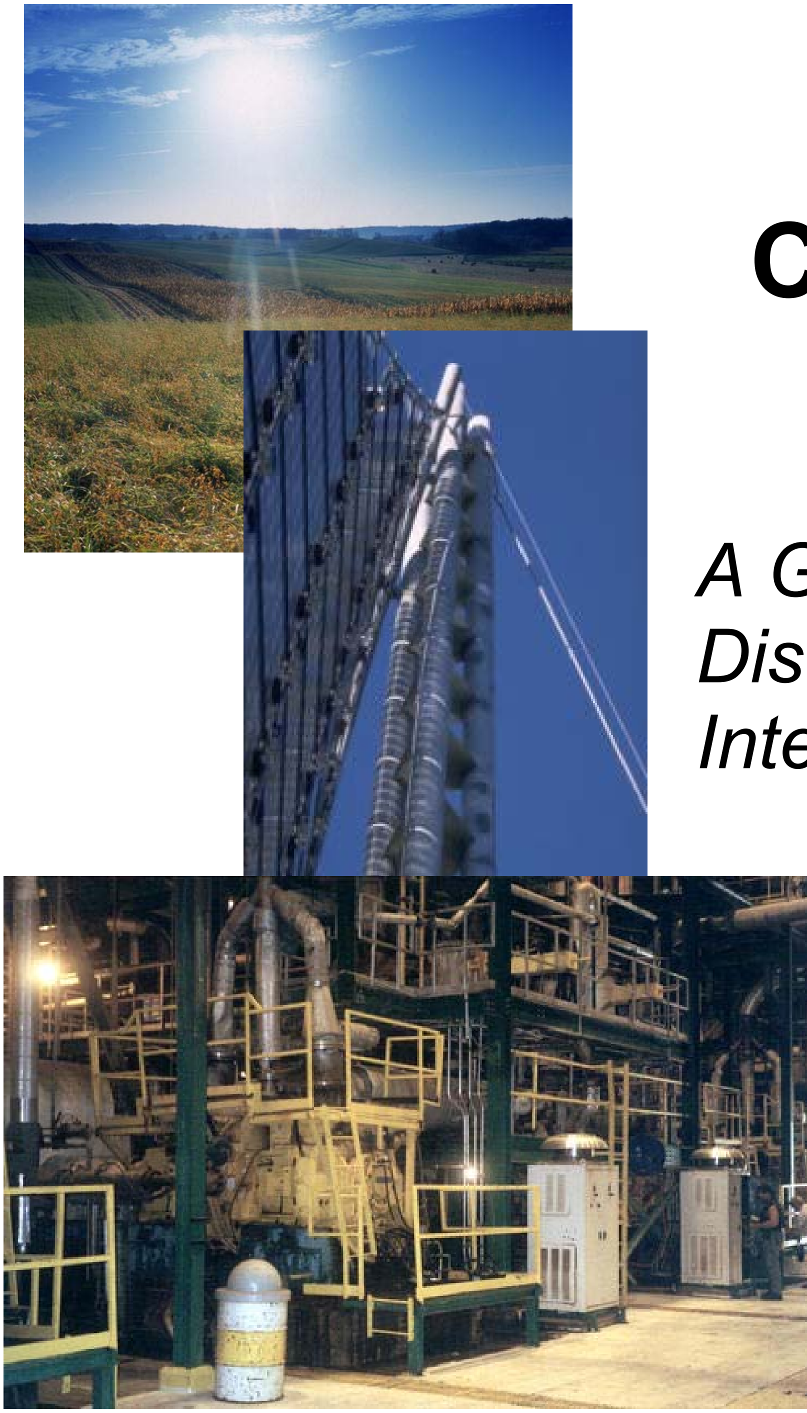

# Connecting to the Grid

*A Guide To Distributed Generation Interconnection Issues*

**Fourth Edition**
**2004**

IREC
Interstate Renewable Energy Council

North Carolina
Solar Center

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# Connecting to the Grid

*A Guide To*
*Distributed Generation*
*Interconnection Issues*

**Fourth Edition**
**2004**

**by**

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**Sponsored by the U.S. Department of Energy**

INTERSTATE RENEWABLE ENERGY COUNCIL

NORTH CAROLINA SOLAR CENTER

# Preface to the 4th Edition

What propels a document to a fourth edition must either be a compelling and ever changing field or persistence of a publisher. In the case of IREC's *Connecting to the Grid*, it is clearly a combination of both. The change in the title of this document is one clue to the change of the field. The new subtitle reflects not simply an expansion of scope of this document, but more importantly it is a manifestation of the shift in state and national regulatory activity to addressing interconnection issues for all distributed generation (DG).

What spurred the first edition, which was authored by Bill Brooks, now with Endecon Engineering, were states with net metering laws that lacked any uniform method for interconnecting systems to the grid despite the net metering laws. That has largely changed such that most – but not all – states with net metering laws now have complimentary interconnection rules. What these net metering-driven interconnection rules left out were provisions for interconnecting the larger technologies that did not normally qualify for net metering.

The other major change in the interconnection landscape is that the Institute of Electrical and Electronics Engineers (IEEE) has completed and published the IEEE 1547 Standard for Interconnection Distributed Resources with Electric Power Systems. Prior to completion of IEEE 1547, the definitive interconnection standard, IEEE 929, only covered small-scale PV interconnection. While 929 is strictly an inverter document, 1547 covers all distributed generation technologies and considers much larger systems and grid impacts. At the same time, Underwriters Laboratories (UL) 1741, the interconnection test standard, expanded its scope to match 1547.

National activity also includes the Federal Energy Regulatory Commission's (FERC) investigation on DG interconnection, initiated in 2002. This process is ongoing and may have an impact on small-scale DG interconnection procedures in certain situations.

The 4th edition of this guide is intended to be of value to states addressing the interconnection of everything from small-scale residential PV to commercial-scale 2 MW distributed generation systems. A major addition to this edition is the IREC Model Distributed Generation Interconnection Procedures, which includes model interconnection applications and agreements. The net metering section is still included in this edition, and an updated model net metering policy is also part of the appendices.

The authors wish to acknowledge the on-going support of IREC and its constant leadership in the interconnection field. IREC has found itself at the forefront of this issue since 1997 when less than twenty states had net metering and distributed generation was not the hot issue that it is today. Supporting IREC all along has been the U.S. Department of Energy, which has through its involvement in national standards and DG testing facilities, been a true leader in addressing the fundamental interconnection issues. The authors also thank Tom Starrs and Bill Brooks, who contributed as co-authors of the 3rd edition. And, finally, our thanks to Alex Hobbs and Steve Kalland of the North Carolina Solar Center, John Wiles of the Southwest Technology Development Institute, and Kevin Lynn of the Florida Solar Energy Center for their thoughtful comments and feedback on this 4th edition.

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# Executive Summary

Small-scale renewable energy and distributed generation (DG) technologies continue to draw more attention as energy issues more broadly have re-emerged in serious national debate. Volatile natural gas prices, blackouts, and major world events are driving more creative thinking about the U.S. electric system and forcing the question of whether a more decentralized and smarter grid will be necessary. Meanwhile, the price and performance of the various renewable energy and distributed generation technologies continue to improve: vendors have responded with easier to install packaged systems for the grid-tied market.

While larger market and policy forces are pushing toward an electric system that accepts DG, it is the interconnection process where the rubber meets the road. Simply put, interconnection refers to the technical, contractual, and rates and metering issues that must be settled between the system owner and the utility and local permitting authorities before the system is connected to the grid. In most cases distributed generation is installed, owned, and operated by a non-utility entity, be it a homeowner, manufacturing facility owner, or a DG equipment vendor. Therefore, DG forces not only a shift in technical thinking – generation incorporated into the distribution grid – but also a shift in thinking about ownership and control.

► *While larger market and policy forces are pushing toward a system that accepts DG, it is the interconnection process where the rubber meets the road.*

DG interconnection issues can be grouped in three categories:

- *Technical issues* include the safety, power quality, and system impacts that must be addressed. Safety must be viewed from both the perspective of the DG owner and the utility, and while there is growing consensus that individual DG and renewable energy systems can be prevented from islanding, attention is now more focused on the high penetration levels on individual distribution feeders. The national safety codes are discussed in this context.
- *Procedural and legal issues* are becoming more important as time delays and uncertainty have been identified as major barriers to successful interconnection. This includes having a clear process defined, incorporating time limits for steps in the process, and using standardized forms.
- *Tariffs, rates, and fees* comprise the third set of interconnection issues and represent major barriers to interconnection if not structured properly. This guide addresses net metering, which has been one of the most important tariff issues related to renewable and DG systems.

While the Public Utilities Regulatory Policies Act of 1978 (PURPA) formally opened the door for non-utility owned generation, the smaller scale of distributed generation technologies today and the potentially high levels of penetration in the distribution grid force the interconnection issues into sharper focus. DG technologies on the market fall in the <1 kW – 10 MW range, which is small compared to industrial cogeneration units, which are commonly greater than 100 megawatts (MW). This difference in scale has important implications for interconnection requirements. Whereas the developer of an industrial cogeneration facility can afford to have a professional engineer (PE) review the system design and an attorney review the utility contract, experience has shown that these sorts of non-equipment expenses can be deal killers for a residential customer looking to install a 1 kW PV system or a small business owner looking to install a 1 MW combined heat and power unit. This was dramatically illustrated in a series of interconnection case studies documented in the 2000 NREL report *Making Connections* (Alderfer et al., 2000).

Meanwhile, significant activity is taking place nationally with the completion of the Institute for Electrical and Electronics Engineers (IEEE) Standard 1547-2003 in June of 2003 and the continuing activity at the Federal Energy Regulatory Commission (FERC). IEEE 1547 specifies the technical performance of DG devices connected to the grid, and unlike IEEE 929, it covers all types of DG up to the multi-megawatt scale. The FERC is addressing DG interconnection through the development of comprehensive technical and non-technical rules for generators up to 20 MW, with proposed simplified procedures for systems under 2 MW. This is the FERC's "Small Generator Notice of Proposed Rulemaking" process, which is ongoing as of September 2003.

Despite the ongoing work of the FERC, nearly all of the activity in implementing interconnection rules is at the state level, where commissions are working to establish uniform statewide technical and procedural rules. Just as many states were inclined to incorporate or duplicate the successful small-scale renewable energy rules passed in other states, we are now seeing commissions look to the successful examples set by states such as Texas and California in the establishment and implementation of broader distributed generation rules.

► *Nearly all of the activity in implementing interconnection rules is at the state level, where commissions are working to establish uniform statewide technical and procedural rules.*

This guide addresses interconnection issues relevant to all DG technologies, including renewables, fuel cells, microturbines, and reciprocating engines. The scope thus covers sub-kilowatt residential PV systems up to multi-MW combined heat and power systems. Earlier versions of this guide only considered small-scale PV systems, but with the increased focus on issues pertinent to larger systems, the scope of this guide has expanded. While many of the issues are similar between larger and small systems, there are important distinctions including the procedural considerations.

The 2 MW upper-limit on system sized, discussed in this guide, is somewhat arbitrary in a technical sense. However, it is used here because it corresponds with the limit to simplified interconnection in the FERC Small Generator interconnection proceeding and to the IREC model interconnection regulations.

Because interconnection issues remain largely in the domain of the states, the primary audiences are state regulators, utilities, and equipment representatives involved in developing state interconnection rules. Fortunately, a great deal has been written on the subject of interconnection, so one of the goals of this guide is to distill and summarize the issues. Where appropriate references are included for more detailed coverage of certain issues.

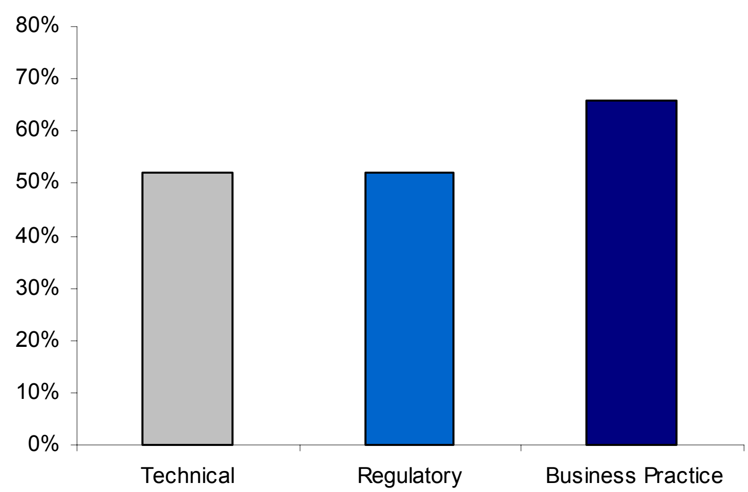
# 1. Introduction

Interconnection is an issue because grid-tied distributed generation (DG) challenges the traditional notion of centralized, utility-owned and operated generation. Before the recent development of national technical standards (IEEE 1547 and UL 1741) and state interconnection rules, determination of procedures and fees for interconnection was left to the discretion of the utilities. In the absence of appropriate standards for these small units, many utilities simply applied existing interconnection procedures for PURPA scale Qualifying Facilities.

In 1999 the Department of Energy through the National Renewable Energy Laboratory commissioned a study to document what was actually happening around the country. The resulting report, *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*, offers case studies of DG interconnection ranging from a 500 Watt residential PV system to a 26 MW cogeneration facility. Barriers were documented through interviews with system owners, project developers, and utilities and were categorized as technical, business practice, or regulatory barriers.

Of the 65 case studies, all but seven encountered significant barriers to interconnection, often times of more than one type. As a result of these barriers, sixteen of these systems did not interconnect at all and were either abandoned or simply reconfigured to only serve local loads in stand alone fashion. Figure 1 highlights the prevalence of problems encountered.

**Figure 1. Types of reported barriers to DG interconnection**

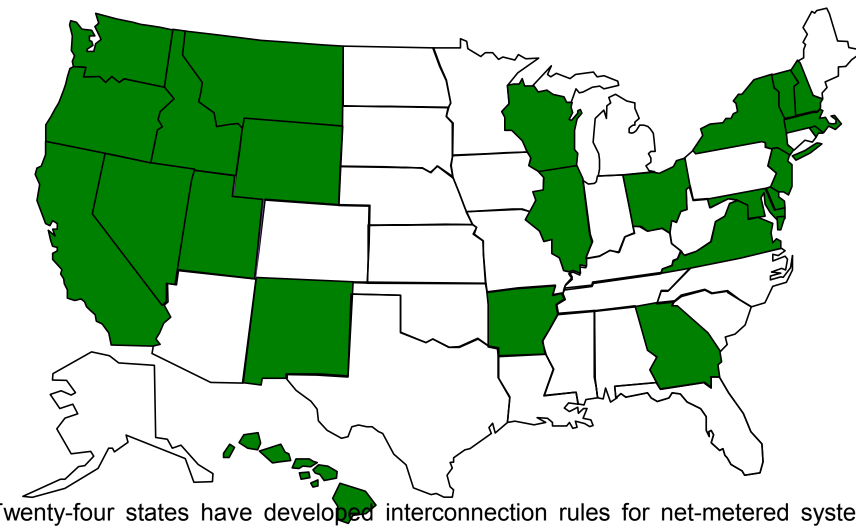



Of the 65 case studies documented in the *Making Connections* report, all but seven reported significant barriers to interconnection, which either slowed or ended the project. In most cases more than one type of barrier was reported.

**Source:** Alderfer et al., *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects* (2000).

Most state interconnection proceedings were initiated through the passage of net metering laws that permit customer generators to exchange their excess generation with the utility. Of the nation's 38 net metering laws, the majority cover only certain technologies, and qualifying systems are typically capped at 100kW or less. Consequently, there are a number of states that have developed interconnection guidelines for net metering, as illustrated in Figure 2.

