Distributed Generation Interconnection Manual

Public Utility Commission of Texas

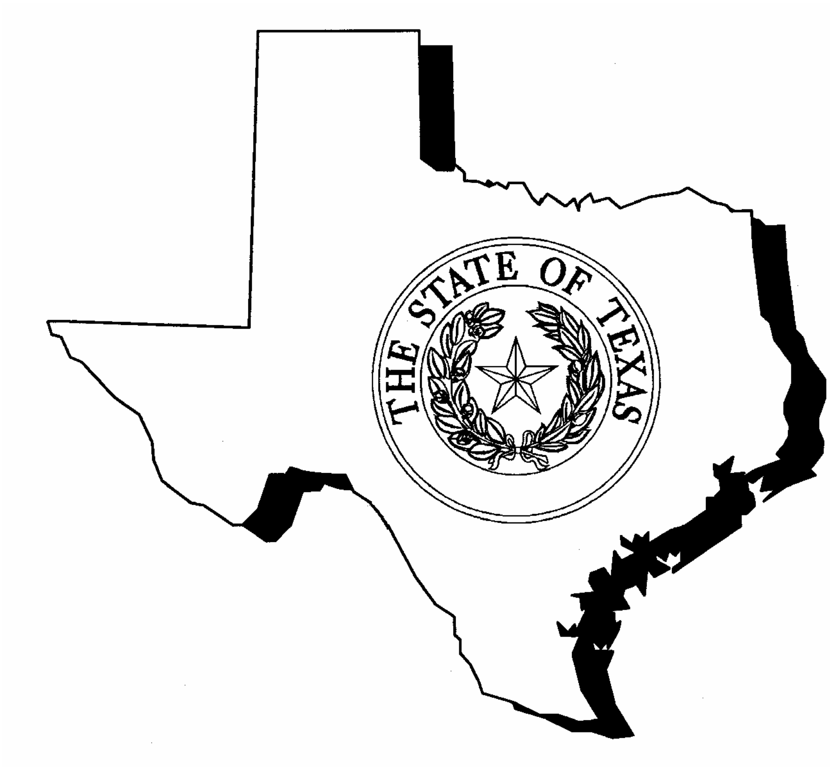

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TABLE OF CONTENTS

1. INTRODUCTION

The Public Utility Commission of Texas (PUCT) has prepared this manual to guide the inclusion of distributed generation into the Texas electric system. It is intended for use by utility engineers processing distributed generation interconnection applications, as well as those persons considering or proposing the interconnection of distributed generation with a transmission and distribution utility (TDU). While every possible eventuality or circumstance cannot be anticipated, the procedures in this manual should cover most important issues or problems, including a process for prompt dispute resolution.

Texas' Public Utility Regulatory Act (PURA) of 1999 included in the list of customer rights and safeguards that "A customer is entitled to have access… to on-site distributed generation…" [§39.101(b)(3)]. This provision led the PUCT in October 1999 to adopt Substantive Rules §25.211 and §25.212 addressing the technical and procedural aspects of interconnecting distributed generation, developed through a collaborative process among the members of the TDU and DG communities. This manual also includes the more recently adopted rules on operational aspects and environmental treatment of distributed resources.

The Public Utility Commission of Texas wants to encourage the use of distributed resources. Distributed resources benefit the state by adding more competitive options, potentially reducing customer energy, improving the asset utilization of TDU distribution systems, firming up reliability, and improving customers' power quality. Texans have the right to use distributed resources for whatever purpose they feel is beneficial and it is the responsibility of the local distribution utilities to accommodate and interconnect distributed generation subject to the rules laid out here.

The philosophy used to develop this manual was that distributed resources will and should be an integral and valued part of the Texas electric supply system. Wherever possible Texas has simplified the process, contractual relationships and hardware required to interconnect distributed resources safely and beneficially for all involved parties.

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2. SAFETY REQUIREMENTS

This section reviews the variety of interconnection-related safety requirements that the DG designer/installer and the utility must take into consideration. The requirements are divided by jurisdiction: State (PUCT), local, and national. These requirements are intended to ensure that DG is designed and installed in a way that

- is not a safety hazard to utility personnel or equipment or to other customers,
- does not disturb other customers or degrade the quality of the distribution system,
- provides reliable service to the DG owner and the utility.

To make certain that these expectations are met, it is critical that the TDU understand the characteristics and requirements of the DG and vice versa.

2.1. PUCT Rules

State regulations regarding the generation, transmission, and distribution of electricity are set by the Public Utility Commission of Texas (PUCT). The PUCT's Web site provides access to all Rules at http://www.puc.state.tx.us under "Rules and Laws". Of technical interest to DG are the following:

Substantive Rules - Chapter 25
Applicable to Electric Service Providers

Subchapter A General Provisions
§25.5 * Definitions

Subchapter C Quality of Service
§25.51 Quality of Service.

Division 2. Transmission and Distribution Applicable to All Electric Utilities
§25.211 * Interconnection of On-Site Distributed Generation
§25.212 * Technical Requirements for Interconnection and Parallel Operation Of On-Site Distributed Generation

The specific requirements of §25.211 and §25.212 are covered in subsequent sections of this manual. These rules detail the operational responsibilities of both the TDU and the applicant.

The PUCT's rules may, in some cases, be superseded by local requirements or modified in the future.

2.2. TNRCC Rules

A distributed generation emissions rulemaking is in progress. This subsection will be updated after a DG emissions rule is adopted by TNRCC.

2.3. Local Codes and Standards

County and city regulations may place additional permit or building code restrictions or requirements on DG systems. These requirements will primarily affect the DG installer, but both the installer and the utility should be aware of local codes and standards that might modify the interconnection requirements specified in the PUCT Rules.

2.4. National Codes and Standards

To address safety and power quality issues, national codes and safety organizations have developed guidelines for equipment manufacture, installation and operation. The major code and safety organizations that apply to distributed generation are the National Fire Protection Association (NFPA), Underwriters Laboratories (UL) and Institute of Electrical and Electronics Engineers (IEEE). Each of these organizations covers different aspects of the DG interconnection in the context of their organizational missions, as explained below.

The national laboratories are also actively involved in issues surrounding DG interconnection. The Department of Energy's National Renewable Energy Laboratory (NREL) in Golden, Colorado and Sandia National Laboratories in Albuquerque, New Mexico work closely with the NFPA, IEEE and UL on code issues and are frequently involved in equipment testing. The labs are not responsible for issuing or enforcing codes, but they do serve as valuable sources of information on DG and interconnection issues. The following subsections discuss each of these standards bodies individually, how the codes interact, and how the documents are being used. A good deal of TDU interconnection work has been done in the renewables arena, primarily PV. Several of the documents listed are PV-specific, but in fact, are relevant to any inverter-based technology and touch on issues that apply to rotating machines as well.

2.4.1. National Fire Protection Association

The National Fire Protection Association publishes NFPA-70, *The National Electrical Code* (NEC), and is the foremost organization in the U.S. dealing with electrical equipment and wiring safety. The scope of the NEC covers all buildings and property except for electric TDU property, i.e., all equipment on the customer's side of the point of common coupling (the meter).

Article 705, Interconnected Electric Power Production Sources, broadly covers DG interconnection. It reinforces many of the topics covered in the PUCT Rule (e.g., "Synchronous generators in a parallel system shall be provided with the necessary equipment to establish and maintain a synchronous condition") and adds some details, for example, related to disconnect switch requirements.

Article 690, Solar Photovoltaic Systems, mentions interconnection to the grid, but focuses more on system wiring and descriptions of components. One key requirement in Article 690 of the NEC is that all equipment interconnecting with the grid must be listed[1]. This requirement is unique both within the code (which primarily encourages rather than requires listed equipment) and within DG. Inverters for a microturbine or fuel cell (which are not explicitly covered by 690) do not have to be listed per the code, though it's nearly always required by electrical inspectors.

The NEC may address fuel cells or utility interconnection issues related to all inverter-based in the future.

Additional relevant standards are found in NFPA-37, the *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*; NFPA-99, the *Standard for Health Care Facilities*; and NFPA-110, the *Standard for Emergency and Standby Power Systems*.

2.4.2. Institute of Electrical and Electronics Engineers (IEEE)

The standards that electric utilities adopt for their equipment often originate from IEEE. Standards balloting rules require that a balanced committee of utilities, manufacturers, users, and general interest groups are involved in the development of new IEEE standards. This diversity ensures that the standards provide a consensus of all interested parties. IEEE standards are voluntary, so utilities are not required to adopt them unless there is a specific Commission or legislative ruling to that effect.

In the 1980s, the Institute of Electrical and Electronics Engineers (IEEE) published ANSI/IEEE Std 1001-1988, *IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems*. This standard addresses the basic issues of power quality, equipment protection, and safety. This document has expired and a new document is under development to take its place. This project, P1547, *Standard for Distributed Resources Interconnected with Electric Power Systems*, was started in 1998 and will be completed 2001.

