratings and insulation levels are usually based on effectively grounded sources, the overvoltages created could cause surge arrester failure and equipment damage on that side of the system. For further clarification of how such overvoltage can occur, Figure 2-14 shows an example of a 46-kV subtransmission line, and where a large PV system could cause ground fault overvoltage. It is noteworthy that even a single substation with high-penetration PV feeding into a subtransmission line can pose a threat of ground fault overvoltage. It follows that large aggregations of many substations feeding in would increase the likelihood of a problem.

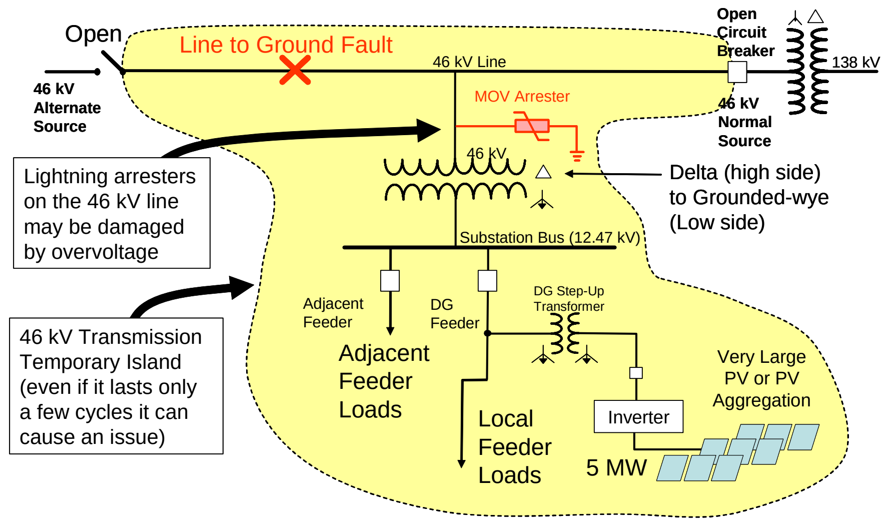

Figure 2-14. Ground fault overvoltage that can occur on subtransmission in some high-penetration PV or DG scenarios

There are methods for mitigating subtransmission ground fault overvoltages. This includes timing the tripping of the subtransmission source grounding transformer so that it is last to clear (after all distribution system energy sources). This may require special high-speed transfer trips to all PV sites from the subtransmission circuit breakers. Another method is limiting the PV and/or DG capacity feeding into the subtransmission line, which would keep the capacity in safe defined penetration limit in relation to the load on the subtransmission line (heavy load causes voltage drop to cancel out the ground fault overvoltage effect [3]). Finally, specifying insulation coordination and arresters on all cables and devices to handle ground fault overvoltages could work as well. This last method, however, is probably practical only for new construction because it would be costly and difficult to retrofit on existing systems.

Ground fault overvoltage is not the only subtransmission issue caused by distributed energy sources such as PV feeding in from the substations. Other problems such as unintentional islanding, interference with sectionalizing switching schemes, and overcurrent protection coordination issues can occur as a result of the feed-in current from the distribution level. A large aggregation of energy sources feeding in at many substations on a common subtransmission circuit, in particular, increases the likelihood of these problems. The aggregation of many distribution substations with each substation having large amounts of generic DG and/or PV (see Figure 2-15) can lead to total fault contribution of several thousand amperes into the subtransmission system. This is likely to confuse various cascaded recloser and sectionalizing switch schemes, shift the apparent locations of faults for certain impedance-based zone-relaying schemes, and result in unintentional islanding conditions that threaten the subtransmission reclosing operations. Standard anti-islanding techniques based on UL 1741 and IEEE 1547 requirements will likely not be able to clear the subtransmission islands fast enough, resulting in reclosing problems and other issues.

The likelihood of aggregation of many substations, each with high-penetration distributed energy sources, on a common subtransmission circuit may seem an unlikely prospect today. In the future, however, this scenario could become relatively commonplace, especially considering the growth projections for PV energy. To facilitate the effects of these energy sources on subtransmission, appropriate communication-based high-speed transfer trips between generating devices and all key switchgear will be needed. These changes are discussed in more detail later in this document.

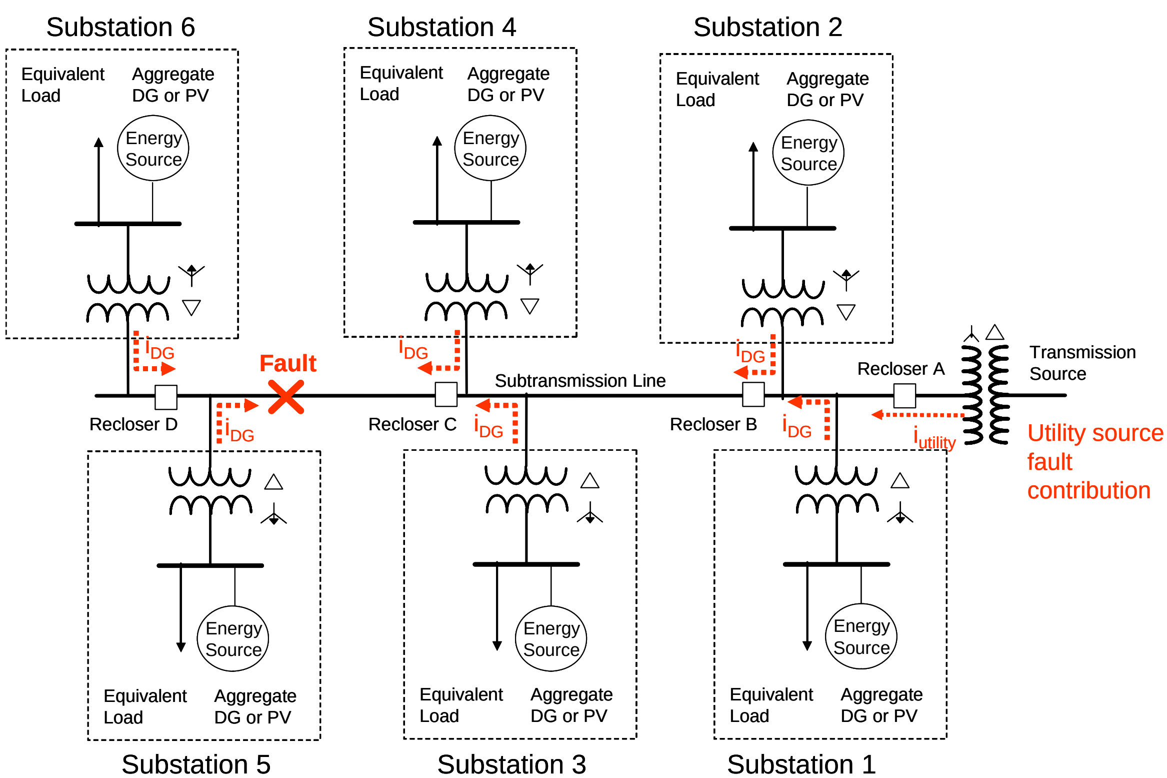

Figure 2-15. Aggregation of distribution-connected PV and other DG resources at many distribution substations can have a significant impact on subtransmission fault levels, affect the switching schemes, pose an islanding risk, and cause ground fault overvoltages

2.6 Limits to High Penetration of Distributed Resources (DR)

With the current state of DR technology, there are increasing opportunities for improving the reliability and the economics of the distribution system. At the same time, there are barriers that can prevent the proper operation of distribution systems as DR penetration increases. Some of these barriers are design characteristics of current distribution systems and others are operations and maintenance characteristics, regulations, and lack of adequate tools for distribution engineers.

Today's electric distribution systems have evolved over many years in response to load growth and changes in technology. A large number of distribution systems employ radial circuits fed from distribution substations designed to supply load based on customer demand requirements while maintaining an adequate level of power quality and reliability. Protection is designed to safely clear faults and get customers back in service as quickly as possible. In areas of high load density, network systems are common. These systems are fed by multiple transmission sources and are therefore highly reliable. The systems currently in use have been designed to serve load with little planning for generation connected at these levels.

The design and technology associated with today's distribution systems impose important limits on the ability of the distribution system to accommodate modern initiatives such as the application of rooftop PV systems. Technologies such as customer load management, distribution system control, and PHEVs are also limited by today's radial system. Characteristics leading to limitations include the following:

- Voltage control is achieved with devices (voltage regulators and capacitor banks) that have localized controls. These schemes work well for today's radial circuits but they do not handle circuit reconfigurations and voltage impacts of local generation well, resulting in restrictions on the ways circuits can be configured and important limits on the penetration of distributed resources. This also limits the ability to control the voltage on distribution circuits to optimize the energy efficiency of customer equipment.
- There is little communication and metering infrastructure to aid in restoration following faults on the system.
- There is no communication infrastructure to facilitate control and management of distributed resources that could include renewables, other types of DG, and storage. In addition, there is no communication to customer facilities to allow customers and customer loads to react to electricity price changes and/or emergency conditions. Customer-owned and distributed resources cannot participate in electricity markets, limiting the economic payback in many cases. Communications to the customer would also provide feedback on energy use, which has been shown to help customers improve their energy efficiency.
- The infrastructure is limited in the capacity to support new technologies such as PHEVs without a communication and control infrastructure. PHEVs would have the potential to seriously affect distribution system load profiles. If they could be used to benefit load profiles and distribution systems through coordinated control, significant benefits could be realized.

At the same time, the distribution system infrastructure is aging, resulting in concerns for ongoing reliability. Utilities are struggling to find the required investment just to maintain the existing level of reliability, much less to achieve higher levels of performance and reliability. New automation schemes are being implemented that can reconfigure circuits to improve reliability, but these schemes do not achieve the coordinated control needed to improve energy efficiency, manage demand, and reduce circuit losses.

A strong interest in placing DR assets on distribution networks is emerging. Deregulation of the power system and performance-based rate-setting are also causing a reevaluation of the existing distribution network—and modern communications, control, and sensing technologies are providing new options to the system designers. These issues and opportunities need to be addressed together, which will allow a diverse set of goals to be achieved.

3.0 Project Results

In the last section, the issues and potential impacts of distribution-connected energy resources such as PV on conventional power distribution and subtransmission systems were discussed. That discussion clearly indicates that there will be difficulty implementing high-penetration PV on the existing system unless significant strategic and tactical modifications are made to the way that the system is designed, operated, and controlled. This section identifies the types of technologies and system changes that can be employed to meet future needs. Also discussed here are targeted research areas where focus is needed to develop systems, technologies, and practices that fulfill the needs of a 21st-century power system that is rich in PV as well as in other types of DG resources.

3.1 Distribution System of the Future

Even with all the challenges that high-penetration distributed PV faces in today's distribution systems, it is viewed as offering the largest potential and the best option for deployment of PV generation. This view results from the widespread presence of these systems and from inherent issues with networked distribution and spot networks [4].

The opportunity to make better use of existing energy resources and to add new ones is increasing pressure to modernize the existing distribution grid. In addition, the availability of better communications, control, and sensing technologies offers new options to system designers. These issues and opportunities must be addressed together to achieve a diverse set of goals.

3.1.1 System Benefits and Challenges

Several potential benefits would be realized from the application of DG on the distribution system. The most promising of these are

- Improved efficiency/reduced losses
- Reduced need for bulk generation and T&D expansions
- Sustainable and environmentally friendly energy sources
- Potential for improved power quality and reliability
- Voltage/volt ampere reactive (VAR) control capabilities.

An overall loss reduction can be expected when generation is connected near the load. This can also lead to reduction of power flow through the transmission grid and the distribution system, which in turn can cause utilities to place a lower priority on upgrading these systems. Diversity of energy sources is a benefit to sustainable power provision and grid security. Over the longer term, distributed PV has the potential to improve both reliability and power quality on a distribution system. The full realization of this benefit, however, will require structural changes in the way the distribution system is built and operated [5]. Similarly, benefits could potentially be realized from allowing inverters to participate in voltage regulation and VAR supply. It is important to document and quantify these advantages so as to properly plan for the deployment of rooftop PV.

To fully realize power reliability and quality benefits, it is expected that the distribution system would include a combination of central and distributed control that will allow an effective interaction of supply and demand. This includes the capability of stand-alone (grid-disconnected) operation. Figure 3-1 shows a range of devices that would work together in a future advanced distribution system.

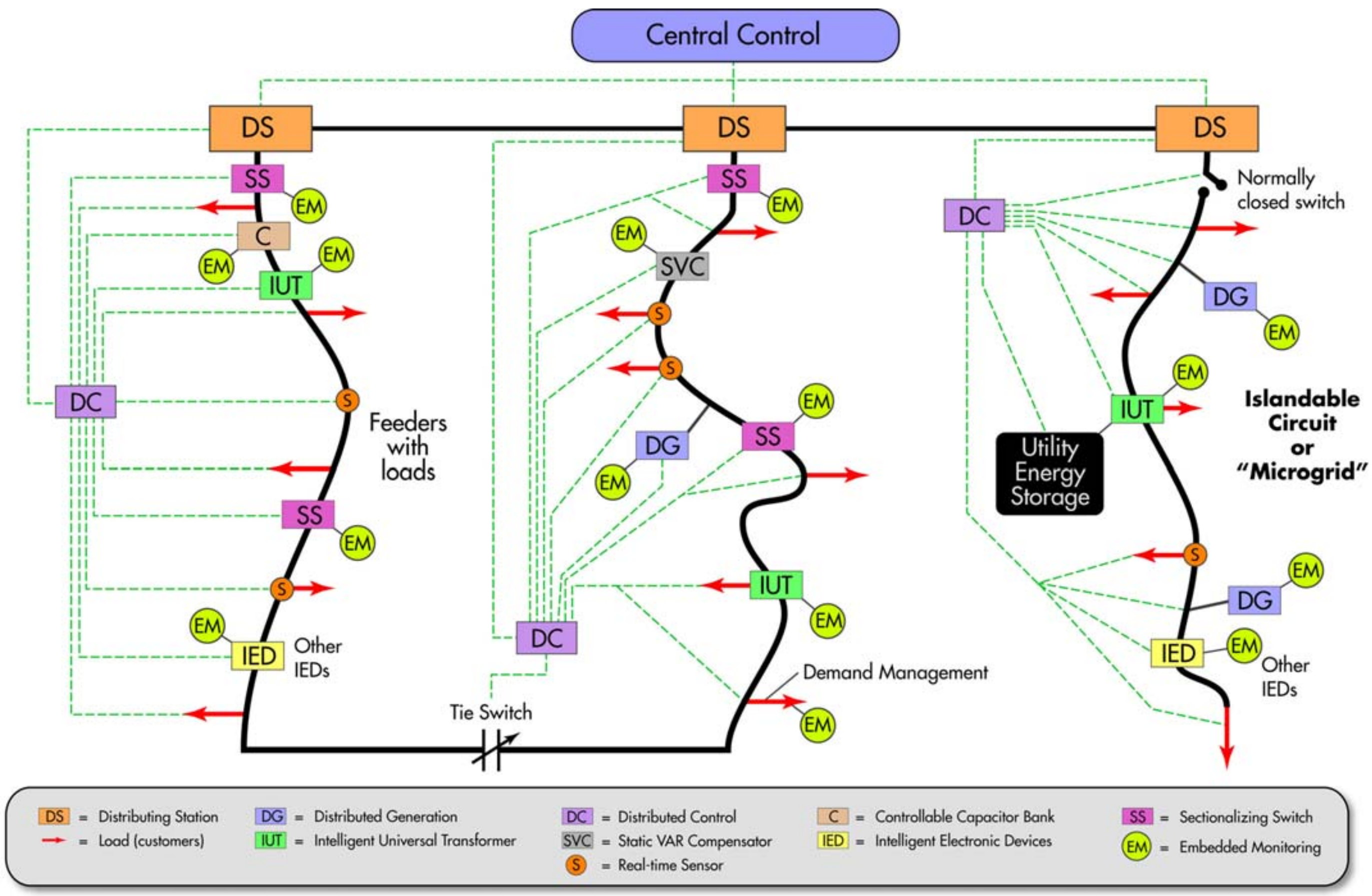

Figure 3-1. Future devices in an advanced distribution system

In the ideal situation, a distributed generator could be placed at a desired location on the distribution system without any adverse impact on the system or any need for system upgrades. The asset, which would have a communications link, would benefit the system by offsetting its energy and capacity needs and improving its reliability and power quality.

Challenges stem from the practical realities. DG placement is often less than ideal, and determining how that placement will affect the feeder can be expensive and time-consuming. In all cases distributed generation must not compromise safety and will lead to increased complexity of the distribution system. Renewable resources, particularly wind and PV, are dependent on meteorological conditions and are not always available. These realities lead to a list of evaluations associated with any grid installation. The following evaluation steps start to become necessary as penetration levels increase:

- Ensure that equipment ratings are not exceeded
- Make sure that steady-state voltage limits are met
- Avoid voltage flicker, harmonics, and other power quality problems
- Avoid ferroresonance
- Ensure that faults are rapidly sensed and cleared
- Maintain and improve system reliability
- Make sure that interactions with voltage regulators, power factor correction capacitors, and other DER are dynamic.

In general, these same criteria are applied when a new customer or a large new load is added to the system. The primary difference is that high penetration levels can cause a reversal of power flow direction on the primary feeder. High penetration can also lead to a lack of either coordination or sensing in protection devices. In large installations, special transformer connections may be necessary for compatible grounding, particularly when islanded operation is envisioned.

3.1.2 Summary of Needed Changes

The distribution power system architecture for the 21st century, which will make high-penetration PV compatible, involves changes to the power system and to the PV equipment itself. These changes will generally include the following:

- **Interactive voltage regulation and VAR management.** Utility voltage regulator and capacitor controls will be interactive with each other and with the PV or general DG sources that reside on the system. A central controller will help manage the interactivity to ensure optimized voltage and reactive power conditions.
- **Bulk system coordination of PV for market and bulk system control.** Control of DER (including most PV) from the dispatch center will be needed. This will allow these resources to participate in and be aggregated into energy markets as well as to preserve system stability, power quality, and reliability at the bulk level.
- **Adaptive protective relaying schemes.** The distribution and subtransmission system will include more extensive use of directional relaying, communication-based transfer trips, and impedance-based fault-protection schemes (like those used in transmission). These can work more effectively in an environment rich with multiple energy sources on the distribution system.
- **Advanced islanding control.** The system will employ smart, automated switchgear. Its enhanced islanding detection and communications will improve the ability to detect unintentional islands and reconfigure the power system, where appropriate, into reliability-enhancing intentional islands fed by properly configured PV and other DG resources.

- **PV interactive service restoration.** Sectionalizing schemes for service restoration will allow PV and other DG resources to help pick up load during the restoration process and allow the system—if it has broken into islands—to self restore into a unified system. These schemes must deal effectively with cold load and inrush currents.
- **Improved grounding compatibility.** The future power system will be designed with the inherent ability to handle large penetrations of distribution-connected PV without running the risk of ground fault overvoltage and or interference with protective relaying schemes.
- **Energy storage.** Energy storage of various forms will be applied to correct temporary load/generation mismatches, regulate frequency, mitigate flicker, and assist with advanced islanding functions and service restoration.

This list of system changes and technology upgrades, if implemented, will represent an extensive investment on the part of government, electric utilities, and equipment manufacturers, as well as a huge change in the way the power system is designed and operated. These changes, which will not come about overnight, will require considerable engineering planning and development designed to weigh the necessary balance of features and capabilities against the cost and complexity of implementation. Nonetheless, these are the long-term approaches needed to move to high-penetration PV, and the industry needs to begin work now on R&D to make the technologies, tools, and approaches available in a timely manner.

The long-term approach recommended in this report involves integrated control of the distribution system. The associated communication infrastructure will support integration of the DG and load management with the operation of the overall distribution system. Other approaches involving advanced, adaptive, autonomous distributed controls at local generators for limiting fault-current contribution and controlling voltage under the supervision of the utility are also being developed. It is possible that these types of local controllers could allow much higher levels of penetration without the full communication and control infrastructure that will eventually be developed for distribution system management and market integration.

Many of the changes recommended in this report also have synergy with other system operating goals that electric utilities and customers have had for decades. They are not solely for the purpose of implementing high-penetration PV. First, the system changes that work for distribution-connected PV can, in large part, work for the other types of distribution-connected DG resources such as fuel cells, microturbines, small combustion turbines, ICE generators, and small wind and hydro installations. These changes, then, would foster increased utilization of all DG sources. Second, there is a major push to integrate demand-response systems with the overall market and expand the concept of demand response all the way down to individual residential customers. The communication and control infrastructure for the distribution system will integrate customer load management as well as distributed generation. Third, regardless of any desire for PV (or other DG) or demand-response systems, utilities have long wanted greater automation of the system that could be cost-justified and allow them to optimize power quality, reliability, situational awareness, and system efficiency.

The research effort and investment put into making the system more compatible with PV can have great synergy with these other long-standing utility objectives. Utilities around the nation are already increasing the amount of automation on the power distribution system to improve performance. They are accomplishing this by adding increasing layers of communications, status monitoring, automated switches, circuit breakers, and other devices. The objectives for a 21st-century power system that is compatible with PV can mesh nicely with these other goals and, to a great extent, can be thought of as an extension and acceleration of the ongoing automation evolution.

3.2 Interactive Voltage Regulation and Reactive Power Management

Voltage regulation is a crucial part of system operation, so one of the most critical upgrades for a 21st-century power system is to make sure that voltage can be regulated with large amounts of PV and other DG resources present. For optimal performance, electric users need voltage at service entrance to be *at least* within the normal ANSI Range A limits (typically within ±5% of nominal voltage rating). Actually, there is considerable research indicating that energy efficiency improvements are possible with better voltage regulation across the entire feeder. Future standards should deal with the relationship between voltage regulation and the overall efficiency of the distribution system and customer loads.

With high-penetration distribution-connected PV, the feeder voltage regulator banks, LTC transformers, and switched capacitors will need to be interactive with each other and various distributed power generation devices. Much of the PV may need to participate actively in the scheme by adjusting reactive or real power levels as needed. Figure 3-2 shows a general scheme for controlling the voltage regulators as well as various PV inverters and rotating power converters.