**Figure 2. States with interconnection rules for net-metered systems**

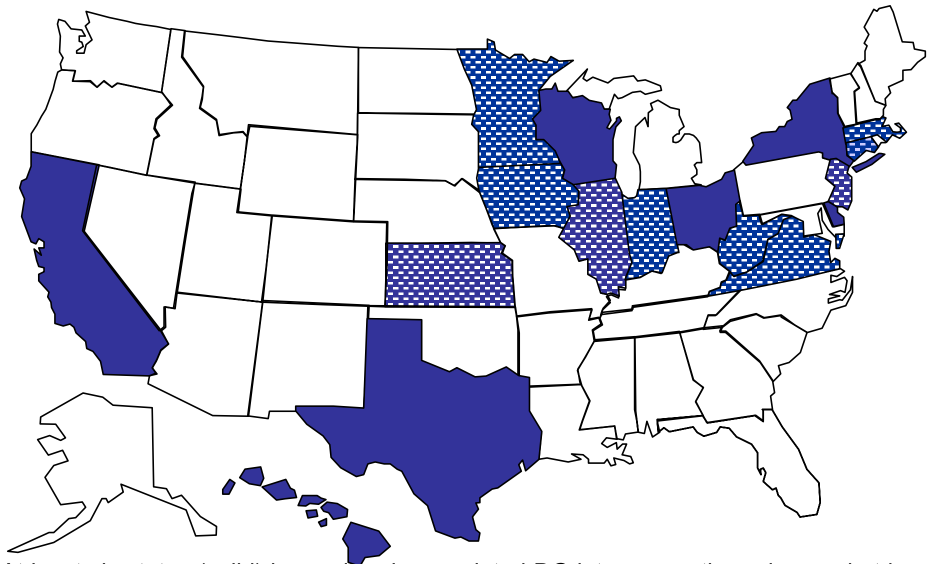


Twenty-four states have developed interconnection rules for net-metered systems. In addition, states such as North Carolina, Louisiana, and Missouri have developed interconnection rules for small-scale systems in the absence of net metering. Similarly, Florida has interconnection rules, and while it allows for net metering, it does not require its utilities to implement net metering.

With growing awareness that interconnection difficulties are faced by all distributed generation technologies, many states, as illustrated in Figure 3, have or are addressing more general interconnection issues for a broader class of DG. At least six states – California, Delaware, Hawaii, New York, Ohio, Texas, and Wisconsin – have already completed their DG interconnection rules, while many others, including Connecticut, Illinois, Indiana, Iowa, Kansas, Massachusetts, Minnesota, New Jersey, Virginia, and West Virginia, are in the process of developing their rules.

States developing DG interconnection rules now have the advantage of completed IEEE 1547-2003 and UL 1741 standards and strong state models, which address with clarity issues of procedure and equipment certification. There are other model documents available, including the guidelines developed by the National Association of Regulated Utility Commissioners (NARUC) (www.naruc.org) and those developed by the Interstate Renewable Energy Council (IREC). The appendices to this guide contain IREC's model interconnection guidelines, which incorporate a model application/ agreement for <25 kW net-metered systems, and a model agreement for all other DG.

**Figure 3. States with DG interconnection rules**



At least six states (solid) have already completed DG interconnection rules, and at least ten others (speckled) are in the process as of 2004. California and New York, which have seen the most DG installations since their rules were completed, have also gone through the effort of revising their rules for more streamlined implementation.

States are moving ahead at a furious pace, and while this guide does not discuss state-by-state activity in detail, this activity can be followed through the monthly Interconnection Newsletter, published electronically by IREC and the North Carolina Solar Center. The free newsletter covers state and federal activity, standards development, events, and equipment certification. Additionally, the *Connecting to the Grid* website (www.irecusa.org/connect/index.html) is an online resource addressing interconnection issues, with contents including:

- *On-line Interconnection Library* with electronic versions of important technical and non-technical reports and papers.
- Subscription form and archives for the electronic *Interconnection Newsletter,* which covers the latest state and national activity.
- Up to date state-by-state information presented both in tabular summary format and in detail through individual state pages.
- Information on interconnection workshops for states.

There is an abundance of resources now available, including growing experience in those states that are now implementing their rules. Useful websites include:

IEEE SCC 21: grouper.ieee.org/groups/scc21

DOE Distribution & Interconnection R&D www.eere.energy.gov/distributedpower

NARUC: www.naruc.org/Programs/dgia/index.shtml

Wisconsin Distributed Resources Coalition: www.wisconsindr.org

California Energy Commission: www.energy.ca.gov/distgen/

# 2. Safety, Power Quality, and Codes

Technical details remain at the heart of the interconnection process with safety, power quality, and system reliability being the primary utility concerns and responsibilities. Fortunately, three national code making bodies – IEEE, UL, and the National Fire Protection Association (NFPA) – have developed codes and tests standards for DG equipment to be interconnected. This section therefore addresses safety and technical issues in the abstract before turning to codes and how they can streamline the interconnection process. The goal here is to demystify and familiarize, while not going into great technical detail, so where appropriate, references are given for those who would like more explanation.



## 2.1 Safety

Like any source of electricity, DG systems are potentially dangerous to both people and property, and much attention has been given to finding ways to reduce these inherent safety risks. Large industrial customers have been generating power on-site for as long as electricity has been used, but interconnecting PV, microturbines, and other relatively small generation systems to operate in parallel with the grid at residential and commercial locations is a relatively new trend. One of the primary concerns of utilities is the possibility of DG devices – not under their control – providing power to a line that is otherwise thought to be de-energized. This *islanding* condition is discussed below.

### *Distinctions Among DGs*

It is impossible to generalize safety issues with regard to all types of distributed generation because there are three distinct type of generators, as far as the grid is concerned: (a) solid-state or static inverters, (b) induction machines, and (c) synchronous machines. Nearly all renewable energy systems produce grid quality AC power through an inverter and are therefore 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 wind turbines, the AC generated by the spinning microturbine is converted to DC before being converted to grid compatible AC by the inverter.

Induction and synchronous generators, on the other hand, are generally lumped together as “rotating machines,” but their different configurations do give them different start-up and operational characteristics. For example, induction machines cannot operate in standalone mode without extra capacitors or other excitation sources and normally have more negative power factor impacts.

The distinction between inverter-based and rotating generators is important. Rotating generators act as voltage sources and thus can operate independently of the grid, while inverters typically act as current sources. As a practical matter, it is therefore much more difficult for inverter-based generators to power an island (discussed below), and inverters can feed far less current into a fault.

Because inverters are power electronic devices, it is possible to incorporate more safety features into the inverter, allowing 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 smaller inverter-based devices requiring less – if any – additional protection equipment.

While inverters are inherently more controllable and thus safer from an interconnection standpoint, their use in grid-tied applications is much newer than with rotating equipment. As technical grid interconnection issues were being debated through the mid and late 1990s, attention was given to whether or not these devices needed the additional familiar protection relays used for rotating generators. Through the process of developing IEEE 929 and UL 1741, it was shown that these solid-state devices could be tested so as to prove they would never "run on" or "island" as is possible with rotating equipment. As a result, most state interconnection rules allow that UL listed *non-islanding* inverters do not need additional standard relays.

But, even with rotating machines, one must recognize the distinction between the smaller (sub-MW) distributed generation equipment, and the larger 100+ MW cogeneration systems that are interconnected as QFs under PURPA. The type of utility grade relays needed to protect rotating, non-inverter equipment is well understood; so the focus of discussions is centered more on the grid impacts of interconnecting many of these devices.

### *PV Power*

Photovoltaic systems have particular characteristics that deserve individual discussion. PV modules produce direct-current (DC) power, and depending on the system design, some utility-interconnected PV systems operate at DC voltages typically up to 600 Volts before being inverted to standard alternating current (AC). The potential fire hazard of DC at these voltages is greater than that of standard AC found in residences because it is more difficult to extinguish a DC arc than an AC arc at the same voltage. Many electricians and electrical inspectors do not regularly deal with DC circuits; however, proper wiring according to the National Electrical Code[1] (NEC) ensures that any hazards related to DC power are significantly reduced. In addition to the NEC, there are guides to the proper wiring of PV systems. Several organizations including PV and inverter manufacturers are producing 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 microinverter built directly onto the back of the module so that AC power leaves the module.

► *The most important safety issue for distributed generation systems is a condition called islanding.*

### *Islanding*

The most important safety issue for distributed generation systems is a condition called *islanding*. Islanding is a situation where a portion of the utility system that contains both loads and a generation source is isolated from the remainder of the utility system but remains energized.

The safety concern is that utility power goes down (perhaps in the event of a major storm) and a DG system continues to supply power to a local area. While a utility can be sure that all of its own generation sources are either shut down or isolated from the area that needs work, an island created by a small distributed power system is out of their control. There are a number of potentially undesirable results of islanding. The principal concern is that a utility line worker will come into contact with a line that is unexpectedly energized. Although line workers are trained to test all lines before working on them and to either treat lines as live or ground them on both sides of the section on which they are working, this does not remove all safety concerns because there is a risk when

[1] The National Electrical Code, which is published by the National Fire Protection Association (NFPA), is discussed in greater detail below.

these practices are not universally followed.

Fortunately, although islanding is a very real condition, current inverter technology is such that there is virtually no chance of an island stemming from interconnected systems using inverters with built-in anti-islanding safety features. Grid-tied inverters monitor the utility line and can shut themselves off as quickly as necessary (less than a second) in the event that abnormalities occur on the utility system. At Sandia National Laboratories and Ascension Technology (now part of RWE Schott Applied Power), extensive testing of inverters under a variety of laboratory-controlled worst-case conditions led to the development of the definition of a "non-islanding inverter." A good discussion of islanding and anti-islanding inverters is contained in the annexes to IEEE 929-2000 and in Greg Kern, et al., "Results of Sandia National Laboratories Grid-Tied Inverter Testing."

For rotating generators, primarily synchronous generators, which are self-excited, there is a real possibility of an island situation. Furthermore, even in the case where a generator responds to a grid fault by shutting off, the inertia contained in the generators creates the possibility of sending current into the fault. These problems are normally dealt with by including utility grade relays between the generator and the point of common coupling with the grid.

### *Manual Disconnect*

An external manual lockable disconnect switch ("manual disconnect") in the interconnection context is a switch external to a building that can disconnect the generation source from the utility line. The requirement for a manual disconnect, stems from utility safe working practices that require disconnecting all sources of power before proceeding with certain types of line repair. Whether a manual disconnect for small systems with UL-listed inverters should be required has been the source of considerable debate.

►*"Utilities may choose to relax their requirement for a utility-interface disconnect switch when a PV system employs a non-islanding inverter."*

– IEEE 929-2000

In strict safety terms, a manual disconnect is not necessary for modern inverter-based systems because of the inverter's built-in automatic disconnect features as discussed in the previous section. Also, in accordance with NEC Article 690 – discussed below – the inverter already must have a manual means of isolation from the grid. The manual disconnect issue then really refers to the need for an additional switch that is (1) external to the building, (2) lockable by utility personnel, and (3) offers a visible-break isolation from the grid. As such, a manual disconnect is an additional means of preventing an islanding situation. And, the key from the utility perspective is that the switch is accessible to utility personnel in the event of a power disruption when utility line workers are working on proximate distribution system lines.

For inverter-based systems, the cost to achieve this redundancy can be high, as for example where the DG installation is far from the facility meter. This may be the case on a multi-building campus with one master utility meter. If the DG device is located far from the master meter, then expensive conduit runs may have to be made between the DG device and the meter. (The same might be imagined for a DG device such as a PV system installed at the top of a building where the meter is at street level.)

State net metering and interconnection rules vary on this issue. For example, New Mexico, New York, and Texas do require a manual external disconnect. Meanwhile, California, New Jersey, Washington, and Nevada do not require a manual disconnect for small systems. Some utilities, such as those owned by National Grid USA, have established their own interconnection guidelines that do not require an external manual disconnect for small systems.

## 2.2 Power Quality

Power quality is another technical concern for utilities and customer-generators. 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 U.S., residences receive single-phase alternating current (AC) power at 120/240 Volts at 60 cycles per second (60 Hz), and commercial buildings typically receive either 120/240 Volts single phase or three-phase power depending on the size of the building and the types of loads in the building.

Each type of DG device has its own output characteristics based the technology. Even those devices that use inverters vary according to their DC source. Device specific power quality issues therefore are not addressed here.

Power quality is important because electronic devices and appliances have been designed to receive power at or near rated voltage and frequency parameters, and deviations may cause appliance malfunction or damage. Power quality problems can manifest themselves in lines on a TV 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 for a building, potentially can inject noise that can cause interference. In addition to simple voltage and frequency ranges, discussions of power quality include characteristics of harmonics, power factor, DC injection, and voltage flicker.[2]

**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 hertz (Hz) with waves at other frequencies that are other 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 are 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 not directly dependant on the voltage. Despite the large amount of discussion this topic generates, the number of documented problems caused by harmonics is relatively small even though various harmonic producing loads are increasing.

**Power factor** is a measure of *apparent power* that is delivered when the 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 entirely in synch. Loads with motors, such as refrigerators or air conditioners, typically lead to reduced (or lagging) power factor. The terms “leading” and “lagging” refer to whether the current wave is

[2] For a more detailed discussion of power quality, see the annexes of IEEE 929-2000, which include an informative discussion of power quality.

ahead of or behind the voltage wave. Although not strictly the case, power factor problems can be thought of as contributing to utility system inefficiencies.

**DC injection** is a potential issue for inverters where an inverter passes unwanted DC current into the AC or output side. This can be prevented by incorporating galvanic isolation through a transformer within the inverter design. DC injection is not an issue for rotating generators, which only produce AC power.

**Voltage flicker** refers to short-lived spikes or dips in the line voltage. A common manifestation of voltage flicker is when your lights dim momentarily. The significance of voltage flicker is highly subjective, but IEEE has established limits. Grid-interactive inverters generally do not create DC injection or voltage flicker problems.

## 2.4 National Codes and Standards

The technical and safety issues discussed above are addressed in a number of key national codes addressing the interconnection of DG systems. The value of these codes and standards to the interconnection process cannot be overstated. Without such national standards, DG equipment manufacturers would be faced with developing separate devices and protection equipment to satisfy each utility that developed its own interconnection safety standards. Safety is enhanced when all parties adhere to nationally determined certified codes and standards.

**Table 1. National electrical standards bodies**

| | |
|---|---|
| Institute of Electrical and Electronics Engineers (IEEE) | 445 Hoes Lane, P.O. Box 459<br>Piscataway, NJ 08855-0459<br>(800) 678-4333 standards.ieee.org |
| Underwriters Laboratories (UL) | 333 Pfingsten Road<br>Northbrook, IL 60062-2096<br>(847) 272-8800 www.ul.com |
| National Fire Protection Association (NFPA) | 1 Batterymarch Park<br>Quincy, MA 02269-9101<br>(617) 770-3000 www.nfpa.org |

A number of organizations have been instrumental in bringing these standards about. The major code and safety organizations (listed in Table 1) that publish interconnection are the National Fire Protection Association (NFPA), Underwriters Laboratories (UL) and Institute of Electrical and Electronics Engineers (IEEE). Additionally, the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) (www.nrel.gov) in Golden, Colorado and Sandia National Laboratories in Albuquerque, New Mexico (www.sandia.gov) work closely with the NFPA, IEEE, and UL 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*

The Institute of Electrical and Electronics Engineers (IEEE) is a non-profit, technical professional association with a worldwide membership. Among its functions, IEEE has over 800 active technical standards and over 700 in development. IEEE has taken a leading roll in addressing technical interconnection issues with the development of IEEE 1547-2003 and IEEE 929-2000.