The recently adopted ANSI/IEEE Std. 929-2000, *IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*, was developed to meet utility concerns with safety and power quality for PV systems. The intent was that there

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[1] As defined in NEC Article 100, listed means "equipment, materials, or services included in a list published by an organization that is acceptable to the authority having jurisdiction and concerned with evaluation of products or services, that maintains periodic inspection of production of listed equipment or materials or periodic evaluation of services, and whose listing states that either the equipment, material, or services meets identified standards or has been tested and found suitable for a specified purpose."

would be no need for *additional* requirements in developing utility-specific guidelines, especially for systems of 10 kW or less. The new Std. 929, replacing a 1988 version, contains a 12-page recommended practice and appendices with detailed background into issues such as how inverters interface with the utility, islanding, and distribution transformers.

Another key standard is IEEE 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.* This guide applies to all types of static power converters used in industrial and commercial power systems, and addresses the problems involved in the harmonic control and reactive compensation of such converters. Limits of disturbances to the AC power distribution system that affect other equipment and communications are recommended. Voltage and current harmonics limits—total and single harmonic—as well as the voltage flicker limits of irritation curves are referenced for both utility practice and DG requirements.

IEEE standards covering many aspects of utility interconnection and distribution system design and operation are listed in Appendix A6.

2.4.3. Underwriters Laboratories

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 toaster ovens to inverters to some office furniture.

Although UL writes the testing procedures, other organizations may do the actual testing and certification of specific products. In addition to UL, other testing labs such as ETL SEMKO (ETL), and the Canadian Standards Association (CSA) are widely recognized listing agencies for electrical components.

UL Standard 1741, *Static Inverters and Charge Controllers for use in Photovoltaic Power Systems,* deals with design requirements and testing procedures for inverters. UL 1741, published in May 1999, is now being revised comport to IEEE Std 929-2000, to cover inverters used for sources other than PV and to cover controllers that might provide similar capabilities for synchronous and induction machines.

3. TECHNICAL SUMMARY

3.1. General

Technical requirements for interconnecting DG to the TDU are defined in §25.212. This section summarizes those requirements. In general, the applicant's generation and interconnection equipment must meet all applicable federal, state and local codes. Interconnection equipment shall be capable of providing TDU system protective functions to prevent the generator from energizing a de-energized circuit owned by the TDU. Use of pre-certified equipment (see Section 7 of this Manual) will ensure that the minimum required capabilities are met, so the TDU will not need to review the DG design (other than to ensure that all necessary equipment is included).

Many of the requirements listed here were developed for <u>non-export</u> systems: those that do not intentionally send power to the TDU across the point of common coupling. The non-export condition can be met either implicitly by establishing that the DG output capacity is less than the applicant's verifiable minimum load (i.e., the DG never generates more than the applicant will consume), or explicitly through the use of a reverse power or under power relay (devices that disconnect the DG from the TDU if it attempts to export power)[2]. Systems that export power can place additional burden on the distribution system, especially a networked secondary, but may provide benefits as well. The TDU may elect to study these systems or any application that they feel would present safety or operational hazards to the distribution system. The results of the study may be a requirement for more sophisticated protective devices and operating schemes. However, the burden is on the TDU to justify the need for any additional requirements. The applicant has the option of complying with the additional requirements, withdrawing the application, or petitioning the commission for a good cause exception.

3.2. Prevention of Interference

Many of the requirements established in Rule §25.212 are based on the assumption of relatively low DG penetration operating from the TDU. Rather than attempting to regulate voltage and frequency, the DG should follow the voltage and frequency imposed by the TDU, and should disconnect under abnormal conditions as defined in Table 3-1 below. Since the DG is not regulating voltage or current, the allowable operating ranges are relatively wide. The ranges and trip times shown in Table 3-1 take into account the fact that losing any generation (including DG) when the system voltage or frequency is decreasing can exacerbate generation-related problems.

After tripping due to a voltage or frequency disturbance, the DG may reconnect once the utility voltage and frequency have returned to the Normal Operating Range and

[2] This may be a discrete relay or a function of a controller or inverter. Throughout this document, the use of the term "reverse power" is intended to include both reverse and under power functions.

have stabilized for 2 minutes or a shorter time as agreed to by the applicant and TDU.

Table 3-1: Voltage/Frequency Disturbance Delay & Trip Times

Range		**Trip Time[2]**	
Percentage	Voltage[1]	Seconds	Cycles
<70%	<84	0.166	10 (Delay) & 10 (Trip)
70%-90%	84 – 108	30.0 & 0.166	1800 (Delay) & 10 (Trip)
90% - 105%	108 – 126	Normal Operating Range	
105% - 110%	126 – 132	30.0 & 0.166	1800 (Delay) & 10 (Trip)
>110%	>132	0.166	10 (Delay) & 10 (Trip)
	Frequency (Hz)		
	<59.3	0.25	15 (Trip)
	59.3 – 60.5	Normal Operating Range	
	>60.5	0.25	15 (Trip)

[1] Voltage shown based on 120V, nominal.

[2] Trip times for voltage excursions were added for completeness by the PUCT Project No. 22318 Pre-certification Working Group as the intent of 25.212.

As with load, minimum harmonics and flicker standards are defined for DG. These limits are established in IEEE 519. In summary, this standard, in Chapter 10 for individual consumers, requires current total demand distortion (TDD) of 5% or less of the fundamental. The standard, in Chapter 11 requires voltage total harmonic distortion (THD) of 5% or less and 3% for any single harmonic, measured at the point of common coupling. Described in Chapter 10 of the standard, flicker, typically associated with induction generator start-up, may not cause a voltage dip of more than 3% as indicated on the border lines of irritation curve of the standard.

3.3. Requirements

Table 3-2 summarizes Texas' equipment and operational requirements for interconnecting DG, based on the characteristics of the proposed system. These requirements are first differentiated by DG paralleling mode and type of connection. Closed Transition is a mode of operation in which the DG is operated in parallel with the TDU for brief period of time, only long enough to ensure that the load is maintained while transitioning from TDU supply to generator, or vice versa. A manufacturing facility looking for peak shaving, but with power quality-sensitive processes, might use this type of system. For such systems, defined here as paralleling for less than 60 cycles (one second), the potential impact on the distribution system, and thus the interconnection requirements, are minimal.

Requirements for DGs that normally operate for more than 60 cycles—the majority of anticipated DG systems—are listed by connection type: single- or three-phase.

Table 3-2: DG Interconnection Requirements

	Closed Trans-ition	Single-Phase	Three-Phase			
	Capacity					
Feature	≤10 MW	≤50 kW	≤10 kW	10 kW - 500 kW	500 kW - 2 MW	2 MW - 10 MW
PUCT Rule Reference	§25.212-(g)	§25.212(d)	§25.212(e)-(3)(A)	§25.212(e)(3)-(B)	§25.212(e)-(3)(C)	§25.212-(e)(3)(D)
Interrupting devices (capable of interrupting maximum available fault current)	✓	✓	✓	✓	✓	[4]
Interconnection disconnect device (manual, lockable, visible, accessible)	✓	✓	✓	✓	✓	✓
Generator disconnect device	✓	✓	✓	✓	✓	✓
Over-voltage trip	✓	✓	✓	✓	✓	✓
Under-voltage trip	✓	✓	✓	✓	✓	✓
Over/Under frequency trip	✓	✓	✓	✓	✓	✓
Synchronizing check (A: Automatic, M: Manual)	A	A/M [1]	A/M [1]	A/M [1]	A [1]	A [1]
Ground over-voltage or over-current trip	[2]			[2]	[2]	[2]
Reverse power sensing				[3]	[3]	[3]
If exporting, power direction function may be used to block or delay under frequency trip					✓	✓
Automatic voltage regulator						[1]
Telemetry/transfer trip						✓

Notes:
✓– Required feature (blank = not required)
[1] – Required for facilities with stand-alone capability
[2] – May be required by TDU; selection based on grounding system
[3] – Required, unless generator is less than applicant minimum load, to verify non-export
[4] – Systems exporting shall have either redundant or listed devices

Single-phase systems will primarily be used on residential or small commercial applications. For closed transition and single-phase DG, Table 3-2 lists the maximum allowable system size. For three-phase DG, the requirements are further broken down by DG capacity, with larger systems having more requirements than smaller systems.

A few additional requirements apply for three-phase generators, by device type:

Synchronous Machines:

- Three phase circuit breakers with electronic or electromechanical control.
- Applicant solely responsible for proper synchronization.
- Excitation response ratio shall not be less than 0.5.
- Excitation system shall conform with ANSI C50.13-1989.

Induction Machines

- May “motor” up to speed if initial voltage drop at the PCC is within the Flicker limits (§25.212(c)(2)).

Inverters

- Line-commutated inverters do not require synchronizing equipment.
- Self-commutated inverters require synchronizing equipment.

