Connecting to the Grid

A Guide to
Distributed Generation
Interconnection Issues

5th Edition
2007

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Preface to the 5th Edition

The first edition of the Interstate Renewable Energy Council's (IREC) *Connecting to the Grid* guide was published in the mid-1990s, in response to the inconsistencies of many state net-metering laws that provided no uniform standards for how to connect renewable-energy systems to the electric grid. The lack of uniform interconnection standards significantly complicates the interconnection process and historically likely has deterred the deployment of customer-sited distributed generation (DG). On the other hand, well-designed uniform interconnection standards facilitate the deployment of renewables and other forms of DG by specifying the technical and institutional requirements and terms that utilities and DG system owners must abide by.

Well-designed uniform interconnection standards facilitate the deployment of renewables and other forms of DG by specifying the technical and institutional requirements, policies, rules and terms governing the interconnection process that utilities and DG owners must abide by.

Although almost all U.S. states with net-metering laws and regulations now have interconnection standards for net-metered systems, most states have not yet adopted uniform interconnection standards for larger DG systems that are not net-metered. The fourth edition of the IREC *Connecting to the Grid* guide, published in 2004, described this technical and policy vacuum.

Significant changes have swept over the technical and policy landscapes – both at the federal and state levels – since the publication of the fourth edition. A multitude of states have adopted interconnection standards for DG, sometimes in conjunction with the implementation of a new renewable portfolio standard (RPS) or the expansion of an existing RPS. Furthermore, in May 2005, the Federal Energy Regulatory Commission (FERC) adopted interconnection standards for generators up to 20 megawatts (MW) in capacity. The FERC's interconnection standards, which generally apply only to transmission-level interconnection (as opposed to distribution-level interconnection), include standard interconnection procedures and a standard interconnection agreement.[1]

The march toward standardization and the broader adoption of DG technologies advances, but not without additional obstacles and complexities. The fifth edition of this guide addresses new and lingering interconnection issues relevant to all DG technologies, including renewables, fuel cells, microturbines and reciprocating engines. Because interconnection issues remain largely in the domain of the states, this guide is designed for state regulators and other policymakers, utilities, and industry representatives and consumers interested in the development of state-level interconnection standards.

This publication will discuss IREC's model interconnection standards for generators up to 10 MW and IREC's model net-metering rules for generators up to 2 MW in capacity. IREC's model rules promote what it believes to be the best practices developed by states, government entities and other non-governmental organizations. IREC's model rules have been instrumental in the development of effective standards and, to an extent, significant DG deployment in several U.S. states.

[1] Note that the FERC governs all wholesale electricity transactions, even those involving systems connected at the distribution level.

The authors wish to acknowledge the ongoing support of IREC and its consistent leadership in the interconnection field through its national *Connecting to the Grid* program. IREC has been a pioneer in interconnection and net-metering issues since 1997, when fewer than 20 U.S. states had implemented net metering, and the concepts of "DG" and "clean energy" were neither widely recognized nor publicly appreciated. The authors also would like to express gratitude to the U.S. Department of Energy (DOE), which, through its involvement in the development of national standards and DG-testing facilities, has provided national leadership in addressing fundamental interconnection issues. The authors also wish to thank Tom Basso, Bill Brooks, Chris Cook, Andy Kruse, Tom Leyden, Larry Mansueti and John Wiles for sharing their time and expertise by reviewing a draft of this publication and providing critical feedback.

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Executive Summary

It appears that a sleeping giant has finally awoken. Accelerated public interest in renewable energy in the United States has accompanied sustained, robust market growth by multiple distributed generation (DG) technologies in the last few years. At the same time, U.S. policymakers are working to address an armada of high-profile problems related to the generation of electricity by conventional means, including aging infrastructure and grid congestion, whopping electric-rate increases in many states, volatile natural-gas prices, global warming, diminished air quality and public health, the looming threat of brownouts and blackouts, energy insecurity, and energy inefficiency. While the true costs of conventional electricity generation become increasingly apparent, the price of distributed, renewable-energy systems continues to drop. Many policymakers have recognized that the need to facilitate the interconnection of clean, customer-sited DG systems to the electric grid is long past due.

Interconnection is an inherently complex issue due to the many technical and contractual considerations that need to be addressed. Many U.S. states, as well as the Federal Energy Regulatory Commission (FERC), have developed interconnection standards that specify the technical and policy requirements and terms that utilities and DG system owners must operate under. In other states, the absence of uniform interconnection standards significantly complicates the interconnection process and likely has obstructed the deployment of renewable-energy systems and other forms of DG, including combined heat and power (CHP).

Most DG systems are installed, owned and operated by entities other than electric utilities, such as homeowners, businesses, farmers, manufacturers, nonprofits and government entities. Because the interconnection of DG challenges the century-old tradition of utility-owned centralized generation, it requires careful technical considerations and evokes new perspectives on ownership and control. There are three primary categories of issues related to DG interconnection: technical issues, legal and procedural issues, and tariff and pricing issues.

Technical issues include safety, power quality and system impacts that must be addressed prior to interconnection. Safety is not only a critical consideration of DG system owners, but also of electric utilities. Relevant national technical standards, including IEEE 1547 and UL 1741, have been developed and are amended or expanded as necessary to ensure that DG products and equipment, as well as interconnection practices, are safe. The value of national codes and standards to the interconnection process is priceless. Without standardized national documents, DG equipment manufacturers would be faced with the nightmare of developing separate devices and protection equipment to satisfy individual utility interconnection-safety requirements.

While a number of the technical issues related to interconnection are now under control, many of the difficulties associated with interconnection now lie in the legal and procedural arenas. Interconnection standards adopted by different governments are still largely disparate, although several states that have adopted standards since FERC Order 2006 have chosen to employ a multi-level approach to system review, depending on the system capacity, type or location. The majority of U.S. states still have not adopted interconnection standards that apply to DG systems that are not net-metered. Many states with DG interconnection standards have developed a standard agreement and concise application forms, while prohibiting utilities from requiring unreasonable amounts of liability insurance or engaging in unnecessary delays. Several entities, including IREC, have developed model interconnection procedures and agreements for use by states.

If not structured properly, utility tariffs, rates and fees may present major barriers to interconnection. Net metering, which has been adopted by 38 U.S. states as of July 2007, is one of the most important tariff issues related to renewables and, in a few states, to CHP systems as well. States continue to tweak existing net-metering laws and regulations as in-state markets evolve and policy needs become more apparent. Although time-of-use (TOU) metering and smart metering do not interact net metering in most states, there is increasing interest among utilities and regulators in these new metering technologies.

The federal government has provided some degree of guidance to states on interconnection policy, and minimal guidance on net metering. FERC Order 2006, adopted in May 2005, includes three levels of review of DG systems up to 20 megawatts (MW) in capacity. Although FERC's interconnection rules for small generators likely will have little impact on distribution-level interconnection (which is generally governed by states), the commission has stated that it hopes states will adopt its rules – with necessary modifications – to promote a more unified interconnection policy around the United States. In addition, the federal Energy Policy Act of 2005 (EPAct 2005) requires state regulatory authorities and certain "nonregulated" utilities to "consider" an interconnection standard based on the IEEE 1547 standard and current best practices by August 2007. EPAct 2005 also requires state regulatory authorities and "nonregulated" utilities to "consider" a net-metering standard by August 2008. These federal requirements have prompted the vast majority of states to consider new standards or to revisit existing standards.

Interconnection standards vary widely from state to state, as do net-metering laws and regulations. The tradition among U.S. states of looking to other states (and to available models) for policy guidance is increasingly evident in these two areas, especially because the issues are complex. Many states prefer to use, at least as a starting point, interconnection models developed by entities such as FERC, IREC or MADRI, or highly effective rules developed by states, such as New Jersey. With respect to net metering, states are constantly retooling existing laws to make net metering more enticing to consumers. As a result, annualized net metering is now more common monthly net metering, and most states have decided that customers own renewable-energy credits (RECs).

DG system developers must make an effort to work with building and electrical inspectors in order to familiarize them with new technologies, especially PV systems. As part of this process, developers should provide inspectors with plans and diagrams detailing the operation of the system.

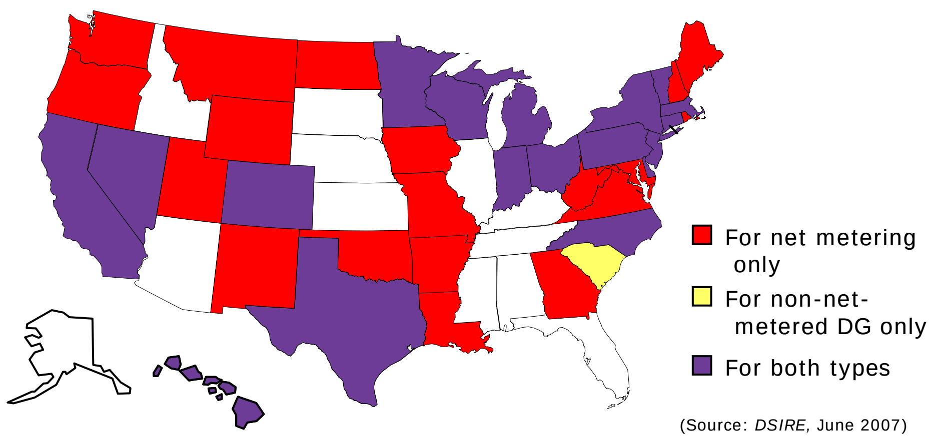
1. INTRODUCTION

The interconnection of distributed generation (DG)[2] remains a significant regulatory issue because of the technical and procedural requirements needed to safely, reliably and efficiently interconnect with the electric grid. Moreover, it challenges the century-old tradition of centralized generation, which historically has been owned and operated by electric utilities. Before the development of certain national technical standards – including the IEEE 1547 and UL 1741 standards – and the adoption of interconnection rules and procedures by some states, electric utilities determined the technical and engineering requirements, and the policies, rules and terms governing the interconnection process for customers. In the absence of appropriate standards for residential-scale generators or small-commercial-scale generators, many utilities simply applied existing interconnection procedures for *qualifying facilities* (QFs) under the federal Public Utility Regulatory Polices Act of 1978 (PURPA).[3] Significantly, PURPA does not mandate special, simplified interconnection procedures for very small systems.

Section 1254 of EPAct 2005 requires all state regulatory authorities and certain "nonregulated" utilities to "consider" adopting an interconnection standard based on the IEEE 1547 technical standard and current best practices.

Figure 1. Statewide Interconnection Standards

(for investor-owned utilities at a minimum)



(Source: *DSIRE*, June 2007)

In 2000, the National Renewable Energy Laboratory (NREL) published a study of barriers that generators encountered while attempting to connect to the grid. This 91-page report, titled *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, examined 65 DG projects ranging in capacity from 500 watts (W) to 26 megawatts (MW). Barriers were documented through interviews with system owners, project developers and utilities, and were categorized as technical, business practice or regulatory. All but seven of the 65 project owners encountered at least one type of significant interconnection barrier. As a result, 16 projects were either abandoned entirely or reconfigured to serve only local loads as stand-alone systems.