IEEE 1547 Standard for Interconnection Distributed Resources with Electric Power Systems addresses the technical specifications for and testing of the interconnection of DG. The single sentence scope is: "This standard establishes criteria and requirements for interconnection of distributed resources (DR) with electric power systems (EPS)." (An EPS essentially refers to the distribution grid.) The focus of the document is on interconnections at the distribution level and is intended for systems up to 10 MVA.[3]

The brevity of the scope is representative of the overall brevity of the 15-page standard, which at one point in draft form totaled over 100 pages. One reason for this is that the standard is strictly concerned with the point of interconnection and does not address the type or operation of the DG device itself, nor is it prescriptive as it does not address how the standards are to be implemented. The heart of the document is contained in sections four and five:

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 reason for the relatively short document is that IEEE 1547 is really a series of standards with 1547-2003 being the lead document addressing only the core issues. During the development of 1547, some of the important issues were

[3] "MVA" stands for megavolt-ampere and is a unit that represents both the reactive and real power output of a device. For simplicity, MVA may be thought of as roughly equivalent to a megawatt (MW). Similarly, a kVA can be thought of as a kW in rough terms. Formally, for a device's MVA and MW ratings to be equivalent, the power factor must be one (1).

taken out and moved into four other documents which are now under development:

- IEEE P1547.1 Draft Standard For Conformance Test Procedures[4]
- IEEE P1547.2 Draft Application Guide for IEEE Std 1547-2003
- IEEE P1547.3 Draft 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

The intention of the P1547.1 testing document is to fill in many of the testing procedure details that are not specified in section 5 of 1547-2003. Much of the detail of P1547.1 addresses the issue of unintentional islanding and how to prevent it. Final approval for this document is expected by June 2005.

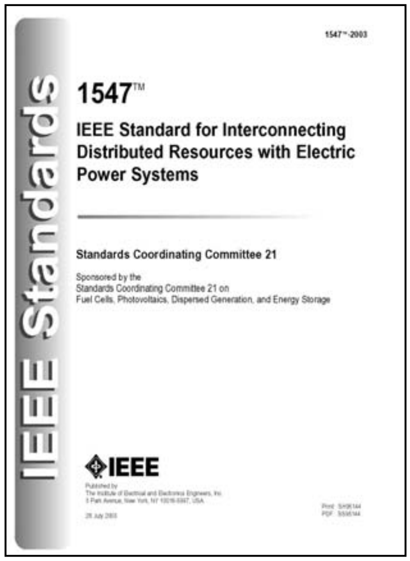
The scope of P1547.2 is to provide technical background and application details to support the understanding of 1547-2003. This document, therefore, fills in much of the interesting technical background on the various DG technologies and their associated interconnection issues. It will include technical descriptions and schematics, applications guidance, and interconnection examples. P1547.3 focuses on the functionality, parameters, and methodologies for DG communications and control.

P1547.4 addresses issues involved in integrating DG systems into the grid. For example, 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.

Note that 1547-2003 and P1547.1 are *Standards*. These documents contain mandatory, enforceable requirements and generally use the word “shall” in describing how equipment must operate. 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.” Between Standards and Guides in the IEEE hierarchy are *Recommended Practices* in which procedures and positions preferred by the IEEE are presented. Here the operative word is “should.”

[4] The “P” in front of and IEEE standard or guide number indicates that the document is pending or in draft form.

**Figure 4. IEEE Standards 1547-2003 and 929-2000**


IEEE Standards

1547™-2003

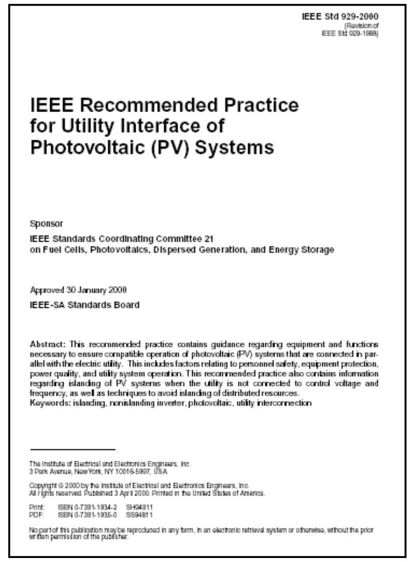
1547™

IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

Standards Coordinating Committee 21

Sponsored by the
Standards Coordinating Committee 21 on
Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

IEEE


IEEE Std 929-2000
(Revision of
IEEE Std 929-1988)

IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

Sponsor

IEEE Standards Coordinating Committee 21
on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

Approved 30 January 2000

IEEE-SA Standards Board

Abstract: This recommended practice contains guidance regarding equipment and functions necessary to ensure compatible operation of photovoltaic (PV) systems that are connected in parallel with the electric utility. This includes factors relating to personnel safety, equipment protection, power quality, and utility system operation. This recommended practice also contains information regarding islanding of PV systems when the utility is not connected to control voltage and frequency, as well as techniques to avoid islanding of distributed resources.
Keywords: islanding, nonislanding inverter, photovoltaic, utility interconnection

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IEEE 1547 was completed and approved by the IEEE Standards Board in June of 2003. This represents a major step forward in addressing the basic technical issues facing interconnected DG. IEEE 929 was completed and approved in January of 2000. This document was a breakthrough in the clarification of standards for small-scale PV and inverter-based systems.

It is important to note that the entire IEEE 1547 series was and is being developed in a collaborative process involving utilities, equipment manufacturers, national labs, end users, and general interest individuals. The working group for the main 1547-2003 standard included over 200 people, many of whom represented or are affiliated with electric utilities.

### *IEEE 929-2000*

Prior to 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 distributed generation technologies and considers much larger systems and grid impacts, IEEE 929 is strictly an inverter document and technically only addresses photovoltaic 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 to that document led to the current version, IEEE Std 929-2000, which was approved by IEEE in January 2000 replacing the 1988 version.

It is the intent of IEEE 929-2000 to meet all legitimate utility concerns with safety and power quality so that there will 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 is also intended to be an informative document and serves as an excellent primer on PV interconnection issues. While the standard itself is only about twelve pages, unlike IEEE 1547, it contains informative annexes with nearly twenty pages of background on islanding, distribution transformers, and manual disconnects. Another important distinction with IEEE 1547 is that 929-2000 is a Recommended Practice and thus does not carry the same enforceability of a standard.

The key technical sections of 929 are sections 4 & 5:

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

At the time the original document was released in 1988, all commercially available U.S. manufactured inverters could be made to “run on” (power an island) for periods longer than two seconds under very controlled laboratory conditions. Although these conditions were extremely unlikely in the real world, they were still possible (Gulachenski, 1990). Inverters that meet the standards described in IEEE Std 929-2000 use more sophisticated means for assuring that under no real world or lab circumstances will they run on when utility power goes down. (Kern, 1997 and Kern et al., 1998).

While IEEE 929-2000 remains an active IEEE standard, with the recent completion of 1547-2003, it is not clear how 929 will be handled when it comes up for review in 2005. The substantive requirements of the two documents are consistent, and because 1547 casts a wider net, which includes PV systems under 10 kW, IEEE 929 may not need to be renewed. Whether it is renewed or not, it remains an informative document and a good read for anyone seeking an introduction to these issues.

### *Underwriters Laboratories Std. 1741*

Underwriters Laboratories (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 U.S., and its label is found on products ranging from light sockets to inverters. Although UL writes the testing procedures, other organizations may do the actual testing and certification of specific products. In addition to the UL testing labs, Edison Testing Laboratories (ETL), the Canadian Standards Association (CSA), and Underwriters Laboratories Canada are widely recognized listing (testing) agencies. A complete list of OSHA Nationally Recognized Test Labs (NRTLs) can be found at www.osha.gov/dts/otpca/nrtl.

The expanded scope of UL 1741 “Inverters, Converters, and Controllers for Use in Independent Power Systems" deals with all forms of distributed generation, including photovoltaics, microturbines, wind turbines, fuel cells, and stationary engine generator assemblies. Until 2002, UL 1741 was strictly an inverter-focused document and previously had only addressed PV systems. Concurrent with the development of IEEE 1547 and 1547.1, UL 1741 expanded its scope, and the committees working on the two documents worked closely together to ensure that the documents are in synch.

At this point the majority of DG equipment with the UL listing is inverter-based. The test procedures proscribed by UL 1741 ensure that inverters meet the guidelines in IEEE 929 and now IEEE 1547. The UL 1741 listing thus conveniently assures the DG system owner that their inverter is in compliance with IEEE 929 and IEEE 1547.

Until a few years ago, no listed inverters were available on the market. The cost of listing equipment in this relatively small market was too expensive for the companies manufacturing the equipment. There are now several listed inverters, and it is now quite possible to install a fully code-compliant DG system that most inspection jurisdictions will accept. Note that UL 1741 deals with both utility-interactive devices (grid-tied) as well as standalone devices, such that equipment can be UL 1741 listed but NOT be listed for utility-interactive operation. In addition to utility-interactive and standalone devices, it also covers multi-mode devices that can operate in either utility-interactive or stand alone modes. DG equipment distributors or manufacturers can provide information on which models are listed as utility-interactive inverters.

Finally, it is worth noting that unlike the IEEE standards discussed here, UL 1741 covers more than simply the grid interconnection issues. Organizationally, UL was originally established as a fire and product safety test facility, thus in addition to utility compatibility issues, 1741's scope includes electric shock hazards, fire hazards, and mechanical hazards.

### *National Electrical Code Article 690*

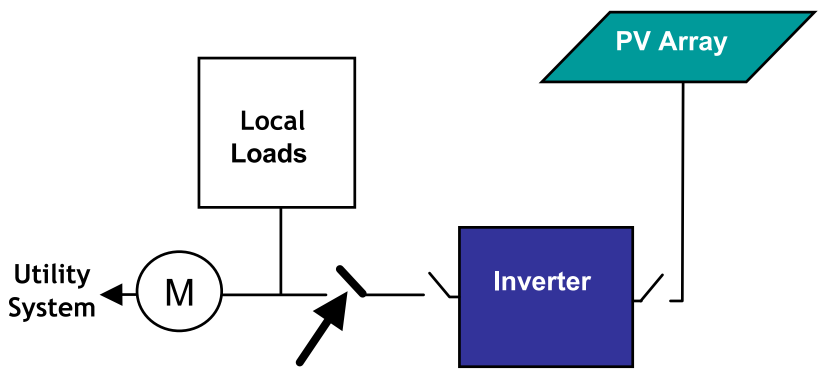
The National Fire Protection Association (NFPA) publishes the National Electrical Code (NEC or NFPA 70) and is the foremost organization in the U.S. dealing with electrical equipment and wiring safety. The National Electrical Code is now 1,069 pages long and is the most detailed of any NFPA code or standard. The scope of the NEC covers all buildings and property except for electric utility property. That is, the NEC applies to your home but not to the power lines or generators operated by your utility. By contrast the National Electrical Safety Code (NESC), addresses equipment on the utility side of the meter.

An entire section of the NEC – Article 690 "Solar Photovoltaic Systems" – deals with PV. This section mentions interconnection to the utility grid but focuses more on descriptions of components and proper system wiring. One key requirement in Article 690 is that all equipment must be listed by a recognized listing agency if a relevant listing exists. For PV inverters, this means that to be code compliant the system must 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 manual disconnects. The code requires that PV systems have both DC disconnects (PV input) and AC disconnects (inverter output). With many inverter models these disconnects are built into the inverter. The NEC-required AC disconnects, however, frequently do not satisfy the requirements of some utilities because they typically are not lockable, and inverters are frequently mounted indoors where they may not be accessible to utility personnel (if the disconnects are part of the inverter). Figure 5 illustrates the placement of disconnects in a generic system. This diagram would be more complicated for multimode inverters, which operate in utility interactive and standalone modes.

**Figure 5. Manual disconnect requirement in a PV system**




The manual, external, lockable disconnect requirement (marked with arrow) for small PV systems is an additional switch beyond those already required of inverters by Article 690 of the NEC. The NEC already requires AC and DC disconnects (shown) for all inverters. One alternative to the additional disconnect requirement is removal of the meter itself to isolate the inverter from the grid or grounding the secondary at the transformer.

**Source:** Endecon Engineering.

PV systems were first given the status of a special equipment article in the National Electrical Code in 1984. Revisions continue to be made to the article, but much of it has remained intact. (The NEC is updated on a three-year cycle, with the 2002 edition being the most recent version.) 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 (Wiles, 1996). 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 on the national level. Once a national standard or code is changed, it is left to the discretion of state and local authorities to adopt the new changes. As an example, there are a few jurisdictions in the U.S. that adhere to the 1990 NEC even though four revisions have been issued subsequent to that version. Although this is the exception rather than the rule, it is an example of 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 the local code supersedes the national code in this situation.

**Table 2. Interconnection-related technical standards**

| | | |
|---|---|---|
| IEEE 929-2000 | Recommended Practice for Utility Interface of Photovoltaic (PV) Systems | |
| IEEE 519-1992 | Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems | |
| IEEE 1547-2003 | Standard for Distributed Resources Interconnected with Electric Power Systems | |
| IEEE P1547.1 | Draft Standard For Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems | |
| IEEE P1547.2 | Draft Application Guide for IEEE Std 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems | |
| IEEE P1547.3 | Draft Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems | |
| UL 1741 | Static Inverters and Charge Controllers for use in PV Power Systems | |
| NFPA 70 Article 690 | Solar Photovoltaic Systems | |
| NFPA 70 Article 692 | Fuel Cell Systems | |
| NFPA 70 Article 705 | Interconnected Electric Power Production Sources | |
| IEEE 1001 | Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems | (Withdrawn) |
| IEEE 1021 | Recommended Practice for Utility Interconnection of Small Wind Energy Conversion Systems | (Withdrawn) |
| IEEE 1035 | Recommended Practice: Test Procedure for Utility-Interconnected Static Power Converters | (Withdrawn) |

# 3. Legal and Procedural Issues

**3.1 Legal Issues**
Insurance
Standard Agreements

**3.2 Procedural Issues**
Small-scale systems
Large DG systems

Many of the barriers to interconnection have little to do with technical functionality or safety. With the passage of the national standards discussed above, technical issues by and large are now being dealt with by states and utilities in a satisfactory manor. At the very least, in many jurisdictions, the technical rules are clear to all involved. Much of the difficulty now is in the legal and procedural aspects of interconnection.

This section first addresses some of the key legal issues including liability insurance and the agreements that must be signed between system owner and utility. Procedural issues are then addressed, including:

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

It is typically at the state utility commission level where these issues are addressed. As we have seen in Texas and California in particular, clear legal and procedural rules have greatly facilitated the interconnection process. In addition to the examples provided by those states, model documents have been developed to aid those states now developing or revisiting their DG interconnection or net metering interconnection rules. The model rules and agreements developed by IREC are discussed below.

## 3.1 Legal Issues

### *Insurance*

Liability insurance is an issue whose importance varies with the scale of the system being installed. For larger systems, greater than ~100 kW, installed at commercial or industrial facilities, additional liability insurance for the DG system is typically not an issue simply because either the facility already has sufficient insurance coverage (> $1 million) or the marginal cost of obtaining any additional insurance is not very large relative to the project cost. In fact, explicit liability insurance requirements are not part of the California DG interconnection rules.

► *In the first test of this issue, the New York Public Service Commission in 1998 rejected the proposal of several NY utilities that PV systems falling under the state's net metering rule have between $500,000 and $1,000,000 in liability insurance.*

Where liability insurance has been a major issue is in the rules applicable to residential and some small commercial applications. Liability insurance is required by most utilities that have interconnection standards for small renewables systems as a way to protect themselves and their employees should there be any accidents attributable to the operation of the customer's installation. Most homeowners already have at least $100,000 of liability insurance through their standard homeowners insurance policies, so a requirement to provide this amount of coverage usually poses no further costs to the system owner. In the first test of this issue, the New York Public Service Commission in 1998 rejected the proposal of several utilities that PV systems falling under the state's net metering law carry between $500,000 and $1,000,000 in liability insurance. The Commission concluded that $100,000 was sufficient.