4. TDU ANALYSES OF DG INTERCONNECTIONS

Introduction

This section is intended to provide a systematic approach for the engineering review process of a typical interconnection study. It includes the steps that must be taken to properly account for site-specific concerns and address the technical and procedural requirements of the Texas interconnection rules §25.211 and §25.212.

The goal of this section is to ensure that TDU interconnection analyses of the impacts of distributed generation are conducted in a clear, unbiased and consistent manner, irrespective of the TDU, the DG technology, or the applicant. This section will give the DG applicant a clear understanding of how the interconnection analysis will be conducted. It also provides a method to determine whether a DG configuration and application will pass or fail Texas' analytical protocols. The analytical directions in this section should allow all members of Texas' TDU and DG communities to use common terms, descriptions and assumptions about the benefits, costs, and grid impacts of DG, so that any disputes about a specific interconnection will focus on whether the proper calculations have been made, rather than whether a specific impact or benefit is legitimate or valid.

However, certain applications may require minor modifications while they are being reviewed by the TDU. Such minor modifications to a pending application shall not require that it be considered incomplete and treated as a new or separate application.

4.1. Utility Processing of DG Applications

As defined in §25.211, upon receipt of a completed application, the TDU has a defined period (4 to 6 weeks, defined below) of time in which to process the application and provide the following:

- Approval to interconnect
- Approval to interconnect with a list of prescribed changes to the DG design
- Justification and cost estimate for prescribed changes to TDU system
- Application rejection with justification

The PUCT limits when and why a TDU may charge the applicant for the performance of a service, coordination, or system impact study. In general, any study performed by the TDU shall follow these rules:

- Study scope shall be based on characteristics of the DG at the proposed location.
- Study shall consider cost incurred and benefits realized as a result of DG interconnection.

- TDU shall provide a cost estimate to the DG applicant prior to initiation of study.
- TDU shall make written reports and study results available to the DG applicant.
- TDU may reject application for demonstrable reliability or safety issues but must work to resolve those issues.
- TDU shall advise the DG applicant of potential secondary network-related problems before charging a study fee.
- TDU shall use best reasonable efforts to meet the application processing schedule, or will notify the DG applicant in writing why it cannot meet the schedule and provide estimated dates for application processing and interconnection.

If the proposed site is not on a networked secondary no study fee may be charged to the applicant if all of the following apply:

- Proposed DG equipment is pre-certified
- Proposed DG capacity is 500kW or less
- Proposed DG is designed to export no more than 15% of the total load on feeder (based on the most recent peak load demand)
- Proposed DG will contribute not more than 25% of the maximum potential short circuit current of the feeder

Certain aspects of secondary network systems create technical difficulties that may make interconnection more costly to implement. If the proposed site is serviced by a networked secondary, no study fee may be charged to the applicant if:

- Proposed DG equipment is pre-certified
- Aggregate DG, including the proposed system, represents 25% or less of the total load on the network (based on the most recent peak load demand)

and either

- Proposed DG has inverter-based protective functions, or

- Proposed DG rating is less than the local applicant's verifiable minimum load.

Otherwise, the TDU may charge the DG applicant a fee to offset the costs of the interconnection study. The TDU must advise applicants requesting DG interconnection on secondary networks about the potential problems and costs before initiating the study.

Note that these provisions do not preclude the TDU from performing a study; they simply regulate when the TDU can charge the applicant for the cost of the study. Whether or not a study fee is billable to the applicant, the TDU may reject an application for demonstrable reliability or safety issues but must work to resolve those issues to the mutual satisfaction of the TDU and applicant. The TDU must make reasonable efforts to interconnect all proposed DG, including the possibility of switching network-secondary service to a radial feed if practical and if acceptable to the applicant.

The flow charts in Figures 4-1 and 4-2 show, for non-network and secondary network systems respectively, how the Rule §25.211 requirements interact and what the TDU must consider when processing a DG interconnection application. Some of the decisions are based on location-specific information not available to the DG applicant at the time of application. It is important that the application be accurate and complete to eliminate delays in processing. These decision paths result in either “Approve Application” or “Recommendation”.

Systems meeting the requirements that result in “Approve Application” are considered simple with little chance of being a hazard to the distribution system, personnel, or neighboring customers. These systems should not require any additional studies, thus the utility is not allowed to charge a study fee.

The Recommendation results from a study that may be charged to the applicant, and may be one of the following:

- Approval of the application as is
- Description of changes to the proposed DG system or to the distribution system necessary to approve the application
- Rejection of the application due to specified reasons

Figure 4-3 provides a timeline of activities, based primarily on the requirements in §25.211(m) . Normally, it is anticipated that the application will be submitted, processed, and an interconnection agreement signed before construction activities begin. However, the Rules do not require this sequence and a more compressed schedule is possible. Rule §25.212(h) requires the DG applicant to provide the utility with two-week notice prior to start-up testing. However the Rules do not specify when this must occur or which events must precede the notice. An applicant can anticipate approval, submit the two weeks notice along with the application and be prepared for start-up testing immediately upon signing the interconnection agreement. If utility system modifications are required that are not considered a substantial capital upgrade, the utility may have to complete those upgrades prior to the start-up test.

If the utility is unable to complete the modifications prior to commissioning (for example, if the two week notice is given with the application), they may work out partial operation or other arrangements with the applicant until such modifications can be completed. Rule 25.211(m)(4) allows the utility extra time to interconnect the DG if it can show suitable reasons for needing an extension to the time allowed.