[2] In general, "distributed generation" (or "DG") refers to relatively small systems that generate electricity at or near the point of use.

[3] PURPA requires electric utilities to interconnect with QFs, provide backup power to QFs and purchase electricity from QFs at a utility's avoided-cost rate. Most QFs are large systems – up to 80 megawatts (MW) in capacity – that generate electricity using renewable-energy resources or combined heat and power (CHP).

Almost all of the 38 states that have adopted statewide net metering (as of July 2007) have adopted interconnection standards for net-metered systems. [4] Net-metering laws and regulations vary widely among states, namely in terms of the types of electric utilities affected, the types of DG systems eligible, and the maximum capacity of an individual net-metered system. (Net metering is discussed in detail in Section 4.)

With a growing awareness that interconnection difficulties persist for DG systems that are not net metered, many states have adopted standards for such systems. Other states are in the process of developing or considering new standards, or revisiting existing standards. At least 20 states (as of July 2007) have already adopted interconnection standards for DG systems that are not net metered, while many others are in the process of developing or considering new standards – either on their own volition or due to the federal Energy Policy Act of 2005 (EPAct 2005). Section 1254 of EPAct 2005 requires all state regulatory authorities, also referred to as public utilities commissions (PUCs), to "consider" adopting an interconnection standard based on the IEEE 1547 technical standard and current best practices, including "model codes adopted by associations of state regulatory agencies."[5] This requirement also applies to utilities that are not subject to state regulatory jurisdiction and that have annual retail sales exceeding 500 million kilowatt-hours (kWh). The deadline for concluding the consideration process is August 8, 2007.

States developing DG interconnection standards now have the advantage of using the IEEE 1547 and UL 1741 technical standards, and modifying and adapting comprehensive model standards that address with clarity procedural issues and equipment certification. Interconnection standards that have served as models include those adopted by states (especially those adopted by New Jersey and Colorado), the FERC's interconnection standards for small generators, [6] and separate model standards developed by IREC, the National Association of Regulatory Utility Commissioners (NARUC), the Environmental Law and Policy Center (ELPC) and the Mid-Atlantic Distributed Resources Initiative (MADRI).[7]

While this guide does not discuss state-by-state activities in detail, IREC's *Connecting to the Grid* newsletter[8] covers state, federal, local and international developments related to interconnection and net metering. This free, monthly newsletter is published by the N.C. Solar Center at N.C. State University. In addition, the IREC *Connecting to the Grid* program web site[9] provides several additional public resources relevant to interconnection issues and net metering. These include:

- Model interconnection standards
- Model net-metering rules
- A state-by-state table of DG interconnection standards and guidelines

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[4] While 38 states have laws that allow customers of investor-owned utilities to net meter, only some state laws allow customers of publicly-owned utilities and electric cooperatives to net meter.

[5] See *16 USCS § 2621(d)(15).*

[6] The definition of "small generators" varies. The FERC refers to "small generators" as DG systems up to 20 MW in capacity and "large generators" as those greater than 20 MW.

[7] Links to the FERC, IREC, NARUC, EPLC and MADRI interconnection models are included in the "References" section of this publication.

[8] This free, monthly newsletter is published by the N.C. Solar Center at N.C. State University. See www.irecusa.org/index.php?id=33.

[9] See www.irecusa.org/index.php?id=31.

- A state-by-state table of net-metering laws and guidelines
- A state-by-state map of net-metering laws and guidelines
- A state-by-state table of EPAct proceedings related to interconnection and net metering
- A library of legal documents related to interconnection and net metering

2. Safety, Power Quality and Codes

Because utilities and DG system owners are concerned with safety, power quality and system reliability, technical details represent a critical component of the interconnection process. Three national standards and code-making bodies – the Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories (UL), and the National Fire Protection Association (NFPA) – have developed installation codes, functional requirements and test standards for DG equipment that will be connected to the grid.

This section first addresses safety and technical issues in general, and then offers a discussion of standards and codes, and how these can streamline the interconnection process. The goal is to familiarize the reader with these issues without plunging too deeply into technical detail.

2.1 Safety

Like any source of electricity, DG systems are potentially dangerous both to people and property. Therefore, much effort and care have been undertaken to minimize these inherent safety risks. Large industrial customers have been generating power on-site for as long as electricity has been used, but interconnecting photovoltaic (PV) systems, microturbines and other relatively small DG systems to operate in parallel with the grid at residential and commercial locations is a relatively new trend. The potential impact of DG on safety is a function of the type of DG system, its size (primarily in relation to the capacity and design of the utility grid to which the system is connected), and the amount and type of neighboring DG systems sharing the grid.

Distinctions Among DG Systems

From a utility interconnection perspective, DG systems are grossly classified by the type of generator[10] that interfaces the system to the grid: (1) solid-state or static inverters, (2) induction machines, and (3) synchronous machines. A substantial portion of renewable-energy systems produce grid-quality alternating current (AC) power using an inverter, and therefore are typically lumped together. Fuel cells also use an inverter interface, as do high-speed microturbines, despite generating power through the rotation of a generator to produce power. As with some wind turbines, the high-frequency AC generated by microturbines is converted to direct current (DC) before being converted to grid-compatible AC by the inverter.

[10] The IEEE 1547 technical standard uses the term “interconnection system” rather than “generator.”

Table 1: DG Systems Types and Characteristics

	Inverter	**Induction Machine**	**Synchronous Machine**
General Characteristics	Commonly current source-like (strictly, voltage regulated, current controlled) in grid-tied mode; voltage source in stand-alone mode, sometimes within the same unit. Low inertia (capable of very high-speed response).	Inherently current source; can be made to act as voltage source with external excitation. High inertia (relatively slow response).	Voltage source. High inertia.
Fault-Current Capabilities	Low (typically <1.2X normal current).	Medium (6X normal current).	High (10X normal current).
Power Quality	Total harmonic distortion and DC injection must be controlled; controllable power factor.	Low total harmonic distortion; power factor must be corrected.	Low total harmonic distortion; controllable power factor.

Because inverters are power electronic devices, it is possible to incorporate safety and operational features into their controls, such as providing fail-safe designs that prevent the inverter from operating unless its protective functions are operating properly. The upshot is that inverter-based and rotating generators are treated differently in the codes and standards, with properly designed and tested inverter-based devices requiring little (if any) additional external protection equipment.

Properly designed and tested inverter-based devices require little (if any) additional external protection equipment.

While inverters are inherently very "controllable," their use in utility applications is newer and less well understood. As technical interconnection issues were being debated through the mid- and late 1990s, attention was given to whether these devices needed the additional familiar protection relays used for rotating generators. Through the process of developing IEEE 929 and UL 1741, it was determined that these solid-state devices could be tested so as to prove they could reliably provide standard utility protective functions (voltage and frequency trip), as well as additional safety features such as *anti-islanding*. IEEE 1547 and 1547.1 further improved upon those tests procedures and applied the procedures to machine-based interconnection systems.

PV Power

PV systems produce DC power and have special characteristics that warrant an individual discussion of the technology. Depending on the system design, some grid-tied PV systems operate at up to 600 volts (V) DC before being inverted to standard AC. While the shock hazard of 60 hertz (Hz) AC is somewhat higher than that of DC at equivalent voltages, the potential fire hazard of DC is greater than that of AC because it is more difficult to extinguish a DC arc than an AC arc. Many electricians and electrical inspectors do not regularly work with DC circuits; however, proper wiring according to the *National Electrical Code* (*NEC*)[11] ensures that hazards related to DC power are properly controlled. In addition to the NEC, there are guides to the proper wiring of PV systems. Several entities, including the North American Board of Certified Energy Practitioners (NABCEP),[12] PV manufacturers and inverter manufacturers, offer training and installation guides.

Not all grid-tied inverters require DC wiring. One PV product innovation is the AC module, which is a PV module with a micro-inverter built directly onto the module so that AC power leaves the module. While these characteristics are of little impact on the utility interconnection discussion, there are a few considerations of PV that do apply to this topic.

PV is considered a *non-dispatchable* resource because the output power is primarily determined by the prevailing (current) sunlight intensity. Whereas output power can be increased or decreased by regulating the fuel source of a dispatchable generator, the output power of a PV system can not increase beyond that allowed by the current sunlight intensity. Furthermore, a PV system's output can not be decreased without losing the energy that could have been generated. The PV output profile over the course of a day generally coincides with load profiles in summer peaking locations. However, without storage availability, PV systems provide no output for roughly half of a 24-hour day, due to the absence of sunlight.

Because the general public values PV as a clean, renewable-energy source that should be encouraged, governments and some utilities offer a multitude of financial incentives to support PV deployment.[13] One significant incentive is net metering, which is discussed in detail in Section 4. While net metering is itself an accounting means, the fact that net-metered systems export power to the utility distinguishes them from sources that are designed as non-export.[14] Power originating at a customer's facility and flowing back towards the substation may conflict with a radial distribution system designed for the opposite flow. For example, exporting DG causes a voltage rise instead of the expected drop wherever there is reverse power flow. Whether this action creates a problem depends on the circumstances, such as the total amount of exporting DG and the capacity (i.e., transformer size, wire length and size, etc.) of the distribution system. Export capability also means a DG system has the potential to power loads beyond the owner's facility, which raises the concern of unintentional islanding.

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[11] The *National Electrical Code*, which is published by the NFPA, is discussed in greater detail below.

[12] For more information, see www.nabcep.org/pvresources.cfm.

[13] The *Database of State Incentives for Renewables and Efficiency (DSIRE)* provides details on government and utility financial incentives for renewables, including PV. See www.dsireusa.org.

[14] There are several flavors of export to consider, related to the magnitude and duration of the export. "Inadvertent export" results when a DG system is unable to react to a sudden drop in load and generates some excess power while it reduces its output.

Islanding

Unintentional islanding is an issue of significant concern, discussion and research for DG systems. *Islanding* is a situation where a portion of an electrical system that contains loads and a generation source is isolated from the remainder of the electrical system but remains energized. Islanding can occur at the customer level, such as when a hospital uses its emergency generators during a utility outage (loss of utility). Islanding may also occur at the utility level (e.g., when one section of a transmission system is isolated from another section for stabilization and load-management reasons). These are both examples of *intentional islanding*, a term that applies to systems that are designed, managed and approved for isolated operation.

Potential safety concerns occur when a customer-sited DG system that is not specifically designed and approved for intentional islanding operation fails to detect the loss of utility power and continues to energize an isolated section of the utility grid. There are three primary concerns related to the lack of utility control over unintentional islanding:

- Shock hazards for utility line personnel working on a line that may become unexpectedly energized;
- Damage to the utility's or customer's equipment resulting from a DG system operating outside of specifications; and
- Interference with automated distribution-system protection functions, such as reclosing.