Indemnity is another liability-related issue that refers to security against or compensation for damage, loss, or injury. In the case of contracts between utilities and system owners, utilities frequently require the system owner or other customer generator to indemnify the utility for any potential damages as a result of operation of the installation. Where there are liability insurance requirements, indemnification requirements are somewhat redundant. As part of its 1998 net metering ruling, the New York Public Service Commission ruled that indemnity requirements are not necessary for PV system owners because generic negligence and contract rules are sufficient.

Beyond the issue of limits of liability and indemnity, some utilities have sought to impose the requirement that they be listed as an "additional insured" on the customer generator'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 parts of the country, insurance companies have indicated that listing a utility as an additional insured is not even possible for residential insurance policies. In light of this, some utilities have dropped this requirement, and where state utility commissions have examined this, they have rejected this requirement.[5]

### *Standard Agreements*

The development of standard agreements for interconnection is a goal of most states developing interconnection rules. Standard agreements make the process easier for utilities and system developers/owners alike and assure that there is equal legal treatment across different utility territories in the same state. Even if a state develops uniform interconnection rules with a clearly defined process for interconnection, if a standard agreement is not developed or recommended, unreasonable contract terms that find their way into utility agreements can be showstoppers for projects.

Again the difference between commercial / industrial DG installations and small-scale / residential installations is worth highlighting. Given the differences in scale, two different model agreements are recommended and have been provided in Appendices 2 & 4. Appendix 2 is a one-page application and agreement for customers seeking to interconnect net metered systems up to 25 kW. (Systems need not be net metered for this application and agreement to apply.) Appendix 4 is a more detailed 9-page agreement that serves DG installations up to 20 MW.

► *Simply put, if a residential customer has to navigate and understand a stack of legal documents before they can install a system they are less likely to move ahead, even if the major technical issues are settled.*

Turning first to the smaller scale installations, the one-page application and agreement is a recognized step toward removing legal and financial barriers to the installation of grid tied renewables. Simply put, if a residential customer has to navigate and understand a stack of legal documents before they can install a system, they are less likely to move ahead, even if the major technical issues are settled. In other words, if legal advice is needed to read and interpret the utility-required paperwork, costs go up and plans are abandoned.

[5] For a more detailed discussion of liability issues related to interconnection, see Starrs and Harmon, "Allocating Risks: An Analysis Of Insurance Requirements For Small-Scale PV Systems."

The one-page agreement and application not only simplifies the process, but it illustrates the importance of reliance on national standards: without getting into technical details, you can state in two lines of a document that systems must meet the requirements established by UL, IEEE, and the NEC. A one-page agreement or modification thereof is now being used by utilities in Rhode Island, by Massachusetts Electric, Commonwealth Edison (Chicago), Connectiv (Delaware), the City of Ashland Oregon, and utilities in Virginia. Other states, such as California have developed slightly longer versions of this document, but with the same intention of simplicity.

The 9-page agreement in Appendix 4 is more of the style of a traditional contract, which is its intent. It is generalized to cover all interconnected installations up to 20 MW, and by covering such a wide range of projects, this application simplifies things for utilities and project developers who may be involved in projects of various sizes. Key issues addressed include:

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

With limited modifications, states should be able to use this agreement as part of their interconnection rules. The agreement in Appendix 4 is similar to the model agreement in NARUC's "Model Distributed Generation Interconnection Procedures and Agreement," which can be found on the web at: www.naruc.org/Programs/dgia/index.shtml.

## 3.2 Procedural Issues

As with prior sections, the discussion of procedural issues is split between small-scale and larger DG systems because the issues are so 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-scale systems*

A standard agreement, no matter how concise, needs to fit into a simplified procedural context. One of the frequent complaints of system owners looking to interconnect under net metering rules is that they (a) were not able to find a utility representative who was familiar with net metering and interconnection procedures or (b) encountered protracted delays in receiving the necessary paperwork or in receiving approval once the paperwork was complete. Still, most utilities do not have standard procedures for dealing with PV and small DG interconnection nor do most utilities have a designated individual to deal with requests. Not many 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 discouraged it *indirectly*.

State regulatory commissions have sought to remedy this by establishing time limits for the various steps and requiring the utilities to designate a certain representative(s) to handle interconnection- or net metering-related queries.

Ideally, information on the process would be available on utility websites and on state commission websites. Such a provision was recently incorporated into the Texas interconnection rules.

In addition to simple procedural barriers, smaller installations can face substantial barriers in the form of fees. There are a variety of fees that utilities may impose on owners of small-scale systems, including permitting fees,[6] interconnection-related fees and charges, metering charges, and standby charges. The imposition of even a modest fee can substantially alter the economics of grid-tied PV systems.

- *Interconnection-related fees and charges* include initial engineering and inspection fees for reviewing the system. Historically, utilities have conducted inspections of individual generating facilities, no matter how small in size, and have tended to charge the facility owners for these inspections. Fees for such inspections for even small PV systems have been reported as high as $900. It is expected, though, that such fees for inspections can be eliminated or reduced with the more widespread recognition of relevant codes and standards such as NEC Article 690, IEEE 929, and UL 1741.

- *Metering charges* may be imposed when a second meter is installed for a PV system. Such charges may range from $4–$8 per month. The first question is whether or not a second meter is needed at all. This will largely depend on whether your state has a net metering rule in place. If a second meter is required, the question is who should pay for the meter – the PV owner or the utility. This issue is still being considered in most states.

- *Standby charges* have been established by utilities for large customer generators. Utilities are required to have capacity in place to meet customer generator loads in the event that the customer's generation system goes down. It costs the utility to maintain this backup power, so large customer generators are required to pay standby charges. At issue is whether standby charges are necessary for small (<10 kW) customer generators. In a case involving Pacific Gas and Electric, the California Public Utility Commission ruled that standby charges would not be allowed for net-metered customers. Since then, a number of other state laws have prohibited standby charges and other such charges for customers with small-scale PV systems. Typical standby charges for small PV systems can range from $2–$20 per month.

In light of the potentially detrimental economic impact of fees on customer generators, many state utility commissions that have ruled on interconnection (or on net metering) have placed limits or prohibitions on the imposition of additional fees by utilities.

### *Large DG systems*

Unlike in the case of small system, there is a legitimate need in many cases for detailed studies before a system can be approved for interconnection. Therefore, the trick is determining when such studies, which can be costly, are indeed necessary. In light of the cost and time issues, DG interconnection procedures are receiving focused attention: in California, the third state to adopt statewide standards, an ongoing working group meets to address the implementation of the state's rules. Good state rules specify not only the steps that must be taken but also the time allowed for each phase of the process. Timing can be critical, and

[6] Permitting fees are discussed below in the section on Building Codes.

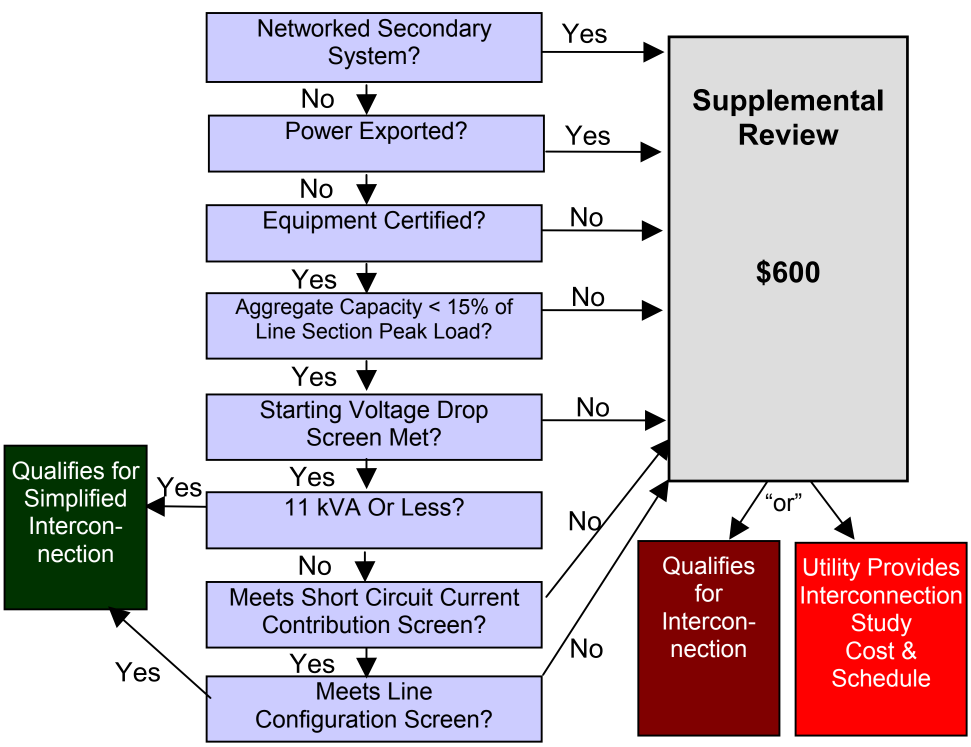
as indicated in the *Making Connections* report, many projects have seen exorbitant delays because time limits were not imposed on the parties involved. In only 17 of the 65 interconnection case studies were no delays reported.

A number of states, as well as the IREC model, suggest a set of separate procedures with varying degrees of complexity depending on the system size and type. Overlaid on top of this is a screening mechanism to determine which procedure a particular system must go through. California provides a useful screening and procedural model as illustrated in Figure 6. As a result of the screening process, the system will face one of three procedures:

- Simplified interconnection,
- Interconnection with system modifications after supplemental review, or
- Full interconnection study.

► *Good state rules specify not only the steps that must be taken but also the time allowed for each phase of the process.*

**Figure 6. California DG interconnection screening process**




California's screening process determines whether a system (a) qualifies for simplified interconnection, (b) qualifies for interconnection with modifications, or (c) requires a full interconnection study. The fee for the screening process itself is $800, and separately the fee for the supplemental review (if necessary) is $600. Application fees are waved for all systems that qualify for net metering.

**Source:** Endecon Engineering.

**Simplified interconnection** allows systems to connect upon completion of the interconnection agreement. Utilities may perform a commissioning inspection at their own cost if they choose to do so. One intended outcome of the screening process is that nearly all small-scale residential PV and renewable systems will qualify for simplified interconnection. Net metering is another factor in California, where net metering is allowed for PV, solar thermal, wind, and biomass systems up to 1 MW. While not all net metering systems will qualify for simplified interconnection, such systems are not required to pay the $800 application fee for the initial review.

Systems not qualifying for simplified interconnection must go through the supplemental review process, which requires the submission of more detailed information about the system. As a result of the supplemental review a system may either qualify for interconnection with limited system modifications or it must undergo a full interconnection study. In the latter case, full interconnection studies are conducted by the utility after the system owner/ developer has approved the cost and schedule quote.

The California screening process and procedures provides just one model. Texas and New York have their own models for determining when a full interconnection study is needed. The Texas model provided greater flexibility for both system owner and utility, as illustrated in a side-by-side comparison in Table 3. The IREC model in Appendix 1 provides a more comprehensive procedural path that accounts for systems that may be interconnected in area and spot network distribution systems.

**Table 3. Texas and New York interconnection study requirements**

| Texas | New York |
|---|---|
| Utilities may conduct studies on any system but cannot charge for it if certain conditions met:<br>• Systems not exporting power.<br>• 1-φ systems exporting <50kW.<br>• 3- φ systems exporting <150kW.<br>• Pre-certified systems up to 500kW exporting <15% of min. load on radial feeder and contributing <25% of max short circuit current.<br><br>Study can take no more than 4 weeks.<br><br>DG benefits must be considered. | No study allowed for systems meeting conditions:<br>• Facilities ≤10kW<br>• Facilities ≤50kW connected on 1- φ line.<br>• Facilities ≤150kW connected on 3- φ line.<br><br>Otherwise, a study is required, and full cost of borne by customer.<br><br>Less discretion for either party. |

**Source:** Alderfer, et al., *Making Connections* (2000).

# 4. Net Metering

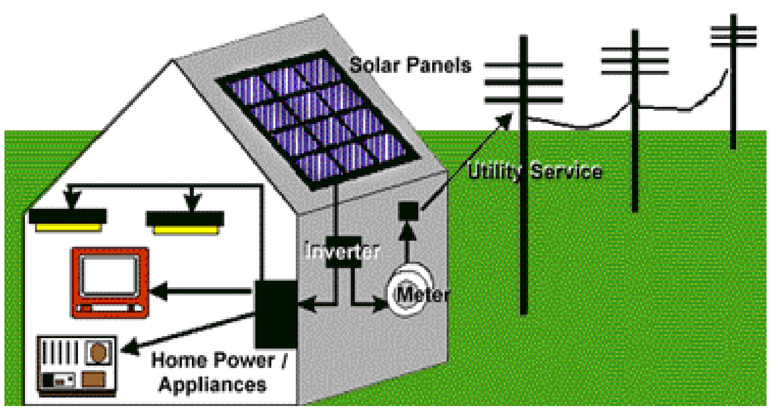
## 4.1 Net Metering Basics

For consumers who have their own electricity generating units, net metering allows for the flow of electricity both to and from the customer through a single, bi-directional meter. This arrangement is more advantageous to the customer than the two-meter arrangements that are more typically used for qualifying facilities authorized under PURPA. Under the most common two-meter arrangement, referred to as *net purchase and sale*, any electricity produced by a consumer that is not immediately used by the customer flows to the utility through the second meter. This excess generation flowing through the second meter is purchased by the utility at the utility's avoided cost, while the customer purchases any electricity off of the grid at the retail rate. There is usually a significant difference in the retail rate and the avoided cost. A typical retail rate might be 9¢/kWh, while the avoided cost rate may be 2¢/kWh.

With net metering, at times when the customer's generation exceeds their use, electricity from the customer to the utility offsets electricity consumed at another time. In effect, the customer is using the excess generation to offset electricity that would have been purchased at the retail rate. Under most state rules, residential, commercial, and industrial customers are eligible for net metering, but some states restrict eligibility to particular customer classes.

Net metering is also a low-cost and easily administered way of promoting direct customer investment in renewable energy. One of the major advantages of net metering is its simplicity; many customers are currently using their existing meter without any additional regulation or equipment.

**Figure 7. Net-metered residential PV system**




In the simplest case of an interconnected residential PV system, the inverter output is connected directly to the home's breaker box and thus is tied to the grid. In more complex configurations, such systems may have a separate AC output for backup loads, which continue to receive power from the PV and batteries in the case that the utility power is lost.

Arizona was the first state to implement net metering in 1981 when the Arizona Corporation Commission allowed net metering for qualifying facilities under 100 kW as an extension of PURPA. As of 2003, over thirty-five states have net metering, and net metering rules or laws are pending in at least three others. In addition, some individual utilities offer net metering to small-scale generators on their own volition, in the absence of any statewide requirement.

Appendix 5 provides a model net metering policy that is recommended as model legislation. It allows net metering of renewable energy systems up to 25kW for residences and 1,000 kW for commercial facilities.

## 4.2 Other Net Metering Issues

### *Annual vs. Monthly Netting*

Recent net metering rules have called for month-to-month carry forward of any net excess generation or "annual netting." Under this provision, if over the period of a month, a customer generates more kWh than is used, the excess kWh or "net excess generation" is carried over to the following month. In the event that there is excess generation carried over to the end of the year, any excess generation by the customer generator is granted to the utility with no payment to the customer generator.

The provision for annualized netting reflects the fact that some renewable energy resources are seasonal in nature. For example, a solar system may produce more energy than a household consumes in the summer months but may also produce less than what the household uses in the winter. Under this scenario the excess from the summer months would roll over to the winter months. The advantage to the utility of this type of arrangement is that not only is the utility granted any net excess generation at the end of the year, but the utility does not incur the administrative costs of paying the customer.

In states with month-to-month carry forward provisions, in the event that a customer-generator produces more than is consumed in a particular month, the customer is normally still required to pay the basic monthly customer charge.