Figure 4-1: Non-Network Study Chart

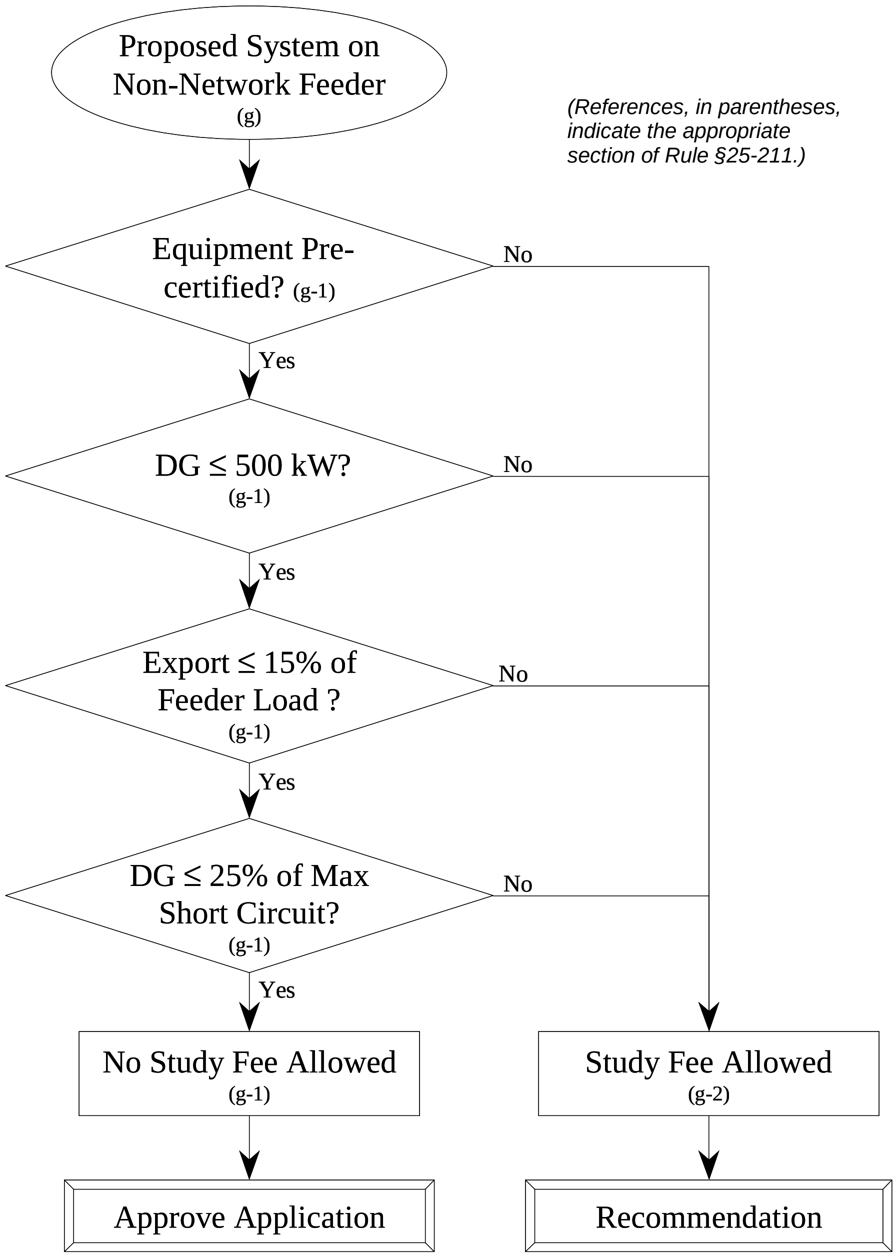


Figure 4-2: Network Secondary Study Chart

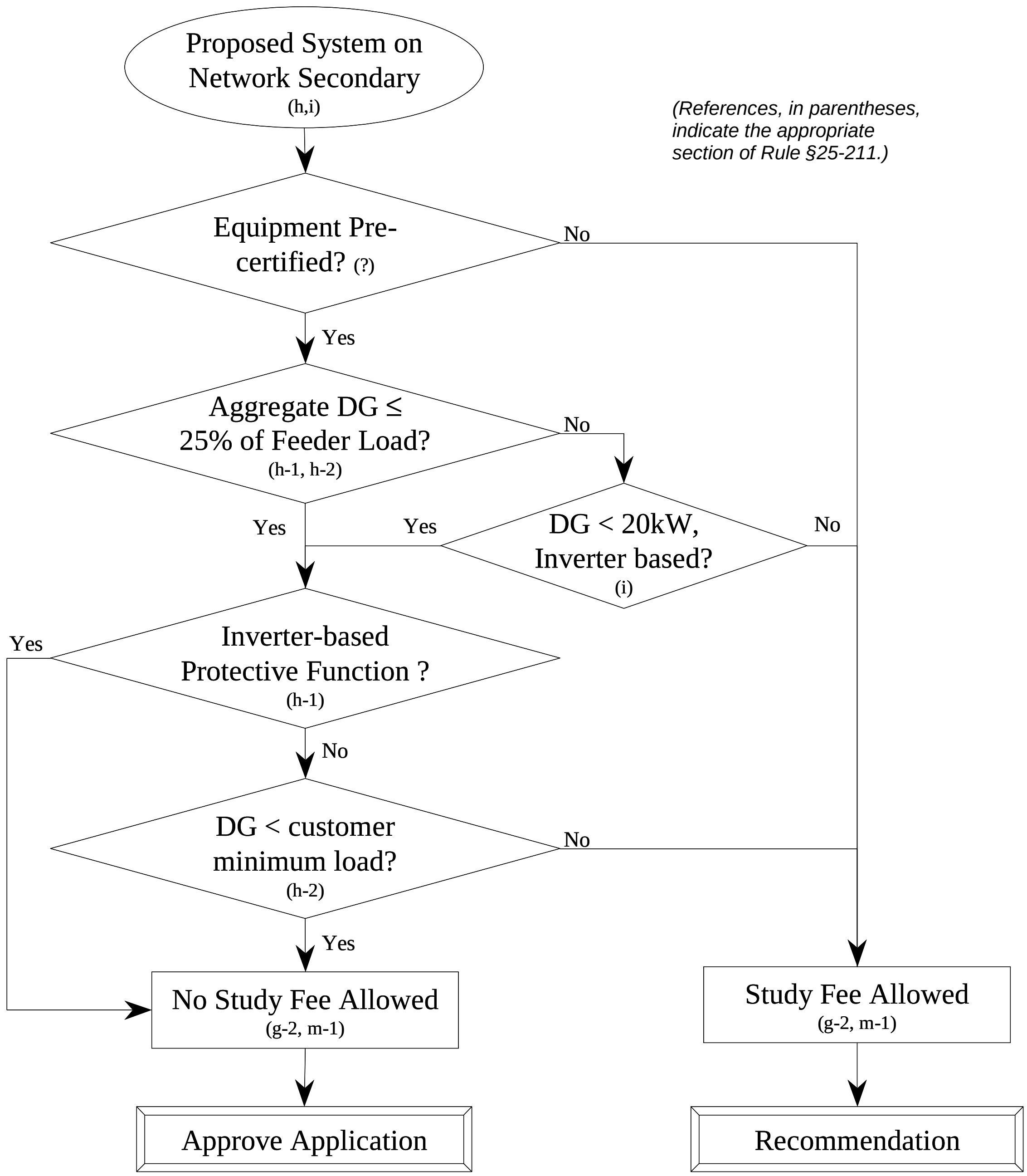
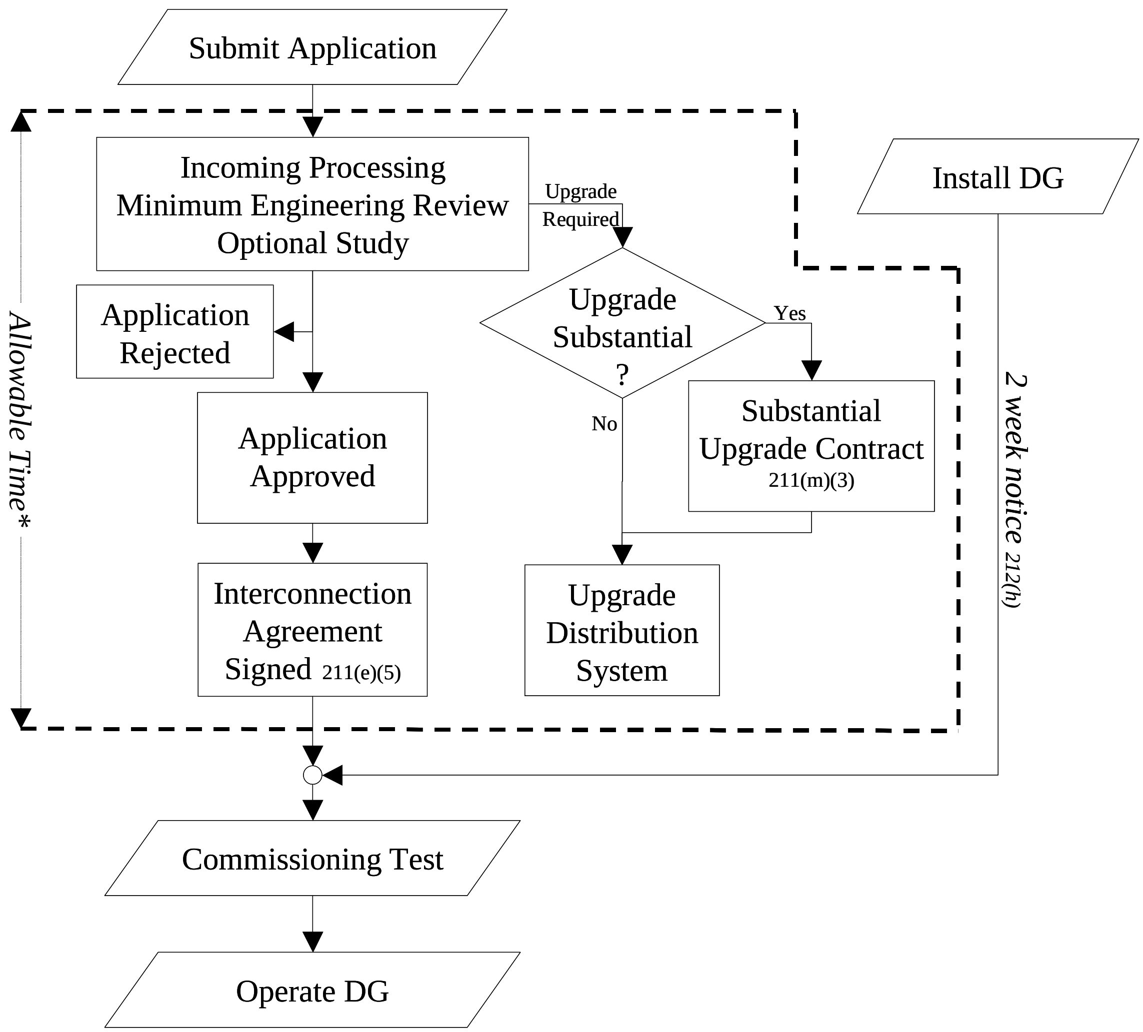


Figure 4-3: Application Processing Activities



* -- Allowable Time from receipt of completed application to a signed interconnection agreement:

1) Systems using Precertified equipment – 4 weeks (§25.211(m)(1))
2) Systems using Non-precertified equipment – 6 weeks (§25.211(m)(2))
3) Add up to 6 weeks for additional interconnection study time for applications in Network secondaries where the aggregate DG exceeds 25% of the feeder load. (§25.211(h)(3))
4) If the proposed system will require substantial capital upgrades to the utility system, the utility shall provide the applicant an estimate of the schedule and applicant's cost, if any, for the upgrade. If the applicant desires to proceed with the upgrade, the applicant and the utility will enter into a contract for the completion of the upgrade. The commissioning test will be allowed within two weeks following the completion of such upgrades. (§25.211(m)(3)).
5) The TDU shall use best reasonable efforts to interconnect facilities within the time frames described above. If in a particular instance, the TDU determines that it cannot interconnect a facility within these time frames, it will notify the applicant in writing. The notification will identify the reason or reasons interconnection could not be performed in accordance with the schedule and provide an estimated date for interconnection (§25.211(m)(4)).