Although line workers are trained to isolate, test, and either treat lines as live or ground all lines before working on them, these precautions do not alleviate all safety concerns because there are risks when these practices are not universally followed. For example, a small gasoline-powered generator[15] illegally plugged into a wall outlet to allow a homeowner to turn on lights during a utility outage is potentially lethal to utility line workers, especially when transformed to distribution system primary-voltage levels. With the pressure to repair a damaged line – or multiple lines – and restore customer service, skipping just one step of the isolate, test and ground procedure could be fatal. A large number of customer-sited DG systems scattered throughout a distribution system raises legitimate concerns for utility line workers.

Grid-tied inverters monitor the utility line voltage and frequency continuously. When abnormal voltage or frequency conditions occur on the utility system, they shut themselves off quickly (or "cease to energize," the phrase that appears in technical interconnection standards). Unintentional islands with inverters are very difficult to sustain because the inverter is not designed to regulate output voltage. Instead, these inverters produce current proportional to the available power from the prime power source. The matched real and reactive load conditions that would sustain an unintentional island must prevent the natural tendency of the island to shift outside the allowable voltage and frequency limits that would otherwise cause the inverter to trip. Extensive testing of inverters at Sandia National Laboratories, under a variety of laboratory-controlled worst-case conditions, led to the development of specific islanding-detection (or anti-islanding) techniques and a generalized test

[15] These personal generators are typically synchronous machines designed to regulate voltage and frequency to the best of their ability. They are not designed to operate in parallel with other generators (and are typically destroyed if utility power is restored while they are operating), and may be able to provide power that is well outside the voltage and frequency specifications established by a utility.

procedure for evaluating the efficacy of any anti-islanding device. These and other anti-islanding techniques reduce the already low probability of inverter islanding such that devices that pass this test, which is detailed in IEEE 1547.1-2005, are considered non-islanding. Informative discussions of islanding and anti-islanding inverters are included in the annexes to IEEE 929-2000[16] and in a study titled *Results of Sandia National Laboratories Grid-Tied Inverter Testing*, [17] published in 1998 by Sandia National Laboratories.

Because induction generators, like inverters, are current-source devices, they can use similar anti-islanding techniques, and are evaluated using the same test procedure in IEEE 1547.1-2005. Synchronous generators are voltage-source devices that are designed to regulate voltage and frequency. The control systems of grid-connected synchronous generators must be designed to follow characteristics set by the utility grid. The conditions that would lead to a stable island are somewhat different than for induction machines and inverters, so different anti-islanding techniques may be employed. IEEE 1547.1-2005 provides an alternate test procedure to evaluate those techniques.

When natural gas, diesel, or another relatively costly and readily dispatchable fuel is used to drive an induction-based or synchronous-based DG system, the cost of those fuels and the lack of incentives such as net metering provide an economic disincentive for exporting power to the utility. In such cases, it makes sense to incorporate special protective equipment to ensure that no power is exported (using what is called a *reverse power relay*) or that a minimum amount of power is constantly drawn from the utility (using an *under power relay*). Because these relays eliminate the possibility of a DG system energizing equipment beyond the customer's facilities, the relays act to prevent unintentional islanding and are considered acceptable anti-islanding methods.

Transfer trip, a design element that provides an operate/disconnect signal over a dedicated communications line (or lines) from the utility, is another means of providing protection against unintentional islanding. However, the equipment capital cost and monthly communications fees make this approach prohibitively expensive for small DG systems. While not a perfect solution, this design element is one that utilities are very familiar with and rely on for ensuring that DG systems – especially large and unfamiliar DG systems – respond properly to fault conditions.

Utility Disconnect

When utility line workers are working on a power line, most utility operating procedures, including the *National Electrical Safety Code* (*NESC*), require that the line must be isolated from all generating sources. Utilities have often required DG owners install a lockable, visible break (sometimes load-break rated) disconnect switch that is accessible to utility personnel in order to provide this isolation. The "accessibility" component of this requirement has been highly problematic for DG system owners, who must install the switch at or near the revenue meter, and must provide utility personnel with access to the switch at all times. When the DG system itself is not readily accessible (e.g., when a system is located on the top floor of a high-rise building or in the garage of a house), providing a utility-accessible disconnect switch could require

[16] 929-2000 was withdrawn in 2006 in favor of IEEE 1547, but as of this July 2007, is still available from IEEE.
[17] See www.sandia.gov/pv/docs/PDF/viennaruss.pdf.

significant amounts of wire and conduit, or trenching, running from the system to the switch and back again. In these cases, the utility disconnect switch is in addition to the maintenance disconnecting means located at the system, required by the *NEC*.

Some stakeholders have argued that the requirements in IEEE 1547-2003 and the testing performed under IEEE 1547.1/UL 1741 provide the means and assurance that DG systems listed to UL 1741 will properly cease to energize under loss of utility conditions, and will not reenergize the line until the line is operating stably within normal voltage and frequency conditions. For small DG systems, such as residential scale PV systems, the installed cost of an additional switch is consequential, so the actual need for the utility disconnect remains a source of considerable debate.

IEEE 1547 states that a readily accessible, lockable, visible-break isolating device should be provided if required by local utility operating practices. State standards for net metering and interconnection vary on this issue. For example, New Mexico,[18] New York and Texas require a utility disconnect. In California, DG systems larger than one kilowatt (kW) require a disconnect, but only when (as in IEEE 1547) a disconnect is required by the local utility. Meanwhile, other states such as New Jersey, Washington and Nevada, and some individual utilities (such as those owned by National Grid USA) do not require a utility disconnect for small systems.

2.2 Power Quality

Power quality is another salient technical concern for utilities and DG system owners. Power quality is analogous to water quality; just as municipal water suppliers and individual water wells must meet certain standards for bacteria and pollutant levels, utility power is consistently supplied at a certain voltage and frequency. In the United States, residences receive single-phase AC power at 120/240 V and 60 cycles per second (Hz). Commercial buildings typically receive either 120/240-V single-phase power or higher voltage (e.g., 120/208 or 277/480) three-phase power, depending on the size of the building and the types of loads in the building.

Each type of DG system has its own output characteristics based on the technology employed. Even those systems that use inverters vary depending on the inverter design, the control algorithms and the characteristics of the input power source. Device-specific power-quality issues therefore are not addressed here.

Power quality is important because electronic devices and appliances are designed to receive power within a reasonable range of voltage and frequency parameters, and deviations outside those ranges can cause appliance malfunction or damage. Power-quality problems can manifest themselves as extraneous lines on a television screen or static noise on a radio, which is sometimes noticed when operating a microwave oven or hand mixer. *Noise*, in electrical terms, is any electrical energy that interferes with other electrical appliances. As with any electrical device, an inverter, which converts the DC power into usable AC power, can introduce noise that may cause interference.

[18] Some utilities in New Mexico and California allow a customer's revenue meter to be used as the utility disconnect.

In addition to simple voltage and frequency ranges, discussions of power quality include characteristics of harmonics, power factor, DC injection and flicker.[19]

Harmonics generically refers to distortions in the voltage and current waveforms. These distortions are caused by the overlapping of the standard sinusoidal waveforms at 60 Hz with waveforms at other frequencies that are multiples of 60 Hz. Generally, a harmonic of a sinusoidal wave is an integral multiple of the frequency of the wave. *Total harmonic distortion* (THD) is summation of all the distortions at the various harmonic frequencies.

Harmonics can be caused by *non-linear loads* (equipment), examples of which include power supplies for computers, variable speed drives and electronic ballasts. Traditional loads such as motors and incandescent light bulbs are *linear loads*, where there is a direct correlation between the voltage supplied and the current drawn by the device. Non-linear loads use solid-state devices, often with microprocessor control, to switch current on and off. Current is drawn discontinuously and is not directly dependent on the voltage. When PG&E (an investor-owned utility) installed a 500-kW PV system in Kerman, California, in 1993, the neighbors across the street complained that their electric clocks were advancing by several extra minutes each day. Further investigation revealed a problem with the harmonics filtering in the inverters. (This problem was resolved fairly easily.) Despite the large amount of discussion this topic generates, the number of documented problems caused by harmonics is relatively low even though various harmonic-producing loads are increasing. Modern interconnection requirements include limits on harmonic injection from DG systems, and devices evaluated to IEEE 1547.1 will have minimal harmonic impact.

Power factor (PF) is a measure of apparent power that is delivered when voltage and current waveforms are out of synch. Power factor is the ratio of true electric power, as measured in watts, to the apparent power, as measured in kilovolt-amperes (kVA). The power factor can range from a low of zero, when the current and voltage are completely out of synch, to the optimal value of one, when the current and voltage are perfectly in synch. Loads with motors, such as refrigerators and air conditioners, typically cause reduced (or *lagging*) power factor. The terms *leading* and *lagging* describe whether the current wave is ahead of or behind the voltage wave. While some engineers believe that power-factor problems may contribute to utility system inefficiencies, this is not strictly the case.

DC injection occurs when an inverter passes unwanted DC current into the AC (or output) side. This action can be prevented by incorporating galvanic isolation through a transformer within the inverter design. The current trend in PV towards ungrounded arrays and un-isolated (i.e., transformerless) inverters, both of which are quite common outside the United States, raises new concerns regarding the potential for DC injection and what a reasonable limit should be. Un-isolated inverters must be more carefully designed to achieve balanced output, and potentially to provide highly accurate DC-sensing circuits. The IEEE 1547 limit of 0.5% of the inverter rated output current was originally derived for IEEE 929-2000, based on comfort levels of a sample of transformer manufacturers. During this process, it was determined that (1) most transformers could tolerate DC current up to 0.5% of the transformer rating without undo concerns related to core saturation, and (2) each inverter should be allowed to contribute a portion of the total allowable current based on its

[19] For a more detailed discussion of power quality, see ANSI C84.1 (voltage ratings), IEEE Std 519 (harmonics), IEEE Std 1453 (flicker) and the annexes of IEEE 929-2000.

rating. This latter conclusion assumes that there would be DG system capacity equivalent to the transformer rating, and that the DC current from multiple inverters would be additive – two very conservative assumptions. DC injection is not an issue for rotating generators, which only produce AC power. The IEEE P1547.2 draft application guide to IEEE Std 1547 provides additional technical background and rationale for the DC injection and other 1547 requirements.

The term *flicker* was originally adopted as a reference to the visible flickering of an incandescent light bulb when subjected to voltage oscillations on a utility line. The perception of flicker is subjective, and depends on the magnitude and frequency of the voltage oscillations. A slow oscillation must be of higher magnitude in order to be as noticeable as a fast oscillation.

Voltage oscillations are caused by changes in the power drawn by a load or output from a DG system. A potential source of flicker from DG systems occurs during startup and shutdown, when there can be substantial changes in power. The synchronization requirement in IEEE 1547-2003 allows for a 5% voltage fluctuation, and tests are provided either to promote a low impact on voltage due to synchronization or to provide a measure of current flow into or out of the DG during the synchronization process. However, note that the flicker requirement in IEEE 1547 is simply that the DG should not "create objectionable flicker for other customers." (But how is this evaluated?)