### *Time-of-Use Metering and Smart Meters*

Time-of-use (TOU) metering refers to a metering arrangement where customers pay differential electric rate based on the time of day that they are consuming electricity. Whereas the flat rate for residences may be 9¢/kWh, the time-of-use rate for peak energy use may be as high as 14¢/kWh and as low as 3¢/kWh for off-peak. The question is how to make time-of-use measurements while net metering. TOU metering requires an electronic pulse meter, which is fundamentally different from standard spinning electro-mechanical meters, and these TOU meters typically do not record energy flows in both directions.

There are two options for those who want to take advantage of both net metering and TOU metering. The first 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 take place. However, these meters can cost up to $300 or more, and this would normally be an expense borne by the customer. The other option – which was incorporated by New York state as part of its net metering rules – is to install a second meter (in addition to the TOU meter) that only measures net flows to the utility. This second meter, under the New York rules, 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.

One approach, which has been adopted in a few states, is to not allow net metering customers to operate under a time-of-use rate. And, as a cautionary note, it is worth pointing out that while intuitively pleasing, TOU net metering may not make much financial sense depending on the TOU schedule in place. In all TOU schedules, the weekends are normally considered off-peak, so the calculation begins with 2/7 or 29% of the site-generated power automatically being applied to the off-peak rate. This is taken into account in the model net metering legislation provided in Appendix 5. Another factor is the cost and availability of advanced metering technology that can accommodate TOU net metering. Such meters exist but typically are designed for commercial and industrial accounts and thus are expensive.

# 5. Other issues for small-scale systems

## 5.1 Electrical Inspectors

In relation to interconnection, more attention is given to utilities than electrical inspectors because there are simply more issues in dealing with utilities; however, building and electrical inspectors have a very important role in ensuring that a grid-tied system goes on-line. Many for example have heard the horror stories of a code compliant PV system not being approved by the electrical or building inspector because the inspector was unfamiliar with PV. Although these cases appear to be rare, this concern lingers, and at the center of the issue is the fact that building inspectors have local autonomy. They 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 National Electrical Code for guidance on most electrical inspection work. Since Article 690 of the NEC goes into detail on how PV systems should be wired for safety, any inspector can review this document and know what to look for in an installation. If the PV installation has not been installed to comply with the Code, the code official has full authority to prevent that system from being operated. And, inspectors are not obligated to approve systems that are installed in compliance with the NEC if they have a documented reason for not being comfortable with the system. Until the code official is satisfied, the system could remain off-line indefinitely.

► *Inspectors are not obligated to approve systems that are installed in compliance with the NEC if they have a documented reason for not being comfortable with the system.*

Most problems start by not properly briefing the code official on the installation. Showing concern to the code official about the issues they care about can help ensure a smoother inspection process. In most cases where inspectors are unfamiliar with photovoltaics, it is the job of the installer to explain the system to the inspector. One thing that electrical inspectors like to see are drawings and wiring diagrams. The installer should provide a complete set of simple plans in addition to the diagrams that come with the equipment.

## 5.2 Building Codes

Building codes are important because they address the physical safety of building structures. These codes, such as the 2003 International Residential Code® (IRC), are developed on the national or international level to provide a consistent minimum standard by which local jurisdictions can evaluate the safety of their buildings. Building inspectors are concerned that the structural integrity of buildings is maintained and that the building will survive intact for many years with typical required maintenance. As this relates to PV, modules must be fastened in such a way that they will not blow off in a heavy wind or cause the roof to leak.

There are no significant barriers to engineering the structural integrity of a building for the mounting of PV systems. Problems have arisen when inspectors have required professional engineer stamps on drawings to ensure they are properly designed. The best way to mitigate this issue is by installing pre-engineered, packaged systems offered by several module manufacturers and large system integrators.

The development of innovative building-integrated PV systems that meet building codes has been ongoing for the last several years. These integrated approaches utilize construction techniques that have been proven in the use of large areas of glass in commercial construction. There are now commercially available products, such as PV roofing materials and PV *curtain wall* products, where the displaced roofing material costs can improve the value of the PV system. Also, the mounting of systems on flat roofs has been greatly simplified and made more affordable through measures like ballasted roof mounting systems, which require no roof penetrations.

Permitting fees may be imposed by a municipality for PV systems where a building permit from the local building department is required. These fees are typically a percentage of the cost of the home improvement and thus can have a large impact on PV economics. One time permitting fees have been reported as high as $500. A key question is whether the PV system is a permanent part of the building structure or is removable and, therefore, considered personal property (Starrs et al., 1998). Prospective PV owners should look into whether permitting fees apply before proceeding with an installation.

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# Appendix 1. IREC Model Distributed Generation Interconnection Procedures and Net Metering Provisions

*Explanatory note: These procedures are intended to be used for interconnections to distribution systems (typically radial circuits at voltages less than 69kV). A 2 MW limitation was selected as both the practical limit for expedited interconnections (above 2MW is typically precluded from expedited treatment because the size of the DG unit is often greater than the 10% limit for circuit peak load) and units greater than 2MW, should, in many cases, be analyzed for power flows onto the transmission system – an analysis not included in these procedures.*

**Chapter 1-1.1 Introduction**
The PUC finds it is in the public interest to adopt the detailed rules in this sub-section in order to simplify the process of interconnecting distributed generation facilities [that will be used for net metered customers]. These rules are intended to both identify a class of distributed generators that, because of their selected Point of Common Coupling, can be interconnected with ease and expedition as well as the standards to be used for ordinary interconnections by all utilities subject to PUC regulation.

**Chapter 1-1.2 Definitions**
The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise.

"Applicant" means a person who has filed an application to interconnect a customer-generator facility to an electric delivery system.

"Annualized period" means a period of 12 consecutive monthly billing periods. A customer-generator's first annualized period begins on the first day of the first full monthly billing period after which the customer-generator's facility is interconnected and is generating electricity.

"Area network" means a type of electric delivery system served by multiple transformers interconnected in an electrical network circuit generally used in large metropolitan areas that are densely populated in order to provide high reliability of service and having the same definition as the term "secondary grid network" as defined in IEEE standards

"PUC" means the state regulatory authority over electricity utilities or any successor agency.

"Class I Renewable Energy" is renewable electrical energy generation as defined by the legislature.

"Customer-generator" means a residential or small commercial customer that generates electricity, on the customer's side of the meter.

"Customer-generator facility" means the equipment used by a customer-generator to generate, manage, and monitor electricity. A customer-generator facility typically includes an electric generator and/or an equipment package, as defined herein.

"Electric delivery system" means the infrastructure constructed and maintained by an EDC, as defined herein, to deliver electric service to end-users.

"Electric distribution company" or "EDC" means an electric distribution company

"Electric generation service" means the provision of retail electric energy that is generated off site from the location at which the consumption of such electric energy and capacity is metered for retail billing purposes, including agreements and arrangements for the provision of electric generation service.

Electric power supplier" means a person or entity that is duly licensed by the PUC to offer and to assume the contractual and legal responsibility to provide electric generation service to retail customers. This term includes load serving entities, marketers and brokers that offer or provide electric generation service to retail customers. This term does not include EDCs, as defined herein.

“Equipment package” means a group of components connecting an electric generator with an electric delivery system, and includes all interface equipment including switchgear, inverters, or other interface devices. An equipment package may include an integrated generator or electric source.

“Fault current” means electrical current that flows through a circuit and is produced by an electrical fault, such as to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase. A fault current is several times larger in magnitude than the current that normally flows through a circuit.

“Good Utility Practice” means a practice, method, policy, or action engaged in and/or accepted by a significant portion of the electric industry in a region, which a reasonable utility official would expect, in light of the facts reasonably discernable at the time, to accomplish the desired result reliably, safely and expeditiously and has the same definition as the term is used in the interconnection rules promulgated by the FERC.

"IEEE" means the "Institute of Electrical and Electronic Engineers."

“IEEE standards" means the standards published by the Institute of Electrical and Electronic Engineers, available at www.ieee.org.

“Interconnection agreement” means an agreement between a customer-generator and an EDC, which governs the connection of the customer-generator facility to the electric delivery system, as well as the ongoing operation of the customer-generator facility after it is connected to the system. An interconnection agreement shall follow the standard form agreement developed by the PUC and posted on the PUC’s website.

"Net metering" means that the customer-generator is billed according to the difference between the amount of electricity supplied by the electric power supplier or basic generation service provider in a given billing period and the electricity delivered from the customers' side of the meter using Class 1 renewable energy systems, with customer generation in excess of electricity supplied credited over an annualized period.

“Point of common coupling” means the point in the interconnection of a customer-generator facility with an electric delivery system at which the harmonic limits are applied and shall have the same meaning as in IEEE Standard 1547.

“Spot network” means a type of electric delivery system that uses two or more inter-tied transformers to supply an electrical network circuit. A spot network is generally used to supply power to a single customer or a small group of customers and has the same meaning as the term is used in IEEE standards.

"Supplier/provider" means an electric power supplier of competitive electricity supply in a retail competition market.

**Chapter 1-1.3 Net metering General provisions *(see also IREC model net metering rules)***

*Note: this net metering model assumes retail competition exists in the jurisdiction*

(a) All Electric Distribution Companies and electric power suppliers shall offer net metering at non-discriminatory rates to their customers that generate electricity, on the customer's side of the meter, using Class I Renewable Energy.

(b) A customer-generator shall not be authorized to net meter if the capacity of the customer-generator's generating facility exceeds two megawatts.

(c) The PUC shall develop a standard tariff providing for net metering. Each supplier and EDC shall make the tariff available to eligible customer-generators on a first-come, first-served basis.

(d) When the amount of electricity delivered by the customer-generator plus any kilowatt hour credits held over from previous billing periods exceed the electricity supplied by the supplier and/or EDC, the supplier and/or EDC shall credit the customer-generator for the excess kilowatt hours until the end of the annualized period at which point the customer-generator will be compensated for any remaining credits at the supplier's avoided cost of wholesale power.

1. When a customer-generator switches electric suppliers, the supplier with whom service is terminating shall treat the end of the service period as if it were the end of the annualized period.

(e) Each supplier shall submit an annual net metering report to the PUC. The report shall include

1. The total number of systems and the total estimated rated generating capacity of its net metering customer-generators;
2. The total estimated net kilowatt-hours received from customer-generators.

(f) A customer-generator owns the renewable attributes of the electricity it generates, and may sell any Renewable Energy Certificates created as a result of that generation, individually or through an aggregator, or through a certificate trading program authorized by the PUC. A customer-generator who wishes to estimate the generation resulting from a facility for purposes of this subsection shall do so using PUC-approved estimation procedures for facilities smaller than 10 kilowatts.

(g) The metering used to effectuate net metering shall be capable of measuring the flow of electricity in both directions, typically through the use of a single bi-directional meter. A customer shall be entitled to use their existing electric revenue meter if it is capable of measuring the bi-directional flow of electricity and is within plus or minus 5 percent tolerance when measuring electricity flowing from the customer to the supplier and/or EDC.

(h) If the existing customer’s electricity revenue meter is not capable of measuring the bi-directional flow of electricity within the tolerances specified in subsection (g), an electric distribution company shall install a new meter for the customer-generator, at the company's expense.

(i) The electric distribution company shall not require more than one meter per customer-generator. However, an additional meter may be installed under either of the following circumstances:

1. The electric distribution company may install an additional meter at its own expense if the customer-generator consents; or
2. The customer-generator may request that the company install an additional meter at the customer-generator's expense. The cost for such a meter shall be limited to the actual cost of the meter and its installation.

(j) A supplier or EDC shall not charge a net metered customer any fee or charges or require additional equipment, insurance or any other requirement unless the same would be required of the customer if the customer were not a net metered customer, except that a supplier or EDC may use a special load profile for the customer that incorporates the customer's real time generation provided the special load profile is approved by the PUC.

(k) Future revisions to the procedural or technical requirements of this subchapter may be made through PUC Order.

### Chapter 1-1.4 Interconnection Standards for Customer-Generator Facilities

(a) There are three interconnection review paths for interconnection of customer sited generation in [[State]].

1. Simplified – This is for qualified inverter-based facilities with a power rating of 10 kW or less on radial or spot network systems under certain conditions.
2. Expedited – This is for certified generating facilities that pass certain pre-specified screens and have a power rating of 2 MegaWatts (MW) or less.
3. Standard – This is for all generating facilities not qualifying for either the Simplified or Expedited interconnection review processes that have a power rating of 20 MW or less.

(b) In order to qualify for Simplified or Expedited interconnection procedures, generators no larger than 2MW must be certified pursuant to Section (c) to comply with the following codes and standards as applicable:

1. IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems or IEEE 929 for inverters less than 10kW in size
2. UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
3. When any listed version of these codes and standards is superseded by a revision approved by the standards-making organization, then the revision will be applied under Section (c).

(c) Certification of Equipment Packages: An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacturer, tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous interactive operation with a utility grid in compliance with the applicable codes and standards listed in Subchapter (b) above. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package, which includes a generator or other electric source, it shall not require further design review, testing or additional equipment to meet the certification requirements of this interconnection procedure. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then an interconnection Applicant must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, no further design review, testing or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the utility.

(d) Screening Criteria for Determining Grid Impacts: A proposed interconnection that meets the following applicable screening criteria shall be processed by the EDC under Expedited procedures for interconnection and if qualified for net metering.

1. For interconnection of a proposed generator to a radial distribution circuit, the aggregated generation, including the proposed generator, on the circuit will not exceed 10% (15% for solar based generation) of the total circuit annual peak load as most recently measured at the substation.
2. The proposed generator, in aggregation with other generation on the distribution circuit, will not contribute more than l0% to the distribution circuit’s maximum fault current at the point on the high voltage (primary) level nearest the proposed point of common coupling.
3. The proposed generator, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or customer equipment on the system, to exceed 90 percent of the short circuit interrupting capability; nor is the interconnection proposed for a circuit that already exceeds 90 percent of the short circuit interrupting capability.
4. The proposed generator, in aggregate with other generation interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level busses from the point of common coupling).
5. The proposed generator is interconnected to the EPS as shown in the table below:

| **Primary Distribution Line Configuration** | **Interconnection to Primary Distribution Line** |
|---|---|
| Three-phase, three wire | If a 3-phase or single phase generator, interconnection must be phase-to-phase |
| Three-phase, four wire | If a 3 phase (effectively grounded) or single-phase generator, interconnection must be line-to-neutral |

6. If the proposed generator is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kiloVolt-Amps (kVA).
7. If the proposed generator is single-phase and is to be interconnected on a transformer center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.
8. The proposed generator’s Point of Common Coupling will not be on a transmission line.

(e) Special Screening Criteria for interconnection to spot and area distribution networks. The Screening Criteria under this subsection shall be in addition to the applicable Screens in subsection (d).

1. For interconnection of a proposed generator to a spot network circuit where the generator or aggregate of total generation exceeds 5% of the spot network’s maximum load, the generator must utilize a protective scheme that will ensure that its current flow will not

affect the network protective devices including reverse power relays or a comparable function.

2. For interconnection of a proposed generator that utilizes inverter-based protective functions to an area network, the generator, in aggregate with other exporting generators interconnected on the load side of network protective devices, will not exceed the lesser of 10% of the minimum annual load on the network or 500 kW. For a solar photovoltaic customer-generator facility, the 10% minimum shall be determined as a function of the minimum load occurring during an off-peak daylight period
3. For interconnection of generators to area networks that do not utilize inverter-based protective functions or inverter-based generators that do not meet the requirements of (e) 2 above, the generator must utilize reverse power relays or other protection devices that ensure no export of power from the customer's site including any inadvertent export (under fault conditions) that could adversely affect protective devices on the network circuit.

(f) Each EDC shall have a Simplified interconnection procedure for Inverter-based Generators not exceeding 10kW in capacity, which shall require the following steps.