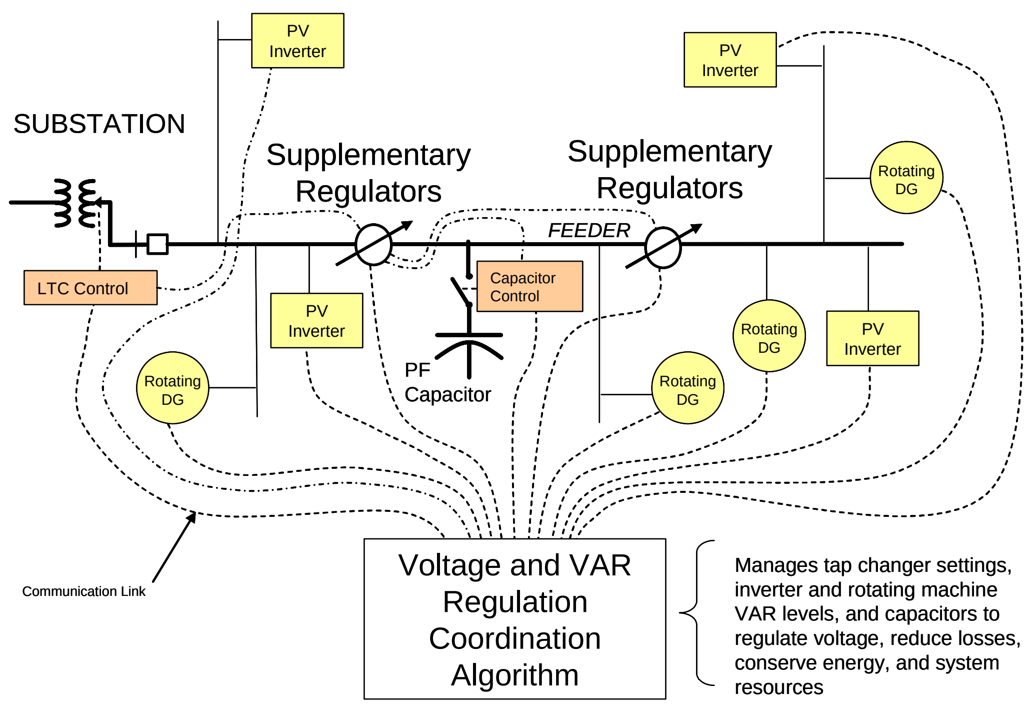

Figure 3-2. Integrated voltage regulation scheme for utility feeders with high-penetration PV and other DG energy sources

The arrangement in Figure 3-2 coordinates LTC transformers, supplementary step voltage regulators, local inverter regulators, and switched capacitors by means of communication links with a central control point. Without such communication and control, multiple regulators and inverters will interact, potentially leading to unstable voltage conditions.

This is a future evolution of the distribution system that requires significant investment and accounts for other benefits that may accrue. It involves replacing the system that has local voltage sensing, no communication, and line drop compensation with a new, coordinated multipoint voltage-sensing approach that does not employ line drop compensation. Implementation will be easier in urban environments and more difficult in rural settings. Where the new approach is implemented, it will lead to improved voltage profiles within all voltage regulation “zones” and less chance of exceeding ANSI limits under various conditions.

In addition to the utility voltage regulation equipment being coordinated by direct communication links and a central controller, under this new regime much of the distribution-connected PV equipment and other generation devices will be asked to adjust real and reactive power levels to assist with the process of managing voltage regulation and reactive power flow. This capability can be used not only to improve voltage regulation but also to reduce power flow losses (I^2R losses) and best allocate system capacity resources.

The power output of key distribution-connected power generation equipment will be carefully monitored and real-time calculations will be performed by a central controller to assist with coordinated adjustments to various voltage regulation devices. The resulting control will be able to provide much more precise regulation on the distribution system than is available today. The control algorithm will be programmed to find the best balance among the needs of voltage regulation, power system loss optimization, and PV resource allocation economics for the operator/owner of the PV equipment and other DG devices where applicable. Note that each local device capable of reactive power control and/or voltage control will have an interface to the central system with its local economic response algorithm. This will allow the central controller to estimate the contribution of these local devices to the overall voltage and loss management requirements. It is possible that the economics of local voltage control and VAR management could justify designing PV inverters with margins for reactive power contributions (e.g., an inverter design with a target power factor of 0.8 at full power rating rather than the 1.0 factor that is often used today). This last point deals with the issue that reactive power capability utilized either from an inverter or a rotating machine above a certain threshold can start to cut into the real power capability of the machine (unless the inverter is designed for this contribution in the first place). Cutting into the real power capability has negative economic consequences for the owner.

The danger of any control scheme involving communication links to a central controller is that it is only as reliable as the central controller and the communication links. To avoid problems if either should fail, the system will include redundant links among specific utility voltage regulation devices and several layered “fallback” control methodologies that can manage the regulation (to a lesser degree but still with acceptable quality) without the oversight of the main controller.

The system will also have two layered voltage regulating capabilities from a speed-of-response perspective. First is the low-speed mode that is coordinated through various communication links as already described. This low-speed system responds as needed over a period of many tens of seconds or minutes to hold steady-state voltage within the ANSI limits. Its response speed is very similar to that of the existing system used today. The second layer is a high-speed system on top of the slow-speed system. This layer will consist of rapid-response (almost instantaneous) reactive control capability within PV or other inverters, as well as power conditioning devices such as static VAR compensators, solid-state dynamic voltage-restoration devices, or both. These are intended to minimize voltage flicker effects and moderate voltage sags and other rapid changes in voltage and power that result from fluctuating wind and solar resources, along with other power variations. A limited amount of energy storage capability—perhaps equal to a few minutes of the feeder's rated power—might be needed to help manage various aspects of this regulation process, but much of it can be accomplished with reactive power only. The high-speed voltage regulation will use autonomous operation and have a low negative feedback gain factor. These features reduce the risk of overcorrection, which could destabilize the fast voltage regulation system and might cause voltage hunting and other problems that are worse than those it was trying to correct.

The communication requirements for a new voltage regulation scheme will not be demanding. For the slow-speed voltage regulation functions, relatively slow equipment access times—on the order of many seconds or tens of seconds—and relatively low data rates will suffice. For the high-speed voltage regulation functions (such as flicker mitigation), localized controls can be used, which do not necessarily require any communications at all. Wireless networks, broadband over power line (BPL), and various Internet techniques should be suitable.

Table 3-1 contrasts the characteristics of existing voltage regulation practices at many utilities today against the possible future voltage regulation methodologies.

Table 3-1. Comparison of Present and Future Possible Voltage Regulation Methods Compatible with High-Penetration PV
(Can Also Apply to General Types of DG for Some of the Functions)

Equipment or Function Description	Current Methods Used (2007) for Low-Penetration PV	Future Methods Needed for High-Penetration PV for 21st-Century Distribution System
Operation of substation LTC transformer and supplementary step voltage regulators	Usually autonomous operation with no communication. Voltage sensing is local at each device. Line drop compensation is often used.	Local autonomous operation is replaced by communication-coordinated operation with other regulation equipment and PV power sources.
Operation of switched capacitors	Locally autonomous with control similar to LTC or remotely dispatched, often by radio signal.	Local autonomous operation is replaced by communication-coordinated operation with other regulation equipment and PV power sources.
Distributed generators (existing)	Almost all PV is voltage-following; does not actively participate in voltage control.	In most cases older existing PV can be grandfathered to continue operating as before.
Distributed generators (new era)	Not applicable.	A significant portion of new PV coming online will actively participate in regulating at least reactive power to assist in voltage regulation and VAR management.
Operation of voltage regulators during system reconfiguration and islanding	Some voltage regulator units today can handle reverse flow caused by alternative source back-feed. None are set up for islands.	The voltage regulation system will be able handle switching reconfiguration of the system and breakup into islands.
Energy storage and solid-state power conditioning	Not used for voltage regulation today (other than demonstrations).	Energy storage is used to manage fluctuating PV and other sources and support the system during islanding conditions and restoration.

3.3 Bulk Market Dispatch and Bulk System Control

At higher penetration levels of PV on the system, the bulk power marketers and independent system operators will need to have partial or full control of a significant portion of the PV and other types of DG resources for three primary purposes:

1. To manage the power market
2. To satisfy transmission power flow constraints, meet bulk system reliability needs, and avoid system overloads
3. To regulate the power system frequency.

Very-high-speed communication that responds within cycles is not needed for these bulk control functions. The response time can be many tens of seconds or even minutes in many cases. In addition, “latency of contact” and “data exchange rate” communication requirements per generator are not significant. On the other hand, there will be a huge number (millions) of generator contact points out on the system, so the aggregate communication requirements could be large. Addressing all these units individually from a single control point may not be the most effective approach. It will be much better to aggregate the smaller generators into various types and dispatch them according to type, system need, and location. Figure 3-3 shows the resource categories that might be defined (many of these already exist today). Some of the PV and general DG will not participate in the active control program and are shown as “nonparticipating.” The market will likely need economic incentives to achieve a certain level of participation. The greater the penetration of DG, the greater the participation needed for system control.

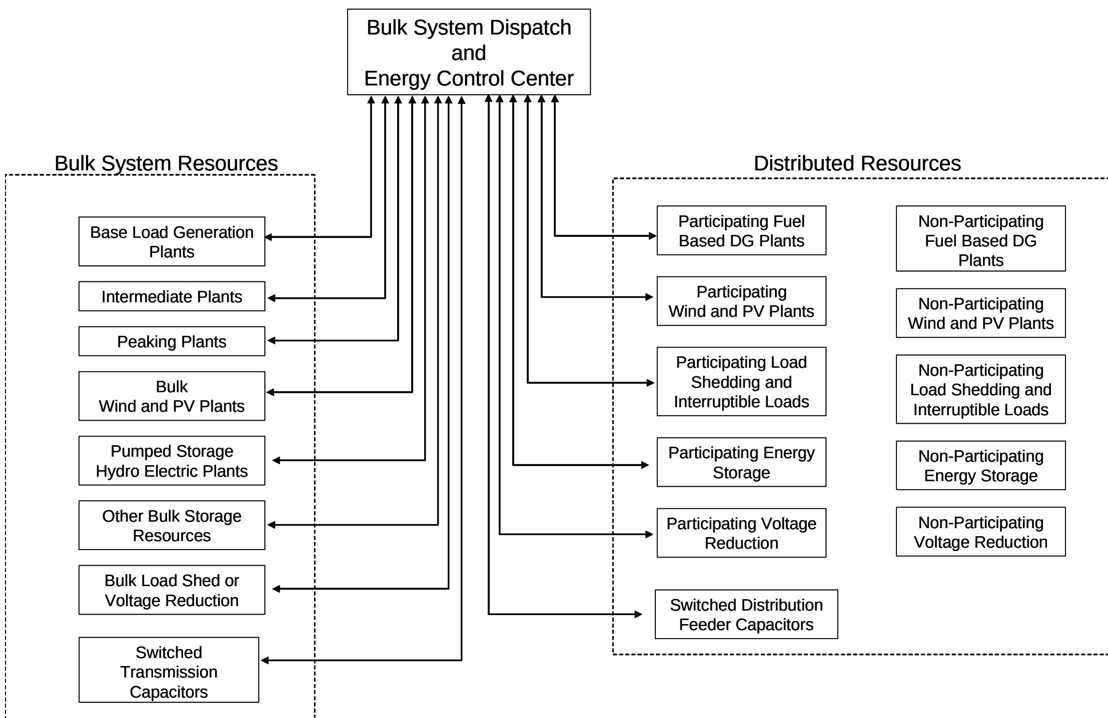

Figure 3-3. Resources available to the independent system operator (ISO) and/or bulk system control center in the 21st-century power system (some resources can be fully dispatched and others are simply monitored or ramped down as needed)

It is important to recognize that Figure 3-3 shows one possible example of direct communication links to the blocks of various types of energy resources. The actual hierarchical structure and physical paths used in the 21st-century system will depend greatly on many factors, including the type of energy market that exists and the communication technologies employed. For example, communication could be from the dispatch center to a substation remote terminal unit (RTU) by traditional means such as leased fiber optic cables, telephone lines, satellite links, or microwave links. From the substation RTU to the individual generator or distributed resource contact points, power line communication techniques, wireless LAN, or BPL could be used. Unlike when dispatching large power plants where the loss of contact with any one plant is a serious problem, because each unit of PV capacity is not particularly large, the danger imposed by losing contact with any one PV unit is not that significant. This means that communications reliability and security to any one PV unit is not particularly important from the bulk system perspective. The ability to control a large aggregated block of PV equivalent in size to a conventional large plant, however, is just as critical as controlling a large plant itself.

It is worth noting that market participation of local PV may represent a level of complexity that is unnecessary in many applications. PV, like wind, can be thought of as a fuel saver and would likely be one of the last resources to be ramped back. Participation in markets through aggregators or some other means, though, has the potential to benefit PV operators if such market participation provides the possibility of realizing premium prices for local generation (either with or without local storage).

There are ways in which PV and other forms of DG can assist in the system frequency regulation and in services such as reactive power support without using communication. For example, the distributed generators can help regulate the system frequency simply by modulating their output based on the locally measured frequency. This is a form of “negative feedback” control that is applied to the measured frequency. If the frequency goes down, the generator output goes up, and vice versa. DG units could also be programmed to adjust reactive output based on locally measured voltage, power factor, temperature, or simply time of day; these are already widely used techniques for capacitor banks. It is unlikely that PV systems would participate in this type of control because it would require operating at a reduced power level to provide margin for the control function. The power generation objective is likely to take precedent over this type of control for some time (very high penetration levels would be required before margin in the available generation is likely to be available for such controls).

It is beyond the scope of this document to discuss in depth the means that can be used to encourage distribution-connected energy resources to participate in bulk system services and control. But it is worth briefly mentioning that a variety of incentive methods are already in use to get customers to sign up for interruptible service devices and demand-response programs, among others. These methods could be applied to various DG and DR technologies in the 21st-century power system. Concepts include

- Discount tariffs for PV inverter or rotating DG sites that hand over some fraction of their capacity (real or reactive) for ancillary services
- Direct purchase of excess capacity on a meter basis
- Credit for lost value of generation when operators are asked to curtail production to meet a system need.

Grid support services are expected to be available at some level from a PV system in the future. When supplied by distributed resources, these services could prove very cost effective for utilities. Reactive power is one of those commodities, especially it is furnished by PV inverters that may be underutilized relative to their rating most of the time and that could have almost “free” available reactive power if only they were designed for that feature.

3.4 Future Protective Relaying Schemes

Historically, autonomous devices such as circuit breakers, reclosers, sectionalizing switches, and various forms of fuses that locally sense current conditions and operate according to their programming or design physics have supplied overcurrent protection at the power distribution system level. With the exception of the newer sectionalizing switch schemes in use today, little or no communication among such devices is employed for distribution system protection. Similarly, to protect most small to mid-sized rotating DG and PV inverters on the system, only local relay-based or microprocessor algorithm-based anti-islanding protection is generally used. In fact, PV and most other types of DG have not usually been required to use a transfer trip signal unless it is at the upper end of the size range (>1 MW). These approaches have worked well up to now because penetration of these resources has been low, but these methods will not work well in the high-penetration environments of the future.

To successfully implement high-penetration PV on the power distribution system, the traditional autonomous protection techniques comprising simple overcurrent relays must give way to a communication-intensive approach with transfer tripping signals or encoded pilot signals for most DER on the system. In addition, more advanced directional relays and dynamic relay settings may be needed for overcurrent functions at key feeder circuit breakers, reclosers, and sectionalizing switches because of the constantly changing fault levels associated with changing source aggregations on the system.

Protective techniques such as “live-line reclose-blocking” relays and “synchronization check” may also be needed at any sectionalizing switchgear points to manage islanding. Even lateral fusing may need to change to an electronics-based system to better handle the range of conditions expected from PV and other DG sources. In total, protection of the new distribution system will begin to look more like current protection of bulk transmission, which uses many of these same technologies. But unlike bulk transmission, which is generally composed of two terminal points on each protected line, the distribution system has myriad feeders, branches, and laterals, and the system can be reconfigured quite a bit in day-to-day operations. Furthermore, generation fault contributions and overall fault-current levels will vary much more than they do on transmission, depending on the availability of PV and other DG units as well as the islanding status. These factors will all make the process much more complex than classical transmission line protection.

The most difficult tasks in converting to the 21st-century system will not necessarily be upgrading the switchgear devices or relay hardware. The big issues will be implementing a cost-effective, reliable communication scheme that has the level of security needed for protective relaying and can respond fast enough (cycles) to successfully accomplish the control objectives. Another difficult part will be establishing algorithms and procedures (software) to control the scheme and provide dynamic protection settings that can deal with all the possibilities.

Although Internet, wireless cell phone, and pager technologies seem, at first glance, to offer endless opportunities for "addressable communications" that might be suitable for this task, it is not clear that they can effectively function as "protection-grade" communication circuits. A protection-grade circuit must be available full time and be able to respond within 50 ms or less when called on suddenly. The Internet and wireless networks have latency in "addressing/handshaking" (the time it takes to acquire contact with a specific device that is being controlled) that is very unpredictable and in many cases unsuitable to this task. If the Internet is to be used in this manner, technologies that solve that issue must be employed. For protection, communication technologies that have minimal latency of contact will be needed, even though many of the specific tripping/control functions will not need high data rates once contact is established.

To provide effective anti-islanding protection to thousands of PV and/or rotating DG on a feeder, a low-frequency, carrier-based, encoded pilot signal—which would enable/disable operation of all generation sources on the circuit—could be employed (see Figure 3-4). This communication technique is simple and cost effective. Presence of the signal at any point on the system would indicate continuity of the path back to the substation, which would allow the source to operate. Absence of the signal would indicate an open connection (open switch, circuit breaker, or fuse) and signify islanding, which would require the source to shut down. Before power line carrier signals can become an accepted utility practice for anti-islanding protection, however, a number of issues must be resolved, including selectivity, speed, loss of signal during faults, and other signal interference.

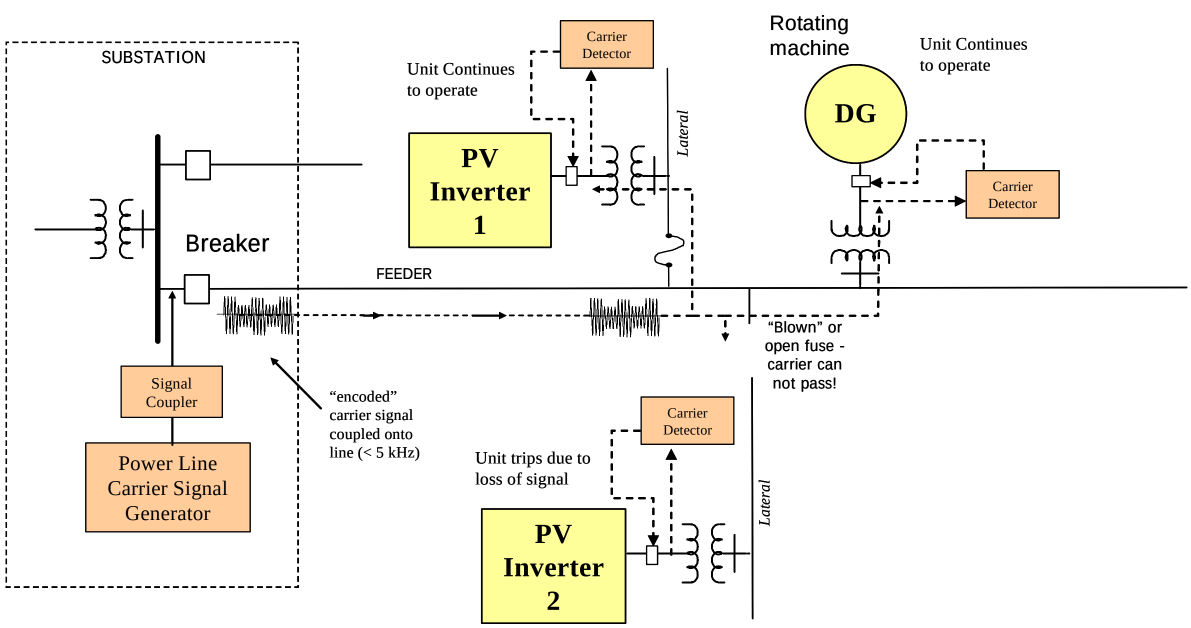

Figure 3-4. Power-line, carrier-based, pilot-relaying scheme for anti-islanding protection

Table 3-2 contrasts some of the design features of present-day distribution overcurrent protection against improvements needed for the 21st-century PV- and/or DG-rich system. Areas of R&D needed include smarter adaptive (dynamic) relays; improved anti-islanding techniques; low-cost, fast-response pilot relaying or other communication technologies; low-cost adaptable electronic fuses; and fault-locating techniques for multisource environments. One of the more complex issues will be controlling the breakup of the system into islands and then restoring the system smoothly and safely.

Table 3-2. Overcurrent Protection Today Compared to the 21st-Century PV-Compatible System
(Comparison Also Applies to Other Forms of DG)

Protection Function	Current Methods Used (2007) for Most Low-Penetration PV	Future Methods Needed for High-Penetration PV for 21st-Century Distribution System
Anti-Islanding Protection of PV	Usually done with passive or active voltage and frequency relaying over an acceptable window.	Pilot signal or direct transfer trip signal will be used as primary protection. Voltage and frequency-relaying acceptable window method will be used as backup.
Overcurrent Relays and Electronic Overcurrent Sensing Devices	Typically nondirectional overcurrent relays.	Overcurrent relays will have directional blocking capability added to prevent sympathetic trips. Relays may need dynamic settings to adjust to changing fault levels. Relays send out transfer trip signal to PV or other devices.
Reclosing Practices	Reclosing widely used on overhead feeder systems with dead times ranging from one-third of 1 s to more than 60 s; multiple shots used.	Reclosing practices need to be altered to allow coordination with intentional islanding scheme. Live-line blocking and/or voltage-synch check may be needed at key switchgear locations to avoid closing out of phase into live island. Communication-based reclose “enable” or “blocking” signal may be needed.
Sectionalizing Switches	Check for fault pass-through, then open on loss of voltage.	More sophisticated sensing and control will be used to deal with PV-caused bidirectional fault flows and advanced islanding considerations.
Lateral Fusing	Laterals fused mainly with thermal links.	Future electronically controlled fuses will allow better coordination with varying fault levels resulting from differing amounts of PV and other DG on the system.
Distribution Transformer Fusing	Current-limiting fuse on high fault-current sections; expulsion fuses on low fault-current section.	Increasing usage of current-limit fuses at transformers on all sections will keep tanks from rupturing in case PV and other DG sources cause higher fault levels.

3.5 Advanced Islanding and Service Restoration Features

The ability of the distribution system to break apart into intentional islands during a fault or system disturbance and then automatically self restore into a unified grid once the disturbance is finished could be a key feature of 21st-century power distribution systems with high levels of local generation (see Figure 3-5). This feature, although complex to implement, could help improve system reliability and make the system more robust against various types of cascading outages.