There are two problems in defining an objective flicker requirement. First, the actual voltage impact of a given DG system depends on both the level of DG current flow and the line impedance, so a unit may work fine in one application but cause problems in another. The measured current flow is used by utility engineers along with an estimate of the system impedance at the interconnection point in an analysis referred to as a *flicker calc*. The flicker calc evaluates the potential impact of a proposed induction motor, which can require significant amounts of in-rush current when starting, but it is readily applied to all types of DG systems as well.

Even with this objective analysis, the requirement still comes down to the phrase "objectionable to other customers." Whether or not a particular voltage fluctuation is objectionable is a function of the proximity of the DG to other customers and their sensitivity to flicker (e.g. sensitivity to light flicker or voltage fluctuations). Finally, even if the customer finds the flicker objectionable, they must file a complaint with the utility before any action will be taken. Flicker is also an "in perpetuity" requirement, in that the complaint can be raised well after the system is installed and operational. If the local utility determines, through a flicker study, that the neighbor has a reasonable complaint, and that a DG system is the cause, then the DG system owner must address the problem.

Depending on their use and location, some DG systems are required to meet the *electromagnetic emissions* requirements described in Part 15 of the Federal Communications Commission (FCC) rules. FCC requirements and testing are intended to ensure that DG systems do not emit or conduct harmful interference with radio or television transmissions.

2.3 National Codes and Standards

The technical and safety issues discussed above are addressed in a number of key national codes and standards related to the interconnection of DG systems. The value of these codes and standards to the interconnection process can not be overstated. Without standardized national documents, DG equipment manufacturers would be faced with the nightmare of developing separate devices and protection equipment to satisfy individual utility interconnection-safety requirements. Safety is enhanced when all parties adhere to nationally determined, certified codes and standards.

The value of national codes and standards to the interconnection process can not be overstated.

A number of organizations have been instrumental in bringing these standards about. The major code and safety organizations that publish interconnection codes and standards are the NFPA, UL and IEEE. Additionally, two federal labs – NREL and Sandia National Laboratories – work closely with the NFPA, UL, IEEE and the DG community on code issues and equipment testing. The labs are not responsible for issuing or enforcing codes, but they do serve as valuable sources of information on PV and interconnection issues.

IEEE 1547 Series

IEEE is a non-profit, technical professional association with a worldwide membership. Among its functions, IEEE has more than 800 active technical standards and more than 700 in development. IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage[20] has taken a leading roll in addressing technical interconnection issues with the development of IEEE 1547-2003 and IEEE 929-2000 (withdrawn). SCC 23, a predecessor to SCC 21, developed IEEE Std 1001-1988 (withdrawn) guide for interfacing dispersed storage and generation facilities with electric utility systems.

IEEE 1547 *Standard for Interconnection Distributed Resources with Electric Power Systems* addresses the technical specifications for and testing of the interconnection of DG systems. The single-sentence scope states: "This standard establishes criteria and requirements for interconnection of distributed resources (DR) with electric power systems (EPS)."[21] This document focuses on interconnection at the distribution level and is intended for systems up to 10 megavolt-amperes (MVA). The standard's carefully worded "Purpose and Limitations" define what the document does and does not address, characterizing the requirements as "universally needed" and "sufficient for most installations," but noting that additional requirements "may be necessary for some limited situations."

The brevity of the scope is representative of the overall brevity of the 15-page standard (which at one point in draft form weighed in at more than 300 pages). One reason why the document is so concise is because the standard is strictly concerned with interaction at the *point of common coupling* – the interface point between a customer and a utility. The standard does not address the type, design or operation of a DG system or of a utility system. Nor is the standard

[20] See http://grouper.ieee.org/groups/scc21/index.html.

[21] An area EPS refers to the utility distribution grid, whereas a local EPS would be the electrical system at the DG owner's facility.

prescriptive, as it does not address how the requirements are to be implemented.

The heart of the document is contained in Section 4 and Section 5:

4. Interconnection Technical Specifications and Requirements
4.1 General Requirements
4.2 Response to Area EPS
4.3 Power Quality
4.4 Islanding

5. Interconnection Test Specifications and Requirements
5.1 Design Test
5.2 Production Tests
5.3 Interconnection Installation Evaluation
5.4 Commissioning Tests
5.5 Periodic Interconnection Tests

The other primary reason for the document's brevity is that IEEE 1547 is actually a series of standards, with 1547-2003 as the lead document addressing the core issues. During the numerous meetings and technical debates that marked the development of IEEE 1547, several important issues were left for further development in companion documents. Currently, there are seven documents in the IEEE 1547 series that have been published or are under development:

- IEEE Std 1547-2003 *Standard for Interconnection Distributed Resources with Electric Power Systems*
- IEEE Std 1547.1-2005 *Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*
- IEEE P1547.2 Draft Application Guide for IEEE 1547[22]
- IEEE Std 1547.3-2007 Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems
- IEEE P1547.4 Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems
- IEEE P1547.5 Draft Technical Guidelines for Interconnection of Electric Power Sources Greater than 10MVA to the Power Transmission Grid
- IEEE P1547.6 Draft Recommended Practice For Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks

The 1547.1 conformance-test document provides detailed procedures for the tests and requirements defined in Section 5 of 1547-2003. It includes sections covering *type tests* (known as "design tests" in 1547) for verifying the suitability of a particular model, *production tests* performed on each unit manufactured, *commissioning tests* for evaluating a newly completed system, and *periodic interconnection tests* to assess ongoing interconnection system health.

The scope of P1547.2 is to provide technical background and application details to support the understanding of 1547-2003. This document, therefore, fills in much of the relevant background on various interconnection technologies and interconnection issues relevant to those technologies. It will include technical

[22] The "P" in front of an IEEE standard number indicates that the document is a project draft.

descriptions and schematics, applications guidance, and interconnection examples, and it is expected to be brought to ballot in late 2007. The recently approved 1547.3-2007 focuses on the functionality, parameters and methodologies for DG system communications and control. This document should be published in summer 2007.

Intentional islanding (discussed above) was purposefully left by 1547 developers to be addressed at a later date. P1547.4 encompasses the issues involved in integrating DG-islanding systems into the grid. The scope of the guide will include topics such as the ability to separate from and reconnect to part of the grid while providing power to the local island.

Whereas 1547-2003 is (somewhat arbitrarily) limited to interconnections of 10 MVA or less and is primarily intended for distribution-level interconnection, P1547.5 will provide guidelines for "interconnecting dispatchable electric power sources with a capacity of more than 10 MVA to a bulk power transmission grid."

The last document in the 1547 series, P1547.6, address interconnection to secondary network distribution systems. A secondary network (also known as an area network) is a form of distribution system typically used in dense, high-load areas where electric reliability is critical. They are characterized by the use of multiple redundant feeders and devices called network protectors that prevent one of the feeders supplying the network from feeding, through the network, a fault on another feeder. The term "secondary" is used because the network is formed on the secondary, low-voltage (i.e., 208-V or 480-V AC) side of the network transformers. This standard will define the technical requirements and tests for such interconnections.

Note that IEEE defines three levels of standards: *standards, recommended practices* and *guides*. Both 1547-2003 and 1547.1-2005 are *standards*. These documents contain mandatory requirements and generally use the word "shall" in describing how the requirements are to be implemented. By contrast, P1547.2, P1547.3 and P1547.4 are *guides*, which are documents where alternative approaches to good practice are suggested, but no clear-cut recommendations are made. The operative word in such documents is "may." *Recommended practices*, such as 1547.6, provide procedures and positions preferred by the IEEE. Here, the operative word is "should."

The use of IEEE standards (and most other standards) is voluntary unless mandated by a party. For example, an individual buying a piece of equipment can require that certain standards be used to test the equipment before a purchase is made. Utility interconnection requirements may be mandated by a state legislature, a state regulatory authority, the board of a publicly-owned utility or the board of an electric cooperative. Once mandated (but depending on how the standard is mandated), the IEEE designation of standard, recommended practice or guide loses its distinction, and in many cases, the "mays" and "shoulds" effectively become "shalls."

Significantly, the entire IEEE 1547 series was developed – and continues to be developed – in an open, collaborative process involving utilities, equipment manufacturers, national labs, end users and other individuals. The working group for the main 1547-2003 standard included nearly 350 official members and hundreds of additional interested parties. The balloting committee had an impressive 230 members, with nearly equal representation from electric users/utilities (35%), manufacturers/producers 31%) and general interest

(35%, e.g., consultants, testing labs). The remaining 4% were government representatives.

IEEE 929-2000 (withdrawn)

Prior to the completion of IEEE 1547, IEEE 929-2000 (*Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*) was the definitive interconnection document. While 1547 covers all DG technologies and addresses much larger systems and grid impacts, IEEE 929 was strictly an inverter document and technically only addressed PV applications. In the 1980s, IEEE published ANSI/IEEE Std 929-1988, *IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems*. This document addressed the basic issues of power quality, equipment protection and safety. Extensive revisions led to the final version, IEEE Std 929-2000, which was approved by IEEE in January 2000, replacing the 1988 version.

It was the intent of IEEE 929-2000 to meet all legitimate utility concerns with safety and power quality so that there would be no need for *additional* requirements in developing utility-specific guidelines, especially for systems of 10 kW or less. In addition to being an enforceable standard, 929-2000 was also intended to be an informative document and still serves as an excellent primer on PV interconnection issues. While the standard itself is only about 12 pages, unlike IEEE 1547, it contains informative annexes with nearly 20 pages of background on islanding, distribution transformers and manual disconnects. Another important distinction is that 929-2000 was only a *recommended practice*, in contrast with IEEE 1547, and thus did not carry the same weight of a *standard* within the IEEE context.

The key technical components of 929 appear in Section 4 and Section 5:

4. Power Quality
4.1 Service Voltage
4.2 Voltage Flicker
4.3 Frequency
4.4 Waveform Distortion (IEEE 519)
4.5 Power Factor

5. Safety and Protection Functions
5.1 Response to Abnormal Utility Conditions
- Voltage Disturbances
- Frequency Disturbances
- Islanding Protection
- Reconnect After a Utility Disturbance

5.2 Direct Current Isolation
5.3 Grounding
5.4 Manual Disconnect

IEEE 929 achieved consensus on several key issues. First, IEEE 929 defined nominal voltage and frequency trip settings that evolved up until the final balloting. These definitions represent the cornerstone of 929 as well as IEEE 1547. Second, IEEE 929 defined a test procedure for anti-islanding techniques, and units that passed the test were designated as “non-islanding.” When the original document was released in 1988, few commercially available inverters included specific anti-islanding features beyond the standard voltage and frequency trip settings, and there were no defined tests to evaluate a product.