1. Customer submits an Application filled out properly and completely indicating which certified generator or equipment package the customer intends to use.
2. EDC acknowledges to the customer receipt of the application within three business days of receipt.
3. EDC evaluates the Application for completeness and notifies the customer within 10 days of receipt that the application is or is not complete and whether the generating facility equipment passes screens 1, 6, 7 and 8 in Subchapter (d).
4. Within 3 days of the customer notification under Subchapter 3, the EDC will execute and send a simplified interconnection agreement to customer (unless an agreement is not required by the EDC).
5. Upon receipt of signed application/agreement and completion of installation, EDC may inspect generating facility for compliance with standards and may arrange for a witness test.
6. Provided the inspection/test is satisfactory, EDC notifies Customer in writing that interconnection is allowed, and approves. Customers who do not receive any notice from the EDC within 15 days are deemed approved for interconnection. Final interconnection of the generator is subject to approval by the appropriate electrical code officials.
7. The Simplified interconnection is provided at no cost to the customer. While additional protection equipment not included with the certified generator or interconnection equipment package may be added at the EDC's discretion as long as the performance of the system is not negatively impacted in any way and the customer is not charged for any equipment in addition to that which is included in the certified equipment package.

(g) Each EDC shall have an Expedited interconnection procedure for customer sited generators not exceeding 2MW in capacity that will use existing customer facilities, which shall require the following steps:

1. To assist customers in the interconnection process the EDC will designate an employee or office from which, basic information on the application can be obtained through an informal process. On request, the EDC will provide Applicant with all relevant forms, documents, and technical requirements for filing a Complete Application for interconnection of generators not exceeding 2 MW to the EDC's electric power system. Upon the customer's request, the EDC will meet with the customer prior to submission of an application for expedited interconnection.
2. Customer shall submit an application for Expedited interconnection to the EDC and may, at the same time, submit an Interconnection Agreement executed by the customer.
3. A customer will be notified by the EDC within 3 business days of its receipt of an interconnection application.

4. The EDC will notify the customer within 8 business days of its receipt of the application whether it is complete or incomplete. If the application is incomplete, the EDC will at the same time provide the customer a written list detailing all information that must be provided to complete the application. Applicant will have 10 business days to submit the listed information following receipt of the notice. If Applicant does not submit the listed information to EDC within the 10 business days, the application shall be deemed withdrawn. An application will be complete upon Applicant's submission of the information identified in The EDC's written list.
5. Within 10 business days after The EDC notifies Applicant it received a Complete Application the EDC shall perform an Initial Review of the proposed interconnection, which shall consist of an application of the screening criteria set forth in subsections (d) and (e). The EDC shall notify Applicant of the results, providing copies of the analysis and data underlying the EDC's determinations under the screens. During the Initial Review, the EDC may conduct, at its own expense, any additional studies or tests it deems necessary to evaluate the proposed interconnection.
6. If the Initial Review determines that the proposed interconnection passes the screens set forth in subsections (d) and (e) as applicable, the interconnection application will be approved and the EDC will provide Applicant an executable Interconnection Agreement within 5 business days after the determination.
7. If the Initial Review determines that the proposed interconnection fails one or more screens in subchapters (d) and (e), but the EDC determines through the Initial Review that the small generator may nevertheless be interconnected consistent with safety, reliability, and power quality, with or without minor system modifications, the EDC will provide Applicant an executable Interconnection Agreement within 5 business days after the determination. The generator is responsible for the cost of any minor system modifications required.
8. If the Initial Review determines that the proposed interconnection fails one or more screens in subchapters (d) and (e), and EDC does not or cannot determine from the Initial Review that the generator may nevertheless be interconnected consistent with safety, reliability, and power quality standards, then the EDC will offer to perform an Additional Review if the EDC concludes that Additional Review might determine that the generator could qualify for interconnection pursuant to the Expedited procedures. The EDC will provide a non-binding, but good faith estimate of the costs of such Additional Review when it notifies the customer its proposed interconnection has failed one or more screens in subchapters (d) and (e).
9. Each EDC will include in its net metering and interconnection compliance tariff the procedure it will follow for any Additional Review including the allocation of cost responsibility to the customer.
10. Final interconnection of the customer's generator is subject to commissioning tests as set forth in the IEEE standard 1547 (subsection (b)) and approval by the appropriate local electrical code officials.
11. An application and processing fee may be imposed on customers proposing interconnection of generators under Expedited interconnection procedures provided the total of all fees to complete the interconnection does not exceed \$50 plus \$1.00 per kilowatt of the capacity of the proposed generator. Additional fees may only be charged to customers if their generator interconnection requires minor system modifications pursuant to subchapter (g)(7) or Additional Review pursuant to subchapter (g)(8). Costs for minor system modifications or Additional Review will be based on quotations for services from the EDC and subject to review by the PUC or its designee for such review. Hourly engineering fees for Additional Review shall not exceed \$100 per hour.

(h) An electric distribution company may not require an eligible customer-generator whose system(s) meets the Simplified or Expedited interconnection standards in (b) through (g) above, as applicable, to install additional controls, perform or pay for additional tests or purchase additional liability insurance, except as agreed to by the customer in (g) above.

(i) Each customer generator approved for interconnection shall affix to their electric revenue meter a standard warning sign as approved by the PUC that notifies utility personnel of the existence of customer sited parallel generation.

(j) Each EDC shall have a Standard interconnection procedure available for generators not exceeding 20MW in capacity interconnecting to distribution level voltages that do not qualify for Simplified or Expedited interconnection procedures, which shall consist of the following:

1. The Customer submits an Application for Standard interconnection review; or a customer's interconnection application is transferred from the Simplified or Expedited interconnection procedures for failure to meet all of the requirements of those procedures.
2. The EDC acknowledges to the Interconnecting Customer receipt of the application or the transfer from the Simplified or Expedited interconnection procedures within 3 business days.
3. The EDC evaluates the application for completeness and notifies the Customer within 10 days of receipt that the application is or is not complete and, if not, advises what is missing.
4. The EDC will conduct an initial review that includes a scoping meeting/discussion with the Customer (if necessary) to review the application. At the scoping meeting the EDC will provide pertinent information such as: the available fault current at the proposed location; the existing peak loading on the lines in the general vicinity of the proposed generator; and, the configuration of the distribution lines at the proposed point of interconnection.
5. The EDC provides an Impact Study Agreement, including a cost estimate for the Impact Study. Where the proposed interconnection may affect electric transmission or distribution systems other than that of the EDC where the interconnection is proposed, the EDC shall coordinate, but not be responsible for the timing of any studies required to determine the impact of the interconnection request on other potentially affected electric systems. The Customer will be responsible to any other affected systems for all costs of any additional studies incurred by any other affected system to evaluate the impact of the proposed generator interconnection.

    i. For generators greater than 2MW, the interconnection study may require analysis of power flows and other impacts on the transmission system if the utility has a reasonable belief that the interconnection of the generator will create power flows that reach the transmission system.
    ii. Transmission system interconnection studies will be governed by separate procedures, which may include submission of an application into a transmission interconnection queue.
    iii. Each EDC will identify the circumstances under which generators larger than 2 MW must submit their application into a transmission interconnection queue.

6. For generators that are certified pursuant to 1.4 (b) and (c), no review of the generator's protection equipment is required. While a utility may review a certified generator's protection scheme, it cannot charge for such review.
7. Each EDC will include in its compliance tariff a description of the various elements of an Impact Study it would typically undertake pursuant to this Section including:

    i. Load Flow Study
    ii. Short-Circuit Study
    iii. Circuit Protection and Coordination Study
    iv. Impact on System Operation
    v. Stability Study (and the conditions that would justify including this element in the Impact Study)

vi. Voltage Collapse Study (and the conditions that would justify including this element in the Impact Study).

8. Once the Interconnecting Customer executes the Impact Study Agreement and pays pursuant to the good faith estimate contained therewith, the EDC will conduct the interconnection Impact Study.
9. If the EDC determines, in accordance with Good Utility Practice, that the EDC electric system modifications required to accommodate the proposed interconnection are not substantial, the Impact Study will identify the scope and cost of the modifications as defined in the study results.
10. If the EDC determines, in accordance with Good Utility Practice, that the system modifications to the EDC electric system are substantial, the results of the Impact Study will produce an estimate for the modification costs (within ±25%). The detailed costs of, and the EPS modifications necessary to interconnect the customer's proposed generator will be identified in a Facilities Study to be completed by the EDC.
11. A Facilities Study Agreement, with a good faith estimate of the cost of completing the Facilities Study shall be submitted to the Customer for Customer's approval.
12. Once the Interconnecting Customer executes the Facilities Study Agreement and pays pursuant to the terms thereof, the EDC will conduct the Facilities Study.
13. Upon completion of the Impact and/or Facilities Study, the EDC shall send the Customer an executable Interconnection Agreement including a quote for any required EPS system modifications. .
14. The Customer returns signed Interconnection Agreement.
15. The Customer completes installation of its generator and the EDC completes any EPS system modifications.
16. The EDC inspects completed generator installation for compliance with requirements and attends any required commissioning tests pursuant to IEEE Standard 1547.
17. Provided any required commissioning tests are satisfactory, the EDC shall notify the Customer in writing that interconnection is approved.

(k) Fees for Standard interconnection review shall include an application fee not to exceed $100 plus $2 per kW capacity, as well as charges for actual time spent on the interconnection study. Costs for engineering review shall not exceed $100 per hour. Costs for EDC facilities necessary to accommodate the customer's generator interconnection will be the responsibility of the customer.

**Chapter 1-1.5 Miscellaneous**

(a) An EDC that charges a fee for an interconnection study shall provide the customer-generator with a bill that includes a clear explanation of all charges. In addition, the electric distribution company shall provide to the customer-generator, prior to the start of the interconnection study, a good faith estimate of the number of hours that will be needed to complete the interconnection study, and an estimate of the total interconnection study fee.

(b) If a customer-generator's facility complies with all applicable standards Chapter 1-1.4, the facility shall be presumed to comply with the technical requirements of this subchapter. In such a case, the electric distribution company shall not require a customer-generator to install additional controls (including but not limited to a utility accessible disconnect switch), perform or pay for additional tests, or purchase additional liability insurance in order to obtain approval to interconnect.

(c) Once an interconnection has been approved under this subchapter, the electric distribution company shall not require a customer-generator to test its facility except for the following:

1. An annual test in which the customer-generator's facility is disconnected from the electric distribution company's equipment to ensure that the generator stops delivering power to the grid; and

2. Any manufacturer-recommended testing.

(d) An EDC shall have the right to inspect a customer-generator's facility both before and after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the customer-generator. If the electric distribution company discovers the customer-generator's facility is not in compliance with the requirements of Chapter 1-1.4 and the non-compliance adversely affects the safety or reliability of the electric system, the electric distribution company may require disconnection of the customer-generator's facility until it complies with this subchapter.

**Chapter 1-1.6 Dispute Resolution**

(a) The PUC may from time to time designate a technical master for the resolution of interconnection disputes. If the PUC has so designated, the parties shall use the technical master to resolve disputes related to interconnection and such resolution shall be binding on the parties.

(b) The PUC may designate a Department of Energy national laboratory; college or university; or an approved FERC RTO with distribution system engineering expertise as the technical master.

# Appendix 2. Standard Form Interconnection Application And Agreement For Power Systems 25 kW or Smaller

**Section 1. Customer Information**

Name: ______________________________________________________

Mailing Address: ______________________________________________________

City: _____________________________ , State _____ Zip Code: ___________

Street address (if different than above): ____________________________________________

Daytime Phone: _________________________ Evening Phone: _______________________

Utility Customer Account Number (from utility bill): __________________________

**Section 2. Generating Facility Information**

System Type: ☐ Solar ☐ Wind ☐ Hydro ☐ Fuel Cell Generator Size (kW AC): _______

Class 1 generator? (Y/N)

Inverter Manufacturer: __________________ Inverter Model: ____________________

Inverter Serial Number: ________________ Inverter Power Rating: _____________________

Inverter Location: ___________________________________

Disconnect Type: ☐ Separate Manual Disconnect – Location: _______________

☐ Meter Removal (If the Generator Owner elects not to install a manual disconnect device accessible to Utility, the Utility shall not be liable when a service meter is removed to disconnect the generator thereby interrupting all utility electric service to the Customer site)

**Section 3. Planned Installation Information**

Licensed Electrician: ________________________________ Contractor #: ______________

Mailing Address: ______________________________________________________

City: _____________________________ , State: _____, Zip Code:___________

Daytime Phone #: _________________________ Planned Installation date:_______________

**Section 4. Certifications**

1. The generating facility' the requirements of applicable IEEE standards and is listed by Underwriters Laboratories (UL) or other nationally recognized testing laboratory

Signed (Equipment Vendor):_______________________________Date:________________

Name (Printed) ____________________________ Company: _______________________

Listing _______________ (UL or other NRTL)

**Section 5. Utility and Building Division Inspection and Approval (to be completed by utility after installation)**

1. Application Approved: ____________________________ Date: ___________________

2. System Inspection by: ____________________________ Inspection Date: ___________

# Appendix 3. Model Interconnection Application For Use With Generators up to and Including 20 MW

**Preamble**

An applicant (Interconnection Applicant) hereby makes application to _____________ (Utility) to install and operate a generating facility up to and including 20 MW interconnected with the ______________ utility system. This application will be considered as an application for interconnection of generators under Expedited interconnection review provided the generator is not greater than 2 MW but shall serve as an Application for Standard interconnection review if greater than 2 MW or if Expedited review does not qualify the generator for interconnection.

Written applications should be submitted by mail, e-mail or telefax to the [Utility], as follows:
[Utility]:_________________________________________
[Utility's] Address:____________________________________________________
____________________________________________________
____________________________________________________
Telefax Number:______________________________________________
E-Mail Address: ______________________________________________

[Utility] Contact Name:_______________________________________________
[Utility] Contact Title:_______________________________________________

An application is a Complete Application when it provides all applicable information required below. (Additional information to evaluate a request for interconnection may be required and will be so requested from the Interconnection Applicant by Utility after the application is deemed complete).