For this feature to work, the system must have sectionalizing devices (such as switches, breakers, or reclosers) that divide it into suitably sized sections, each with sufficient generation for the load. There will likely need to be a power conditioning device on each island (with some limited energy storage) to manage voltage, help regulate frequency, and match temporary load to generation imbalances. There may be both inverter sources (PV, fuel cells, and so on) and rotating generators on the islands. A local island controller would be assigned to each island to oversee operation. A master controller could manage the entire feeder group of islands. Each sectionalizing device would have relays and controls to manage synchronization and reconnection of the islands when the system was ready to be restored to a unified grid. Depending on power quality needs, in some cases the sectionalizing devices would be static switches that provide nearly seamless isolation from faulted or troubled adjacent sections/islands.

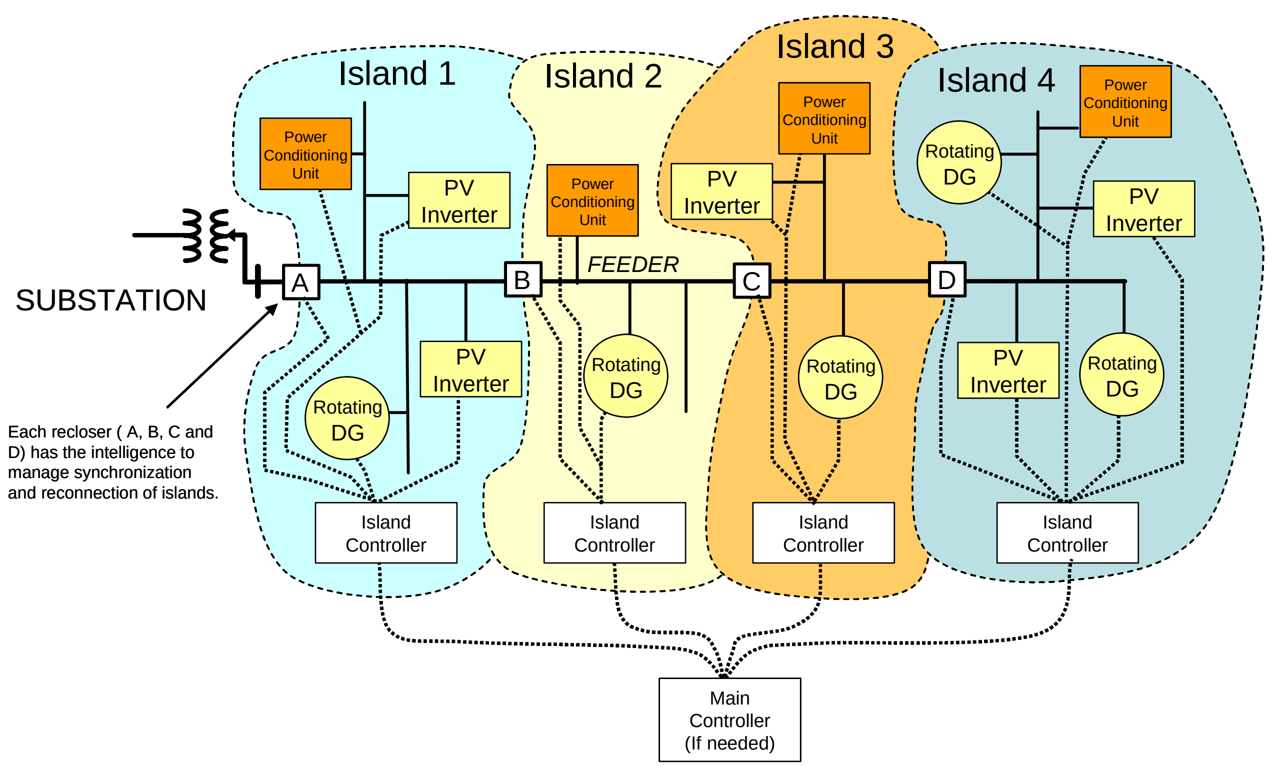

Figure 3-5. Four-island distribution feeder

Another capability that can be achieved using sectionalizing switches is the ability to restore service in a manner that minimizes cold load pickup and inrush. The cascaded load pickup scheme shown in Figure 3-6 automatically restores load to sections of the dead feeder in increments from the front to the end section. Timing delays between each switch closure allow the cold load pickup current and inrush to subside before each new increment is brought online. The distribution-connected PV units and other DG in each respective section can begin operating within a few minutes or even more quickly after voltage is restored to those sections.

This capability can help avoid nuisance feeder-breaker trip-outs during the cold load pickup of the entire feeder at once. It can also allow PV and other feeder energy resources to participate in the service-restoration process. One of the valid criticisms of relying on PV or conventional DG for T&D support has been that during restoration these resources would be unable to assist with load pickup (because they tripped offline during the disturbance that caused the outage). As a result, the substation and feeders would still need to be built to full design capacity for cold load pickup. The methodology proposed here, however, can help to partially alleviate that concern and to increase the system support capacity during power restoration of various feeder energy resources.

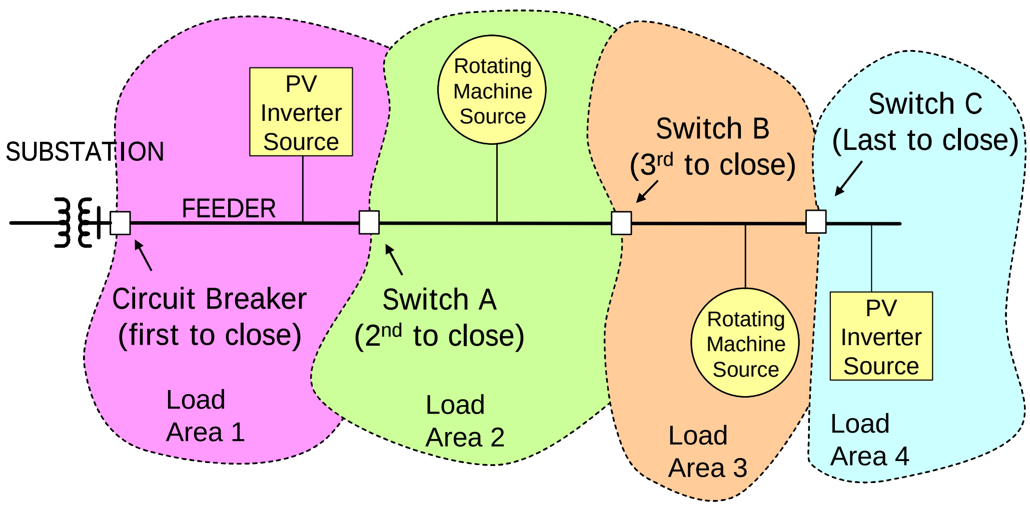

Figure 3-6. Use of cascaded restoration switches to allow PV and other feeder energy resources to help with load pickup

In general, intentional islanding will be justified based on local circumstances, typically the increased reliability benefits to the local system. Most local systems that can be islanded will be connected to the main grid in the normal configuration and will be able to operate as an island during contingencies with local controls for voltage and power management in combination with local storage. A master controller for the local island system will coordinate with the grid for voltage- and VAR-control functions and also for participation in markets as appropriate. Systems with multiple islands in series are not as likely to be justified in the foreseeable future. Many of the benefits described previously can also be achieved by coordinating the response of multiple local systems to disturbances and protection requirements.

3.6 Improved Grounding Compatibility

As discussed earlier, the grounding compatibility of the four-wire multigrounded neutral distribution system leaves much to be desired with respect to integrating high-penetration PV into the system. This type of system necessitates a delicate balancing act between requiring the PV to be effectively grounded (to avoid ground fault overvoltage) and having too many grounding sources on the distribution system—which can result in interference with the system's ground fault protection. The low penetration of PV in the past has generally meant that this latter point could be ignored at most sites, leading to a decree that all PV and other types of DG would be effectively grounded when connected to the four-wire multigrounded neutral system. PV systems are always interfaced to the grid through inverter systems that inherently limit fault-current contribution. In addition, advanced controls for these inverters could quickly detect fault conditions and halt the inverter contribution completely. These types of controls may become more important as PV penetration levels rise. On the other hand, an issue related to effective grounding—which is somewhat independent of the inverter's fault-current contribution—is that the zero-sequence fault-current contribution of some arrangements of the effectively grounded interface transformers that would be used for PV can be significant even when the inverter contribution itself is minor. So the types of transformer grounding arrangements employed for high-penetration PV will be as important as the PV inverters in determining the ground current flow on the system. Large penetration of many delta (inverter-side) and grounded-wye (feeder-side) interface transformers would create the biggest concern because of their low zero-sequence impedance.

Grounding compatibility is an area of system design that needs to be closely investigated to see what future design techniques, if any, can be applied to minimize this problem and make the system grounding more compatible with various distribution-connected energy sources such as PV. Fortunately, the industry has already been dealing with this problem for some time with conventional larger DG installations, so experience has been gained in methods to mitigate the problems. A future system could be more grounding-compatible by employing one—or a combination—of the following options:

- **Technique 1:** Control or limit ground fault overvoltage through relaying techniques or ancillary devices instead of by requiring effectively grounded DG.
- **Technique 2:** Harden the power system and loads to be less susceptible to ground fault overvoltage (i.e., increase voltage-withstand ratings).
- **Technique 3:** Change protective relaying of ground faults so that high penetration of grounding sources is immaterial in terms of its effect on ground fault relaying.
- **Technique 4:** Change the feeder-grounding or load-serving scheme back to a three-wire system.
- **Technique 5:** Implement advanced inverter controls and transformer schemes that limit the contribution of the inverters to ground faults to very low levels so that they can be implemented even in high-penetration scenarios without changing protection strategies.

The material that follows discusses how each of these techniques could be applied to 21st-century power distribution systems. This discussion focuses on how four-wire multigrounded neutral distribution and/or loads on such systems could be changed or controlled to alleviate the concerns. Implementing Technique 5 (which is not discussed in detail here) in the inverter design could reduce the need for these system-level approaches.

Technique 1 is already used by some utilities in some DG installations. In this scheme, the DG is not effectively grounded (with a delta winding transformer on the high side) and the timing of circuit breaker tripping of the feeder and reclosers with the DG breaker is set to clear the DG before the “grounding bank” effect of the substation transformer is cleared from the system. This works because, with an ungrounded DG, the ground fault overvoltage would not usually be substantial until the substation transformer was separated from the feeder. This technique requires fast and reliable tripping of the DG, usually involving a communication link. In areas of the feeder where islands might be desired or for additional grounding redundancy, grounding bank transformers could be added to supplement the substation’s grounding capabilities.

In Technique 2, all devices on the feeder (surge arresters, loads, line-to-ground transformer fusing, and so on) are upgraded to handle the full ground fault overvoltage without damage. This approach would be costly and difficult to implement in the short term (a few years) but could be a manageable change in the long run (a few decades). To protect against lightning surges, lightning arresters that are “full rated” line-to-line arresters would need to be used instead of the line-to-neutral voltage-rated types. Although this causes minor added difficulty in certain insulation coordination applications, it is not an insurmountable issue. In many cases, cables, wires, transformers, and other devices may already have sufficient margins for the overvoltage. The devices that do not can be gradually upgraded over time.

In addition, making customer loads withstand ground fault overvoltage is simpler than it might seem. Many switch-mode power supplies on computers and appliances today are already rated for 75% to 208% voltage (90 to 250 volts alternating current [VAC] on a 120-V base). Future appliance standards could require that all customer loads be rated in this range so that ground fault overvoltages would eventually cease to be an issue for loads. This approach has an added benefit, in that future loads would be more robust and less susceptible to a full range of overvoltage-related power quality problems. After playing out over 20 to 30 years of steady adaptation, this strategy would make the system capable of handling full ground fault overvoltages without incident, and the utility industry could drop the effective grounding requirement.

Technique 3 continues to require all PV to be well grounded (effectively grounded or better) on four-wire systems but changes the nature of the relay so that the interference from such PV grounding sources no longer matters. This could be achieved in a number of ways. First, ground fault currents could be monitored at many points on the feeder. The resulting data could be sent by communications link back to the key ground fault relays controlling the feeder circuit breakers and reclosers.

Essentially this would mean that the feeder circuit breakers and the recloser would trip based not just on their own local current measurements but on measurements from other locations.

This would enable a more accurate assessment of ground fault current flow conditions. Another possibility is to largely give up on the ground fault relaying in favor of increased reliance on other types of overcurrent and undervoltage relaying to detect various types of fault conditions such as phase overcurrent relays. By using multiple measurements points, special voltage restraint relaying techniques, and adaptive relays with microprocessor algorithms, system designers can make this approach plausible.

A final technique, which is likely the most costly and least practical method but still worth mentioning, is to return to the three-wire system by converting the four-wire systems that are in place to three-wire systems. All load-serving distribution transformers that currently have phase-to-neutral input connections would be converted to phase-to-phase input connections (phase-to-phase connections will not be subjected to ground fault overvoltage because they are phase-to-neutral phenomena). The utility equipment on four-wire circuits such as surge arresters, cables, wires, and transformers would need to be upgraded along with the protective relaying. Laterals would need a second insulated cable to bring phase-to-phase connections to the loads. The neutral could remain in place but would be used only as a safety ground that does not carry ordinary zero-sequence load currents. As a three-wire system, effective grounding of distribution-connected PV would no longer be needed and ground fault overvoltages would not be an issue. Some of the fusing issues of old three-wire systems of the past could be eliminated using modern electronically controlled fuses.

These techniques vary greatly in terms of complexity and scope of system alteration, level of investment needed to accomplish the changes, and effectiveness at improving the system's grounding compatibility for PV and other DG resources. The best approaches cannot be chosen within the framework of this report. The ideas presented here are suggested as possibilities, and not all may prove cost effective or appropriate. The purpose of this discussion, however, is to identify possible upgrades and start the industry thinking about needed research activities. This is an area requiring detailed technical study by system designers and engineers to balance the costs and benefits of the various approaches. It is recommended that DOE support research activities to review these grounding alternatives and identify which approaches make the most sense for the industry.

3.7 Distributed Energy Storage

As mentioned earlier, energy storage will be a key player in the 21st-century power system. It will be especially necessary if there is a high penetration of fluctuating energy resources such as wind and PV energy on the system. These fluctuating sources add uncertainty to the generation dispatch process and power flow conditions. In addition, some of the features desired for a future system, such as automated intentional islands, will require short-term energy storage to satisfy various operational requirements.

Some of the roles for energy storage in the 21st century grid include:

- Provide bulk system and local intentional island frequency regulation (necessary because of power fluctuations from varying wind and solar energy resources)
- Improve the capture of the solar or wind resource during curtailed power production periods (i.e., store the energy and then dispatch later)

- Enhance transient and steady-state stability by providing disturbance damping and mitigation when the power system is subjected to a fault, sudden loss of load, tripped generation, and so on
- Help the system reenergize during cold load and inrush conditions
- Absorb the excess power from a generator on an island until it can be ramped down to reduce overvoltage transients (called "load rejection absorption").
- Balance distributed power generation and load on intentional islands during grid transition conditions in the short term (especially during the transition from grid parallel to islanded condition)
- Use storage to temporarily support power quality and reliability islands, even those with no DG.

Energy storage technologies that are currently available include

- Batteries
- Flow batteries
- Advanced flywheels
- Ultracapacitors
- Superconductive magnetic energy storage (SMES)
- Compressed air energy storage (CAES)
- Pumped storage hydroelectric power.

The main problem with most of these storage technologies is high cost. With the exception of pumped storage hydroelectric technology and perhaps CAES, the other energy storage technologies have, up to now, been an expensive proposition (costing well over 20 ¢/kWh of cycled energy). As a result, they are not widely used on a large-scale commercial basis for long-duration applications, which require many hours of power output at the storage device's rated power capacity. Long-duration applications include load peak shaving, load-leveling, intentional islanding for long periods by means of energy storage, and renewable resource energy collection and dispatch.

On the other hand, the use of batteries, flow batteries, flywheels, ultracapacitors, and SMES for short-duration storage (involving seconds or minutes of discharge) has gathered considerable steam in recent years. In short-duration applications the cost of the energy storage medium is not so crucial; it is the cost of the power converter that matters. Batteries, flow batteries, flywheels, ultracapacitors, and SMES are particularly well suited for rapid compensation for fluctuations from wind and PV. In fact, many recent distribution-scale demonstration projects have successfully established the value of these technologies for frequency regulation, intentional island transitioning, and other such applications. Figure 3-7 illustrates several energy storage technologies.

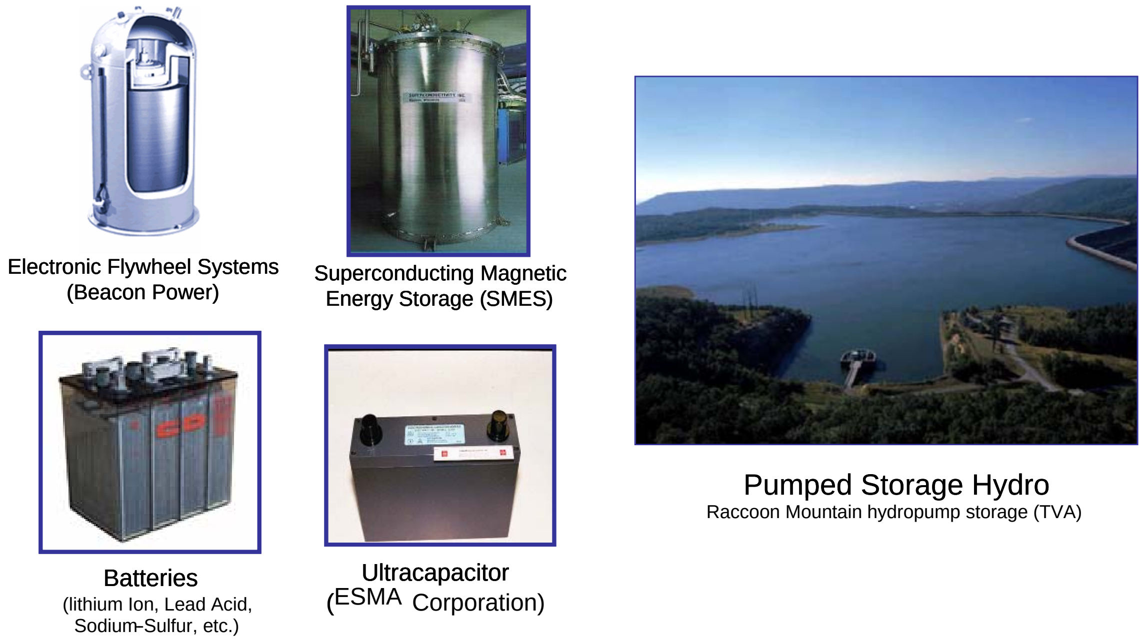

Figure 3-7. Energy storage can play a critical role in allowing high-penetration PV and wind energy to be successfully implemented and can enable advanced islanding features in future designs

For the broader objective of looking at ways to make the grid compatible with high-penetration PV, DOE's energy storage research should focus on assessing how such storage technologies can be applied at four distinct locations: the distributed energy resource, the distribution feeder, the substation, and the bulk power system level. Energy storage in a future system will likely be needed in a variety of sizes and configurations to meet needs at all system levels. Pumped storage hydro and CAES are most likely to be applied at the bulk system level to manage daily regional and macrosystem needs as wind and solar resources vary. At the distribution level and the customer-distributed resource location, the compact short-duration forms of energy storage (batteries, flow batteries, flywheels, ultracapacitors, and SMES) are more likely to be used for applications where only seconds to minutes of storage are required but high instantaneous power may be required. At the distribution level and with much PV, storage can be useful to help regulate frequency, mitigate ground fault overvoltage, absorb load rejections, adjust fault currents, balance load and generation on intentional islands, regulate voltage, and assist with service restoration. These functions are all important to the successful implementation of high-penetration distribution-connected PV and the 21st-century features that are envisioned for the grid.

A final point about emerging energy storage technology is that the power industry must find ways to transfer some of the significant breakthroughs currently occurring in hybrid-electric vehicle energy storage technologies (nickel-metal-hydride and lithium ion batteries) into applications for terrestrial power systems [6]. The major automobile manufacturers are spending billions of dollars on hybrid vehicle batteries and the performance parameters, particularly for the new lithium ion batteries that are being developed for PHEVs, may also be suitable for power system applications.

3.8 Microgrids

A microgrid is a power system with DER serving one or more customers. A microgrid, which can operate as an electrical island independent of the bulk power system, is a natural evolution of DER that can be used to serve energy customers in situations where conventional power system approaches cannot fully meet the customer's needs. Microgrids can offer advantages over the conventional power system such as lower environmental impact, higher efficiency, higher reliability, and more flexibility to meet changing or unique loads.

Microgrids can be applied in a broad range of sizes and configurations. Figure 3-8 shows examples of possible microgrid subsets that could be derived on a typical radial distribution system. These subsets include a single customer, a group of customers, an entire feeder, or a complete substation with multiple feeders. A very large substation, which could be serving more than 10,000 customers, could have up to 100 MW of capacity and eight or more feeders.

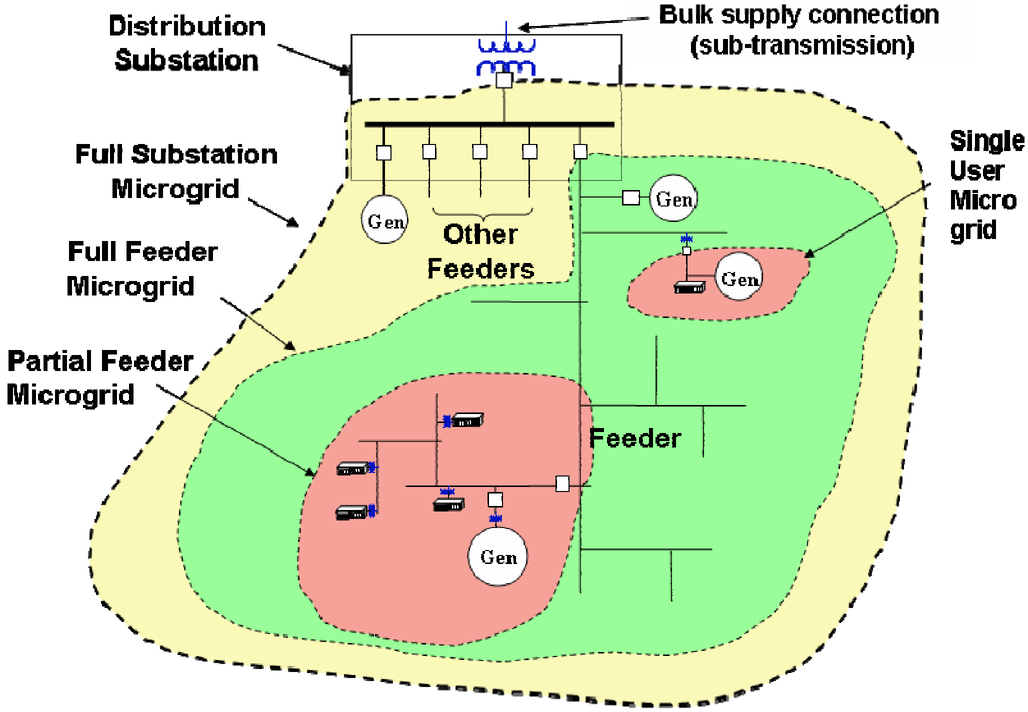

Figure 3-8. Examples of microgrids on a radial distribution system—from a single customer up to an entire substation

Microgrids can be full time, where they always operate independently from the bulk power system and are never connected, or they may be part time, operating in tandem with the bulk supply system during normal conditions but disconnecting and operating as an independent island in the event of a bulk supply failure or a bulk system emergency.