Although the conditions that might support a PV inverter-based unintentional island are extremely unlikely to occur spontaneously, the mere possibility raised concerns with utility engineers and line workers. To pass the islanding-protection test described in IEEE 929-2000, inverters had to use more sophisticated means for detecting loss of utility. Defining limits for DC injection and harmonics, and raising the discussion of the utility (manual) disconnect contributed to the broad acceptance of 929.

IEEE 929 was withdrawn in 2006 in lieu of 1547, which, with a larger, more diverse working group, refined and expanded the 929 tests and requirements. The IEEE 1547 standard is available for purchase from IEEE.

UL 1741

UL is a private, not-for-profit organization that has evaluated products, materials and systems in the interest of public safety since 1894. UL has become the leading safety testing and certification organization in the United States; its label is found on products ranging from light sockets to inverters. Although UL writes the testing procedures, other organizations may perform the actual testing and listing of specific products. In addition to the UL testing labs, Intertek (formerly ETL), the Canadian Standards Association (CSA) and TUV Rheinland of North America are recognized listing (testing) agencies. The U.S. Occupational Safety and Health Administration (OSHA) maintains a complete list of *nationally recognized testing labs* (NRTLs) and the tests these labs are qualified to perform.[23]

Local building inspectors look for a listing mark (such as UL, ETL or CSA) that provides assurance that installed equipment has been tested and verified to meet the proper requirements. The NEC requires all equipment used in an electrical installation to be “examined for safety.” The NEC does not specifically require that all equipment be listed, although some equipment, including utility-interactive inverters used in PV systems and fuel cells, are required to be listed.[24] Most inspectors are likely to require either that components to be listed or that qualified test results be presented. Without a listing mark, additional on-site third-party testing is usually required. For large DG systems, the cost and hassle of on-site testing for each installation is factored into the system cost and schedule, resulting in minimal adverse impacts on the project and allowing flexibility in the design of individual systems. However, for smaller DG systems, the cost and complexity of on-site testing can sink a planned project. The option to have those products listed and avoid additional requirements and testing is extremely beneficial to manufacturers of equipment of smaller DG systems.

Prior to the mid-1990s, no listed PV inverters were available for purchase, and the regulatory process of installing PV systems was hampered significantly as a result. Listed PV inverters were unavailable for several reasons:

- The cost and uncertainty surrounding unspecified test requirements;
- The low market volume over which to amortize the cost of listing;
- Frequent changes needed to improve product quality and reliability; and

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[23] See www.osha.gov/dts/otpca/nrtl.

[24] Curiously, the *NEC* requires neither inverters used with other energy sources nor machine-based DG to be listed.

- A lack of specific requirements for listed equipment from the various PV funding organizations.

Development on the UL 1741 began in the mid-1980s in order to provide test requirements for PV inverters and charge controllers. UL 1741 was (finally) published in May 1999, following parallel development with the revised IEEE 929, with major revisions in January 2001 and November 2005.

Table 2: UL 1741 Development

Version	**Published**	**Title**
1st Edition	May 1999	*Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*
1st Revision	Jan 2001	*Inverters, Converters, and Controllers for Use in Independent Power Systems*
2nd Revision	Nov 2005	*Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources*

As of June 2007, PV inverters still comprise the majority of listed DG equipment intended for utility interconnection.

The title changes reflect the expanding scope of UL 1741, which now addresses all forms of distributed generation, including inverters for PV, microturbines, wind turbines, fuel cells, and control equipment for synchronous and induction generators. Until 2001, UL 1741 was strictly an inverter-focused document that only addressed PV systems. Concurrent with the development of IEEE 1547 and 1547.1, UL 1741 expanded its scope, and the committees developing the two documents worked closely together to ensure that the documents were in synch. All utility interaction tests were removed from the current rendition of UL 1741 and replaced with a simple reference to IEEE 1547.1.

As of June 2007, PV inverters still comprise the majority of listed DG equipment intended for utility interconnection. However, UL 1741 has been successfully applied to inverters used with other systems such as wind turbines, fuel cells and microturbines, and it now provides tests and processes to list single and multi-function relays and controllers for machine-based DG systems.

Finally, it is worth noting that unlike the IEEE standards discussed here, UL 1741 covers more than just grid-interconnection issues. Organizationally, UL was originally established as a fire and product safety test facility. Thus, in addition to utility-compatibility issues, the scope of 1741 includes electric-shock hazards, fire hazard and mechanical hazards. UL 1741 also covers stand-alone devices, such that equipment can be UL 1741 listed but not listed for utility-interactive operation. UL 1741 evaluations also address some ancillary equipment used for PV systems, such as battery charge controllers and combiner boxes used on the DC side of a PV system.

National Electrical Code Article 690

The NFPA publishes the *NEC* (or NFPA 70). It is the foremost U.S. organization that addresses electrical equipment and wiring safety. The *NEC* is now 780 pages long and is the most detailed of any NFPA code or standard. The scope of the *NEC* covers all buildings and property except for electric utility property. That is, the *NEC* applies to homes (or “dwellings”), and other public and private buildings and installations, but not to the power lines or generators operated by utilities. By contrast, the NESC addresses equipment on the utility side of the meter.

An entire section of the *NEC* – Article 690 “Solar Photovoltaic Systems” – pertains to PV. While interconnection to the utility grid receives mention, this section emphasizes descriptions of components and proper system wiring and protection. One key *NEC* requirement is found in Article 90.7, which states that all equipment must be tested. Article 690 takes this one step further, requiring utility-interactive inverters to be listed – a certification process that includes testing – by a recognized listing agency. To meet this requirement, PV systems will typically use a UL 1741-listed inverter.

It is important to note that the *NEC* is legally mandated in most states and in many large cities. Therefore, by extension, the requirement for listed components is also a legal requirement.

Article 690 is also applicable to the question of utility disconnects. The code requires that PV systems have both DC disconnects (for the PV power source) and AC disconnects (for the inverter output). In many inverter models, these disconnects are built into the inverter. However, the AC disconnects required by the NEC frequently do not satisfy utility disconnect requirements because they may not provide a visible separation, may not be lockable, and are mounted at the inverter where they may not be accessible to utility personnel.

PV systems were first given the status of a “special equipment” article in the *NEC* in 1984. Although revisions are continuously made to this article, it has remained largely intact. (The *NEC* is updated on a three-year cycle. The 2005 edition is the most recent version, and the 2008 edition is scheduled for publication in October 2007.) To help system designers and installers with specific *NEC* issues, the Southwest Technology Development Institute at New Mexico State University and Sandia National Laboratories publish a guide with recommended practices based on the *NEC*.[25] This guide provides practical information on how to design and install safe, reliable and code-compliant PV systems.

Building and electrical codes are often changed at the national level. After a national standard or code is amended, state and local authorities may choose to adopt the new changes at their own discretion. There are jurisdictions that purposely remain one or more revisions behind the latest version, to illustrate local autonomy. Local jurisdictions also frequently impose stricter rules than the national codes require. (One example is the requirement of sprinkler systems for fire protection in residences in certain jurisdictions. No national building code requires sprinkler systems for residences, but some local codes supersede the national code in this case.)

[25] See www.nmsu.edu/~tdi/pdf-resources/PV=NEC_V_1.6lowres.pdf.

3. Legal and Procedural Issues

Many of the barriers to interconnection have little to do with technical functionality or safety. Since the adoption of the national technical standards discussed in Section 2, states and utilities have been addressing technical issues in a satisfactory, uniform manner. At the very least, in many jurisdictions, the technical rules are clear to all parties involved. A substantial portion of the difficulties associated with interconnection now lie in the legal and procedural arenas.

This section describes some of the significant legal issues related to interconnection, including liability insurance and agreements between system owners and utilities. Then, procedural issues are addressed, including:

- Screening processes for determining the appropriate interconnection procedure;
- Interconnection applications; and
- Time constraints on parties involved.

Many of the primary difficulties associated with interconnection now lie in the legal and procedural arenas.

Procedural regulations are developed by state regulatory authorities, usually with input from interested stakeholders. In several states, including Texas, California and New Jersey, clear legal and procedural rules have greatly facilitated the interconnection process. Some states' rules have served as models for other states, although it should be noted these models are not always favorable to small generators. As mentioned previously, the FERC and several non-governmental organizations – IREC, NARUC, ELPC and MADRI – have developed model DG interconnection standards for small generators to assist states in developing new standards or revising existing standards. In addition, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) and Office of Electricity Delivery and Energy Reliability (OE) issued a brief, two-page document in March 2007 listing best practices for DG interconnection.[26]

The current version of the NARUC model has not been updated since the FERC adopted standards for small generators in May 2005. The MADRI model was developed with what many stakeholders consider to be a preponderance of input by electric utilities; as a result, some stakeholders believe the MADRI model is less favorable than the other models to small generators. The ELPC's model is similar to IREC's model.

The IREC model incorporates what IREC believes to be the best practices of interconnection standards adopted by various state governments, the FERC, NARUC and MADRI. Furthermore, the IREC model has been peer-reviewed and is in harmony with DOE's best practices for DG interconnection. IREC's model is discussed below.

[26] See http://www1.eere.energy.gov/solar/pdfs/doe_interconnection_best_practices.pdf. (This document also is included as an appendix to this publication.)

3.1 Legal Issues

Insurance

The impact of liability-insurance requirements depends on the size of a DG system. Additional liability insurance to cover systems greater than 100 kW installed at commercial or industrial facilities is generally not an issue because owners of such facilities likely already have sufficient liability-insurance coverage (i.e., at least $1 million in coverage), or because the marginal cost of additional insurance is not prohibitive relative to a DG project's cost. Significantly, there have been no known liability awards related to the malfunction of interconnected, customer-sited renewable-energy systems.

There have been no known liability awards related to the malfunction of interconnected, customer-sited renewable-energy systems.

However, liability insurance has been a major battleground in the development of rules applicable to DG systems sited at homes or small businesses. Some states with interconnection standards require liability insurance for small systems as a means of protecting the utility and its employees from any accidents attributable to the operation of a customer's system. Because most homeowners already have liability insurance through a standard homeowners insurance policy, a requirement to provide a reasonable amount of liability coverage usually does not impact these system owners. Many states with DG interconnection standards have prohibited utilities from imposing insurance requirements on customers beyond reasonable limits established by state regulatory commissions.

Indemnity, another salient insurance issue relevant to DG interconnection, refers to security against or compensation for damage, loss or injury. In contracts between utilities and system owners, a utility frequently requires the system owner or other customer-generator to indemnify the utility for any potential damages as a result of operation of the installation. Indemnification requirements are somewhat redundant in states with liability-insurance requirements. States that have specifically addressed indemnification in DG interconnection standards usually require mutual indemnification (as opposed to requiring indemnification of the utility by the system owner but not of the system owner by the utility).