4.2. DG Interconnection Requirements Review

The discussion below lays out when a TDU is authorized by the PUCT Rules to charge for a DG Interconnection Study, and provides some guidance as to how a study should be performed. Rule language does not preclude the TDU from performing a study at anytime, limiting only when the applicant may be billed for the study. However, it is expected that as each TDU gains experience with DG on its system, the TDU will reduce its reliance on studies as well as the level of effort necessary to perform them.

4.2.1. DG Application Review

The DG applicant should provide all necessary information with the application, including documentation verifying compliance with the technical requirements of Rule 25.212. Failure to supply all necessary information is grounds for rejection of the application.

The following information must be supplied for the application package to be viewed as complete.

1. DG generator or inverter nameplate capacity in kilowatts ($DG_{Capacity}$)
2. Maximum DG capacity allocated for export in kilowatts (DG_{Export})
3. DG Output (voltage, single-phase or three-phase)
4. DG type (e.g. inverter-based, synchronous, induction)
5. DG short circuit capability ($DGSC_{max}$)
6. Whether the DG facility meets the Texas pre-certification requirements (see Section 7 of this Manual)
7. Location of DG (street address, applicant account number)
8. Minimum load of the facility to which the DG is connected.
9. Documentation that the DG facility contains all the minimum protective functions required in Rule §25.212 (see Table 3-2).
10. Documentation that the appropriate protective functions are either factory preset to proper values or are capable of being set according to the parameters set forth in Rule §25.212 (see Table 3-1).

4.2.2. Distribution System Type Review

Once the application package is complete, the TDU should determine whether the proposed DG installation site is on a secondary network by locating the proposed facility on its distribution circuit. The answer to this question will impact the type of review process and study fees and schedules associated with the application.

Q: Is the proposed DG facility to be located on a networked secondary distribution system?
If yes, proceed to section 4.2.3: Secondary Network Review.
If no, proceed to section 4.2.4: Non-Network Review.

4.2.3. Network Secondary Review

In a network secondary distribution system, service is redundantly provided through multiple transformers as opposed to radial systems where there is only one path for power to flow from the distribution substation to a particular load. The secondaries of networked transformers are connected together to provide multiple potential paths for power and thus much higher reliability than an equivalent radial feeder. To keep power from inappropriately feeding from one transformer back through another transformer (feeding a fault on the primary side, for example), devices called network protectors are used to detect such a backfeed and open very quickly (within a few cycles).

If the aggregate DG output within a networked secondary exceeds the aggregate load, the excess power will activate one or more network protectors. If such a situation were allowed, the reliability of the secondary network would be reduced. In such a circumstance, DG could compromise grid reliability.

Most downtown areas of larger cities have secondary networks (e.g., Austin, Dallas, Houston and San Antonio). How far those networks extend and where the network ends and radial distribution begins is a function of the density of the load and a number of other factors. Facilities in the center of downtown areas are very likely to be on networks, whereas facilities in suburban and rural areas are almost certain to be on a radial distribution system.

4.2.3.1. DG Pre-Certification Review – Secondary Network

If the DG qualifies as pre-certified under Texas' pre-certification requirements (Rule §25.211(c)(12) and §25.211(k); see section 7 of this manual), the review can proceed to the DG Capacity Review. If the DG does not qualify as pre-certified, the TDU is allowed up to six weeks to perform a study that may involve a fee.

4.2.3.2. DG Capacity Relative to Load – Secondary Network

Secondary networks are used where load is sufficiently dense to justify the added reliability and added cost of such a system. As a result, the DG facility (or aggregate DG) could be sizeable before the utility engineer needs to be concerned. For example, one-megawatt of DG on a 10-megawatt network would be of little concern.

Conversely, one-megawatt of DG on a three-megawatt network could be of significant concern.

Rule §25.211(h)(1) and (2) define when the TDU shall approve applications for interconnection (the TDU may elect to do a study but may not charge a fee). These are as follows:

- §25.211(h)(1): Distributed generation facilities that use inverter-based protective functions with total distributed generation (including the new facility) on the affected secondary network representing no more than 25% of the total load of that network.

- §25.211(h)(2): Other on-site generation facilities whose total generation is less than the local customer's load (non-export) and with total distributed generation (including the new facility) on affected secondary network representing no more than 25% of the total load of that network.

The aggregate DG is determined by summing the nameplate ratings of each of the DG units within the network. The total load of the network is defined as the maximum load of the network for the previous 12-month period. This threshold, expressed in equation form, is the following:

$$TotalDGCapacity_{network} = TDGC_{network} \leq 0.25 \times TotalLoad_{network}$$

This is the value at or below which inverter-based DG should not require costly changes to the utility system in order to accommodate the DG installation. The TDU shall accept applications, and a study fee may not be charged since it is assumed that no study is necessary. It is assumed that all inverter-based DG under 20kW is so small that, irrespective of the 25% threshold, no study is necessary and therefore the application shall accepted and no study fee may be charged.

4.2.3.3. Power Export Review

To determine whether or not a distributed generator complies with §25.211(h)(2) above, it must be determined whether the DG will export power. No export limit was provided for network systems, meaning that all export systems on network secondaries may be subject to a study for which a fee may be charged (excluding inverter-based systems).

A DG system designed for non-export (i.e., it only offsets applicant load without feeding into the grid) simplifies the review process. Non-export systems will not adversely impact the secondary network protection schemes and, for systems with explicit non-export capabilities, the need for additional islanding detection is eliminated. There are three methods to ensure that power is not exported:

(1) (Implicit) To ensure no export of power without the use of explicit non-export protective functions, the capacity of the DG must be no greater than the customer's verifiable minimum annual load. Use of additional anti-islanding functions may be required to ensure worker and equipment safety.

(2) (Explicit) To ensure power is never exported, a reverse power protective function must be implemented within the facility. Default setting shall be 0.1% (export) of transformer rating, with a maximum two-second time delay.

(3) (Explicit) To ensure at least a minimum import of power, an under-power protective function may be implemented within the facility. Default setting shall be 5% (import) of DG Gross Nameplate Rating, with maximum two-second time delay.

Non-inverter-based DG that does not export and meets the 25% threshold should not require changes to the utility system in order to accommodate the installation. The serving utility shall accept these applications, and a study fee may not be charged since it is pre-assumed that no study is necessary. Although the sections of the Rules addressing studies do not specifically provide options for non-export other than (1) above, options (2) and (3) are technically equivalent to (1) and do not require a study fee.

If the DG is not inverter-based and is <u>not</u> less than minimum applicant load, but still complies with the 25% threshold, a study fee may be charged to the applicant to determine whether any modifications need to be made. The study can take up to four weeks.

If the total DG capacity on a particular network exceeds 25% of the total load of the network, the TDU may halt the application process up to six weeks while performing a study that may involve a study fee. Such an analysis may require detailed dynamic modeling of the load/DG/network interaction. Depending on such issues as load diversity and generator dispatch, the utility may determine that some DG beyond the 25% limit may be acceptable while others may be unacceptable. As such modeling can be quite costly, the utility must inform the DG applicant of the potential issues and appropriate study cost before initiating the study. Once the study is complete, the application processing and the allowable processing time (see Figure 4-3) shall continue.

4.2.3.4. Conditions When Service Needs To Be Converted To Radial

As the total DG on a secondary network grows relative to total network load, so does the likelihood of reverse power flow through one or more network protectors causing them to open and interrupt service. In this case, power flow studies may be needed to determine if it is possible for the network protectors to see reverse power (even momentarily) from the DG and initiate a trip.

If the power flow study determines that the DG installation could cause unintended operation of the network protector, one way to mitigate this problem is to switch the DG facility service to a radial service. If the proposed DG location is close to a network protector, it might be easy to switch the DG onto a radial feeder, making the change less costly. If the 25% of network load requirement is not met, the utility should conduct a power flow study and investigate whether it is necessary to convert the DG service from network to radial to mitigate the unintended operation of the network protectors.

4.2.4. Non-Network Review

4.2.4.1. DG Pre-Certification Review – Non-Network

If the DG qualifies as pre-certified under Rule §25.211(c)(12) and §25.211(k), the non-network review can proceed to the DG Capacity Review. If the DG equipment is not pre-certified, a study may be performed that can take up to six weeks and involve a study fee.

4.2.4.2. DG Capacity Review – Non-Network

If the DG capacity is less than or equal to 500 kW, the review can continue to the export level review. If the DG capacity, as reported on the completed application, exceeds the 500 kW threshold, the TDU is allowed up to four weeks to perform a study that may involve a fee.

4.2.4.3. Export Level Review – Non-Network

A key question for each DG installation is whether the DG applicant intends to export generation across the point of common coupling (PCC); and if so, how much. If power is to be exported across the PCC:

- DG that exports can cause reverse voltage drops (from the DG towards the substation). Thus, the TDU may need to study the local distribution system and determine if adjustments to local voltage regulation schemes are necessary.
- Protection against the formation of unintended islands becomes more complicated since the DG will be supporting load beyond the PCC.