Microgrids employed on radial circuits are not the only possibility. They can also be employed within looped or networked architectures. In fact, for reasons of reliability and control flexibility, if a system were designed from scratch and were intended for high reliability, it would likely employ a looped or network architecture. This would allow redundant power flow paths between generation sources and loads, along with improved voltage regulation.

Microgrids, regardless of their size, must take on key control responsibilities while operating in the islanded state. While the generation is operating as an island, the generator must provide voltage and frequency control, low harmonic levels, the ability to load follow, and adequate reactive power for loads. For closed transition transfer or parallel operation with the utility system, the generator must be able to properly synchronize with the main utility system before connecting with the system and picking up load. Otherwise, serious damage can result. The generator must not have an adverse impact on reliability, voltage regulation, or power quality while it is connected to the bulk power system.

3.8.1 Microgrids with High Penetrations of Microsources

There is considerable interest in developing microgrids with multiple generators at widely dispersed locations and with a variety of generation types. Generation types could include various combinations of solar, wind, fuel cell, reciprocating engine, combustion turbine, and energy storage devices.

Compared to a single generation plant, using multiple generators at dispersed locations requires significant changes in protection and control methodologies. No longer will the standard radial protection and relaying approaches be appropriate, and the generators must communicate with each other in a manner that ensures adequate load sharing, system stability, proper frequency and voltage control, and optimal system performance in terms of efficiency and energy production cost.

Figure 3-9 shows an example of a microgrid employed on a radial campus distribution system. This figure shows the incremental capacity gain for a distribution planning area blanketed with 4 MW of solar PV generation. Based in equal energy exceeding normal (EEN), the gain is approximately 40% of the power rating of the solar generation, which is a good value for this type of generation. The system primary voltage is 13.2 kV. The peak load on the microgrid area is 2,975 kW, and generation capacity is 3,000 kW of dispatchable ICE units and 150 kW of intermittent renewable resources. The bulk system isolating device shown in Figure 3-9 is responsible for separating the campus system from the bulk utility system. A sectionalizing switch farther down the feeder provides the ability to break the microgrid apart into two smaller microgrids, which supplies added reliability if one section of the campus becomes faulted or if one of the generation plants is unavailable. The closing of the sectionalizing switch is blocked unless proper synchronization between the grids is achieved or unless override from the master controller indicates a need to close. The master controller monitors loads, voltage, and frequency and adjusts the generators and switching devices accordingly to ensure proper load sharing and optimal economic dispatch. The ICE units are operated as synchronous voltage sources, adjusting their excitation levels to regulate voltage on the system.

The energy storage device provides a few seconds of energy storage to an inverter that is programmed to function as a power conditioning device that stabilizes the voltage and frequency of the system during large load steps. Load shedding (not shown) could be added to improve the ability of the microgrid to ride through various contingencies, such as the loss of a generator.

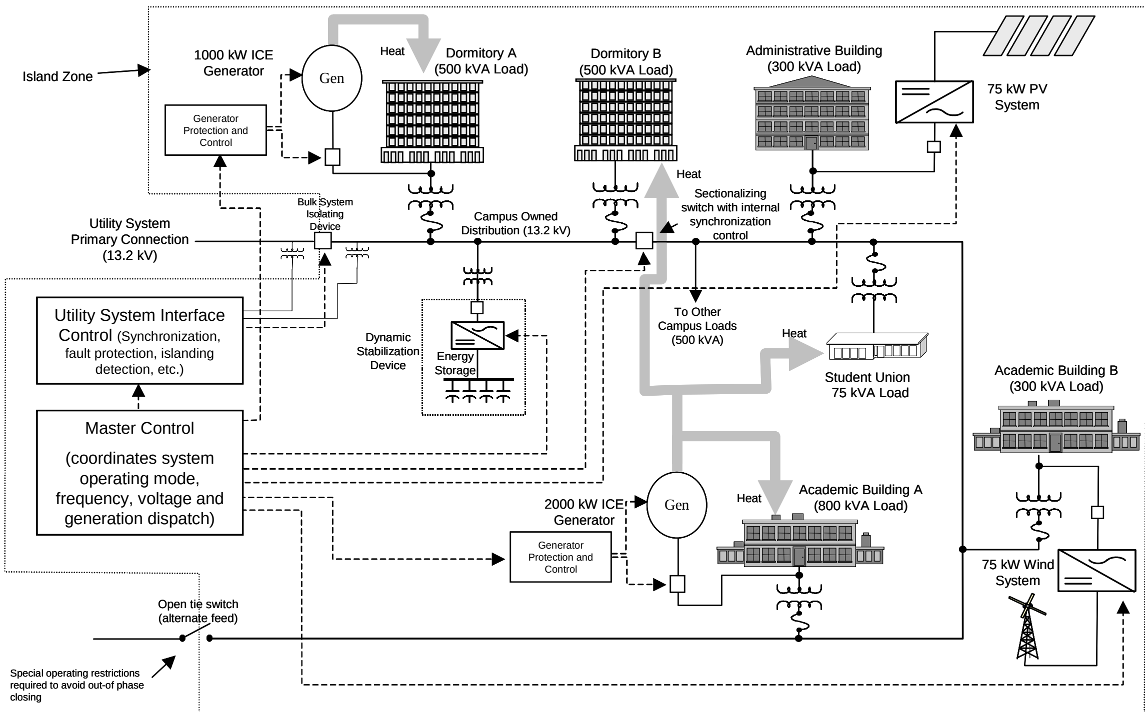

Figure 3-9. Conventional radial campus distribution system converted to a microgrid

The campus microgrid of Figure 3-9 could operate in parallel and independently from the bulk utility supply. Normally, it would operate in parallel but would separate during emergencies or interruptions of the utility supply. Depending on the length of the feeder, voltage regulation devices (such as step-voltage regulators) might be needed on the feeder. If these devices are used, they would need to employ regulator controls capable of responding properly to bidirectional power flow. Note also that the open tie switch located at the lower left in Figure 3-9 is meant for emergency back-feed but has not been equipped with synchronization equipment. Without synchronization, this switch could be used only when both the normal utility feed and the microgrid generation were disabled and it was being closed into a dead feeder.

3.8.2 DC Power Distribution and DC Microgrids

The power system changes discussed so far for the 21st-century grid have been for conventional AC power distribution systems only. Because DC power has great potential for increased compatibility with high-penetration, distribution-connected PV and other DG sources, it is worth considering as a possible future alternative. DC systems can also have significantly improved reliability and power quality compared to AC systems.

To understand the value of DC distribution, a quick historical review is in order. DC was actually the original form of power system, predating the AC system by about five to ten years. The original power grids developed by Thomas Edison, such as the Pearl Street Station grid in New York City in 1882, were small DC grids that worked well for delivering power over short distances (up to perhaps 1/2 mile from the generating station). Even though it was possible at the time to build higher voltage DC generators rated at as much as several thousand volts, which could reach many miles from the station, there was no way to step this high voltage back down to lower levels for safe use in homes. For safety reasons, then, the voltage had to be generated, transmitted, and utilized at only a few hundred volts. Such a low voltage would not work (because of wire losses and voltage drop considerations) for power transmission distances much beyond about 1/2 mile from the generating source. The Edison grids, which were built in many towns and cities around the country, typically served an area of about 1/4 to 1/2 of a square mile around each main generating station.

The power transformer (a device that works only with AC), which was invented in 1886, was the key breakthrough that allowed AC power systems to flourish because the voltage could be stepped up or down as needed for safety. AC power systems allowed utilities to develop remote, previously untapped hydroelectric resources and bring these energy resources over great distances to the cities. In addition, the extreme distances over which AC power could be transmitted enabled the creation of a complex interconnected network of lines between cities and various power generation centers. This improved the overall system reliability and the economics of power dispatch. Another advantage of switching to AC power was the AC induction motor. It was far better than DC motors of the era because it had no brushes. Brushed motors were maintenance intense, with the brushes needing periodic adjustment and replacement. For all these reasons, AC power eventually won the battle over DC in the early 20th century. By 1910 the era of the Edison DC grid was fading and the power system was transitioning to AC.

Times have changed and new technology has alleviated some of the key drawbacks of the Edison-era DC systems. Today we have solid-state switching DC/DC converters that can transform DC from one voltage level to another with fairly high efficiency. In addition, solid-state switching devices now allow DC motors to be brushless, a huge improvement over the brushed DC motors of the Edison era. The two big factors that gave AC the edge over DC 100 years ago have been eliminated.

In addition, today's loads are becoming more compatible with DC power, so making the transition back to a DC-based power system seems much more plausible. Devices such as electronic ballasts for lighting, switch-mode supplies for computers and appliances, and electronic motor drives (increasingly found in many appliances) can all be DC-compatible. Many DG resources, including PV, fuel cells, rectified high-frequency alternator outputs on microturbines or flywheels, batteries, and ultracapacitors, are DC-oriented.

Even though the idea of switching to DC distribution represents a massive change, it is a credible option for consideration in the distant future because of the changing nature of loads and generation devices, along with the potential benefits of DC. In considering DC over AC, many details must be factored into the analysis, including fault clearing, voltage regulation, losses, and power quality. The Galvin Institute recently investigated DC systems as one part of a larger project on technology for reliable power systems, and more details on the attributes and forms of DC systems can be found in *The Galvin Path to Perfect Power—A Technical Assessment* [7].

For a distribution-connected PV-rich environment in a world with increasing needs for power quality and reliability, DC has advantages that could make it attractive over AC. Some of the key benefits of DC power follow:

- Directional fault-flow blocking, which improves reliability and power quality
- Better voltage regulation and quality
- Easier interfacing of PV inverters and other DG types to the power system
- Better power system control and stability (especially with multiple varying energy sources).

Figure 3-10 is an example of a small-area 400-V DC grid with high-penetration DG coupled to the AC system. It could replace an existing AC lateral. Homes served by this system might be directly powered by DC or use an DC/AC inverter if AC power is needed. This DC grid features the directional fault-blocking capability. When strategically placed on the feeder as shown, diodes have the ability to block the reverse flow of current from one section to another. This physical feature has important ramifications from a power quality and reliability perspective. If reverse current can be blocked, contributions to faults at an upstream fault location from downstream PV inverters and other DG sources will not occur. In addition, strategically placing distributed PV and other energy resources, along with small amounts of energy storage, in zones blocked by diodes can essentially isolate deep voltage sags and interruptions to small portions of the feeder while delivering seamless power quality at most other locations (see Figure 3-10). This is a huge improvement over conventional AC systems.

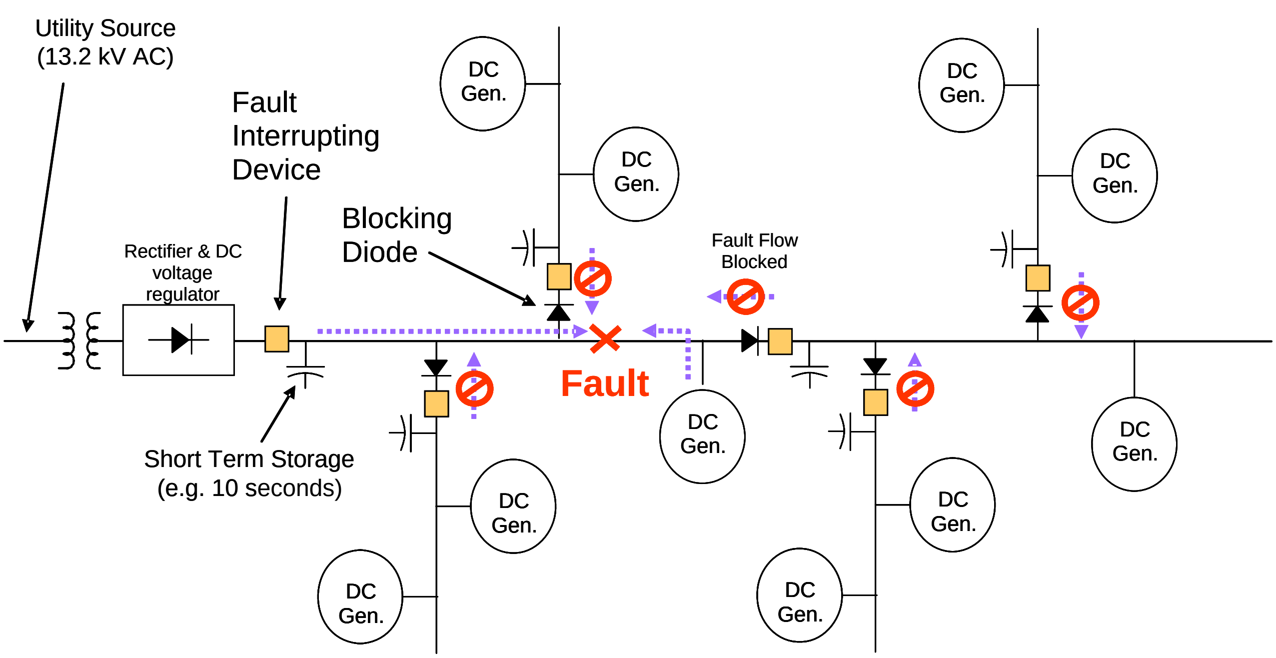

Figure 3-10. Fault and voltage sag blocking concepts using DC distribution, diodes, and energy storage. The DC generator sources can be PV or other types of distributed energy sources.

An example of a hybrid (AC/DC) power system is shown in Figure 3-11. This type of layout would make an excellent research and/or demonstration project to test various DC power distribution equipment and technologies for the future. It could serve as a model for a piece-by-piece conversion of the AC distribution system into a DC system. The figure shows a single-phase lateral on a conventional 13.2-kV three-phase AC system that has been converted to a 400-V DC lateral. With 400 V DC, the lateral has a voltage regulation reach and reasonable loss limit of about 1/2 mile for up to about 100 kW of uniformly distributed load. Both DC and AC homes could be connected on the system. The AC homes would employ DC/AC inverters and the DC homes would use DC/DC converters to convert 400 V DC to a safer level for use inside the home (perhaps 100 to 150 V DC). Because the lateral AC feeder to the 400-V DC interface unit blocks flow in the reverse direction—and because a small amount of energy storage is present on the DC side—any voltage sags and momentary interruptions that affect the main feeder will not reach the customers on this DC lateral. These DC customers should have vastly superior power quality to their peers on the AC system.

The various forms of power generation on the lateral could allow it to function as a microgrid if sufficient generation is available and if the right types of controls are employed. This could also alleviate long outages. Because power cannot be fed back into the main feeder through the rectifier unit, there would be little concern about fault contributions into the main AC system, islanding, or synchronization with this system. The layout of the lateral, energy sources, and DC/DC converters shown in the diagram is intended to illustrate the idea of a DC grid, to show the key elements, and to spark thought about future DC power systems. It is not meant to portray a carefully optimized arrangement from a cost and efficiency perspective. Other arrangements could use fewer converters and be more efficient from a power loss and cost perspective.

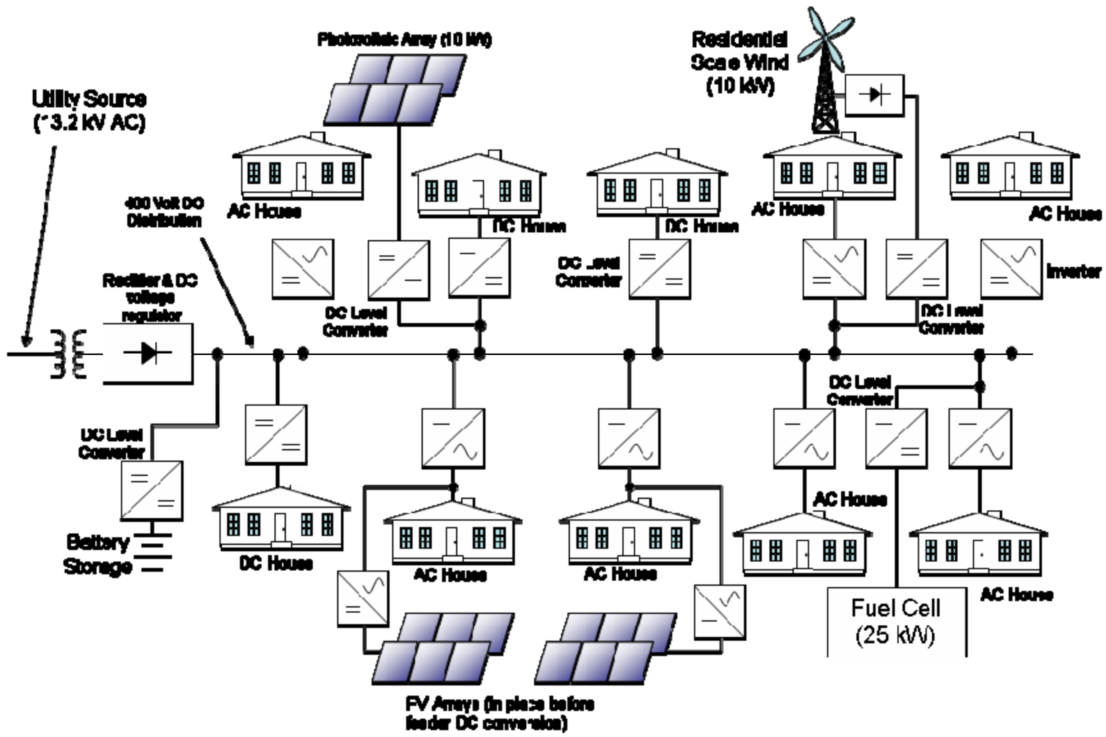

Figure 3-11. Residential single-phase lateral converted from 7620 V AC to 400 V DC with high-penetration DG

Besides the power quality and reliability attributes of the preceding DC layouts, another big advantage of DC power distribution is that it can reduce cost and complexity for interfacing all forms of DG (including PV) to the power system. Some valuable characteristics of DC as related to distributed generation follow:

- It can reduce the cost and complexity of distributed resource power conditioners (i.e., inverters are replaced by simpler and less costly DC/DC converters).
- The DC/DC converter (when designed for efficiency) can have slightly lower power losses than an inverter, so more net energy is delivered from the PV or other DG source to the power system. Modern inverters are 92% to 96% efficient, whereas DC/DC converters that are carefully designed for high efficiency can have an efficiency of 98%.
- Synchronizing a connecting energy source with DC is easy. Only the voltage needs to be matched, not the phase angle or frequency.
- Islanding issues are not as critical as they are with AC systems because the synchronization issue essentially disappears and because interface diodes can block power flows out of islanded areas.
- Stability and transient response/interaction of the distribution-connected energy sources are greatly improved during system disturbances.

- The ability to block PV and other fault currents on the network with diodes simplifies the overcurrent protection by keeping the PV and other sources from contributing to faults outside certain designated regions.
- Interfacing DC-based energy storage devices such as capacitors and batteries is very straightforward on DC systems, allowing for great improvement in reliability and power quality with minimal use of controls and switching devices.

3.8.3 DC Low-Voltage Networks

Perhaps one of the most exciting opportunities related to potential future use of DC distribution is the possibility of implementing partial-DC configurations for LV network systems and other types of high-reliability multisource power systems.

AC LV spot networks and grid networks are already renowned for their high reliability, but AC networks have a big problem when penetration of PV or other energy resources is high. Whenever PV power production on such a network is large enough to force reverse power flow through network protectors, these protectors can open, creating an island. This can fail the network protectors, either at the moment of island separation or later, when it recloses with the utility system and island out of synchronization. This compatibility problem can be solved by using a partial-DC network, which will dramatically improve the power quality and reliability on the LV network.

As defined here, a partial-DC network converts the AC power to DC power just after the network protector (see Figure 3-12). The resulting DC power is then routed to the LV network bus. With this arrangement, no matter how much power the PV energy source attempts to produce, it cannot export that current through the network protectors because the diodes will block it. The protectors simply cannot open on reverse power because none is present. Furthermore, even if an island forms, the nature of the blocking diodes and system voltages across the protector are such that the duty imposed on the protectors—should they close into the energized island—is less than the normal duty that the protector is designed to withstand when closing into a normal AC bus.