**Section 1. Applicant Information**

Legal Name of Interconnecting Applicant (or, if an Individual, Individual's Name)

Name:_______________________________________________________________________

Mailing Address: __________________________________________________________________

City: ___________________________ State:_______________ Zip Code: ________________

Facility Location (if different from above): ______________________________________________

Telephone (Daytime): ____________________ (Evening) ___________________
Facsimile Number:_____________________________
E-Mail Address:______________________________

| | |
|---|---|
| ___________________________________ | ______________________________________ |
| (Utility) | (Existing Account Number, if generator to be interconnected on the customer side of a utility revenue meter) |

Type of Interconnect Service Applied for (choose one): ________ Network Resource, _______ Energy Only, ______ Load Response (no export) ________ Net metering

**Section 2. Generator Qualifications**

***All data collected in Sections 2, 3, and 4 are applicable only to the generator facility, NOT the necessary interconnection facilities***

Fuel Type or Renewable Energy Source:_______________________________________________

If proposed generator or equipment package certified list UL or equivalent testing number

Equipment Type Testing Procedure or Listing

1. ___________________ ________________________________
2. ___________________ ________________________________
3. ___________________ ________________________________
4. ___________________ ________________________________

Generator Nameplate Rating: __________________ kW (Typical)
Generator Nameplate KVAR: __________________ (Reactive Load)
Maximum Physical Export: ____________________ kW (or estimate if not known).
Type of Generator: ____ Synchronous ____Induction ____DC Generator or Solar with Inverter

**Section 3. Generator Technical Information – may be omitted in initial application if data not available)**

Generator (or solar collector) Manufacturer, Model Name & Number:
____________________________________________________________________________
Version Number_______________________
Nameplate Output Power Rating in kW: (Summer)___________(Winter)____________
Nameplate Output Power Rating in kVA: (Summer)___________(Winter)____________
Individual Generator Power Factor
Rated Power Factor Leading_______
Rated Power Factor Lagging_____________
Total Number of Generators in Wind Farm to be interconnected pursuant to this application:________
Elevation _____________ _____ Single phase _____ Three phase
Inverter Manufacturer, Model Name & Number (if used):
_________________________________________________________________________
Adjustable Setpoints (if any)
__________________________________________________________________________

Generator Characteristic Data (for rotating machines): (to be completed only where Utility requests dynamic study)
Direct Axis Transient Reactance, $X'_d$: _______ P.U.
Direct Axis Unsaturated Transient Reactance, X'di:__________P.U.
Direct Axis Subtransient Reactance, $X''_d$: _______ P.U.
Direct Axis Unsaturated Substransient Reactance, $X''_{di}$:__________P.U.
RPM Frequency_____________
Total Rotating Inertia, H:________Per Unit on KVA Base

**Section 4. Interconnecting Equipment Technical Data – this section may be omitted in initial application if data is not available.**

Will a transformer be used between the generator and the point of interconnection?
____Yes ___ No

Transformer Data (if applicable, for Interconnection Applicant Owned Transformer):

Size: ______ KVA .
Transformer Primary : ________ Volts ___Delta ____ Wye _____Wye Grounded
Transformer Secondary: ________ Volts ___Delta ____ Wye _____Wye Grounded Transformer Impedance: ______% on ______ KVA Base

Transformer Fuse Data (if applicable, for Interconnection Applicant Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt & Total Clearing Time-Current Curves)

Manufacturer: ____________ Type: ___________ Size: ____________ Speed: __________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: _________________ Type: ______________ Load Rating (Amps): ______
Interrupting Rating (Amps): _______ Trip Speed (Cycles): ____

Circuit Breaker Protective Relays (if applicable):
(Enclose copy of any proposed Time-Overcurrent Coordination Curves)

Manufacturer: _____________ Type: _____________ Style/Catalog No.: _______________
Proposed Setting: ____________________

Manufacturer: _____________ Type: _____________ Style/Catalog No.: _______________
Proposed Setting: ____________________

Manufacturer: _____________ Type: _____________ Style/Catalog No.: _______________
Proposed Setting: ____________________

Manufacturer: _____________ Type: _____________ Style/Catalog No.: _______________
Proposed Setting: ____________________

Current Transformer Data (if applicable):
(Enclose copy of Manufacturer's Excitation & Ratio Correction Curves)

Manufacturer: ____________________ Type: ___________ Accuracy Class: _____________
Proposed Ratio Connection: ______/5
Manufacturer: ____________________ Type: ___________ Accuracy Class: _____________
Proposed Ratio Connection: ______/5

Potential Transformer Data (if applicable):

Manufacturer: ______________________ Type: __________ Accuracy Class: _____________
Proposed Ratio Connection: ______/5

Manufacturer: ______________________ Type: __________ Accuracy Class: _____________
Proposed Ratio Connection: ______/5

**Section 5. General Technical Information**

Requested Point of Interconnection (if known): ___________________________________

Interconnection Applicant's requested in-service date_______________________________

Enclose copy of site preliminary electrical One-Line Diagram showing the configuration of all generating facility equipment, current and potential circuits and protection and control schemes.
Is preliminary One-Line Diagram Enclosed?: _____Yes

Enclose copy of any site documentation, including USGS topographic map or other diagram or documentation that indicates precise physical location of generating facility.

**Section 6. Applicant Signature**

**I hereby certify that, to the best of my knowledge, all the information provided in the Interconnection Application is true and correct. I also agree to install a Warning Label provided by (utility) on or near my service meter location. Generating systems must be compliant with IEEE*, NEC, ANSI, and UL standards, where applicable.* By signing below, the Applicant also certifies that the installed generating equipment meets the appropriate preceding requirement(s) and can supply documentation that confirms compliance.**

Signature of Applicant: ______________________________________ Date: ___________

**Section 7. Information Required Prior to Physical Interconnection (Not required as part of the application, unless available at time of application.)**

Installing Electrician: ____________________ Firm: ___________________
License No.: _____________
Mailing Address: ________________________________________________________________________
City: _________________________ State:____________________ Zip Code: _________________
Telephone: __________________________

Installation Date: ____________________________
Interconnection Date: _____________________________

Signed (Inspector – if required): ___________________________________
Date: ___________________________
(In lieu of signature of Inspector, a copy of the final inspection certificate may be attached)

# Appendix 4. Agreement for Interconnection and Parallel Operation of Distributed Generation (Generators Less Than 20 MW Capacity)

This Interconnection Agreement ("Agreement") is made and entered into this ________ day of ________________, 20__, by ______________________________________("Company"), and ____________________________________________ ("Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties".

**Customer Information:** **Company Information:**

Name: _________________________________ Name: _______________________________

Address: _______________________________ Address: _____________________________

Telephone: _____________________________ Telephone: ___________________________

DG Application No. ___________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

**1. Scope and Purpose of Agreement:**
This Agreement describes *only* the conditions under which the Company and the Customer agree that the distributed generating facility or facilities ("DG") described in Exhibit A may be interconnected to and operated in parallel with the utility company's system. Other services that the Customer may require from the Company will be covered under separate agreements. The technical terms used in this agreement are defined in Exhibit B.

The following exhibits are specifically incorporated into and made a part of this Agreement:
Exhibit A: Summary and Description of Interconnection
Exhibit B: Technical Definitions

**2. Summary and Description of Customer's Distributed Generation Equipment/Facility to be Included in Exhibit A:**
A description of the Generating Facility, including a summary of its significant components and a diagram showing the general arrangement of Customer's DG and loads that are interconnected with Company's electric distribution system, is attached to and made a part of this Agreement as Exhibit A.

**2.1** DG identification number: _________________ (Assigned by the Company)
**2.2** Company's customer electric service account number: ____________ (Assigned by Company)
**2.3** Customer's name and address as it appears on the Customer's electric service bill from the Company:

________________________
________________________
________________________

**2.4** Capacity of the DG is: _____ kW.
**2.5** The expected annual energy production of the DG is ______ kWh.
**2.6** For the purpose of identifying eligibility of the Customer's DG for consideration under the federal Public Utility Regulatory Practices Act of 1978 ("PURPA"), and amendments, the Customer hereby declares that the DG _ does/ _ does not meet the requirements for "Cogeneration" as such term is used under applicable federal or state rules or laws.
**2.7** The DG's expected date of Initial Operation is ____________. The expected date of Initial Operation shall be within two years of the date of this Agreement.

**3. Operating Requirements**
Customer shall operate and maintain the generator in accordance with the applicable manufacturer's recommended maintenance schedule, in compliance with all aspects of the Interconnection Tariff. The Customer will continue to comply with all applicable laws and requirements after interconnection has occurred. In the event the EDC has reason to believe that the Customer's installation may be the source of problems on the EDC's EPS, the EDC has the right to install monitoring equipment at a mutually agreed upon location to determine the source of the problems. If the generator is determined to be the source of the problems, the EDC may require disconnection as outlined in Service Agreement. The cost of this testing will be borne by the EDC unless the EDC demonstrates that the problem or problems are caused by the generator or if the test was performed at the request of the Customer.

**4. No Adverse Effects; Non-interference**
The EDC shall notify the Customer if there is evidence that the operation of the generator could cause disruption or deterioration of service to other Customers served from the same EDC EPS or if operation of the generator could cause damage to the EDC's EPS. The deterioration of service could be, but is not limited to, harmonic injection in excess of IEEE STD519, as well as voltage fluctuations caused by large step changes in loading at the Facility.

Each party will notify the other of any emergency or hazardous condition or occurrence with its equipment or facilities, which could affect safe operation of the other party's equipment or facilities. Each party shall use reasonable efforts to provide the other party with advance notice of such conditions.

The EDC will operate the EPS in such a manner so as to not unreasonably interfere with the operation of the generator. The Customer will protect itself from normal disturbances propagating through the EDC's EPS, and such normal disturbances shall not constitute unreasonable interference unless the EDC has deviated from Good Utility Practice. Examples of such disturbances could be, but are not limited to, single-phasing events, voltage sags from remote faults on the EDC's EPS, and outages on the EDC's EPS. If the Customer demonstrates that the EDC's EPS is adversely affecting the operation of the generator and if the adverse effect is a result of an EDC deviation from Good Utility Practice, the EDC shall take appropriate action to eliminate the adverse effect.

**5. Safe Operations and Maintenance**
Each party shall operate, maintain, repair, and inspect, and shall be fully responsible for, the facility or facilities that it now or hereafter may own unless otherwise specified in the Service Agreement. Each party shall be responsible for the maintenance, repair and condition of its respective lines and appurtenances on their respective side of the PCC. The EDC and the Customer shall each provide equipment on its respective side of the PCC that adequately protects the EDC's EPS, personnel, and other persons from damage and injury.

**6. Access (see Section 17)**

**7. EDC and Customer Representatives**
Each party shall provide and update as necessary the telephone number that can be used at all times to allow either party to report an emergency.

**8. EDC Right to Access EDC-Owned Facilities and Equipment**
If necessary for the purposes of the Service Agreement and in the manner it describes, the Customer shall allow the EDC access to the EDC's equipment and the EDC's facilities located on the Customer's premises. To the extent that the Customer does not own all or any part of the property on which the EDC is required to locate its equipment or facilities to serve the Customer, the Customer shall secure and provide in favor of the EDC the necessary rights to obtain access to such equipment or facilities, including easements if the circumstances so require.

**9. Right to Review Information**
Except for customer-generators interconnected under the Simplified procedures, the EDC shall have the right to review and obtain copies of the Customer's operations and maintenance records, logs, or other information such as, unit availability, maintenance outages, circuit breaker operation requiring manual reset, relay targets and unusual events pertaining to Customer's generator or its interconnection with the EDC's EPS. This information will be treated as customer-confidential and only used for the purposes of meeting the requirements of this section.

**10. Prior Authorization**
Except for generators using Simplified interconnection procedures, for the mutual protection of the Customer and the Company, the connections between the Company's service wires and the Customer's service entrance conductors shall not be energized without prior authorization of the Company, which authorization shall not be unreasonably withheld.

**11. Warranty Is Neither Expressed Nor Implied**
Neither by inspection, if any, or non-rejection, nor in any other way, does the Company give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Customer or leased by the Customer from third parties, including without limitation the DG and any structures, equipment, wires, appliances or devices appurtenant thereto**.**

**12. Liability Provisions**
**12.1 Limitation of Liability**
Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever.

**12.2 Indemnification**
a. Notwithstanding Paragraph 6.1 of this Agreement, the Company shall assume all liability for and shall indemnify the Customer for any claims, losses, costs, and expenses of any kind or character to the extent that they result from the Company's negligence in connection with the design, construction, or operation of its facilities as described on Exhibit A; provided, however, that the Company shall have no obligation to indemnify the Customer for claims brought by claimants who cannot recover directly from the Company. Such indemnity shall include, but is not limited to, financial responsibility for: (a) the Customer's monetary losses; (b) reasonable costs and expenses of defending an action or claim made by a third person; (c) damages related to the death or injury of a third person; (d) damages to the property of the Customer; (e) damages to the property of a third person; (f) damages for the disruption of the business of a third person. In no event shall the Company be liable for consequential, special, incidental or punitive damages, including, without limitation, loss of profits, loss of revenue, or loss of production. The Company does not assume liability for any costs for damages arising from the disruption of the business of the Customer or for the Customer's costs and expenses of prosecuting or defending an action or claim against the Company. This paragraph does not create a liability on the part of the Company to the Customer or a third person, but requires indemnification where such liability exists. The limitations of liability provided in this paragraph do not apply in cases of gross negligence or intentional wrongdoing. b. Notwithstanding Paragraph 6.1 of this Agreement, the Customer shall assume all liability for and shall indemnify the Company for any claims, losses, costs, and expenses of any kind or character to the extent that they result from the Customer's negligence in connection with the design, construction, or operation of its facilities as described on Exhibit A; provided, however, that the Customer shall have no obligation to indemnify the Company for claims brought by claimants who cannot recover directly from the Customer. Such indemnity shall include, but is not limited to, financial responsibility for: (a) the Company's monetary losses; (b) reasonable costs and expenses of defending an action or claim made by a third person; (c) damages related to the death or injury of a third person; (d) damages to the property of the Company; (e) damages to the property of a third person; (f) damages for the disruption of the business of a third person. In no event

shall the Customer be liable for consequential, special, incidental or punitive damages, including, without limitation, loss of profits, loss of revenue, or loss of production. The Customer does not assume liability for any costs for damages arising from the disruption of the business of the Company or for the Company's costs and expenses of prosecuting or defending an action or claim against the Customer. This paragraph does not create a liability on the part of the Customer to the Company or a third person, but requires indemnification where such liability exists. The limitations of liability provided in this paragraph do not apply in cases of gross negligence or intentional wrongdoing.

**12.3 Force Majeure**
If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible.

**13. Insurance**
The Customer is not required to provide general liability insurance coverage as part of this Agreement, or any other Company requirement. At no time shall the Company require that the Customer negotiate any policy or renewal of any policy covering any liability through a particular insurance company, agent, solicitor, or broker.

**14. Effect**
The inability of the Company to require the Customer to provide general liability insurance coverage for operation of the DG is not a waiver of any rights the Company may have to pursue remedies at law against the Customer to recover damages.

**15. Severability**
If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction, such portion or provision shall be deemed separate and independent, and the remainder of this Agreement shall remain in full force and effect.

**16. Notices**
Any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:
If to Customer: ____________________________(Customer Name)
Address: __________________________________
City: ______________________
Phone: __________________
FAX: ___________________
If to Company: _____________________________(Company Name)
Address: __________________________________
City: ______________________
Phone: __________________
FAX: ___________________

**16.1 Notices**
A Party may change its address for Notices at any time by providing the other Party Notice of the change in accordance with Section 10.

**16.2 Communications**
The Parties may also designate operating representatives to conduct the daily communications which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's Notice to the other in accordance with Section 10.

**17. Right of Access, Equipment Installation, Removal and Inspection**
Upon reasonable notice, the Company may send a qualified person to the premises of the Customer at or immediately before the time the DG first produces energy to inspect the interconnection, and observe the DG's commissioning (including any required testing), startup, and operation for a period of up to no more than three days after initial start-up of the unit. In addition, the customer shall notify the company at least seven days prior to conducting any on-site Verification Testing of the DG.

Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, Company shall have access to Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

**18. Disconnection of Unit**
Customer retains the option to temporarily disconnect from Company's Company system at any time. Such temporary disconnection shall not be a termination of the Agreement unless Customer exercises its termination rights under Section 19.

Subject to Commission Order or Rule, for routine maintenance and repairs on Company's Company system, Company shall provide Customer with seven days' notice of service interruption. The Company shall have the right to disconnect service to Customer without notice to eliminate conditions that constitute a potential hazard to Company personnel or the general public. The Company shall notify the Customer of the emergency as soon as circumstances permit.

The Company may disconnect the DG, after notice to the Customer has been provided and a reasonable time to correct, consistent with the conditions, has elapsed, if the DG adversely affects the quality of service of adjoining customers.

If, after the DG has been commissioned, the operations of the Company are adversely affecting the performance of the DG or the Customer's premises, the Company shall immediately take appropriate action to eliminate the adverse effect. If the Company determines that it needs to upgrade or reconfigure its system the Customer will not be responsible for the cost of new or additional equipment on the Company's side of the Point Of Common Coupling between the Customer and the Company.