Beyond the issues of limits of liability and indemnity, some utilities have sought to impose a requirement that the utility be listed as an *additional insured* on the customer's liability policy. In essence, what this means is that a utility would be protected under the system owner's policy in the event that the utility is sued in relation to the operation of the system. However, in most areas of the country, insurance companies have indicated that listing a utility as an additional insured is not even a possibility for residential insurance policies. In light of this, some utilities have dropped this requirement. Where state regulatory authorities have examined this issue, this attempted requirement has been rejected.

Standard Agreements

In the process of developing interconnection standards, most states choose to adopt a standard interconnection agreement in order to assure that there is equal legal treatment of DG system owners across different utility service territories in the same state.[27] Standard agreements essentially make the interconnection process easier and clearer both for utilities and system owners. Even if a state adopts uniform interconnection rules with a clearly defined interconnection process, unreasonable contract terms that find their way into utility agreements can be fatal to DG projects when a standard agreement has not been developed or recommended.

Standard agreements essentially make the interconnection process easier and clearer both for utilities and system owners.

The difference between larger DG installations (for commercial or industrial applications) and smaller systems (for residential or small commercial applications) is worth highlighting once again. Given the differences in scale and project application, three different model agreements are included in IREC's model interconnection rules.[28] The first model agreement, which appears in IREC's model rules as Attachment 3, is a two-page document that addresses the interconnection of certified, inverter-based systems up to 10 kW in capacity. The model application for these systems is also two pages in length. These systems are usually net-metered. The second model agreement, which appears in IREC's model as Attachment 5, applies to certified systems up to 2 MW and to certified, non-exporting systems up to 10 MW. The third model agreement, which appears as Attachment 6, applies to all systems up to 10 MW.

Turning first to the smaller-scale installations, the two-page application and two-page agreement serve as a first step to removing legal and financial barriers to the installation of grid-tied renewables. Simply put, if a residential customer is forced to navigate and comprehend a pile of abstruse legal documents before a system may be installed, the customer is less likely to move forward with a viable project – even if the major technical issues have been settled. In other words, if legal advice is necessary to interpret the paperwork required by a utility, then project costs rise, and plans are more likely to be abandoned.

The concise agreement and application for certified, inverter-based systems up to 10 kW not only simplify the interconnection process, but also illustrate the importance of relying on national technical standards. Without wading into technical details, it is possible to state in a single sentence of a document that systems must meet the requirements established by UL, IEEE and the NEC. Several states now use a one-page or two-page interconnection agreement and application for very small DG systems, especially for net-metered systems. Other states, including California, have developed slightly longer document, but with the same intention of simplicity.

Simplified, expedited interconnection for very small DG systems (e.g., certified, inverter-based systems up to 10 kW in capacity) allows system owners to conne The IREC model includes four levels of interconnection for systems up to 10 MW that connect at the distribution level.

The two standard interconnection agreements (Attachments 5 and 6) for larger systems are presented in IREC's model as a contrast in style. One of these agreements (Attachment 5) is based on NARUC's agreement, while the other (Attachment 6) is based on FERC Order 2006, as modified in the MADRI model. The two documents easily could be combined into a single standard agreement.

These longer standard agreements reflect the style of a traditional contract, which, after all, is their purpose. The more general standard agreement (Attachment 6) is designed to cover all interconnected systems up to 10 MW, regardless of whether a system is certified or uncertified, or whether the system exports electricity or does not export electricity.

[27] One notable exception is New Jersey. Although New Jersey is widely considered to have excellent interconnection standards, it has not adopted a standard interconnection agreement (as of July 2007).

[28] The current version of IREC's model interconnection standards (*IREC MR-I2005*) is available at www.irecusa.org/index.php?id=87.

Key issues addressed in the model standard agreement for systems up to 10 MW include:

- Statement of technical performance principles;
- Rights of access to the system;
- Liability and indemnification;
- Dispute resolution;
- Termination of contract; and
- Disconnection of system from the grid.

As a best practice, IREC believes that all customers who generate electricity using renewable-energy resources should retain ownership of the associated RECs.

With limited modifications, states should be able to incorporate any of these agreements – as well as IREC's standard application forms – into their interconnection rules. The standard application forms included in IREC's model are nearly identical to those included in FERC Order 2006, with modified language for state use. Significantly, these application forms were universally supported by all stakeholders involved in FERC's process to develop interconnection standards for small generators.

Lastly, a relatively new contract issue – the ownership of renewable-energy credits (RECs) – has been vigorously contested in the state arena since the FERC ruled in 2003 that RECs associated with renewable-energy generation by QFs under PURPA do not automatically convey to utilities. Rather, the FERC decided, states must determine which party owns RECs. Several states have since ruled on this issued. The majority of those that have ruled thus far allow utilities to take ownership of RECs under existing PURPA contracts, but allow system owners to retain ownership of RECs under new PURPA contracts. Most states that have ruled on REC ownership for net-metered systems allow the system owner to retain the credits. As a best practice for DG interconnection (and for net metering), IREC believes that all customers who generate electricity using renewable-energy resources should retain ownership of the associated RECs.

3.2 Procedural Issues

The discussion of procedural issues is commonly split between small-scale DG and larger DG systems because many of the issues involved are different. As illustrated in the larger DG subsection, however, a clear and unified procedural policy can consistently and fairly accommodate both small and large systems.

Small DG Systems

A standard agreement, no matter how concise, must fit into a simplified procedural context. System owners seeking to interconnect under net-metering rules commonly complain that they (1) were unable to work with a utility representative familiar with net metering and interconnection procedures, or (2) encountered extensive delays in receiving the necessary paperwork or in receiving approval after the paperwork was completed and submitted. Many utilities still do not have standard procedures for dealing with small DG interconnection, and most utilities do not have a designated individual to address interconnection requests by customers with smaller systems. It deserves mention that few utilities have *directly* used their control over interconnection rules and procedures to discourage PV systems or other customer generation. However, by failing to facilitate a simple process for small systems, many have *indirectly* discouraged interconnection.

State regulatory authorities have sought to remedy this problem by establishing timelines for the various steps of the process, and by requiring utilities to designate a certain representative or representatives to address customer requests for interconnection and net metering. Ideally, explicit information on the interconnection process should be available on utility web sites and on state regulatory authority web sites. Many states and some utilities have done this.

Most states with interconnection standards have prohibited or strictly limited the imposition by utilities of unwarranted additional fees, such as undefined or vaguely-defined "interconnection charges."

In addition to simple procedural barriers, smaller installations sometimes face substantial obstacles in the form of fees. Utilities may impose a variety of fees on owners of small-scale systems, including permitting fees, interconnection fees and charges, metering charges, and standby charges. The imposition of even a modest fee can substantially alter the economics of smaller, grid-tied DG systems.

Interconnection-related fees and charges include initial engineering and inspection fees for reviewing a system. Historically, utilities have conducted inspections of individual generating facilities – no matter how small in size – and many charge the system owners for these inspections. Fees for such inspections for even small PV systems have been reportedly as high as $900. It is expected, though, that such fees for inspections could be eliminated or reduced with the more widespread recognition of relevant codes and standards such as NEC Article 690, IEEE 1547 and UL 1741.

Metering charges may be imposed when a second meter is installed for a DG system. Such charges typically range from $4 to $8 per month. These charges were more common before the ubiquitous adoption of net metering in the United States. Currently, 38 states have adopted net-metering laws and/or regulations that allow for the use of a single, bi-directional meter. If a new meter is required for net metering, states have generally ruled that the utility must furnish the meter. A few states require the customer either to pay for the meter or to share some of the costs associated with the new meter and its installation. A second meter is still used to measure customer generation in states without net metering, and by customers who choose to pay for an additional meter in order to measure output for the purpose of selling RECs.

Standby charges have been established by utilities for customers with larger DG systems. Utilities are required to have capacity available to meet customer loads in the event that a customer's DG system fails. Because utilities incur costs to maintain backup power, larger generators are usually required to pay standby charges. At issue in some states is whether standby charges are necessary for smaller systems, especially those 10 kW and under. Typical standby charges for small PV systems can range from $2 to $20 per month. A number of states, including California, have prohibited standby charges and other such charges for customers with small-scale PV systems.

In light of the potentially deal-breaking impact of fees on potential system owners, most states that have adopted interconnection standards have prohibited or strictly limited the imposition by utilities of unwarranted additional fees, such as undefined or vaguely-defined "interconnection charges."

The FERC has stated that its interconnection standards likely will not be used for very small systems because most of these systems will be connected at the distribution level.

Large DG systems

Although the interconnection of smaller DG systems rarely warrants engineering studies,[29] in many cases there is a legitimate need to conduct detailed studies before a larger DG system may be approved for interconnection. It is critical to determine when such studies, which can be prohibitively expensive, are indeed necessary.

Effective interconnection standards specify not only the procedural steps that must be taken, but also the amount of time allowed for each phase of the process. Timing can be critical, and exorbitant delays may arise if standards do not include specific, reasonable time limits for each step of the procedure.[30] Such time limits require both the utility and the DG system owner to stay on track and communicate with one another as a project develops.

Many states, including California, Colorado, New Jersey, Ohio, Pennsylvania, Indiana and Vermont, have adopted DG interconnection standards that include different procedures for interconnection depending on a system's size, type or complexity. In addition, separate DG interconnection models developed by the FERC, IREC, ELPC and MADRI each include either three or four separate levels of interconnection. These standards include a screening mechanism to determine which procedure a particular system must go through.

The current IREC model provides a comprehensive procedural path that accounts for systems that may be interconnected with area and spot network distribution systems. The IREC model includes four levels of interconnection for systems up to 10 MW that connect at the distribution level:

- Level 1: certified, inverter-based systems up to 10 kW;
- Level 2: certified systems up to 2 MW;
- Level 3: certified systems up to 10 MW that do not export electricity (designed for combined-heat-and-power facilities); and
- Level 4: all other systems up to 10 MW, including generators that attempt but do not qualify for other, more expedited standards.

The FERC model, which applies to transmission-level interconnection (and to distribution-level interconnection when wholesale electricity sales are involved), includes three levels of interconnection for DG systems. The first two levels are generally the same as the first two levels in the IREC model, while the third level applies to all other systems up to 20 MW in capacity, including generators that attempt but do not qualify for the other two levels. Unlike the IREC model, the FERC rules do not include a separate level of interconnection for larger systems that do not export electricity. In its model, IREC chose to limit distribution-level interconnection to 10 MW under the assumption that larger systems are more likely to impact transmission and will be processed under FERC interconnection rules.

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[29] Many state-level interconnection standards prohibit or restrict interconnection to area networks, which are distribution systems that serve densely populated urban areas with a very high electricity demand. Area networks are discussed in Section 2.

[30] As noted previously, a report published by the NREL in 2000, titled *Making Connections*, found that many DG projects experienced lengthy delays because time limits were not imposed on the parties involved. Of the 65 project owners or installers projects examined, only 17 of the projects' owners or installers reported no delays.