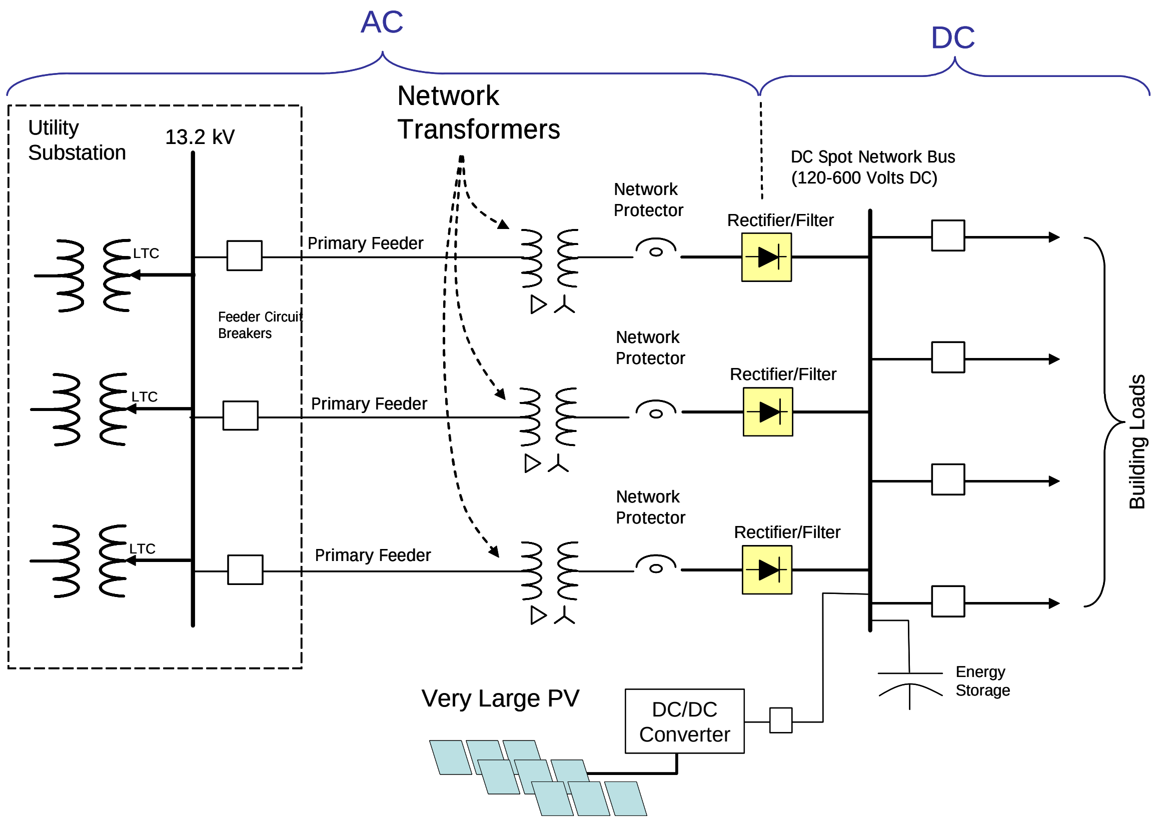

Figure 3-12.An LV spot network partially converted to DC solves protection problems associated distributed energy sources located on LV networks

An ancillary benefit of DC architecture is that power quality and reliability can improve on the LV network. If some energy storage is placed on the network bus (see the capacitor in Figure 3-12), it should be possible to mitigate incoming voltage sags from the utility system. The capacitor energy storage will support the voltage until the sagged utility voltage recovers (voltage sags usually last only 2 s or less). With enough energy storage in the capacitor—perhaps 20 s at the building's equivalent peak load—standby generation can even have time to pick up the load before the capacitor energy is dissipated. This would be necessary if all feeders went down because of a blackout or if PV were unavailable during, for example, the night.

This sequence operates seamlessly without switching transitions and no back-feeds to the network feeders. It also forms a stable intentional island that poses no threat to the utility system. The concept of using DC power for the LV network, then, is an elegant solution. Of course, the building loads must be capable of operating on DC, which is something that is not yet quite ready for prime time. Nonetheless, at this time various engineering studies and a test program with an actual DC LV network would make excellent research projects in which to study the performance of this type of architecture under a variety of conditions. The results of these studies and projects could set the stage for converting buildings to DC networks in the future.

Using DC power in a possible future architecture is not limited to spot networks. An LV grid network could also work effectively with DC architecture. Grid networks are similar to spot networks in that they have multiple sources feeding into an LV system; however, unlike spot networks, the LV bus is not located in a single facility vault or equipment room. Instead, the bus is an LV grid of wires spread across many blocks of a city. It is noteworthy that AC LV grid networks are typically used in large cities like New York City, Boston, and Chicago, and conventional wisdom is that the economics of high load-density urban environments are the only places where such grids make sense. With the advent of distributed generation, however, the idea that LV grid networks are suitable only for dense urban areas might need to be revisited.

With numerous DG sources (PV, fuel cells, and so on) available in homes and small businesses and the improved voltage drop made possible by DC compared to AC, some suburban and light urban environments that were formerly served by radial distribution may be economically serviceable by an LV DC network grid that is rich in various PV and other DG resources. Figure 3-13 shows an example of a future DC grid network that includes a variety of DC DG resources as well as some primary utility sources. A research project to perform technical planning on the costing and design of LV DC grid networks targeted for application in suburban and light urban areas is highly justified and because it could lead to lower cost, safer, and better performing distribution systems that work well in a PV-rich environment. A demonstration and test site could follow the analytical paper studies.

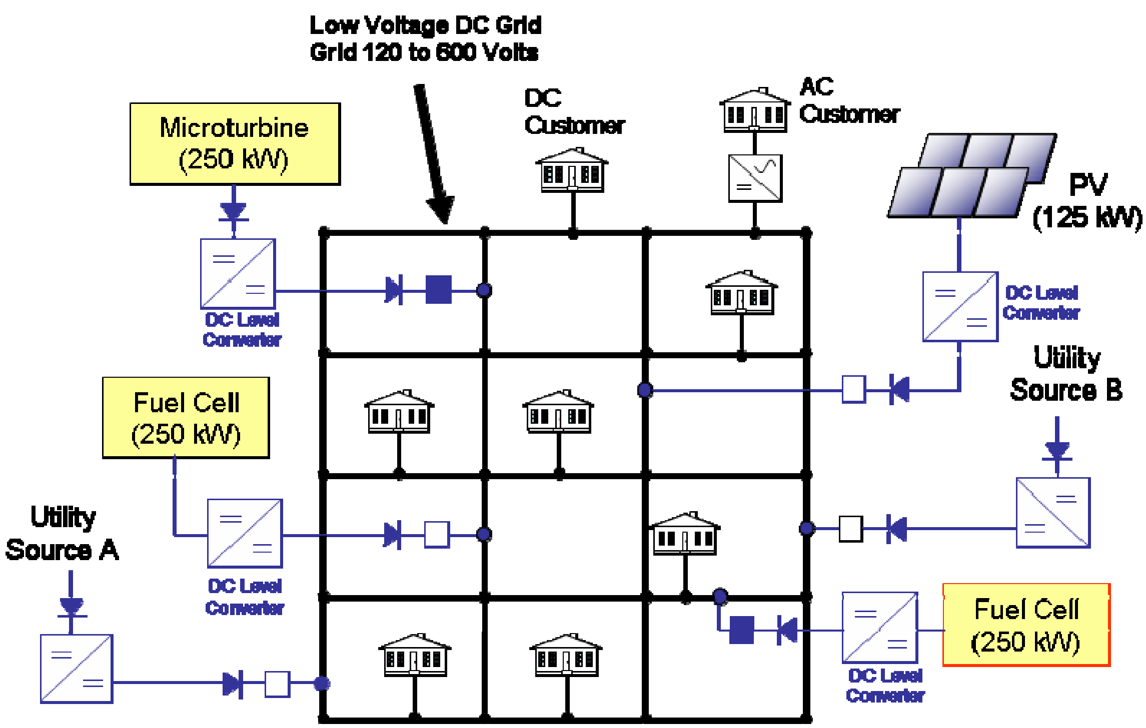

Figure 3-13. An LV DC grid network, rich in DG, for suburban and light urban areas
(section current limiter omitted for clarity)

3.8.4 Microgrid Demonstration Projects in the United States

Several U.S. microgrid demonstration projects are briefly described in the following subsections.

3.8.4.1 Consortium for Electric Reliability Technology Solutions (CERTS) Microgrid Test Bed

American Electric Power (AEP) is currently hosting the CERTS microgrid test facility near Columbus, Ohio. The test facility includes a full-scale microgrid suitable for research and demonstration purposes, including three 60-kW generation sources; a variety of loads; the necessary system protection equipment (relays, breakers, and so on); a data-acquisition system; and an interconnection to the utility's distribution system.

The following major system tests are planned for the CERTS microgrid test facility [8]:

1. **Demonstrations of load-flow control** will demonstrate the flexibility of the microgrid to accommodate different loads and power flows, including power flows between the microgrid and the utility.
2. **Microgrid operation with difficult loads** will demonstrate the ability of the microgrid to accommodate challenging load conditions in both the islanded and utility-tied mode of operation. This test focuses on the operational limits of the microgrid with low pf , motor, harmonic, and unbalanced loads.
3. **Fault testing** will scrutinize the effectiveness of the microgrid protection schemes and examine how the microgrid and the utility will respond to faults.

Research activities are currently under way on the CERTS test bed. Initial test results have shown that the control algorithms developed for the CERTS microgrid perform well during a variety of transient events, including intentional islanding and step-load changes during islanded conditions [9]. If the test bed research continues to prove successful, one or more full-scale demonstrations is likely to follow.

3.8.4.2 General Electric Microgrid Energy Management (MEM) Framework

DOE is cofunding an initiative by General Electric Global Research to develop and demonstrate an MEM framework. The framework is intended to provide a unified control, protection, and energy management platform [10]. The desired goal of MEM is to provide control and coordination functionality both at the asset level and at the supervisory level. The end result will be a control platform that permits coordinated microgrid operation to achieve specific customer goals (such as minimizing environmental impact and cost and maximizing reliability).

Phase I, which is complete, focused on simulation and verification of control and energy management processes. Phase II, scheduled for completion in mid-2008, will be a field demonstration at a multibuilding campus that will focus on validation testing of the concepts developed in Phase I.

3.8.4.3 Distributed Utility Integration Test (DUIT)

The DUIT, conducted by Distributed Utility Associates in Livermore, California, is the first full-scale integration test of commercial-grade utility-interactive DER in the United States [11]. This project has strong ties to microgrid development even though it is not specifically labeled a microgrid project. The DUIT's core focus is on addressing the technical issues that surround high-penetration applications of DER in utility distribution circuits. The test program calls for demonstrating the feasibility of remote monitoring and dispatch of numerous types of DER and characterizing the DER value to both ratepayers and utilities.

3.8.5 Microgrid Projects in Europe

A European consortium called the Framework Programme began investigating the microgrid concept with a project that ran from 1998 until 2002 (the 5th Framework Programme) [12]. The consortium, which included 14 partners from 7 European Union countries, was led by the National Technical University of Athens (NTUA). The focus of this early research was to study high renewable and microsource penetration on the power grid as well as microgrid control and islanding operation. Research continued after 2002 with the 6th Framework Programme (2002–2006), but the research focus shifted to new microsources, energy storage, control, network design and protocols, and microgrid economics. At the time of publication of this report, the 7th Framework Programme is starting a new series of projects.

The European research has resulted in several pilot microgrid installations. There are several notable projects as follows [10, 12]:

- **The Kythnos microgrid in Greece** utilizes 10 kW of PV generation, 53 kWh of battery energy storage, and a 5-kW diesel generator to serve 12 homes on Kythnos Island in Greece's Cyclades Archipelago. The Kythnos microgrid has been in operation since 2003.
- **The Continuon holiday camp microgrid in the Netherlands** uses 315 kW of PV generation to serve more than 200 cottages. Preparations are being made to test the microgrid in an islanded configuration using flexible AC distribution and energy storage.
- **The Am Steinweg residential estate microgrid in Germany** has a sizable 69 kW of generation including 28 kW of combined heat and power (CHP) and 35 kW of photoelectric generation. The generation is complemented by an 880-Ah battery storage system.

Additional European microgrid projects are being conducted in Denmark, Portugal, Italy, and Spain.

3.8.6 Microgrid Projects in Japan

The Japanese government is funding microgrid research that has focused primarily on controllable prime movers to better accommodate variable demand and existing small renewable energy installations. The Ministry of Economy has initiated four government-funded microgrid field trials through its research funding organization, which is known as the New Energy and Industrial Technology Development Organization [13]:

- **The Nagoya fuel cell microgrid** was originally started during the 2005 World Exposition and has recently found a new home at the Central Japan Airport City in Nagoya. It currently supplies a Tokoname City office and sewage treatment plant from a variety of fuel cells. The microgrid includes 270-kW and 300-kW molten carbonate fuel cells (MCFC), four 200-kW phosphoric acid fuel cells (PAFC), and a 25-kW solid oxide fuel cell.
- **The Hachinohe, Aomori Prefecture microgrid** began operating in October 2005 and is scheduled to run through March 2008 with research focused on microgrid economics and reduced carbon emissions. The microgrid uses 100 kW of wind turbine generation, 510 kW of digester-gas-powered engine generators, and a 100-kW lead-acid battery bank. Energy is supplied to seven buildings in the city of Hachinohe via a 5.4-km distribution line operated at 6 kV. The microgrid has a single point of interconnection to the utility grid.
- **The Kyotango City microgrid** is a virtual microgrid demonstration employs real distributed energy resources in the city of Kyotango. Fifty kilowatts of PV generation and 50 kW of wind generation are used along with five 80-kW biogas engines, a 250-kW MCFC, and 100 kW of battery storage. The distributed energy resources are coordinated over the existing utility network via a single "energy centre."
- **The Sendai Miyagi microgrid** serves a university, a high school, a rest home, and a waste treatment plant. The microgrid combines a 250-kW MCFC, two 350-kW natural-gas-fired generators, 50 kW of PV generation, and battery energy storage. It connects to the local utility through a single coupling point. This microgrid features DC service telecom loads as well as AC service at four different service qualities. Critical loads are served at a premium level (A level; very clean, uninterruptible power supply service); the rest of the loads are served at B level quality. B level service is divided into three categories: B1 service, which is backed up with energy storage; B2 service, which is backed up with slower responding generation; and B3 service, which has no backup.

There are also several ongoing microgrid projects in the private sector in Japan. The Shimiz Corporation and the University of Tokyo are collaborating on a microgrid demonstration project utilizing gas engine generators and some energy storage. Tokya Gas has also proposed a microgrid using controllable prime movers and energy storage.

3.8.7 Future Research Needs for Microgrids

Integrating large amounts of DER into a microgrid is a key challenge that raises many complex issues, which can be both technical and policy-oriented:

- **Enhanced component characterizations.** Although some very powerful software tools are available for microgrid simulation, the industry is sorely lacking detailed modeling information for the many devices that populate a microgrid (such as microsources and energy storage units). Microgrid modeling would benefit greatly from having readily available "performance profiles" for each DER in the microgrid. A DER's performance profile consists of the device's fault contribution curve, rate of output change, response to small and medium signal steps, and islanding test results.

The industry could compile these data by undertaking a significant testing regime. Another possible mechanism for acquiring this information would be to find a suitable method for persuading manufacturers to supply this information for new products. Requiring a performance profile to be submitted when applying for UL certification is one possible strategy.

- **Master controller development.** The master controller considers economic, environmental, creature comfort, and other end-use objectives as well as physical and regulatory constraints in day-to-day microgrid operation. The master controller is the key to highly sophisticated microgrid operation that maximizes efficiency, quality, and reliability. Although some of the capabilities identified for an intelligent microgrid master controller are currently being researched, other capabilities do not yet exist. The Galvin Electricity Initiative has documented the functional requirements for master controller software in *Master Controller Requirements Specifications for Perfect Power Systems, Revision 2-1* (EPRI, Palo Alto, CA, November 15, 2006). This document is available from the Galvin Electricity Initiative's Web site at www.galvinpower.org.
- **Develop plug-and-play units.** If widespread adoption of DER into distribution feeders or microgrid applications is to be realized, it is desirable for the DER to have plug and play functionality. Once connected into the microgrid, the unit should automatically be integrated for control and status reporting. This type of compatibility, which will require standardized connection ports and communication protocols, is as much a technical research need as it is a collaborative effort between government and industry.

3.9 Issues That Extend to Subtransmission

High penetration of PV and other DG resources on the system means that significant changes are also needed at the subtransmission level. The following main issues need solutions:

1. Unintentional islanding of a substation with respect to the subtransmission line. In high-penetration situations, design practice must assume that individual distribution substations can island if a high-side switch or circuit breaker opens at the substation, isolating it from the subtransmission line. Methods are needed for detecting this condition (to avoid closing back into it out-of-sync) and for controlling or disabling the island (to facilitate safe and proper system operation).
2. **Unintentional islanding of the entire subtransmission line or a portion of the line.** Methods similar to those described in item 1 are also needed for subtransmission reclosers and circuit breakers.
3. **Fault contributions of PV interfering with subtransmission sectionalizing schemes, distance relays, overcurrent relays, and so on.** The system needs improved relaying methods and communication coordination among subtransmission circuit breakers, reclosers, and sectionalizing switches to overcome any confusion that would be caused to existing schemes by the fault current contributions from PV and other generation sources. This is not likely to be an issue for PV generation alone because of the fault current limiting capability of the inverters.

4. **Subtransmission ground fault overvoltage.** The subtransmission system will experience significant ground fault overvoltages in high-penetration PV cases. Methods to limit this effect must be incorporated into the design.

Methods to control or solve these problems include the use of transfer trip signals between key circuit breakers, reclosers, the PV sources, and switchgear associated with the identified islanding possibilities. In some cases, protective relaying functions such as live-line reclose blocking, directional overcurrent blocking, longer reclosing dead times, and revised overcurrent pickup and time delay settings, which are less affected by PV fault contributions, can be enough to solve the problems without the need for transfer trips.

A conservative rule of thumb can be established for the typical penetration threshold where the ground fault overvoltage on the subtransmission line could begin to be an issue. When the aggregate capacity of PV sources and other forms of DG associated with substations connected to the line is greater than 20% of the minimum load on the section of subtransmission with which the stations can be isolated (isolation occurs when a breaker, switch, or recloser opens), ground fault overvoltage could become a problem. The actual penetration level at which the issue arises could be higher, depending on the case specifics. These specifics could include the impedances of the distribution-connected energy resources; the types of resources present (PV inverter, rotating machine, and so on); their location on the distribution system; and the power system impedance itself. In less sensitive cases, the penetration threshold where danger begins might be as high as 60% or 70% of load, but this cannot be certain. If the penetration level is high enough to be of concern, the problem of ground fault overvoltage at the subtransmission level can be solved in a number of ways. One, for example, is by timing the operation of the subtransmission breaker to preserve grounding bank effects of the transmission source transformer on the line until the PV sources are cleared out. Another is by adding supplemental “grounding transformer banks” in special areas of the line. The latter method may be needed in cases where there are several cascaded switching devices on the feeder.

These are but two of the possible solutions. Figure 3-14 illustrates how these solutions could be generically applied to a radial subtransmission line (these are generic examples for illustration only and not all of them necessarily need to be applied together). Research studies to model the extent and severity of the impacts of PV and other DG types on various subtransmission line configurations are needed to identify the methods that yield the best balance of mitigation, cost, and flexibility with various penetration levels of PV and other DG forms. Some types of DG are likely to be more problematic than others. Inverter-based DG, such as PV and fuel cells, are likely more benign in this regard than rotating generator-based DG.

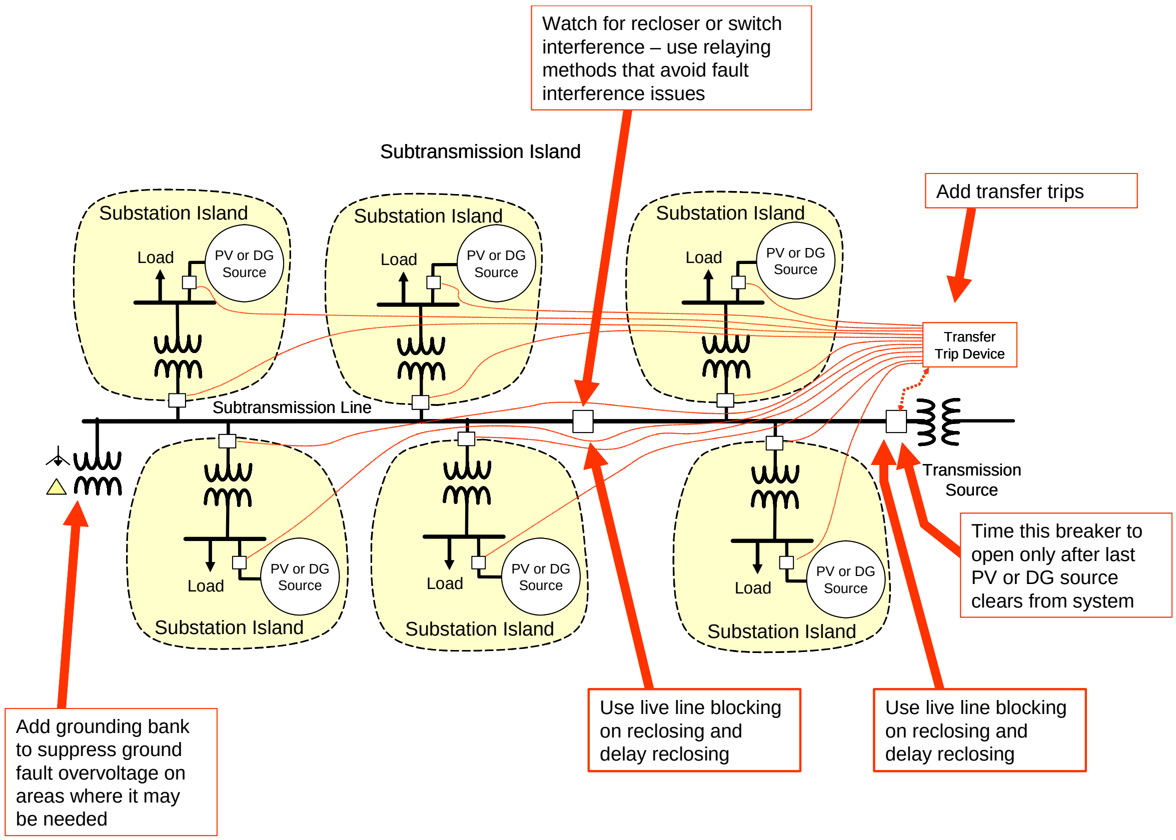

Figure 3-14. Subtransmission issues and upgrades to handle higher penetration of PV

3.10 Distribution Automation

Distribution automation has the potential to provide multiple advantages to distribution system performance. There is significant interest among power distribution companies in expanding applications in each of the following areas [3]:

- Advanced substation control and monitoring
- Distribution feeder supervisory control and data acquisition
- Automatic volt/VAR control
- Outage management system (OMS) integration
- Advanced load (and DR) monitoring and control applications
- Advanced metering integration
- Real-time state estimation.

The benefits to be realized through distribution include improvements in the areas of reliability, efficiency, asset management, customer service, operations, and planning. This broad base of applications and benefits will aid in the deployment of these technologies.

There is widespread agreement that a common communications infrastructure is needed to achieve distribution automation goals. The goals of the Gridwise Consortium, for example, are:

- To utilize information technologies to revolutionize energy systems as they have revolutionized other aspects of U.S. business
- To create value for all participants by developing and deploying technology solutions that cross enterprise and regulatory boundaries
- To enhance security and reliability through an information-rich power grid that is flexible and adaptive
- To empower consumers to benefit from their participation in the operation of the power grid.

Each of these goals depends on the ability of a wide range of devices to communicate with each other effectively and efficiently. More specifically, the Intelligrid Consortium project goals state [14]:

> The goal of developing and implementing an industry-level architecture is to enable the effective use new devices and systems that interoperate, meet minimum key requirements and are strategically integrated into a utility communication and distributed computing infrastructure. Moreover the system needs to evolve according to key principles, goals, and guidelines. These key principles, goals, and guidelines are collectively known as the IntelliGrid Architecture (IA). Conformance to the IA will help to ensure that these goals are achieved by individual utilities as well as the industry as a whole.