**19. Effective Term and Termination Rights**

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. The agreement may be terminated for the following reasons: (a) Customer may terminate this Agreement at any time, by giving the Company sixty days' written notice; (b) Company may terminate upon failure by the Customer to generate energy from the Facility in parallel with the Company's system by the later of two years from the date of this agreement or twelve months after completion of the interconnection; (c) either party may terminate by giving the other party at least sixty days prior written notice that the other Party is in default of any of the material terms and conditions of the Agreement, so long as the notice specifies the basis for termination and there is reasonable opportunity to cure the default; or (d) Company may terminate by giving Customer at least sixty days notice in the event that there is a material change in an applicable rule or statute concerning interconnection and parallel operation of the DG, unless the Customer's installation is exempted from the change or the Customer complies with the change in a timely manner. Nothing in this provision shall limit the ability of the Company to disconnect the Customer without providing notice as specified herein if necessary to address a hazardous condition. Upon termination of this Agreement the DG will be disconnected from the Company's electric system. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

**20. Governing Law/Regulatory Authority**

This Agreement was executed in the State of [[State]] and must in all respects be governed by, interpreted, construed, and enforced in accordance with the laws thereof. This Agreement is subject to, and the parties' obligations hereunder include, maintaining and operating in full compliance with all valid, applicable federal, State, and local laws or ordinances, and all applicable rules, regulations, orders of, and tariffs approved by, duly constituted regulatory authorities having jurisdiction.

**21. Assignments**

**21.1 Assignment to Corporate Party**

At any time during the term, the Customer may assign this Agreement to a corporation or other entity with limited liability, provided that the Customer obtains the consent of the Company. Such consent will not be withheld unless the Company can demonstrate that the corporate entity is not reasonably capable of performing the obligations of the assigning Customer under this Agreement.

**21.2 Assignment to Individuals**

At any time during the term, a Customer may assign this Agreement to another person, other than a corporation or other entity with limited liability, provided that the assignee is the owner, lessee, or is otherwise responsible for the DG.

**22. Confidentiality**

**23. Dispute Resolution**

Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner, consistent with applicable Commission Rules.

**24. Amendment and Notification**

This Agreement can only be amended or modified by a writing signed by both Parties.

**25. Entire Agreement**
This Agreement constitutes the entire Agreement between the Parties and supersedes all prior agreements or understandings, whether verbal or written. It is expressly acknowledged that the Parties may have other agreements covering other services not expressly provided for herein, which agreements are unaffected by this Agreement.

**26. Non-Waiver**
None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to this agreement to insist, on any occasion, upon strict performance of any provision of this agreement will not be considered to waive the obligations, rights, or duties imposed on the Parties.

**27. No Third Party Beneficiaries**
This agreement is not intended to and does not create rights, remedies, benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of Parties, their successors in the interest and, where permitted, their assigns.

**Signatures**
IN WITNESS WHEREOF, the Parties have caused this Agreement to be signed by their respective duly authorized representatives.

| | |
|---|---|
| [COMPANY NAME] | [CUSTOMER NAME] |
| BY: ________________________ | BY: ____________________________ |
| TITLE: ________________________ | TITLE: ____________________________ |
| DATE: ________________________ | DATE: ____________________________ |

**Exhibit A**
*[Attach customer's completed interconnection application here]*

**Exhibit B**

**Definitions for Terminology Used in the Agreement**
- **Commission –** The utility regulator in [[State]]
- **Company** - An electric Company operating a distribution system.
- **Customer –** Any entity interconnected to the Utility Company system for the purpose
- of receiving [or exporting] electric power from [or to] the Utility Company system.
- **Distributed Generation ("DG") –** An electrical generating installation consisting of one or more on-site generating units. The total capacity of the aggregated generating units to be interconnected at any Point Of Common Coupling under this Agreement shall not exceed 2 Megawatts.
- **Force Majeure Event** - For purposes of this Agreement, a "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected Party; and (b) that the affected Party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lightning, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes; and sabotage.
- **Indemnification –** Protection against or being kept free from loss or damage.
- **Interconnection** – The physical connection of distributed generation to the Company system in accordance with the requirements of this Agreement so that parallel operation can occur.
- **Interconnection Agreement ("Agreement")** – This standard form of Agreement,
- The Agreement sets forth the contractual conditions under which the Company and the Customer agree that DG may be interconnected with the Company's system.
- **On-site Generating Units (or Distributed Generation**) [get definition]
- **Standardized Application –** The standard application for interconnection and parallel operation with the Company system, approved by the Commission.
- **Company System –** A Company's distribution system to which the distributed generation equipment is interconnected.

**Exhibit C**
**Allocation of Cost Responsibility for the Design, Installation, Operation, Maintenance and Ownership of the Interconnection Facilities, if any.**

**Note: this Interconnection Agreement (IA) is substantially similar to the NARUC model**

# Appendix 5. IREC Model Net Metering Policy

AN ACT RELATING TO NET METERING FOR CERTAIN RENEWABLE ENERGY SYSTEMS

Be It Promulgated by the Regulatory Commission of the State of ____________:

**Section 1.** INTENT. The Commission finds that a net energy metering program for customers with renewable-fuel electric generating facilities encourages private investment in renewable energy resources, stimulates the economic growth of this state, encourages energy independence and security, and enhances the continued diversification of this state's energy resources; now, therefore,

**Section 2.** DEFINITIONS. The definitions in this section apply throughout this chapter unless the context clearly indicates otherwise.

(1) "Commission" means the [State Public Utilities Commission] as defined in [State] Code [#].

(2) "Customer-Generator" means a non-utility owner or operator of a net metering facility that is not larger than 25kW if installed at a residential service or not larger than 1000kW at other customer service locations.

(3) "Electric Utility" means:
- (a) a public utility regulated under Title [#] of the [State] Code;
- (b) a municipal utility operating under [State] Code [#];
- (c) a cooperative electrical association as defined in [State] Code [#]; or
- (d) an irrigation district operating under [State] Code [#]

that is engaged in the business of distributing electricity to retail electric customers in the state.

(4) "Eligible Renewable Energy Resource" means electricity generation facilities or fuel cells fueled by: [[options]]
- (a) wind;
- (b) solar energy;
- (c) geothermal energy;
- (d) methane gas from landfills, sewage treatment plants, or animal wastes;
- (e) biomass energy [[define]]
- (f) hydropower.

(5) "Governing Body" means the governing body of a municipal utility operating under [State] Code [#], a cooperative electrical association as defined in [State] Code [#], or an irrigation district operating under [State] Code [#].

(6) "Net Metering" means the difference between the electricity supplied by an electric utility and the electricity generated by a customer-generator over the applicable billing period and that is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(7) "Net Metering System" means using a single meter to measure the difference between the electricity supplied by an electric utility and the electricity generated by a customer-generator interconnected and operated in parallel with an electric utility.

**Section 3.** NET METERING. An electric utility:

(1) Shall offer to make net metering available to customer-generators on a first-come, first-served basis; provided, that after the cumulative generating capacity of net metering systems equals 2% of the utility's single hour peak load during the previous year, the obligation of a utility to offer net metering to a new customer-generator may be limited by the Commission, for a public utility, or the

governing body for other electric utilities, in order to balance the interests of retail customers.

When limiting net metering obligations under this subsection, the Commission, for a public utility, or the governing body, for other electric utilities shall consider the economic, environmental and other public policy benefits of net metering systems. The Commission may limit net metering obligations under this subsection only following notice and opportunity for public comment. The governing body, for other electric utilities, may limit net metering obligations only following notice and opportunity for comment from the customers of the utility, cooperative, or district.

(2) Shall allow net metering facilities to be interconnected using a standard kilowatt-hour meter that is capable of registering the flow of electricity in two directions.

(3) May, at its own expense and with the customer-generator's consent, install one or more additional meters to monitor the flow of electricity in each direction.

(4) Shall offer to the customer-generator a tariff or contract, that is identical, in energy rates, rate structure, and monthly charges, to the contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator, but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge.

(5) Shall not require a customer-generator to surrender or convey any marketable environmental attributes related to the renewable or other qualities of their generation at less than market value. Marketable environmental attributes include, but are not limited to, green tags, renewable energy certificates and generation used to meet state or federal renewable portfolio standards.

(5) Shall disclose annually the availability of the net metering program to each of its customers, with the method of disclosure being at the discretion of the electric utility.

**Section 4.** NET ENERGY MEASUREMENT; BILLING. Consistent with the other provisions of this Act, the net energy measurement must be calculated in the following manner:

(1) For a customer-generator, an electric utility shall measure the net electricity produced or consumed during the billing period in accordance with normal metering practices of customers in the same rate class.

(2) If the electricity supplied by the electric utility exceeds the electricity generated by the customer-generator during the billing period, the customer-generator shall be billed for the net electricity supplied by the electric utility in accordance with normal metering practices of customers in the same rate class.

(3) If the electricity generated by the customer-generator exceeds the electricity supplied by the electric utility during the billing period, the customer-generator shall be billed for the appropriate customer charges for that billing period, in accordance with Section 3 of this Act, and shall be credited for the excess kilowatt-hours generated during the billing period, with this kilowatt-hour credit applied to the following billing period. Any excess kilowatt credits shall be granted to the utility when a customer closes their account [[option for retail competition jurisdictions]] or switches electricity suppliers.

(4) An electric utility may require customer-generators take service under an existing non time of use tariff that it offers to similarly situated customers without generators, if it also installs, at its own cost, a non time of use meter for the customer-generator and demonstrates to the Commission that a non time of use tariff and meter would be a less costly method to implement this requirements of this section. The customer-generator must consent to service under the non time-of use tariff.

**Section 5.** NET METERING SYSTEMS.

(1) A net metering system used by a customer-generator shall include, at the customer-generator's own expense, all equipment necessary to meet applicable safety, power quality and interconnection requirements established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories.

(2) An electric utility may not require a customer-generator whose net metering system meets the standards in subsection (1) of this section to comply with additional safety or performance standards, perform or pay for additional tests, or purchase liability insurance. An electric utility shall not be liable directly or indirectly for permitting or continuing to allow an attachment of a net metering system, or for the acts or omissions of the customer-generator that cause loss or injury, including death, to any third party.

(3) An electric utility may require a customer-generator to enter into an interconnection agreement prior to the commissioning of a customer-generator's facility. If required, the utility shall file with the Commission a simplified standard form interconnection agreement for systems located at a residential service.

**SECTION 6.** Sections 1 through 5 of this Act constitute a new chapter in Title [#] [State] Code.

STATEMENT OF PURPOSE

The proposed rules intend to provide for a program of net metering for utility customers with small-scale, electric generating facilities utilizing renewable fuels to encourage private investment in renewable energy sources, stimulate the economic growth of the state, provide customers with options to reduce demand for utility provided power, increase energy independence and security, and enhance the continued diversification of [State]'s energy resources.

FISCAL NOTES -- None.

*[[Note 1: Section 4 (4) is added as an option because time of use reversible meters are expensive and time of use tariffs can be administratively difficult to implement for net metered customers (e.g. excess production in one time bin must be manually credited to another). An NREL study showed time of use may be advantageous to solar net metering but the extent of the benefit was minor. Typically 2 days of the week are off peak periods – thus 28% of PV production falls into the very low cost off peak rate category.*

*[[Note2: There should be language added that limits the size of a customer's generator to something less than the current service entrance capacity of the customer's existing service. Utility system upgrades to accommodate larger generators should be exempted from the no additional costs provisions.]]*

*[[Note3: for the larger sized systems (>100kW), there should be parallel interconnection procedures that dovetail with these Net Metering provisions.]]*

# Appendix 6. Interconnection Rules for DG and Non-net metered Renewables

| State (utility)[7] | Net metering | Effective or in progress (IP)[8] | Applic. Cost[9] | Sep. Rules for small DG & renewables[10] | Breakpoint for small system (simplified) rules | Tech-nologies | Sys. Size limit | Stand. Agree-ment | Addi-tional insur-ance | Screening process for intercon-nection studies | Network intercon-nection addressed | Agency / Authority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arizona (SRP) | Y | 2002 | | N | 50 kW | All DG | NA | Y | Y | Y | N | Utility |
| Arizona (APS) | Y | 2002 | | N | 50 kW | All DG | NA | Y | Y | Y | N | Utility |
| Arizona (TEP) | Y | 2002 | | N | 50 kW | All DG | NA | Y | Y | Y | N | Utility |
| California | Y | 2000 | $800 (plus $600 for supp. review) | Y | Depends on screens, but generally 11kVA. | All DG | 10 MW | Y | N | Y | N | CPUC |
| Colorado (Coops) | N | 2002 | None | Y | Varies by utility | Renewab les | NA | N | N | N | N | Legislature |
| Colorado (Xcel) | Y | 1996 | None | Y | 100kW | All DG | NA | Y | Y | N | N | COPUC |
| Connecticut | Y | IP | Y | Y | 10kW | All DG | 25MW | Y | Y | Y | Y | CT DPUC |
| Delaware (Conectiv;DEC) | N | 2000 (update IP) | N | Y | 25 kW | All DG | 1 MW | Y (Conectiv) | Y (DEC) | N | N | DPSC |
| Hawaii | Y | 2003 | | Y | 10 kW | All DG | NA | Y | N | N | N | HI PUC |
| Idaho (ID Power) | Y | 2002 | | Y | 100 kW | All DG | 1 MVA | N | N | N | N | ID PUC |
| Illinois (ComEd) | Y | 1999 | | Y | 25 kW 40 kW if net metered | All DG | NA | N | N | N | Not allowed (applies to downtown Chicago) | Utility |

[7] Where interconnection rules only apply to specific utilities or were developed by particular utilities, they are listed in parentheses.
[8] For states listed in progress (IP) information is based either on draft rules or likely consensus positions among stakeholders. Dashes indicate undecided issues.
[9] ND = Not determined. This applies to states or utilities where there are ongoing discussions and particular aspects of the rules are still under consideration.
[10] Many states and utilities have a separate set of interconnection rules for very small, e.g. < 25kW, renewable and DG systems. Frequently such rules are tied to a state's net metering rules.

| State (utility) | Net metering | Effective or in progress (IP) | Applic. Cost | Sep. Rules for small DG & renewables | Breakpoint for small system (simplified) rules | Tech-nologies | Sys. Size limit | Stand. Agree-ment | Addi-tional insur-ance | Screening process for intercon-nection studies | Network intercon-nection addressed | Agency / Authority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Indiana | Y | IP | ND | Y | 10 kW | All DG | ND | ND | ND | ND | N | IURC |
| Iowa | Y | IP | ND | ND | ND | All DG | ND | ND | ND | ND | ND | IA DNR |
| Kansas | N | IP | ND | Y | ND | All DG | 5 MW | Y | ND | ND | N | KCC |
| Louisiana | Y | IP | ND | Y | 25 kW resid 100 kW com. | Renewab les | 100 kW | N | ND | ND | N | LPSC |
| Massachuset ts | Y | 2004 | $3 per kW; $2500 max | Y | 10 kW | All DG | None | Y | Y | Y | Y | MA DTE |
| Michigan | N | 2003 | $0.50 per kW; $500 max | Y | 30 kW, 150kW, 750kW, 2MW | All DG | None | Y | N | N | N | MI PSC |
| Minnesota | Y | IP | ND | Y | 40 kW | All DG | ND | Y | ND | ND | ND | MN PUC |
| Missouri | N | 2003 | | Y | 100 kW | All DG | 10 MW | Y | Y | N | N | MO PSC |
| New Jersey | Y | IP | ND | Y | Depends on screens, but generally 25kW | All DG | 20MW | Y | N | Y | Y | NJBPU |
| New York | Y | 2000 (modifications in progress) | Depends on sys size | Y | 10kW | All DG | 300kW | Y | Y | Y | Y | NYPSC |
| North Carolina | N | IP | ND | Y | 20 kW residential 100 kW com. | All DG | 20MW | Y | N | N | N | NCUC |
| Ohio | Y | 2001 | Varies | Y | 25 kW | All DG | 300 kW | Y | N | N | N | OH PUC |
| Texas | Y | 2000 | Varies | Y | 10 kW | All DG | 10 MW | Y | N | Y | N | TX PUC |
| Virginia | Y | IP | ND | Y | 10 kW residential 40 kW com | All DG | 10 MW | Y | N | N | N | VA SCC |
| Wisconsin | Y | 2004 | Varies | Y | 20 kW | All DG | 15 MW | Y | N | N | N | WI PSC |
| IREC Model | Y | NA | | Y | 25 kW | All DG | 20 MW | Y | N | Y | Y | NA |

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