The FERC has stated that its DG interconnection standards likely will not be used for very small systems, especially Level 1 interconnection, because most of these systems will be connected at the distribution level. (As noted previously, distribution-level interconnection is regulated by states, with the exception of electricity generated for wholesale purposes.) Regardless, the FERC has stressed that it hopes states will adopt – or consider adopting – its interconnection standards for small generators, modified as necessary.[31] Indeed, Colorado adopted DG interconnection standards in 2005 that closely resemble the FERC model.[32] Other states are currently considering adopting FERC's small-generator interconnection standards as well.

ct upon completion of an interconnection agreement. Nearly all small-scale residential PV and other renewable-energy systems will qualify for simplified, expedited interconnection in states where multiple levels of interconnection have been adopted. For these systems, utilities may choose to perform a commissioning inspection voluntarily at their own expense.

In states with multiple levels of interconnection, systems that do not qualify for simplified interconnection usually require a supplemental review. This process requires project owners or developers to submit to the utility more detailed information about the system. As a result of the supplemental review, a system could qualify for interconnection with limited system modifications, or the project could be subject to a full interconnection study. Such interconnection studies are conducted by the utility after the system owner or developer has approved the cost and schedule quote. States have different requirements for determining if a full interconnection study is necessary.

IREC maintains an online state-by-state table that allows users to compare state standards and utility guidelines for DG interconnection.[33] For each state or utility, the table indicates the breakpoint for simplified interconnection rules, eligible DG technologies, the maximum individual system capacity, application costs, additional insurance requirements, requirement for an external disconnect switch, screening processes for interconnection studies, and network interconnection provisions. *DSIRE* provides detailed information on interconnection standards adopted by states.[34]

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[31] In the introduction to Order 2006, the FERC stated: "We conclude that general consistency between the Commission's interconnection procedures document and interconnection agreement adopted in this Final Rule and those of the states will be helpful to removing roadblocks to the interconnection of Small Generating Facilities. To a large extent, this [order] harmonizes state and federal practices by adopting many of the best practices interconnection rules recommended by [NARUC]. By doing so, we hope to minimize the federal-state division and promote consistent, nationwide interconnection rules. We hope that states that do not currently have interconnection rules for small generators will look to the documents presented in this [order] and NARUC as guides for their own."

[32] A primary difference is that Colorado's rules include a 10-MW limit on individual systems.

[33] See www.irecusa.org/index.php?id=89.

[34] See www.dsireusa.org.

4. Net Metering

4.1 Net-Metering Basics

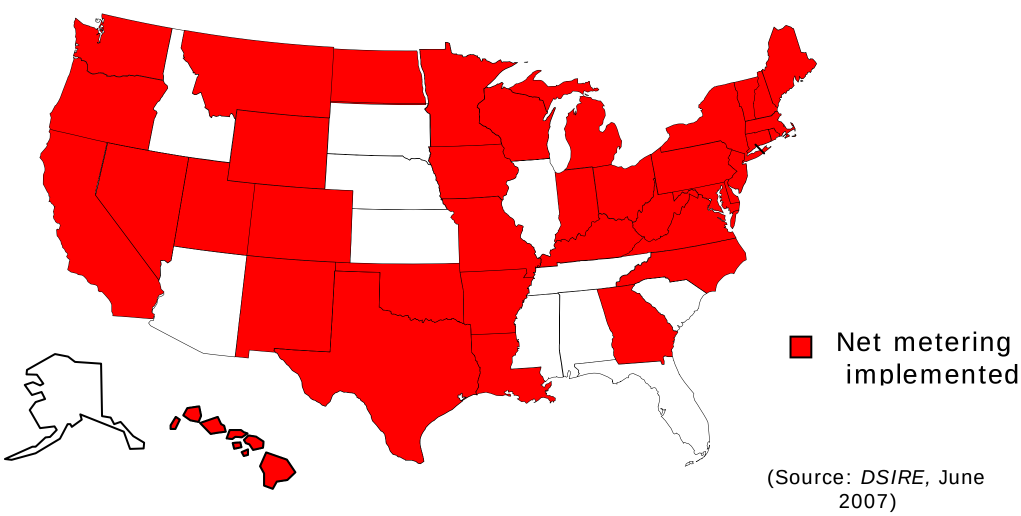
For customers that generate their own electricity, net metering allows for the flow of electricity both to and from a customer's facility through a single, bi-directional meter. This arrangement is much more advantageous for customers than the various two-meter arrangements used for QFs authorized by PURPA. Under the most common two-meter arrangement, usually known as *dual metering* or *net billing*, any electricity produced by a customer that is not immediately used by that customer flows to the utility through the second meter. The excess generation flowing through the second meter is purchased by the utility at the utility's avoided-cost rate, while the customer pays the utility's retail rate for all electricity the customer purchases. There is usually a significant difference between a utility's retail rate and its avoided-cost rate. While a typical utility's retail rate for residential customers is approximately $0.09 per kWh, the same utility's avoided-cost rate is likely to be about $0.03 per kWh.

Net metering is a low-cost and easily administered means of promoting direct customer investment in renewable energy.

Net metering, on the other hand, is a low-cost and easily administered means of promoting direct customer investment in renewable energy. One of the major advantages of net metering is its simplicity; most customers can use their existing meter without any modification or additional equipment. With net metering, at times when a customer's electricity generation exceeds the customer's electricity use, electricity supplied by the customer to the utility offsets the electricity the customer must purchase for the utility at another time during the same billing period. In effect, during a single billing period, the customer uses any excess generation to offset electricity the customer otherwise would have had to purchase at the utility's retail rate. The electric grid is used for storing electricity.

Figure 2. Statewide Net Metering

(for investor-owned utilities at a minimum)



Proponents and opponents of net metering have developed separate laundry lists of arguments that support or oppose net metering. While a discussion of these arguments falls outside the scope of this publication, it should be stated that no comprehensive report has been published that details the costs and benefits of net metering to utilities, to net-metered customers, to non-net-metered customers, and to the general public. The actual value of electricity generated by net-metered customers is one of the most strongly contested issues. In the near future, it is likely that the evolution of time-of-use (TOU) meters and smart meters will provide more insight regarding the actual value of the electricity generated by net-metered customers.

In most states, all customers are eligible for net metering, but some states restrict eligibility to particular customer classes. Furthermore, while all state-level net-metering laws and regulations apply to investor-owned utilities, only some of them also apply to publicly-owned utilities (such as municipal utilities) and/or electric cooperatives. Some publicly-owned utilities voluntarily offer net metering, often in the absence of state laws or regulations.

A handful of states, including Iowa and Minnesota, implemented net metering for small renewable-energy systems in the early 1980s, as an extension of PURPA. As of July 2007, 38 states and Washington, DC, have net metering that applies to investor-owned utilities *at a minimum*. New regulations and amendments to existing laws are consistently under consideration by states, in both the legislative and PUC arenas. In addition, Section 1251 of EPAct 2005 requires all state regulatory authorities, and utilities that are not subject to state regulatory jurisdiction and that have annual retail sales exceeding 500 million kWh, to "consider" adopting a net-metering standard by August 8, 2008.[35]

All state net-metering laws and regulations are different, and many vary dramatically. Common variables include: eligible technologies, eligible customer classes, limit on individual system size, limit on aggregate capacity of net-metered systems in a utility's service territory, treatment of customer net excess generation (NEG), types of utilities affected and REC ownership. IREC maintains an online state-by-state table that allows users to compare net-metering laws, regulations and utility programs by most of these criteria.[36] In addition, DSIRE provides detailed information on state laws and regulations, and voluntary utility programs.

IREC has developed model net-metering legislation for use by states. IREC's model, which incorporates what it believes to be the best practices of net-metering policies already implemented by U.S. states, allows net metering for renewable-energy systems up to 2 MW in capacity. IREC's model has been influential in New Jersey, Colorado, Maryland and Pennsylvania, all of which have adopted net metering for systems up to 2 MW. The following provisions are included in IREC's net-metering model:

- All renewable-energy systems, and CHP systems, up to 2 MW are eligible.
- All customer classes are eligible.
- There is no limit on the aggregate capacity of all net-metered systems in a utility's service territory.
- NEG is carried over to the customer's next monthly bill indefinitely. (Alternatively, customer NEG is credited at the utility's retail rate and

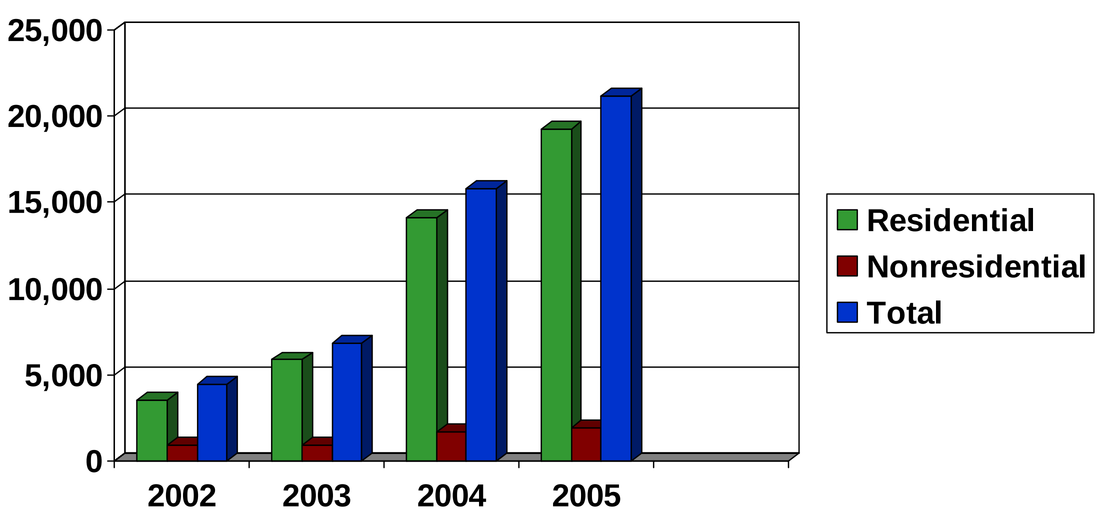
[35] See *16 USCS § 2621(d)(11)*.
[36] See www.irecusa.org/index.php?id=90.

carried over to the customer's next bill for 12 months. A utility must pay, at its avoided-cost rate, for any customer NEG remaining at the end of an annualized period.)

- All utilities, including publicly-owned utilities and electric cooperatives, should participate.
- Customers retain ownership of all RECs associated with customer generation.
- Interconnection standards, including a standard agreement, should be adopted for net-metered systems.
- Utilities may not charge customers special fees for net metering; net-metered customers should be treated no different than customers who are not net-metered

Two of these issues – NEG and REC ownership – and new metering options are discussed in greater detail below.