Key features of the IA are:

- Integration of systems
- Use of standards-based open systems that interoperate
- Definition of applications and requirements
- Mapping of technology solutions to requirements.

The Intelligrid Consortium is currently involved in projects that implement components for new grid technologies at consortium member sites. These projects include:

- Advanced metering infrastructure development
- Substation LAN deployment and equipment monitoring
- Utility and consumer device supervisory control and data acquisition (SCADA) via BPL and wireless communications
- Demand-responsive infrastructure reference design
- Field device communications, phasor measurement, and FSM implementation

- Distribution system SCADA replacement
- IntelliGrid model as part of DFSM project development.

The consortium selects projects that will incrementally employ and evaluate the architecture and provides a laboratory where the architecture will be tested and improved.

At the same time, standards bodies are active in the development of protocols specifically for DR technologies. The IEC Technical Committee (TC) 57, Power Systems Management and Associated Information Exchange, is developing international standards for power system control equipment and systems. Working Goal (WG) 17 of TC 57, Communications Systems for Distributed Energy Resources (DER), specifically addresses the needs of DR systems within the broader framework. At the same time, IEEE P1547.3, *Draft Guide for Monitoring, Information Exchange and Control of Distributed Resources Interconnected with Electric Power Systems*, has similar goals. There is definite interest in unifying these standards. At this point, however, it is not known how these efforts will conclude.

Distribution automation has several key features that will make a distribution system more DR friendly:

- **Individual customers (meters and loads).** Advanced metering will be an integral part of distribution monitoring systems. Intelligent meters should have high-speed two-way communications functionality with information models that permit convenient integration with distribution management functions. Advanced metering is a necessary prerequisite for implementing rate structures that more closely track the real-time costs of energy. This should naturally lead to rates that allow DR owners to maximize their benefit from these devices. This technology would also include the ability to control certain loads, either directly from the signals supplied to the owner of the load energy provider or through the cost.
- **Transformers or groups of customers** (including the intelligent universal transformer [IUT]). Transformers are an ideal location for intelligent agents (distributed control with limited autonomy) that manage data from groups of meters. Future advanced transformer technologies will permit additional functionality at this location, including VAR control, local voltage control, and power quality management. This is also a location for management of local DG and storage, and DR can benefit from the coordinated management of voltage, VAR, and power quality and perhaps produce revenue by supplying these as ancillary services.
- **Intelligent devices on the distribution system**. There will be many intelligent nodes throughout the distribution system. Sensed quantities will include fault location, voltage, power, power factor, and power quality. A variety of controls will be improved through the coordinated use of these quantities, including capacitor bank controllers, voltage regulators, and power conditioning equipment. Knowledge of fault location and characteristics will be particularly important for DR strategies involving intentional islanding. It will also play an important role in the restoration of load and DR following faults and can be used to switch DR resources to feeders that are experiencing high losses or congestion.

- **Distributed generation and storage.** Individual DR installations are an important distribution automation node. Distribution automation will allow the more effective and flexible integration of distributed generation and storage within the overall management of the local distribution system and the overall grid. These locations are obvious locations for intelligent monitoring nodes that coordinate with overall system control. The information from distributed generation and storage will include both operational information and information to support analysis of the response of the generation to different system conditions.

- **Intelligent switches, breakers, and reclosers**. Intelligence about the circuit parameters where relays may adapt to existing operating conditions at these locations will result in improved protection and coordination functions that react both accurately and quickly to faults. The combination of accurate fault detection with automation will allow the rapid isolation of faulted sections and restoration of load on unfaulted sections. The monitoring at these locations will feed information to the central controller, allowing for optimization of system configuration and management of the protection settings based on actual conditions (generation, weather, risk analysis, and other factors).

- **Substation data management.** Substation monitoring will integrate data from throughout the distribution system and manage the substation monitoring infrastructure. Information from voltage regulators, capacitor banks, breakers and switches, distributed resources, and customer loads will allow for continuous system diagnostics and optimization. The substation monitoring and control will be integrated with the planning area-wide system simulations that are being performed in real time to manage the system. Real-time state estimation software will provide system operators with information necessary to make informed decisions quickly and effectively.

- **Planning area data management.** The monitoring system will manage information at the planning area level to coordinate data from multiple distribution systems and permit simulations that assess options for optimizing system performance and reducing risk of outages through system reconfiguration and management of distributed resources and demand response. This system will also log data useful for the distribution system and DR planning process.

Overall, the ongoing development and implementation of distribution automation is a synergistic activity that is partially driven by the expansion of DR resources. There is no doubt that an automated distribution system will be more DR-friendly than the current systems. This will, in turn, promote higher penetration of DR technologies.

4.0 Conclusions and Recommendations for Future Research

The arrival of high-penetration PV on the power system will force a reevaluation of the industry's current strategy for integrating of PV and other types of DG resources. The increasing presence of PV on the system will force a move from the current strategy, which essentially involves integrating PV onto the system as a passive or neutral player with the minimum impact possible, to a strategy that involves the active participation of PV resources with system power dispatch operations, voltage regulation, reactive power balance, reliability management (intentional islanding), and service restoration operations.

With the changing role of PV will come major changes in the utility system protection, controls, and equipment configurations that must be utilized. The increases in penetration will not be limited to PV—all forms of DG connected to the system are expected to increase in quantity. New strategies, then, may need to apply to all types of distributed resources. The DG equipment itself will also need to change—inverters, synchronous generators, and induction generators will need more communication ports, transfer trip capability, reactive power features, and new modes of operation such as intentional islands and microgrids.

All types of distribution-connected generators are increasing in quantity, but PV is by far the fastest growing. It is expected to be the technology that forces the changes in distribution strategy. Exactly when the transition will begin from the current era of interconnection practice (based on IEEE 1547-2003) to the new era is difficult to pin down and will vary around the country. Once the transition to a new system strategy begins, it will likely take several decades to fully implement. Starting now, research efforts by DOE, EPRI, utilities, and equipment manufacturers can lay the groundwork for new and changed technologies that will be ready when the need becomes strong.

It is clear that changes in design and practices and operating modes will be necessary to create a 21st-century power system with a high penetration of PV generators. The key research needs that will be needed to enable this change are summarized in the subsections that follow.

4.1 Near-Term Research

- In the next five years, research objectives should be to solve the problem of ground fault overvoltage on the subtransmission system by investigating the use of grounding bank transformers, special switchgear timing considerations, transfer trips in switchgear operations, and upgraded voltage ratings of devices
- To solve the problem of unintentional islands on the subtransmission and distribution system by developing improved autonomous anti-islanding algorithms or by using communication-based transfer tripping techniques.
- To investigate the communication technologies that can be reliable and secure and can provide sufficient bandwidth and cost effectiveness to meet the first two objectives. (These technologies could include BPL, wireless LAN/WAN, power line carrier, low frequency pilot signaling, and optical fiber, among others.)

- To find ways to adapt the protective relaying and fusing in the distribution system to deal with fault currents that arise from larger quantities of DG (issues to solve include sympathetic circuit breaker or recloser operations, fuse-saving coordination, fault levels that exceed device limits, distribution transformer case rupture issues, network protector reverse power issues, sectionalizing switch interaction, and so on). Although the contributions are not as significant for PV, research should look at further inverter developments that could prevent high-penetration PV from being a factor in fault current coordination.
- To develop new voltage regulation schemes for steady-state (slow) regulation based on communication between LTC transformers, step-voltage regulators, capacitor banks, and DG. DG can actively participate in voltage regulation by adjusting reactive power levels. The need for reactive power margins in PV inverters should be evaluated based on the potential economics of contributing to distribution voltage control and reactive power requirements.
- To study the effective grounding compatibility problem associated with DG and determine the best path (equipment technologies and system changes) to most cost effectively reduce the need to effectively ground all DG on the four-wire multigrounded neutral distribution systems. All possibilities are up for consideration including upgrading voltage withstand of loads and equipment, returning to a modified three-wire system, strategic use of grounding bank transformers, and timing-coordinated breaker tripping.

4.2 Longer Term Research

- Over the next 5 to 20 years, research objectives should be to plan and demonstrate communication infrastructure for distribution systems for implementation of overall system controls that will allow controlled islanding and other optimizing functions to take full advantage of distributed resources.
- To identify storage systems that will integrate with distributed generation to allow islanding and system optimization functions (demand control) to increase the economic competitiveness of the distributed generation. Investigate strategic and tactical application of energy storage (ultra capacitors, flywheels, pumped storage, batteries) to assist in solving many of the problems mentioned here.
- To evaluate advanced methods for intentional islanding to improve reliability (controls, relays, switchgear, power generation, storage and communication requirements).
- To explore autonomous regulation concepts to be imbedded in DG inverters and dedicated voltage conditioner technologies and interact with power system voltage regulation for fast voltage regulation to mitigate flicker and faster voltage fluctuations caused by local wind and PV fluctuations.
- To investigate opportunities in communication of the synthetic signals (as demonstrated with price signals in the case of the Olympic Peninsula GridWise project). There is potential to coordinate demand and generation at the distribution level for overall feeder reliability and safety as well as coordination with transmission-level needs.

- To study real-time integration of fast regulation resources and energy storage to provide voltage support for renewables interconnection across multiple control areas. Utility system models and data as have been developed in the western interconnect will allow consideration of new information sources such as wide-area phasor data for arming voltage control schemes.
- To assess schemes and develop analysis tools that allow a sufficient portion of DG to participate in bulk market dispatch operations, transmission power flow management and in the overall system frequency regulation so as to maintain system market and technical performance criteria within a high penetration DG framework.
- To investigate DC power distribution architectures as longer term method for obtaining improved reliability, power quality, local system cost and very high penetration DG.
- To develop controllers for DR that implement the information models described above and interact with overall distribution management systems and higher level system controls. The master controller considers economic, environmental, comfort, and other end-use objectives as well as physical and regulatory constraints in day-to-day microgrid operation.

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Appendix A: Power System Penetration Levels and Capacity

For the sake of this discussion, we can break the system into two discrete levels: the “bulk” system and the “distribution” system. The higher level bulk power system is composed of large centralized generation plants as well as large transmission and subtransmission lines (generally ranging from 46 kV up to 765 kV.)

The distribution system is the lowest level and is composed of distribution substations, radial or looped feeders (4.8 kV to 34.5 kV), secondary distribution (120 V to 480 V), low-voltage (LV) networks (208 V to 480 V), and customer facilities fed from the distribution system. It is important to recognize that these two distinctly different systems behave differently because of design and operating philosophy differences. High-penetration photovoltaic (PV) and general distributed generation (DG) scenarios will have an impact on both levels. Strategies for applying distribution-connected PV, especially in large quantities, must deal with system needs at both levels, but a strategy that works well at the distribution level may not be suitable for the bulk system level and vice versa. To date, the bulk system impacts of distribution-connected PV have generally been ignored because the quantity of PV installed is miniscule in relation to the amount of conventional generation capacity on the system. As the use of distribution-connected PV increases, however, the bulk system impacts will grow until they must be taken into consideration. Furthermore, increased PV on the system means that the already noticeable impacts on the distribution level—as well as emerging impacts on the subtransmission system—will become significant.

For the future, we need strategies for both system levels. Policies that satisfy the needs of the distribution system while also meeting the needs of the bulk system are an important part of the U.S. Department of Energy (DOE) strategy for dealing with high penetrations of distribution-connected PV (or, for that matter, all general forms of DG). It will become necessary to significantly adapt power distribution system designs, operating strategies, and PV equipment to successfully achieve a high-penetration environment. Research is needed in the following areas:

- Improving protective relaying techniques
- Regulating voltage by coordinating interactive operations between PV devices and power system voltage regulators
- Improving islanding protection and control
- Overcoming grounding issues
- Better managing power quality and reliability on a system that will be rich with distribution-connected PV sources.

A.1 Penetration Level

Although the penetration level of distribution-connected PV or general DG on the system is an important parameter, the term “penetration level” can cause considerable confusion if we do not define it carefully. For example, the PV penetration level on the system can be defined as the amount of distribution-connected PV capacity compared to total installed system generating capacity on a national basis. As an alternative, it can be the total energy production of distribution-connected PV compared to total system energy production on a national basis. Finally, it can be the distribution-connected PV capacity related to either the local transmission and distribution (T&D) capacity or the load on the system at a particular point. The Electric Power Research Institute (EPRI) report entitled *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems* [15] explains many other types of penetration calculations as related to generic DG. The following general equations illustrate just some of the more common ways to calculate penetration levels.

$$\textit{National Penetration \% on a Capacity Basis} = \frac{\textit{[Total National PV capacity]}}{\textit{[Total National System Generating Capacity]}} \times 100\%$$

$$\textit{National Penetration \% on a Energy Basis} = \frac{\textit{[Total National PV energy production]}}{\textit{[Total National System Energy Production]}} \times 100\%$$

$$\textit{Local Penetration \% with Respect to Capacity} = \frac{\textit{[Aggregate PV Capacity at Localized Area]}}{\textit{[Distribution System Capacity at Area of DG Application]}} \times 100\%$$

$$\textit{Local Penetration \% with Respect to Load} = \frac{\textit{[Aggregate PV Capacity at Localized Area]}}{\textit{[Distribution System Load at Area of DG Application]}} \times 100\%$$

With these formulas, we should focus not so much on the specific details, but rather on the concept that, depending on which part of the system we are talking about and the type of analysis we are interested in, we may want to use a particular type of penetration level calculation.

Confusion about penetration level terminology usually arises when policy makers think about a broader goal of a certain “percent penetration” of DG on a national capacity basis or energy basis. Engineers, on the other hand, consider the *impacts* of such penetration goals with respect to local capacity of or load on the distribution or subtransmission system. For example, a relatively benign-sounding goal of 5% DG penetration on a national basis can mean that, as the DG is applied by market forces across the system in a somewhat nonuniform manner, the localized DG—as a percent of the local distribution capacity—can be much higher than 5% on certain feeders and at certain substations. Any policy that is to be effective needs to consider how the DG will be distributed around the power system. Such policies must also allow for designs and procedures where there will be locally high DG penetration. In concert, these policy elements will permit us to achieve a modest national goal for total system penetration.

A.1.1 Penetration Level of DG on a National Basis

In 2007, the level of distribution-connected PV operating on the U.S. power system is less than 0.5 GW [16]. This compares to the roughly 1,100 GW of total bulk system generating capacity installed in the United States [17]. Consequently, national distribution-connected PV penetration is currently less than 0.05% of system generating capacity. The amount of all forms of DG on the system is greater than that of PV alone because the percentage includes PV plus sources such as microturbines, fuel cells, internal combustion engines (ICEs), small hydropower and wind installations, and small- to mid-sized combustion turbines (CTs). Even when we consider these broader forms of DG, to date its penetration level on the power system is still quite small compared to total installed capacity. Two sources [18, 19] state that, in 2004, about 234 GW of DG was in operation, but that 81% of that amount included standby generation. If we exclude the standby generation penetration, 45 GW of DG or about 4% of the system total was operating in 2004. This number can vary depending on how DG is defined. The calculated current penetration value for all DG types can be anywhere from about 1% to 10% of the bulk system generating capacity.

If we use the strict definition of DG as a generation source that is connected to the public power system at the distribution system level at generally less than 10 MW of capacity, the total DG installed today and available and operating is still likely less than 2% of the bulk system capacity. If we use a more relaxed definition of DG that also includes larger, independent, industrial combined heat and power (CHP) plants, DG is already approaching 10% of capacity. Defining such larger industrial CHP as DG, however, yields a deceptively large figure because much of that generation is already operated like central stations, in that they have interactive control and coordination with the utility dispatch center and are connected to the utility system at the subtransmission level. In other words, because much of that larger CHP operation is already “actively controlled,” it can be treated as bulk capacity. For our focus in this document, we should stay with the more restricted classical definition of DG, which puts its current level at less than 2% of total system capacity.

If true DG (per the strict definition) were to reach 20% of the total current system generating capacity, 220 GW would need to be deployed nationwide. Of course, the system capacity is always growing, and in another 20 years, 400 GW may be needed to reach such a goal. To reach a goal of 20% DG penetration on a national basis, we need more than an order of magnitude increase in DG beyond what we have right now. From the perspective of achieving this entirely with PV, the world production of PV modules would need to be at least ten times greater than current world market size. In addition, much of the world’s module manufacturing capacity would need to be sold to (dedicated to) the U.S. market for two decades. Even though PV market growth over the past decade has been spectacular (30% to 40% annually), PV manufacturing limitations probably preclude such high levels of PV penetration for several decades even in the best-case scenario. On the other hand, achieving 20% or greater penetration on a national basis from all forms of DG combined within less than two decades is quite plausible if the energy industry, regulatory framework, technical innovations, and market forces continue the push in that direction.

A.1.2 Penetration Level with Respect to the Distribution System

For our immediate concerns of growing DG utilization, it is important to consider the level of DG penetration with respect to the distribution system. The penetration level of DG relative to the distribution system capacity can be quite high at specific sites, even though the national system penetration level is low. This is because most distribution substations have a capacity of only between 5 and 50 MVA (as is usually determined by substation transformer ratings) and the capacities of the feeders are typically between 1 and 10 MVA, depending on feeder location and system design. The larger forms of DG such as multimegawatt-rated ICEs or CT plants at hospitals, college campuses, and commercial facilities can easily reach a 20% or much greater penetration level as a percentage of local feeder capacity for just a single site. In fact, many conventional DG projects are already operating on feeders that exceed 50% of the feeder capacity, even though DG is still less than 2% of the national generation capacity. These larger sites are not just dropped onto the system. Instead, they often have controls and features that allow more active interaction with the power distribution system (such as transfer trips, the capability to report back to a dispatch center, and modifications to upstream utility equipment to avoid voltage control problems). Reports on large-scale DG installations that have recently been successfully integrated and operated at Hawaiian Electric Company illustrate the details that must go into designing and operating high-penetration DG [20, 21].

There is increased aggregation of PV installations of all sizes ranging from a few to hundreds of kilowatts. In a few cases, entire housing subdivisions are now being built with PV where there are hundreds of sites on a feeder. The trends of increasing individual PV installation size and the aggregation of many PV units on a feeder mean that PV penetration on some specific circuits could approach 50% or even nearly 100% of the local capacity, even though PV penetration is still tiny when measured on a national basis. PV is beginning to enter the realm of size and scope where we will need to treat it much more like the large hospital and campus ICE or CT units. In other words, larger PV installations will require special communications and controls to operate effectively (in terms of safety, reliability, and efficiency) with the distribution system.

Uneven allocation of distribution-connected PV installations around the country will lead to some feeders with relatively high penetration of PV capacity even with relatively low overall contribution on a national basis. As these instances of high penetration increase, it will eventually become apparent that we need to transition to an active strategy for PV interconnection. The penetration level at which active control becomes necessary depends on the distribution system characteristics, its operating environment, and how PV (or DG) is distributed around the system, so there is no firm value that can be used as a universal rule. In general, the more distributed the power generation resources on the feeder, the less need for active control at a given penetration level, so PV has that advantage when it is applied in small rooftop increments. With existing power distribution system designs, once PV begins to exceed 20% of a feeder's local capacity, we will need to assess—but not necessarily apply—more active methods of control or special system provisions.

A.2 What Is the Capacity of the Distribution System?

The capacity of the distribution system is not, as it might seem, a simple straightforward value that is constant over the entire system. Capacity depends on the nominal voltage level, the distance of the connection point from the substation, the feeder or cable type, the substation impedance, and many other factors. In some cases, capacity at a given point on a feeder is determined by "voltage drop limits" and in others the "thermal limits" of cables, wires, or transformers. Generally, the capacity of the feeder is highest at the top of the feeder (near the substation source). At that location, power flow losses (I^2R losses) in wires and transformers (heating) usually determine the current-carrying capabilities of the feeder. Farther down the feeder, voltage drop considerations rather than thermal issues can determine capacity (see Figure A-15). On long rural feeders, it is not unusual for the capacity near the end of feeders to be less than 1 MW. Most urban feeders are short enough that thermal limits dictate their capacity. In many cases, because of the nature of distribution-connected PV utilization, voltage capacity will be the key issue that affects distribution-connected PV application, not thermal capacity.

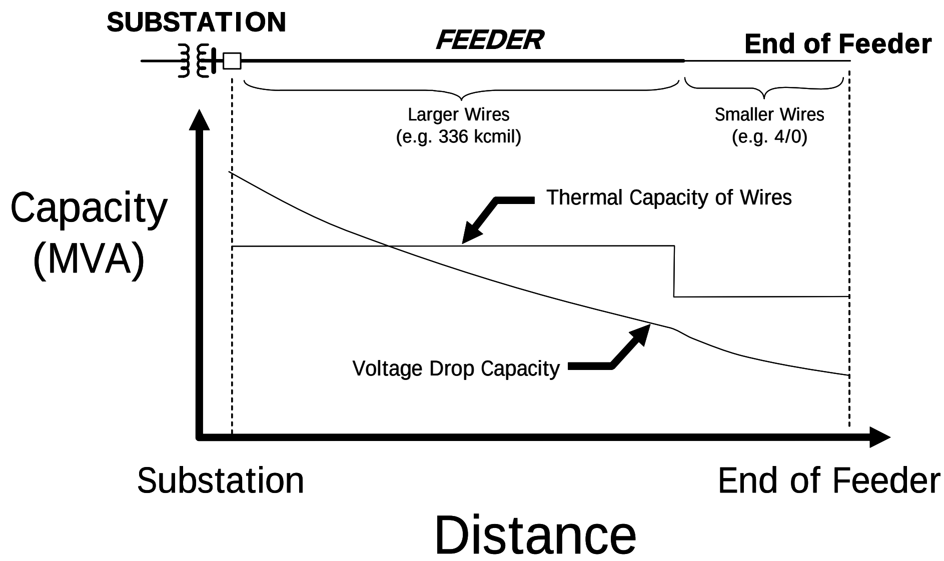

Figure A-15. The capacity of a feeder changes as one moves further from the source. Capacity is the lesser of either the voltage drop or thermal limits at the point of interest.

The preceding discussion of thermal versus voltage drop-related capacity illustrates the need to be careful about how we define distribution system capacity when we discuss penetration limits of distribution-connected PV or general DG. Some ways that penetration of distribution-connected PV or general DG can be defined at the distribution system level follow:

1. As a percent of feeder or local interconnection point peak loading (varies with location on the feeder)
2. As a percent of substation peak loading or substation capacity
3. As a percent of voltage drop capacity at the interconnection point (varies with location on the feeder)
4. As a percent of thermal capacity at the interconnection point (varies with location on the feeder)
5. PV source fault current contribution as a percent of the utility source fault current (at various locations)

For engineers calculating the effects on the distribution system, any one of these (or other forms of distribution system penetration level) may be of interest. For example, the percentage of PV relative to load is useful for assessing PV islanding potential and determining how the system power flow direction and magnitude may be affect. The PV fault contribution relative to the utility system contribution can be used to determine the seriousness of certain system protection impacts. The percentage of PV relative to distribution system voltage drop capacity is helpful from a voltage regulation and voltage flicker perspective.