Rule §25.211 (g)(1) provides a threshold to address these concerns, stated as 15% of the total load on a single radial feeder. Here again, total load is defined as the maximum load over the previous 12–month period. This threshold, expressed in equation form, is the following:

$$\text{DGexport}_{\text{max}} \le 0.15 \times \text{FeederLoad}_{\text{max}}$$

This is the value at or below which the DG can export without requiring costly changes to the TDU system in order to accommodate the DG export. If the system falls within the export limit, it is assumed that the application of the DG on that portion of the distribution system will not cause the complications listed above. DG which exceeds this threshold may be studied to determine whether it could cause islanding or adverse power flows.

4.2.4.4. Short Circuit Contribution Review – Non-Network

If the DG passes the export level threshold of 15% of feeder load, the maximum short circuit current on the radial feeder must be calculated. The TDU will then calculate the maximum short circuit current contribution at the DG location. Once this value is determined, multiply that quantity by 0.25 to establish the 25% threshold for the primary feeder. The DG's maximum short circuit capability found in the application must then be converted to the corresponding short circuit current after transforming to primary voltage. This transformed DG short circuit must be less than or equal to the 25% threshold. This threshold is expressed through the following equations:

Assume:

$$\text{FeederShortCircuit}_{\text{max}} = \text{FSC}_{\text{max}}$$

and:

$$\begin{aligned}\text{DGShortCircuit}_{\text{max}} &= \text{MaxDGShortCircuit} \times \text{DGOutputVoltage} \div \text{PrimaryVoltage} \\ &= \text{DGSC}_{\text{max}}\end{aligned}$$

To comply with this threshold, $DGSC_{max}$ must be less than or equal to 25% of $FSC_{max.}$:

$$\text{DGSC}_{\text{max}} \le 0.25 \times \text{FSC}_{\text{max}}$$

If the DG complies with this threshold, it is assumed that:

- the DG has little impact on the distribution system's short circuit duty.
- the DG will not adversely affect the fault detection sensitivity of the distribution system.

- the utility's relay coordination and fuse-saving schemes are not significantly impacted.

If the DG does not comply with this threshold, the TDU may study the DG application over four weeks with a study fee. If the DG passes all these thresholds, it will not require changes to the utility system to accommodate the installation. Such DG will not require additional studies or equipment to accommodate, and can interconnect without any study fees.

4.2.5. Issues That May Require Additional Review

Rule §25.211 limits when the utility may charge the DG applicant for performing an interconnection study. However, it also states that an application may be rejected if it can "demonstrate specific reliability or safety reasons why the DG should not be interconnected at the requested site." The utility is then responsible for working with the applicant "to attempt to resolve such problems to their mutual satisfaction."

There are special cases that may require the interconnecting utility to take a closer look to ensure the proposed system satisfies the technical requirements set forth in Rule §25.212.

4.2.5.1. DGs That Motor To Speed

Some generators use the utility to bring the generator up to operating speed. Other generators use the prime mover or do not require high currents to start. In the case where a DG is using the utility to motor to speed and requires starting currents well above normal operating currents, it may be necessary to check the resulting voltage drop to ensure that it passes the flicker requirement of 3% found in §25.212(c)(2). This threshold of 3% voltage dip is calculated on the primary side of the distribution transformer. If an installation causes nuisance voltage fluctuations to neighboring customers after installation, it may be necessary to perform a site assessment of the voltage fluctuations to verify that it is within the stated standard.

4.2.5.2. DG on Four-Wire Feeders

If a DG is located on a three-phase four-wire feeder, the DG interconnection should be reviewed to confirm that it will not cause phase overvoltages in the event that the feeder is disconnected from the rest of the distribution system. The concern is that a DG of sufficient size could provide brief phase-to-neutral overvoltages that could damage customer's equipment on the local distribution system in the event of a system outage.

There are several ways that a DG can be integrated with such a feeder without potential for causing harmful voltages:

1) If the DG is single-phase connected line-to-neutral, it is incapable of contributing to phase-to-neutral overvoltages given the over-voltage trip requirements;
2) if the DG is small enough relative to the feeder size (10% of feeder peak load), it does not contribute enough voltage support to raise the voltage to hazardous levels; or
3) if the DG has some way of regulating phase-to-neutral voltage, it can ensure that this will not happen.

If the DG installation does not comply with one of these three options for limiting voltage overloads, it may require additional study to determine what can be done to mitigate this issue.

4.3. Cost/Benefit Impacts of DG

4.3.1. TDU Benefits and Costs

4.3.1.1. Deferral of Capital Expenditures

As load on a distribution system grows, eventually a point is reached when the load outgrows the capacity of one or more components of the power system, such as a transformer or distribution line (feeder). The traditional utility response to this situation is to install additional capital equipment to relieve the overloading. Not investing in capacity upgrades increases the risk that system components will fail under stress, degrading reliability and increasing O&M costs.

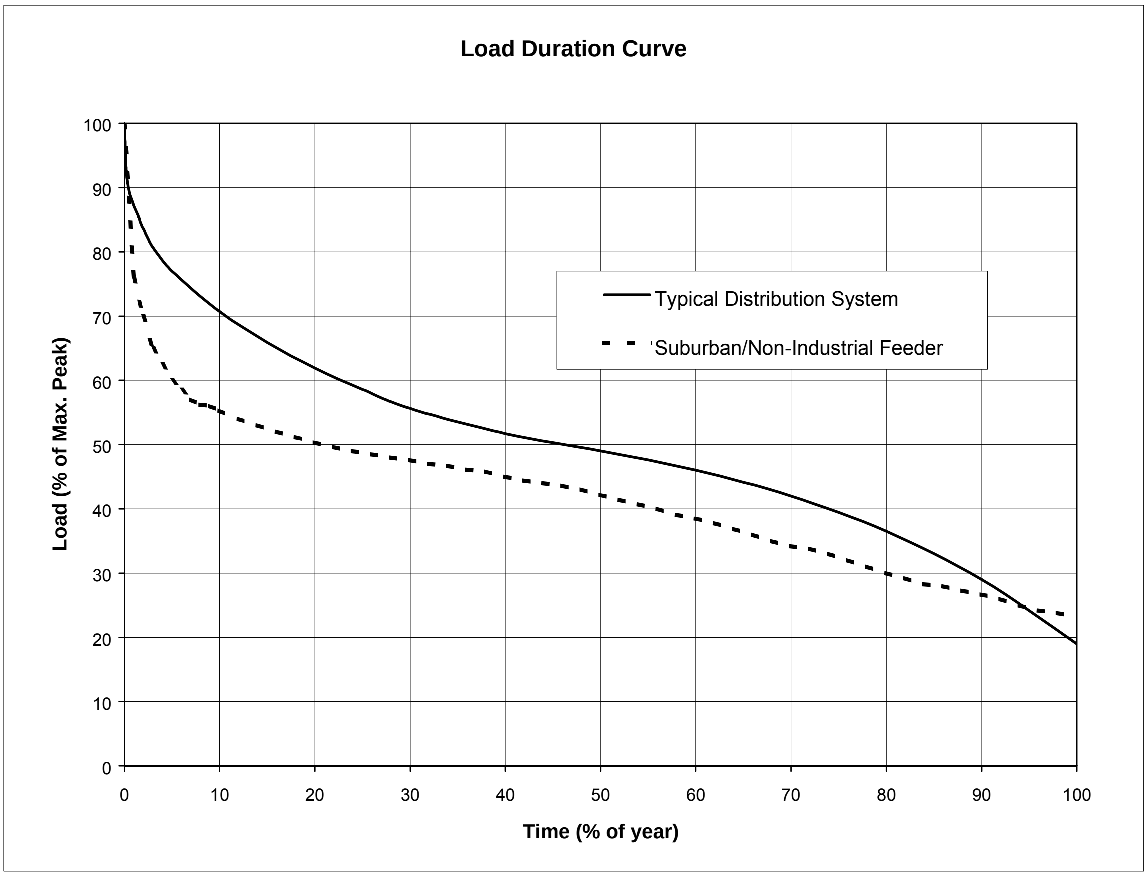
A load duration curve is an analysis tool used to depict the amount of time (in percent) during a year that the load on a system is above a given fraction of its maximum (peak) value. Typical load duration curves for distribution systems are shown in Figure 4-4. Since load duration curves are normalized to the peak during the year, the curve begins at 100% decline steadily to the right, eventually showing the minimum load point on the right hand edge. At any point in between, a load duration curve shows the need to serve load relative to the peak demand. For example, for a typical TDU distribution system with a mix of residential, commercial and industrial load (the solid curve in Figure 4-4), the total load will exceed 70% of its peak for only about 10% of the year, or about 900 hours.