Figure 3. Net-Metered DG Systems, United States



4.2 Special Issues

Annual vs. Monthly Netting

Most net-metering programs allow customers to carry NEG forward to the following month at the utility's retail rate, usually for a 12-month period. This arrangement is commonly known as "annualized" net metering. If a customer generates more kWh during a monthly billing period than the customer uses, then this net excess generation is carried over to the customer's next monthly bill as a kWh credit. In some states with annualized net metering, if a customer has NEG remaining at the end of a 12-month period, the utility pays the customer for the excess kWh at the utility's avoided-cost rate. In other states with annualized net metering, any NEG remaining at the end of a 12-month period is granted to the utility with no compensation for the customer. A few states appear to allow indefinite carryover of customer NEG. In a handful of states, including Pennsylvania, Massachusetts and New Mexico, NEG is credited at the utility's avoided cost rate – as opposed to the utility's retail rate – and carried over the customer's next monthly bill. This arrangement is less favorable to net-metered customers than annualized net metering.

Annualized net metering takes into account the fact that some renewable-energy resources, (especially PV and wind) are somewhat seasonal in nature. For example, a PV system may produce more electricity than a household consumes in the summer, but the system likely will produce less electricity in the winter. With annualized net metering, NEG in summer months may balance reduced system output in winter months. Utilities benefit from annualized net metering because they do not incur the administrative costs of paying customers for NEG on a monthly basis. Customers that produce NEG in a given month are usually required to pay the utility's basic monthly customer charge.

Ownership of Renewable-Energy Credits

As discussed above, REC ownership has emerged as a critical policy and economic issue for DG system owners, utilities and regulators, especially in the wake of rampant state adoption and modification of renewable portfolio standards (RPSs) in recent years. States began to focus on this REC ownership after the FERC ruled in 2003 that RECs associated with renewable-energy generation by QFs under PURPA do not automatically convey to utilities. The vast majority of states that have ruled on REC ownership for net-metered energy systems, including California, Colorado, Michigan, Minnesota, Nevada, New Jersey, New Mexico, North Dakota and Oregon, have decided that system owners retain RECs. Some states, including Arkansas and Maryland,[37] have enacted legislation that specifies that system owners retain RECs. A report titled *Who Owns Renewable Energy Certificates?*, published by Lawrence Berkeley National Laboratory in April 2006, details how states have approached REC ownership.[38]

REC ownership has emerged as a critical policy and economic issue for DG system owners, utilities and regulators.

States with viable trading mechanisms for RECs may present significant financial opportunities to consumers with net-metered renewable-energy systems.

States with viable trading mechanisms for RECs may present significant financial opportunities to consumers with net-metered renewable-energy systems. For example, under New Jersey's Solar-REC program, PV system owners have the opportunity to earn $0.20 to $0.25 for the RECs associated with each kWh of electricity generated. However, in states without viable REC-trading markets, opportunities for owners of renewable-energy systems to sell RECs are generally limited, while opportunities for owners of very small renewable-energy systems are severely limited.

Time-of-Use Meters and Smart Meters

A few states, including California and New York, allow customers who net meter to do so under a TOU tariff. *TOU metering* allows customers to pay different electric rates based on the time of day they consume electricity. Whereas the flat rate for residential customers may be $0.09 per kWh, the TOU rate for on-peak energy may be as high as $0.15 per kWh, and as low as $0.03 per kWh

[37] Arkansas, Maryland and Nevada enacted legislation in spring 2007 addressing REC ownership.
[38] See http://eetd.lbl.gov/ea/ems/reports/59965.pdf.

for off-peak energy. The salient issue is how to record TOU measurements under a net-metering arrangement. TOU metering requires an electronic meter, which is fundamentally different from standard spinning electro-mechanical meters. Some of these TOU meters do not record electricity flows in both directions.

There are two options for consumers who seek to take advantage of net metering and TOU metering simultaneously. The first option is to install a special electronic meter, or *smart meter*, that can measure energy flows in both directions and keep track of when those flows occur. However, these meters may cost up to $300 or more, and the customer usually must pay for this expense. The second option, which has been adopted by New York, is to install a second meter (in addition to the TOU meter) that only measures net flows to the utility. This second meter is not a TOU meter, so the generation recorded on that second meter is allocated to the different rates based on expected PV output, which is based on meteorological data.

Most states do not allow net-metered customers to use TOU metering. In fact, depending on the structure of the TOU schedule in place, TOU metering may not make good financial sense for net-metered customers.[39] In TOU schedules, weekends are normally considered off-peak, so the calculation begins with two-sevenths (29%) of the electricity generated by a customer credited at the off-peak rate. Other considerations include the cost and availability of advanced metering technology that can accommodate TOU net metering. Such meters are typically designed for commercial and industrial accounts, and thus can be expensive for residential customers. Some utilities have provided residential customers with TOU meters as part of a voluntary or mandatory TOU residential rate, and the cost of the meters is rate-based. There is increasing interest among utilities and some regulators in promoting smart meters for all customers.

5. Electrical Inspectors

Electric utilities and DG system owners have an obvious interest in assuring that interconnected DG systems operate safely. Electrical and building inspectors share this interest in safety, and in many jurisdictions they play an important role in allowing projects to go forward. While reports of inspectors' unfamiliarity with smaller, customer-sited DG systems have waned, concerns remain that an inspector could disapprove systems simply because the inspector does not fully understand the system design or technology. At the center of this issue is the fact that inspectors have local autonomy. Though they follow the codes to the best of their abilities, local inspectors are not bound to national codes and, in most cases, are not bound by state codes either.

Most city or county inspection departments look to the *NEC* for guidance on electrical inspection work. Since Article 690 of the *NEC* addresses in detail how PV systems should be wired for safety, any inspector can review this document to gain an understanding of how to assess an installation. If a PV installation has not been installed according to NEC requirements, then the code official has full authority to prevent the system from operating. Furthermore, an inspector is not obligated to approve a system that is installed in compliance with the NEC

[39] In North Carolina, for example, all net-metered customers are required to take service under a TOU tariff. The conditions that apply under this arrangement undermine the economic benefits and general appeal of net metering. For more information, see www.dsireusa.org.

if the inspector documents appropriate concerns. Until the code official is satisfied, the system remains dormant.

Most problems begin when a system owner fails to brief a code official properly on the installation. Expressing concern to a code official about the issues the official is trained to assess may can help ensure a smoother inspection process. In most cases where inspectors are unfamiliar with PV systems, the system installer should explain the system and its operation to the inspector. In general, it is beneficial to provide electrical inspectors with drawings and wiring diagrams. An installer should furnish an inspector with a complete set of simple plans in addition to the diagrams that come with the equipment.

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Appendix A: List of Acronyms Used

AC: Alternating Current
ANSI: American National Standards Institute
CHP: Combined Heat and Power
CSA: Canadian Standards Association
DC: Direct Current
DG: Distributed Generation
DOE: U.S. Department of Energy
DR: Distributed Resources
DSIRE: Database of State Incentives for Renewables and Efficiency
EERE: U.S. Department of Energy Office of Energy Efficiency and Renewable Energy
ELPC: Environmental Law and Policy Center
EPAct 2005: Energy Policy Act of 2005
EPS: Electric Power System
FCC: Federal Communications Commission
FERC: Federal Energy Regulatory Commission
Hz: Hertz
IEEE: Institute of Electrical and Electronics Engineers
IRC: International Residential Code
IREC: Interstate Renewable Energy Council
kVA: Kilovolt-Ampere
kW: Kilowatt (1 kW = 1,000 W)
kWh: Kilowatt-Hour
MADRI: Mid-Atlantic Distributed Resources Initiative
MVA: Megavolt-Ampere
MW: Megawatt (1 MW = 1,000 kW)
NABCEP: North American Board of Certified Energy Practitioners
NARUC: National Association of Regulatory Utility Commissioners
NEC: National Electrical Code
NEG: Net Excess Generation
NESC: National Electrical Safety Code
NFPA: National Fire Protection Association
NREL: National Renewable Energy Laboratory
NRTL: Nationally Recognized Testing Laboratory
OE: U.S. Department of Energy Office of Electricity Delivery and Energy Reliability
OSHA: U.S. Occupational Safety and Health Administration
PF: Power Factor
PUC: Public Utilities Commission
PURPA: Public Utility Regulatory Polices Act of 1978
PV: Photovoltaic
QF: Qualifying Facility
RPS: Renewable Portfolio Standard
SCC: Institute of Electrical and Electronics Engineers Standards Coordinating Committee
THD: Total Harmonic Distortion
TOU: Time of Use
UL: Underwriters Laboratories
V: Volt
W: Watt

Appendix B: U.S. DOE's Best Practices for Distributed Generation

March 15, 2007

DISTRIBUTED ENERGY INTERCONNECTION PROCEDURES
BEST PRACTICES FOR CONSIDERATION

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) and Office of Electricity Delivery and Energy Reliability (OE) recognize the importance of electric utilities adopting procedures for implementing interconnection requirements that allow for simple connection of distributed energy technologies to the electric grid. Promoting distributed interconnection furthers Administration policy of modernizing our nation's electric grid and can be accomplished in a manner that is fair to interconnecting generators, utilities, and ratepayers.

Section 1254 of the Energy Policy Act of 2005 (EPAct) requires each State regulatory authority for its jurisdictional electric utilities (and non-State regulated utilities), to have commenced consideration by August 8, 2006 of whether to require interconnection service to any consumer the utility serves who has on-site generation, and to complete its determination by August 8, 2007. The service is to be based on the Institute of Electrical and Electronics Engineers Standard 1547 for the Interconnecting Distributed Resources with Electric Power Systems. Several States have already established interconnection procedures, while other organizations have developed model procedures.

Although EERE and OE do not endorse the model interconnection procedures of any single external organization, EERE and OE do encourage State and non-State jurisdictional utilities to consider the following "best practices" in establishing interconnection procedures:

- First and foremost, EERE and OE note that EPAct requires that agreements and procedures for interconnection service "shall be just and reasonable, and not unduly discriminatory or preferential." As such, generators and utilities should be treated similarly in terms of State requirements.
- Create simple, transparent (1- or 2-page) interconnection applications for "small
- generators" (equal to or less than 2 MW), as noted in the FERC Order 2006.
- Standardize and simplify the interconnection agreement for "small generators" and, if possible, combine the agreement with the interconnection application.

- Set minimum response and review times for interconnection applications. Provide expedited procedures for certified interconnection systems that pass technical impact screens.
- Establish small processing fees for “small generators”, otherwise the interconnection request must be accompanied by a deposit that goes toward the cost of the feasibility study, per FERC Order 2006.
- Set liability insurance requirements commensurate with levels typically carried by the respective customer class.
- Require compliance with IEEE 1547 and UL 1741 for safe interconnection.
- Avoid overly burdensome administrative requirements, such as obtaining signatures from local code officials, unless such requirements are standard practice in a jurisdiction for similar electrical work.
- Develop administrative procedures for implementing interconnection requirements on a statewide basis through a rulemaking or other appropriate regulatory mechanism for state-jurisdictional utilities to apply uniformly to all regulated electric distribution companies in the State. Where practical, State interconnection administrative procedures should reflect regional best practices and be comprehensive in scope. Administrative procedures should also be transparent to both small generators and electric distribution utilities.