In performing analytical studies, we need to be certain that we have assessed the situation using the appropriate penetration measure and at the correct location on the system. For example, a proposed 1.5-MW PV system with a relatively benign penetration level of 10% of the substation capacity may, at first glance, appear to be a low-impact site. Further assessment can show, however, that such a site might have too much PV generation if it is to be installed at the end of a long rural feeder served by that substation. At the end of such a feeder, the 1.5-MW PV may represent more than 100% of the feeder capacity.

The aggregation of distribution-connected PV and other DG forms on the power system complicates matters because with many energy source types on the distribution system it is difficult to assess the effective penetration level and to identify any particular fixed threshold of penetration where problems begin to arise. The percentage of penetration where problems begin could be 5% on one system and 30% on another, and the factors that would determine this are the type of distribution system layout, the type of DG sources (including PV) on the system, the spatial arrangement of these sources, and various other technical factors. Simple screening procedures that easily identify system upgrade needs may not be applicable in most cases once a reasonable amount of distribution-connected PV or general DG is on the system. On conventional power distribution systems, high-penetration situations invariably lead to the need for in-depth and costly analysis that can include load flow, power quality, stability, and short-circuit studies to assess the impact on the system. Required upgrades of the conventional distribution system may be costly and impractical. At higher penetration levels, then, we must change today’s strategy for facilitating DG integration, moving from merely upgrading existing systems on an as-needed piecemeal basis to designing a more advanced and flexible 21st-century power system that is compatible “as is” because of its inherent design attributes.

A.3 Energy Sources with Fluctuating Output

Not all distributed generation sources are created equal when it comes to the effect of their capacity on the power system. Fuel-based generation systems tend to have constant or slowly ramped output while running and can be controlled (throttled) to meet system needs. PV and wind systems are generally at the mercy of the instantaneous wind or solar resource available, and there can be huge fluctuations over seconds or minutes. The issue of fluctuating wind and PV sources on distribution circuits is an added complication that causes wind- or PV-connected capacity to have more impact on the system (at least from a voltage regulation perspective) than the equivalent level of “steady-type” generation such as combustion turbines, fuel cells, microturbines, and internal combustion engines. We presented an example of fluctuations from a larger PV system in Figure 2-6.

The array output shown in Figure 2-6 fluctuates slowly over a 24-h cycle but also can experience rapid changes in output over a period of 30 s to several minutes under certain types of partly cloudy conditions. For a single large PV system (for illustration’s sake, 1,000 kW and greater on the feeder), the fluctuations resulting from the movement of cloud shading can be sudden and will have a significant impact on the operation of the feeder voltage regulation system. For dozens or hundreds of small scattered PV systems of equivalent total capacity spread over many square miles of a distribution feeder service area, the rapid cloud shading impacts are likely to “cancel” each other, resulting in much slower power variations that are far less problematic. This is because as one rooftop is entering a shading period on one part of the feeder, another may be coming out of the shade at a different location.

The same effect occurs when considering wind power fluctuations if we compare one large wind turbine connected to the feeder to numerous smaller ones of equivalent total capacity scattered about the service area of a typical feeder. The allowable penetration levels of DG and especially wind or PV energy sources must take into account the type of generation fluctuations that can occur. In future power systems that are DG-compatible, the use of energy storage and reactive power control systems can combat these effects, allowing essentially full (100%) penetration.

Appendix B: PV Inverter Design Features

Modern inverters used for PV are typically pulse-width modulated (PWM) units with switching bridges composed of insulated gate bipolar transistors (IGBT). In theory, this type of switching technology is capable of operating in a variety of modes (voltage or current source) and able to operate in all four power quadrants (see Figure B-1). In practice, these capabilities are not used with most PV inverters because the usual operating strategy requires that distributed generation should not regulate the utility system voltage and should essentially provide only real powe*r*. This strategy confines inverter operation essentially to the real-power axis and there is no attempted adjustment of the reactive power level for regulation purposes. Although the policy of using no active voltage regulation has worked well up to now, active participation of the PV inverters with system voltage regulation will be helpful to manage system voltage conditions in the future, so inverters will need to provide reactive power control to do this. By adjusting reactive power output, system voltage regulation can be assisted; positive reactive power raises the voltage and negative reactive power lowers the voltage. For active regulation, the inverter will usually operate in quadrants 1 or 2 or perhaps even in 3 or 4 if equipped with some form of energy storage.

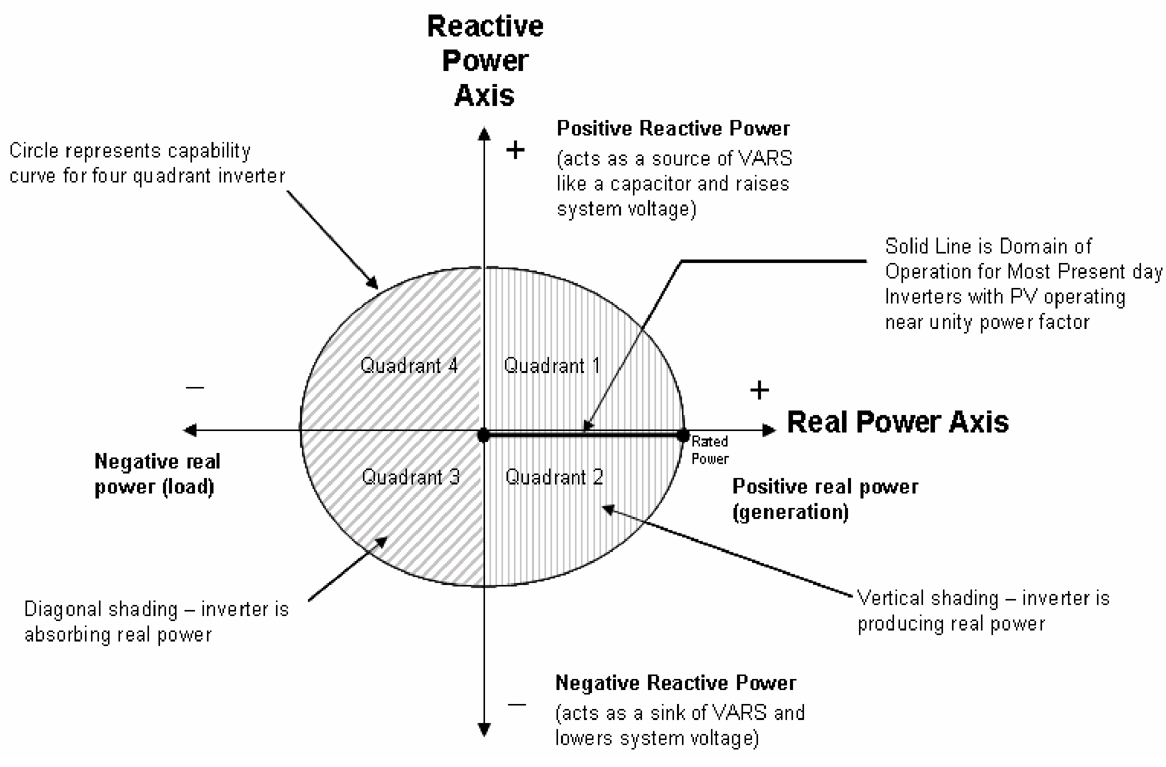

Figure B-1. Quadrants of inverter operation

B.1 Inverter Active Regulation Features

Active system regulation features embedded within inverters will be helpful for high-penetration PV situations to help regulate voltage and frequency. A key factor that determines the capability of inverters to assist with system regulation is the number of quadrants in which they operate. Two-quadrant operation includes positive real power with lagging volt amperes reactive (VARs) or positive real power with leading VARs, and this is fine for many voltage regulation needs of the 21st-century power system. Four-quadrant operation is the ability to produce real power or absorb power and also to produce lagging or leading VARs in any combination with the real power. The ability to absorb real power is a bonus in certain situations of excess generation or to provide damping of power transients. Energy storage (see Figure B-2), a load resistor, or a novel technique (discussed later) to turn PV cells briefly into loads would be needed if the unit is to absorb power.

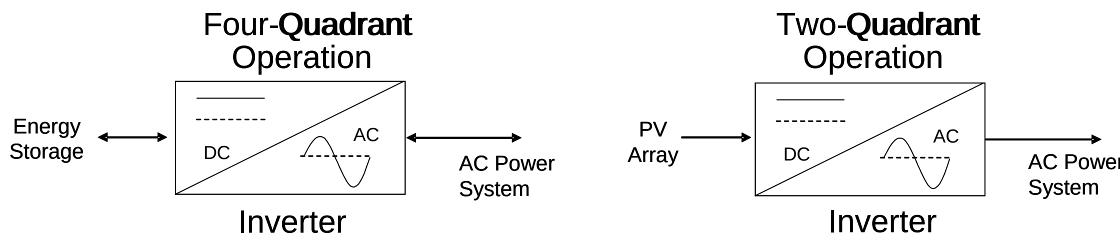

Figure B-2. Inverter devices capable of two- and four-quadrant operation

Key features of a PV inverter suitable to actively participate in the distribution system of the future include the following:

- Ability to provide slowly changing reactive power (acting in two quadrants as a VAR source, either leading or lagging) for system voltage regulation and VAR management. This function is to be coordinated with substation load tap changing (LTC) transformers, feeder regulator banks, and switched capacitors.
- Ability to provide fast-changing reactive power (acting in two quadrants as a VAR source, either leading or lagging) for system voltage flicker mitigation. This function operates independently of conventional feeder regulation equipment but might be supplemented by distribution static VAR compensator units if needed.
- Ability to slowly modulate the output level of real power for frequency regulation based on external command or local measurement of frequency.
- Ability to rapidly modulate real power for system oscillation damping and stability enhancement. (Note: This technique would normally focus only on positive energy for PV—produced energy—but it also could include negative energy—absorbed power—depending on various system design factors such as the presence of energy storage or a technique that could make the array an energy sink.)

The preceding features can be implemented as either an internal algorithm (in an autonomous mode based on local measurement) or as an external control input port (which would be able to receive instructions from a remotely located master controller that would be coordinated with other devices on the system). Hybrid forms of control that include both locally measured autonomous operation as well as remote oversight from a master controller layered on top of the local controls could also be a possible architecture. A functional diagram of an inverter with such a layered approach to control is shown in Figure .

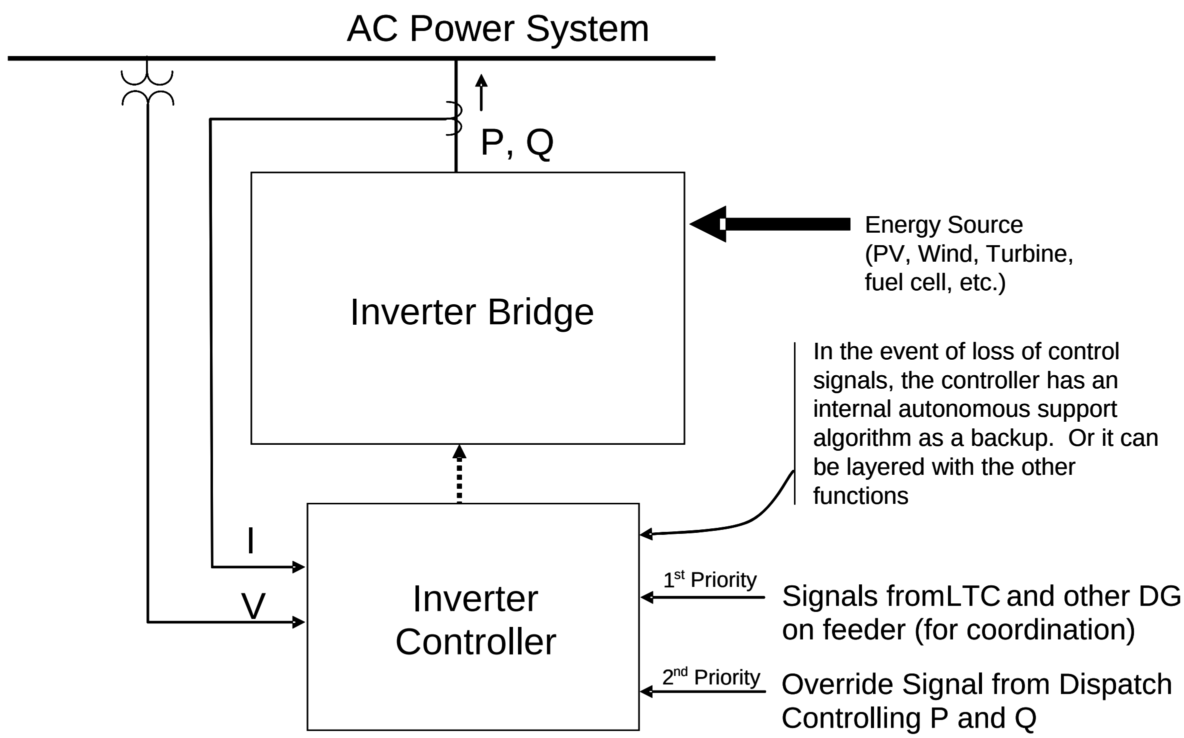

Figure B-3. Features of an inverter with active control capability

B.2 Inverters Used to Absorb Bursts of Energy

As stated earlier, PV systems that have no energy storage do not normally operate in four quadrants because the array is not usually considered an "energy sink." It might be possible, however, to make the PV array into an energy sink if the inverter drives current into it and the energy is dissipated in the cells themselves. This concept is worth investigating because it could have potential for using PV systems as dampers (energy absorbers) to help mitigate ground fault overvoltage, perform frequency regulation, provide load rejection support, and enhance power system stability. The objective is not to constantly use the cells as an absorber; that approach would be wasteful of energy and impractical. The cells could, though, be used for occasional bursts of energy absorption as needed to manage transient events; these bursts would generally last a few seconds and could be equivalent to the transient rating of the inverter in its reverse direction. Such bursts might only be required a few times per month as needed to mitigate system issues.

The big question is, can a solar cell really absorb power? The answer is yes, if the correct provisions are made. The equivalent model of a solar cell is a diode in parallel with a DC current source and some shunt and series resistances (see Figure). Using a four-quadrant inverter, AC power can be converted to DC and fed into the solar array if the voltage at the inverter DC terminals is high enough. At power injections up to the rated power of the array, this should not damage the cells in any way as long as current balance between panels is maintained. Inverters could be modified to have this feature, and the change in inverter architecture/controls should be minor. In high-penetration PV scenarios, the amount of "transient energy sinking capability" could be large and of great value to the power system. The biggest stumbling block to implementing this concept is not with the inverter itself but rather with overcoming the effect of "blocking diodes." These diodes are often installed on solar arrays to prevent accidental DC back-feed into the array under various conditions and to help prevent a roof fire if a cell fails. But there can be ways around this issue. Even if the blocking diode issue cannot be overcome, simply using larger capacitors on the inverter bus could also accomplish the needed power absorption effect for a few seconds, which is the duration required to mitigate many ground fault overvoltage issues, load rejection issues, and so on. This research area, which can expand the ancillary system control and regulation benefits that could be offered by PV inverters, is an area worthy of DOE research.

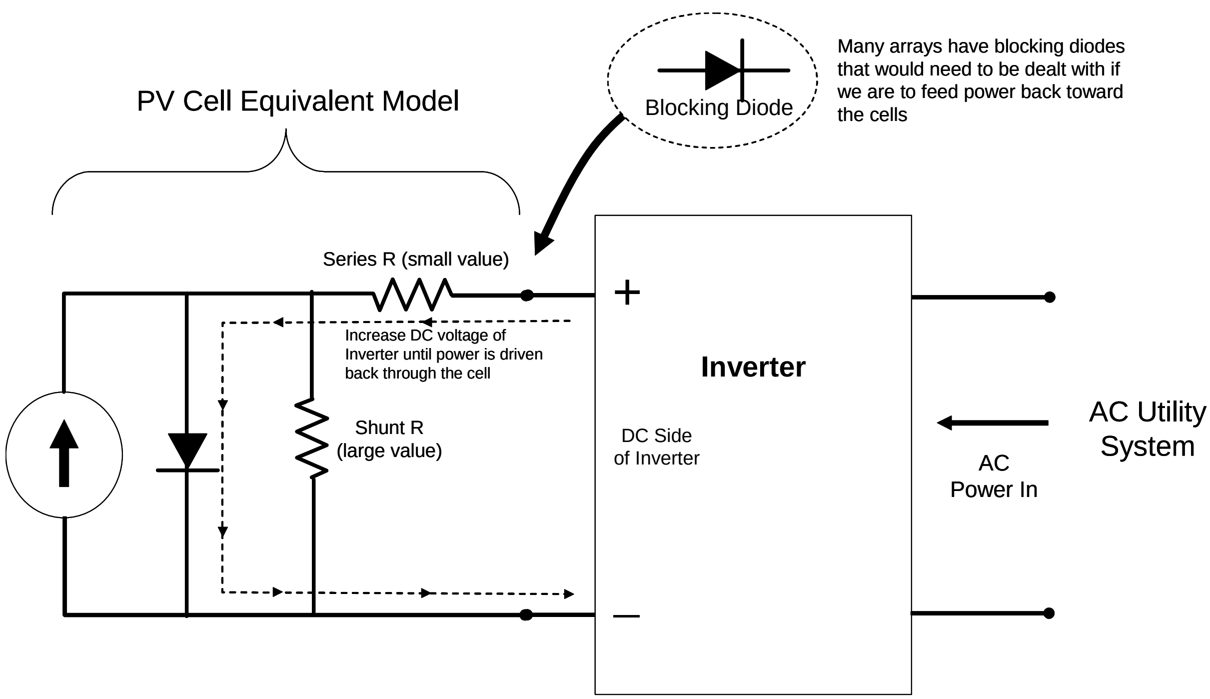

Figure B-4. Using a solar array as an energy absorber to provide system damping and suppression of transient overvoltage conditions

B.3 Inverter Fast Voltage Regulation Algorithm

Inverters could have two voltage regulation algorithms. One is a slow-speed function that operates over 30 s or more and supplies steady-state voltage regulation. Another is a fast function that operates within a few cycles and up to 30 s. The fast function can help mitigate voltage flicker and excursions resulting from PV and wind power fluctuations. The fast algorithm would be autonomous, running in the background of the slow algorithm and mitigating voltage fluctuations by making fast adjustments to the reactive power contribution of the inverter. The amount of injected reactive power could be based either on the measured terminal voltage or on the real output power of the inverter. The algorithm operation based on real power measurement might look like that shown in Figure B-5.. To avoid overcompensating, which could trigger instabilities, the compensation algorithm can use a limited gain in its feedback so that it will only partially mitigate voltage changes that occur. The suitable amount of gain for future inverters would be decided based on system studies and experience and could be directly incorporated into manufactured inverter products and changeable via firmware or uploading of specialized control settings.

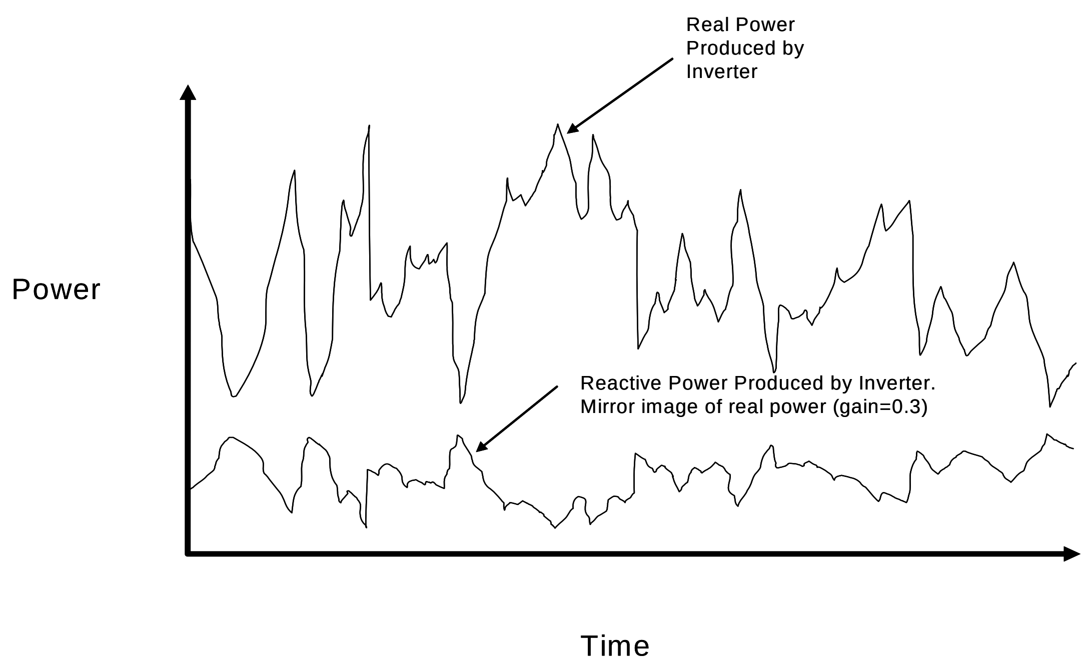

Figure B-5. Inverter mirror image reactive power compensation to help reduce the voltage change effects resulting from PV power variations (could be an autonomous algorithm)

The compensation algorithm could have limits that engage based on inverter ratings and/or economic factors because each inverter on the system has only a small fraction of the reactive capability needed for correction of feeder voltage events. An inverter would easily become saturated if it attempted to fully correct the voltage.

An algorithm might better work on a feeder-wide basis if the inverter used its own real output as a gauge for compensation injection as opposed to the terminal voltage. As an illustration, it could be programmed to change its reactive power level by a value equal to 30% of the real power change. In other words, if the inverter real output varied by 1 kW (because, for example, cloud shadows are moving over the array), the reactive output would change by 0.3 kVAR in a direction that offsets the voltage change resulting from the real power fluctuations. Because most locations on power systems have X/R ratios much greater than 2, this could be very effective in canceling out voltage changes. In fact, gains even lower than 30% might be more suitable for many sites.