The load will exceed 80% of peak for only about 3% of the year, about 260 hours. While extreme peaks are very infrequent events, the T&D system is designed specifically to serve peak loads, and thus growth in peak loading determines when action is needed to prevent system overloads during peaks.

The dashed curve in Figure 4-4 depicts the load duration characteristics of a feeder that is primarily residential and commercial with a minimal industrial component, a characteristic that is increasingly common for many feeder systems in suburban areas. The load profile of this feeder is characterized by a higher component of air conditioning load during summer peaks. For this curve, the 70% load level corresponds to about 2% of the year (175 hours), and the 80% load level to less than 1% of the year (about 80 hours).

Understanding the duration of loads on a feeder indicates how much distributed generation could be used for reducing peak demands on the distribution wires, and how many hours of operation on peak would be needed.

Figure 4-4: Load Duration Curves



These curves clearly illustrate the potential for DG as a peaking resource to defer or avoid T&D capital investments. As the load grows past the capacity of the distribution system to handle the peaks, small amounts of DG operating few hours per year could "clip" the top of the curve by meeting applicants' energy needs at the point of use rather than relying on grid-delivered power. For either of the curves in

Figure 4-4, and assuming that the peak feeder load is 10 MW, it would appear that 1 MW of distributed generation operating less than 100 hours per year would provide relief for feeder line loads during times when the feeder is under its most severe situations.

Capacity costs are quantified in terms of dollars per kilowatt per year ($/kW-yr). Budgets for capacity upgrades can be translated into capacity costs by dividing the budget dollars by the capacity in kW that those upgrades provide:

$$\text{Capacity cost, \$/kW-yr} = \frac{\text{Budget\$}}{(\text{kW})*(\text{years})}$$

The benefit is calculated by evaluating the present worth of the kW deferred. A present worth calculation assumes a certain number of megawatts installed each year, with costs discounted according to the estimated interest rate and referred back to the present year.

Benefit, $/year = Present Worth {(kW of DG)*(capacity cost, $/kW-yr)*(# of years)}

Example Calculation

Consider the case in which transmission capacity planned for the next ten years is 1000 MW, at a budget of $200 million. Assume the capacity would be installed in equal increments of 100 MW each year.

Installing 100 MW of DG this year can defer 100 MW of capacity for one year:

Capacity cost, $/kW-yr = ($200,000,000)/((1,000,000 kW)*(10 years))
= 20 $/kW-yr

Benefit ($) = (100,000 kW)*(20 $/kW-yr)*(1 year)
= $2,000,000

4.3.1.2. Utilization Of Existing Transmission and Distribution Assets

While section *4.3.1.1. Deferral of Capital Expenditures* pertains to financial and/or capital assets, *4.3.1.2.* addresses the utilization of the physical assets in a power system. If DG is used to serve peak load growth, the load duration curve will “flatten” out; the existing distribution system will become loaded to a higher percentage of its maximum capability more of the time, and become more fully utilized.

In general, the closer to the load distributed generation can be located, the greater the asset utilization benefits are possible. DG located on the distribution system—whether by the utility, a third party working with the utility, or a customer placing DG on his premises—can reduce the need for both transmission and distribution upgrades and will likewise increase the utilization of these assets. A utility can use this knowledge to conduct a strategic review of its T&D system and identify key feeders and substations with fast-growing load or poor utilization that would benefit from DG deployment.

4.3.1.3. Distribution System Reliability

Distributed generation can have a positive impact on system and local distribution reliability. For a TDU the primary economic impact of poor reliability is increased expenditures for emergency maintenance. An analysis of applicant loads and local reliability data would allow a TDU to identify locations where DG could have the best impact on reliability improvement. In Texas, TDUs cannot own or operate DG, but they can work strategically with energy service companies, vendors and customers to contract for DG in places where reliability enhancement is desired.

Qualitative distributed generation reliability benefits include faster restoration times, and improved feeder reliability due to reduced stress and overloading of feeder equipment. Other hard-to quantify benefits include customer good will, customer retention, and avoided damage claims and/or lawsuits.

4.3.1.4. Risk Transfer

Regulators have assigned to the TDU the full responsibility for the safe and effective delivery of power to all customers on its distribution system. It has the responsibility to design and operate the distribution system to meet voltage and frequency limits and power quality metrics set by the standard practices in the TDU. The advent of customer-owned and -operated DG in the system adds complexity and uncertainty to the operation of the distribution system, and shifts some of the responsibility for power delivery from the utility to the DG-using customer.

Where a customer has installed DG, the TDU has four options regarding future nearby wire upgrades:

1) Ignore the presence of the DG unit and invest in wires as if the DG did not exist (implicitly discounting the unit’s peak load reduction impacts).

2) Include the likelihood that the unit will be on during feeder peak times (implicitly anticipating that the unit will reduce feeder peak loads).

3) Establish formal agreements and incentives by contract with the DG owner to encourage DG operations at peak and reduce the TDU’s responsibility for delivery at peak to that customer.

4) Account for the existence of any customer-owned DG on the distribution system by planning to handle the composite, statistical net (of DG) customer loads on feeders and substations.

Using approach 1), the TDU will continue to plan and finance “lumps” of distribution capacity to accommodate the expected load growth over a specified planning horizon. Not only is most of the new capacity not used in the early years of the upgrade, but if the load does not grow as forecasted, the investment decision becomes (retrospectively) a poor one. Not accounting for customer DG can lead to over-investment in unneeded capacity.

Using approach 2), the utility will defer its own capital investment due to the capital investment of the customer in the distributed generation unit. In essence the TDU has chosen to “lean” on the customer’s DG. Note that the logic would be the same in the case of the TDU requesting load reductions by some of the customers on the feeder and trusting that the load reductions will be available during the distribution system peak.

But the utility is also assuming that the DG will operate during critical peak times as designed, for example with high availability and good power quality. If either of these operational assumptions is false, especially during severe peak feeder load periods the utility will have to shed customer load, risk physical damage to the wires, or risk experiencing electrical parameters outside of normal specifications. In this sense the utility has increased its risk in exchange for the right to lean on the customer DG.

Assuming that the customer owning the DG has not been compensated for the “leaning rights,” the customer is under no obligation to the TDU for failing to operate the DG in the way anticipated by the TDU. Using approach 3), in which the utility and the customer have signed a performance contract, the customer’s compensation should be impacted by his failure to supply those services. A utility that designs and builds to accommodate installed DG should also have contractual assurance that the customer’s load is shed first if the DG is tripped off-line.

The magnitude of the savings from relying on customer-owned and -operated DG to defer TDU investments can be substantial, essentially equivalent to a permanent deferral of all anticipated reinforcements, including land acquisition, new substation equipment, etc.

Approach 4) uses the measured loads on feeders for planning purposes, unadjusted for known DG on the distribution feeder. Only a modest amount of risk is placed on the TDU in this case. The DGs on the feeder are seen essentially as load reduction and are smoothed out statistically. If multiple DGs are in place, their unreliability is probably smoothed out also.

An important case of very large benefit to the TDU is relying on the customer DG to hedge the risk of planning for uncertain "block" loads. These are loads that represent a significant quantum increase in feeder load in a single year, such as a commercial or industrial facility coming on-line. If the load is delayed or fails to materialize as planned, any investments the utility may have made in wires upgrades to accommodate the load will become negative financial impacts. Using DG to hedge such load growth uncertainty can be very valuable.

4.3.1.5. TDU Costs of Accommodating DG

The TDU's accommodation of customer DG will have some adverse impacts on the TDU:

- The TDU pays for needed hardware upgrades (e.g., DG-compatible breakers, reverse power relays, sensors, instrumentation, communication devices and/or meters) to the distribution system to accommodate DG (to the extent that the costs for such upgrades are allocated to the TDU and not the customers).
- To the extent that the TDU relies on the DG to support the grid, the TDU assumes additional risk, since the DG may not be as reliable as the wires investments it displaced or deferred.
- The TDU must pay for some engineering staff time and study costs.
- The TDU must provide training to its staff to anticipate and understand the implications of customer-owned and -operated DG.

However, most of these costs are no different than the costs of planning, owning and operating a T&D system with full risk and responsibility for high-reliability electric distribution service.

4.3.2. Customer Benefits and Costs

4.3.2.1. Bill Reduction: Avoided Energy Costs and Demand Charges

A customer's bill consists of two categories of charges — energy and demand.

Energy is the commodity purchased from the utility or retail electric provider (REP), and is measured in kilowatt-hours (kWh). The price per kWh charged may be higher the more energy is used; e.g., one price can be charged for up to (say) 1,000 kWh, and a higher price for every kWh above that threshold. Energy can also be more expensive during certain times, such as system peaks; this is called time-of-use (TOU) pricing.

Peaking energy prices can be high at certain times in today's market. When system peaks occur, if supplies are tight, spot energy prices can skyrocket, although they may be subject to caps by regulation or ISO rules. DG can represent insurance against risk of high energy prices and a means of energy price management.