When used in large amounts, inverter reactive power for voltage regulation is not free. It comes from the rating of the inverter device and must be coordinated with the economics of the PV site or other type of DG system where it is used. Most PV operators would prefer to run the inverter near unity power factor because this gives the best inverter power rating economics. The trigonometric relationship between reactive power and real power, though, is such that small amounts (20% or less) of reactive power can be extracted from a device with almost no real power penalty. Furthermore, most PV inverters spend 95% of their lives running well below rated power because of haze, clouds, nighttime, and so on. When there is cloud variation (when we most need the reactive capability), PV inverters are underutilized relative to their full rated power capability and, if so equipped, could easily be employed to provide reactive power—in many cases as much as 50% of the inverter rating. Furthermore, because the compensation function is a transient function (lasting only a few seconds), the thermal capability of the inverter could be sufficient for short overloads of about 30% to 50% higher than rated power lasting a few seconds. In many respects, we can think of the cost of the reactive capability almost as "free" under the real operating conditions and ratings that exist when such capability is usually needed.

A final point on the inverter fast voltage control algorithm is that the discussion so far has been from the perspective of mitigating the voltage fluctuation conditions on the distribution feeder (voltage flicker, voltage excursions, and so on). But the algorithm could also be put to use in a more localized fashion—that is, correcting flicker confined just to the customer's system to which the PV is connected. Homes and businesses that experience voltage flicker resulting from, for example, their own air-conditioning compressor cycling and other load fluctuations within their facilities, could see improved power quality and less lighting variation if these algorithms were implemented in inverters.

It is possible to discriminate between incoming (external) voltage fluctuation from the feeder system and a localized voltage fluctuation at the customer facility if the inverter has the appropriate voltage and load current sensing capabilities. The inverter control algorithm could be programmed to provide one degree of compensation for an "external voltage event" originating on the utility system, another degree of compensation for PV power fluctuation from the inverter itself, and a third level of compensation for an internal voltage disturbance originating at the customer. When such localized events are detected, they could be significantly corrected by the inverter. Such inverter capability is not built in and might require beefing up the electronic components and modifying the control software and firmware.

B.4 Features Needed to Improve System Interaction during Faults

In addition to voltage regulation features, other features are valuable for inverters in high PV and/or DG environments:

- More robust anti-islanding algorithms
- An encoded pilot-signal-receiving circuit or control port to be used for communication based transfer tripping.
- Fault limiter and enhancer mode, which increases fault contribution during intentional islanding and decreases it during grid parallel mode
- Advance intentional islanding capability.

Next, we discuss each of these and how they might be implemented.

B.4.1 More Robust Anti-Islanding Algorithms

Active anti-islanding algorithms currently used to pass the nonislanding inverter test (UL 1741 test [22]) generally perform much better than a standard passive anti-islanding scheme. The current UL 1741 method and 2-s requirement is adequate today because

- Most present-day inverters trip faster than the test requires.
- In the current low-penetration environments, the inverter is usually isolated on a section of line where the load is vastly larger than the inverter capacity.
- It is rare that inverters would also be isolated with other sources in a load-matched situation.

In the future we will need to revisit the 2-s limit. One issue is that in a high- penetration environment, where the inverter is islanded with numerous other inverters and/or rotating forms of DG, and where the load reasonably matches the island generation, it is possible to exceed the 2 s. In addition, 2 s may be too long for many utility system situations where fast reclosing schemes are employed. Even today, many utilities are using distribution feeder and subtransmission line reclosing dead time settings of 2 s or less (some even as short as 1/3 of 1 s).

As the penetration level of DG increases, many of the these mitigating factors will no longer be true such that problems will start to arise with islanding of so-called "nonislanding" inverters. Many conditions found on the feeders of the future will be outside the UL 1741 test conditions—for example, rotating DG may be trapped on the island too. For the future, the industry needs to revisit the nonislanding inverter test requirement and see how it can be revised to better conform to fast utility reclosing practices and high DG penetrations outside of standard UL test conditions. The inverter industry should also work on improvements in anti-islanding algorithms (some of these are described in Reference [23]).

B.4.2 Pilot Signal or Transfer Trip Port

Inverters are likely to need something beyond autonomous anti-islanding algorithms because even the best islanding detection algorithms may not be able to handle all conditions involving high-penetration PV and DG. A communication-based transfer trip method is a way to reliably trip PV inverters and other types of DG when a switch or circuit breaker opens that may create an island no matter how much generation is present. We recommend performing research to investigate ways in which some sort of active carrier detection scheme can work with future inverters. The presence of the signal as measured by the inverter would indicate "permission to operate normally." The absence of the signal would mean “trip immediately.” We discussed this pilot carrier concept in Section 3 of this report (see Figure 3-4 in particular).

The pilot signal would need to be of a frequency that easily works its way through various obstacles in the power distribution system such as transformers and capacitors. It would be transmitted over the line from the substation to all devices out on the radial feeder and would be similar to the old “ripple control” signals used for various load control applications. The pilot signal would need to satisfy the following requirements:

- Signal generation and incorporation of detection circuitry into inverters and other DB devices must be cost effective.
- The signal must not cause power quality problems for loads, equipment, or adjacent telephone line infrastructure.
- Transmission of the signal through the distribution line to all points must be reliable, meaning that it must get past distribution transformers and shunt capacitor banks.
- The signal must be secure and not result in unnecessary tripping of DG or PV inverters caused by the various forms of electrical inference that may produce a similar frequency.
- When a fuse, switch, or circuit breaker opens, the signal must disappear on the affected phase(s), leading to the tripping of all PV inverters and other DG on that section of line. Cross-coupling of the signal from other phases must not cause a false presence of the signal that prevents the generators from tripping.

One possible signal frequency that might meet these criteria is a carrier frequency that is transmitted between the fifth and sixth harmonics (between 300 Hz and 360 Hz; perhaps 330 Hz). The signal could be about 1/2% to 1% of the 60-Hz voltage magnitude and modulated with a recognizable amplitude variation so that any naturally occurring 330-Hz electrical phenomena (such as interharmonics) would not be mistaken for the signal.

It is noteworthy that the pilot signal may have ancillary value beside just the anti-islanding protection. The pilot relaying scheme could also “piggyback” on a limited number of other functions on top of its primary function. The signal could also be simultaneously used for low bandwidth transmission of data, perhaps to coordinate voltage regulator controls, switched capacitors, intentional islanding switches, and so on.

B.4.3 Fault Current Limiter and Enhancer Mode

The inverter could interact more effectively with the power system if it could adjust its fault level to more closely match the immediate requirements of the system. Some situations call for more fault current and others call for less. For intentional islands where there only weak DG is present and where there a strong utility source is no longer available, the problem would usually be too little fault current. Low fault current may make it hard for fuses and circuit breakers on the island to operate during the fault. For such intentional islands, it would be desirable to have the inverter adjust itself to provide the maximum fault current that it could physically produce without damage. On the other hand, when operating in parallel with the main utility system (not in an island), less fault contribution could be helpful to preserve utility system overcurrent device coordination and limit other impacts. When in parallel with the system, the inverter would set itself to deliver the minimum possible contribution during the fault event.

The inverter could know whether it was islanded or not islanded based on the status of the pilot signal or fast-reaction anti-islanding detection algorithms. When the terminal voltage of the inverter sags below a certain threshold (say 50%) and based on the islanding status flag at or just before that moment of the fault, it would adjust its fault contribution accordingly. The presence of increase energy storage on the inverter bus could be helpful in delivering more fault current when it is needed.

B.4.4 Intentional Islanding Capabilities

Intentional islanding will become a more common operational mode in 21st-century distribution systems, so that the potential reliability and power system support benefits that are possible with high-penetration PV and DG scenarios can be realized. To capture this opportunity, some of the future-generation PV inverters need to have advanced features that support a variety of intentional islanding capabilities. Inverters make excellent sources from which to power intentional islands (also known as microgrids) if energy storage or other sources are present in addition to the PV. PV energy alone might be able to sustain an intentional island for short periods during the daytime if loads were less than the maximum power level available from the sun during the islanding period, but control would be difficult.

Figure B- shows a PV inverter architecture that allows the inverter to isolate itself from the utility system during abnormal system utility voltage conditions and continue to carry the customer load as an intentional island. Some inverter products that provide this sort of emergency or islanded power are already available, but the technology for this type of advanced islanding control for DG is still in its infancy and needs to mature. Research projects aimed at developing these sorts of technologies and refining their performance can help foster this market area. It is noteworthy that intentional islanding with a customer load does not preclude the capability of having suitable anti-islanding protection looking out to the larger utility system. The isolating device that performs the anti-islanding protection may be either a mechanical switch or a static switch in series with a mechanical switch.

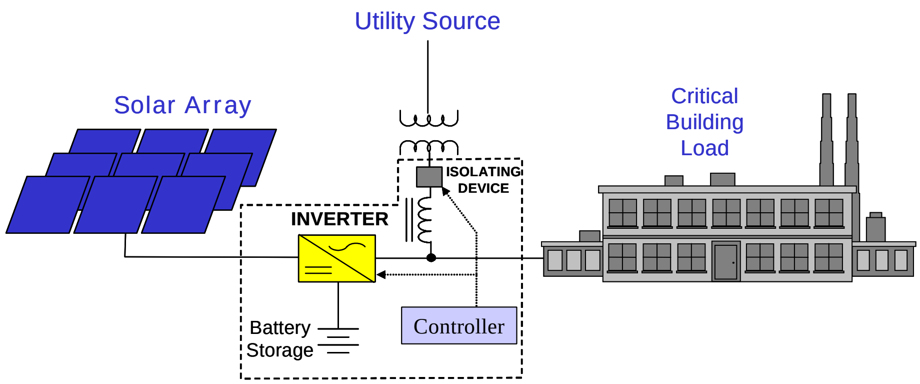

Figure B-6. Functional arrangement of a PV device that can operate in parallel with the utility system but can instantly and seamlessly transition to microgrid mode to support a critical load

If seamless islanding, which delivers high power quality and uninterruptible-power-supply (UPS)-grade power is desired, a static switch that can sense abnormal conditions and isolate the island within 1/2 of a cycle must be used as the isolating device. A mechanical switch will typically let through a few cycles of voltage sag or interruption until it clears the connection to the main system. In either case the switch would be controlled by anti-islanding relays a transfer trip signal, or both.

The requirements for a PV inverter that can create intentional reliability islands are significant compared to those for a standard inverter:

- In grid-parallel operation the inverter tracks the solar array maximum power point and stays synchronized with the power system. If there is a battery storage device, it must always be charged and ready to be used for power quality events.
- When a disturbance occurs, the inverter controls must detect the disturbance and isolate the unit from the system within a very short period of time (1/2 of 1 cycle for critical power applications) while also continuing to maintain acceptable power quality to the load on the local island. The storage battery may need to be dispatched at that instant to sustain the load.
- At the moment that the intentional island is formed, the inverter must balance the load-generation mismatch that might be present and transition to a frequency and voltage regulating mode that follows the local island load. At least some energy storage (5 min or so) must be present to help with power mismatch and make the unit suitable for mitigating momentary interruptions and power quality events that occur at times when the solar output is insufficient to carry the load. The unit may need to start a local standby generator if long-duration islanding beyond the limits of the battery bank is needed.
- After the utility system voltage is restored to a proper operating state, the inverter unit can reconnect automatically. This requires resynchronizing to the system and transitioning back to a voltage- and frequency-regulating mode suitable for grid-

parallel operation. Recharging of the battery (if it was used during the islanded period) will ensue after reconnection.

Figure B- shows an experimental 125-kW inverter demonstrated by Niagara Mohawk Power Corporation (now part of National Grid) in the late 1990s. This inverter was configured similarly to the diagram of Figure B- and had the capabilities we just described. The unit had a PV array, static switches, and battery storage to provide an intentional island and UPS-grade power capabilities to a demonstration-critical load [24, 25].

Figure B-7. Example of a 125-kW PV UPS unit developed by Power Technologies, Inc., for Niagara Mohawk Power Corporation in the late 1990s

Today, nearly ten years after the original Niagara Mohawk research effort, interest has grown greatly in the use of a PV backup power and islanding concept. Several manufacturers offer products that combine UPS features with PV inverters. For example, Beacon Power Corporation’s Smart Power™ M4 and M5 Plus inverter and Xantrex Technologies’ PowerHub can perform intentional islanding of small loads [26, 27].

In addition to individual inverter source intentional islands, there is also ongoing microgrid research in the United States and elsewhere to demonstrate and study the operation of microgrids that have multiple sources [28]. A variety of control methodologies and system configurations are being studied, including architectures with autonomous generation devices on an island as well as master-controller-based microgrids. Some projects involve totally independent microgrids that never connect to the utility system, and others involve part-time microgrids that can stay connected to the main utility grid during most normal conditions and separate into an intentional island during abnormal conditions or upon control center request. PV inverters of the future that are to be part of such multisource intentional islands (or microgrids) will need to have control provisions to handle sharing of load between units and to provide voltage and frequency regulation when needed.

To foster these technologies, DOE should conduct research projects that encourage development of these features and capabilities within inverters, which will allow them to operate within the framework of intentional islands and microgrids. These capabilities should include having the ability to transition to the appropriate operating modes for load sharing, voltage and frequency regulation, and enhanced fault levels, depending on the state of the island or microgrid. The units may also need output control ports that could be used to control islanding switches and other devices as well as having the necessary input control ports for receiving signals from the microgrid master controller and other DG or PV devices.

B.5 Testing to Characterize PV Inverter Systems

From a software tools perspective, the main deficiency in the industry today is a lack of accurate analytical models that describe the dynamic behavior of PV inverters and other forms of DG for use in the existing software.. In many cases, power generation equipment vendors have not made sufficient information available in a convenient public database that can be used in existing software to accurately model the fault contributions, the machine response to voltage sags, and so on.

Rotating machines (synchronous and induction generators) are better defined than inverters because in large part their response is determined by basic physics that do not change much once the fundamental machine design is known. From basic parameters such as the subtransient and transient reactance, the machine inertia and time constants, and the characteristics of the exciter and governor, the machine’s overall response to various system conditions—including fault current contributions, dynamic voltage sag/swell response, and stability behavior—can be easily modeled. With inverters, however, we are dealing with great uncertainty because the behavior is determined in large part by the control software (firmware) that resides within the inverter, not by the basic physics. Many inverter manufacturers have not performed the tests or made the data easily accessible to describe fault contributions or dynamic response adequately.

The uncertainties in inverter behavior have not been much of a problem for the industry so far because penetration of PV is small on the system, so crude estimates (usually assuming worst-case values) work fine for most calculations. As penetration expands, however, assumed inverter responses will not be adequate to model the overall system response. One of the most important areas of industry assistance that DOE could support is the development of a series of inverter tests and classifications that describe the behavior of the inverter under the range of conditions expected in the field. These tests could include

- Fault contribution test
- The rate of output change (driven by solar insolation changes under partly cloudy conditions)
- The response to small and medium signal-step conditions (voltage, phase, and frequency)

- Islanding test (must be multiple inverters in parallel with a rotating machine source and defined with specific machine ratings relative to the inverter rating and various defined load mismatches at the island transition).

B.5.1 Fault Contribution Test

The fault contribution test is one of the most important tests that is needed by industry. The data could be compiled in table format, as a family of curves, or best of all, as a mathematical equation that defines the current contribution versus time for all terminal voltage conditions.

Table B-1 illustrates, in tabular form, the fault data that inverter manufacturers are encouraged to provide. To generate the necessary data, the inverter would be configured in the test lab with the version of software intended for field usage. It would then be subjected to terminal voltage sags of a given percentage (90%, 80%, 70%, and so on) of the nominal operating voltage. For each specific sag test, the root-mean-square (RMS) current contribution versus time would be measured with 1/2-cycle resolution until the unit stopped injecting current. From all of the data, a table (such as the one shown here) or an equation could be created for use in the power system inverter model. Remember, the whole reason for the test is to provide a specific current level versus time that can be used for short-circuit and overcurrent protection coordination studies. A simple report from the manufacturer stating that the inverter will disengage from the system after so many cycles (as is currently provided) does not give the necessary detail to perform overcurrent protection studies. We need data like those shown in Table B-1, especially for high-penetration PV scenarios where fault contributions must be precisely calculated.

Table B-1. Hypothetical Fault Contribution Test Table (for Illustration Only)

Duration (Cycles)	Voltage at Inverter Terminals During Sag (%) (current is shown in per unit of RMS rated output)									
	0	**10**	**20**	**30**	**40**	**50**	**60**	**70**	**80**	**90**
½	2.8	2.5	2.0	1.9	1.8	1.5	1.3	1.3	1.2	1.1
1	0	0	0	1.8	1.7	1.5	1.3	1.3	1.2	1.1
2	0	0	0	0	1.7	1.5	1.3	1.3	1.2	1.1
4	0	0	0	0	0	1.5	1.3	1.3	1.2	1.1
8	0	0	0	0	0	0	1.3	1.3	1.2	1.1
16	0	0	0	0	0	0	1.3	1.3	1.2	1.1
32	0	0	0	0	0	0	1.3	1.2	1.1	1.1
64	0	0	0	0	0	0	1.3	1.1	1.1	1.1

Inverter Trip-Out Zone

B.5.2 Insolation Change Test

The inverter unit's response to changes in solar energy levels that result from passing cloud shadow effects must be modeled precisely so that the rates of change and magnitudes of the change can accurately included in power system models. These data would be very useful for voltage flicker and voltage regulation analysis. There are really two steps to define this characteristic. The first is how the array responds (which is obviously a function of the local array configuration and size), and then there is the way in which the inverter responds. These two elements are put together to create a total response model.

Every inverter would need a published response curve or equations showing how it responds to input changes in DC power. The inverter response time would be a function of the amount of energy storage (capacitors on the inverter DC bus) as well as the imbedded inverter power tracking and control algorithm. The test data and model provided by the manufacturer should be such that when the model is coupled to the model of the solar panel cloud change effects, the two models together in series adequately describe the rate of power fluctuation that would occur under rolling cloud conditions.

Although independent of the inverter, the cloud model is related in that it is part of the total model. In general, the inverter manufacturer must provide the inverter model, and the PV system integrator, based on the spatial size and orientation of the array, must provide the rolling cloud model. The industry needs to select standard cloud shading models to use for this type of analysis. The models need to take cloud focusing effects into account as well as array cooling by sudden rain contact. These factors can cause the panel output to rise to 30% to 40% higher than its rated value for brief bursts. There has been much published work on cloud variations, but the industry needs to formalize the models used for analysis and to make them conveniently accessible to power engineers.

B.5.3 Inverter Dynamic Response to Small and Medium Perturbations

Another type of important test is the inverter ramp rate (rate of output change) and its dynamic response under various “small signal” changes in conditions on the AC side of the inverter. Whereas the fault contribution test models the inverter output current for mild to deep voltage sags at the terminals, the small signal test looks at the inverter response to more subtle changes of a few percentage points or so. This lab test would be performed by subjecting the unit to small step changes in voltage, frequency, and phase angle of the AC system within the realm of expected changes that are usually under “normal” operating conditions on the power system. These could be used to identify any responses that could lead to small signal dynamic instability.

Another part of the test is also to command the inverter unit to execute a change in its output either up or down under steady terminal voltage conditions and measure the time constants and ramp rates associated with its response to the commanded change. These would help assess how effectively the inverter could be used to actively control the power system.

Overall, both the ramp rate test results and the small signal perturbation test results can be used to establish models that characterize how the units can be ramped to support system needs as well as characterize the small signal variations in output for steady-state stability analysis.

B.5.4 Islanding Tests

As mentioned earlier, the industry needs a more robust anti-islanding test than what is currently provided in UL 1741.This more robust test is needed if we are to rely on locally measured (at the inverter) active anti-islanding algorithms in high-penetration situations to detect the island and disengage the unit from an island. The industry needs to revise the test and publish the data for each inverter in a fashion that power system engineers can incorporate into the modeling programs. Because of the increased possibilities for a range of island types and energy sources on the islands, several different islanding classification tests may need to be developed that describe the ability of an inverter to detect an island and respond appropriately. The test should say what types of islands the inverter algorithm can detect (is rated for). Examples of some possible nonislanding inverter ratings are as follows:

- **Rated for single-source simple island.** The inverter is the only source on the island.
- **Rated for multisource simple island.** The inverter is one of up to "X" inverters on the island, all with the same algorithm.
- **Rated for multisource complex island.** There is more than one source on the island and not all sources have the same active anti-island algorithms, or some do not have active anti-islanding protection at all (rotating machines).

Based on which type of nonislanding protection the inverter has, the power system engineer would use these classifications to determine whether transfer trip communication is needed, as well as to assess the overall risk of islanding. For example, if a nonislanding inverter is rated only for a single-source simple island, it will usually be able to detect and trip off if it is the only source on that island. If other sources are present, though, the detection algorithm is considered unreliable.

Another issue is that the existing UL 1741 test has a long 2-s disengagement requirement, which is slow for many reclosing situations. Not only is it too slow for high-penetration scenarios, but the disengagement time of the current UL test is stated vaguely, which limits its value to a protection engineer in a high-penetration environment. For protection studies, the engineer needs to know if the unit clears in a specific number of cycles—simply saying that it will clear within 2 s or less for mild events and 10 cycles or less for severe events is not sufficiently accurate for a protection study with high-penetration PV on the feeder. When they are modeling a high penetration of inverters on the system, engineers will need to know the specific number of cycles that can be expected to hang online in order to perform accurate calculations. The inverter manufacturers should provide charts, curves, and/or tables of specific clearing times for various conditions.

A final point related to islanding protection data is that, in the future, inverters will be involved in intentional islands. So in addition to the nonislanding inverter tests that we have described, we must also establish tests for the behavior of intentionally islanded inverters. We need to describe how they transition from one mode to another and document the various response time and fault contributions associated with each mode.

B.6 Recommendations for Inverter Development

Based on the inverter technology discussion in the preceding section, we make a number of recommendations for future inverter research and development:

- Study the use of active power system control features by inverters and other DG. This includes reactive power compensation, voltage regulation, and frequency regulation features in inverters and rotating DG (this effort will consider both technical and cost details).

- Investigate incorporating an encoded pilot signal receiving circuit into each inverter (or DG). This circuit will be used for transfer tripping and perhaps some other control functions (ramping up or curtailing output). Consider its cost, reliability, security, and so forth.
- Investigate improved internal anti-islanded algorithms and perform tests with “real islands” with multiple inverters and also rotating generators to see if any technique has dead zones.
- Research requirements for inverters to best support intentional islands.
- Research the requirements and needs for advanced DC/DC converters for use in DC architectures (DC/DC converters will be the new inverters if we move to a DC system).
- Consider plug-and-play elements in inverters for microgrid application. This will be required for widespread adoption of distributed energy resources (DER) into distribution feeders or microgrid applications if it is desirable for the DER to have plug-and-play functionality. Once connected into the microgrid, the unit should automatically be integrated for control and status reporting. This type of system compatibility will require standardized connection ports and communication protocols.

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