Demand charges (for commercial and industrial customers) are fixed monthly charges based on the highest instantaneous load the customer may have during the month, although the specific terms may vary under different customer contracts or tariffs. For example, if the customer's peak load is 10 kW, even if it's only for one hour, he is charged a monthly fee based on that 10 kW. Thus, by producing power at peak times, a DG can help a customer reduce both energy and demand charges. Peak periods may total a relatively few hours per month, but may represent a significant percentage of a customer's total bill.

In order to justify using a DG in baseload operation, a careful analysis of the customer's processes and economics is needed. Low-cost fuel must be available, allowing the customer to produce power for a lower cost than the REP would charge. DGs suitable for baseload use tend to be more efficient and require generally lower O&M than peaking units. Using combined heat and power (CHP, also known as cogeneration, in which the customer produces electric energy from a DG but also utilizes waste heat from the generator for industrial processes, space or water heating, or other uses) typically increases overall economic efficiency substantially, increasing the probability that baseload DG operation will be economic for the customer.

Calculation of the estimated cost savings from a DG is relatively straightforward. A review of the energy consumption and demand charges recorded on the customer's recent billing statements will reveal how much energy is used during which time periods, and what the costs are. DG size is matched to the peak load reduction desired, or the full customer load if baseload operation is desired, and hours of operation are determined. Total monthly costs are computed, consisting of all fixed and variable costs of running the DG in the desired mode plus energy and demand charges for whatever portion of customer requirements are not met by the DG. The cost of the DG itself must also be included, using suitable financial parameters. The difference between the no-DG situation and the with-DG case is the projected cost savings of using the DG.

The cost of energy, whether purchased from the utility or generated on-site, is the product of power (in kW) times the number of hours of operation times the cost per kilowatt-hour:

Energy cost = (kW)*(hours)*($/kWh)

Both power level and energy cost are variable with time. Typically, energy costs are computed on an hourly basis, summing the results to a monthly total. Energy cost savings due to DG use would be computed by first calculating total energy costs the customer would have paid absent the DG, and subtracting the total energy costs paid with the DG.

The demand charge from the utility is the product of the customer's peak power demand during the month (in kW) times the monthly charge per kW of peak demand:

Demand charge, per month = (peak kW)*($/kW/month)

The demand charge savings due to using a DG for peak reduction is the product of the customer's peak power demand reduction (equal to the size of the DG) times the charge per kilowatt-hour:

Demand charge savings, per month = (kW of DG)*($/kW/month)

Example Calculation

Consider the case where:

- The utility charges 3¢/kWh off-peak, and 12¢/kWh on-peak.
- Utility demand charges are $10/kW/month.
- The customer's load is 2000 kW during peak periods, for 6 hours/day, 20 days per month; all other times the load is 1000 kW.
- The customer owns a 1000 kW gas turbine that operates at a cost of 6¢/kWh, inclusive of fuel and all O&M.

The customer operates the gas turbine to cut load during peak periods; the customer generates 1000 kW and buys 1000 kW from the utility. (Off-peak utility usage won't change, since it's cheaper to buy than generate during off-peak.) For peak periods, on a per-month basis:

Energy cost, no DG = (2000 kW)*(6 hrs/day)*(20 days/month)*(12 ¢/kWh)
= $28,800/month

Energy cost, with DG = (1000 kW)*(6 hrs/day)*(20 days/month)*(12 ¢/kWh) +
(1000 kW)*(6 hrs/day)*(20 days/month)*(6 ¢/kWh)
= ($14,400 + $7,200) per month
=$21,600 per month

Energy cost savings = $28,800 – $21,600 per month
=$7,200 per month

Demand charge savings = (1000 kW)*(10 $/kW/month)
= $10,000 per month

The customer's total savings = $17,200 per month

4.3.2.2. On-Site Reliability

To serve critical loads during sustained TDU outages, a customer would use a DG capable of being started up in a matter of minutes, and operated for the duration of the outage. The cost of purchasing, maintaining and operating a DG for reliability enhancement would need to be cost-justified based on the expected number and duration of TDU outages and the estimated costs of those outages to the customer.

The customer's "value of service" (VOS) will vary according to a customer's individual situation, and may be subjective to some degree. Residential customers experience inconvenience, but usually do not suffer significant economic losses for most outages, which normally last only a few minutes to a few hours. Research[3] has determined that residential VOS is valued in the vicinity of $1/kWh.

For commercial and industrial customers, the VOS can be much greater, depending on the process that is interrupted. Product and equipment can be damaged, revenue lost, and labor forces idled until power is restored. Research has estimated the VOS for these customer classes to be in the range of $10 to $70 per kWh [Ibid.].

Note: Operating a DG to serve customer load when the TDU supply is interrupted requires "islanded" operation, i.e., there is no live connection between the customer and the TDU at the point of common coupling, and the DG operates only to serve local load. Interconnection rules will specify the protection equipment that must be installed to prevent the DG from reconnecting with the TDU until such time as TDU service is restored.

Assuming that the costs to a DG owner are proportional to the length of the outage, the value of service interruptions on a yearly basis can be calculated from the following equation:

Benefit, $/year = (kW of load)*((SAIDI, min/yr)/60)*(VOS, $/kWh)

where: SAIDI for the feeder supplying the customer=system average interruption duration index (minutes/year)

Alternatively, there may be fixed costs associated with an outage, regardless of the length of the outage. In this case, the value is the fixed cost times the number of times per year the interruption occurs:

Benefit, $/year = (SAIFI, outages/yr)*(FC, $/outage)

where: SAIFI for the feeder supplying the customer = system average interruption frequency index (outages/year)

FC = fixed costs associated with a customer outage ($/outage)

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[3] Pupp, Roger and Woo, C.-K.: Costs of Service Disruptions to Electricity Customers, The Analysis Group, Inc., January 1991.

The total benefit to the customer may be a combination of these two values.

Example Calculation

Consider the case where:

Customer load = 1000 kW
SAIDI = 90 min/year
SAIFI = 1.25 outages/year
VOS = $50/kWh
FC = $5,000

For this situation, installing a DG that is capable of providing standby service provides the DG owner an estimated yearly reliability benefit of:

Benefit, $/year = (1000 kW)*((90 min/yr)/60)* (50 $/kWh)
+ (1.25 outages/yr)*(5000 $/outage)
= ($75,000 + $6,250) per year
=$81,250 per year

4.3.2.3. Power Quality Improvement

Power quality is related to reliability in some ways, and the potential solutions can be similar to those for reliability. In general, power quality problems tend to be short in duration and small in magnitude, but frequent or constant in occurrence. They may include voltage sags or spikes, switching transients, harmonics (frequencies other than 60 Hz), noise, and momentary outages (less than 5 minutes, according to the definition in the IEEE Reliability Standard 1366; there is no similar standard for power quality).

Customers can experience many of the same consequences from poor power quality (PQ) as they would from poor reliability. For many industrial and commercial customers a momentary outage is just as bad as a sustained outage, since production processes or electronic equipment and records may be disrupted in either case. If so, benefits may be computed according to the same value of service principles as described in the previous section on reliability.

Resolving power quality issues can be difficult, since the problems may have their origin in the TDU system, the customer’s own equipment, the equipment of other customers on the feeder, or an interaction between any combination of these parties’ systems. The proliferation of solid-state electronics, in customer equipment as well as TDU equipment, is frequently the source of many PQ anomalies.

Since many PQ symptoms are low-energy or short-term phenomena, distributed storage (e.g., batteries or flywheels) linked to the customer's most sensitive loads may be an economic solution, relative to the expense and effort of implementing a DG system. A power conditioning system (power electronics-based converter system) or an isolation transformer may be economical alternatives as well. Whatever system is used, the basic approach is to interpose the system between the customer and the TDU, so as to filter or smooth out PQ anomalies.

4.3.3. Other Benefits and Costs

This category of benefits and costs arising from installation and operation of DG cannot, at this time, be directly allocated to any particular stakeholder or participant in the Texas market. Before electric industry restructuring occurred, these impacts would have been included in an integrated utility's analysis of total benefit and cost impacts of DG. In the current ongoing evolution of industry restructuring, it may be worthwhile to analyze these impacts and evaluate how they may be allocated in the future.

4.3.3.1. Line Losses

When transmitting electric energy through TDU transmission and distribution systems, the impedance (electrical resistance) of wires and transformers causes resistive or "I^2R" losses, where I is the current in the line in amperes (A) and R is its resistance, in ohms (Ω). These losses are typically on the order of 4 to 7% system-wide; that is, about that much of the total energy generated is lost in transit from generation sources to loads. This energy must be generated or purchased, just like any other energy the TDU requires.

DG can reduce line losses by providing more of the supply locally, rather than through transmission and distribution lines. This benefit is more likely to be quantified on radial distribution lines than on networked distribution or transmission lines. The reduction in line loading due to a distributed generator can be directly seen on a distribution feeder, whereas the impact on a network is spread over multiple lines.

If the system or TDU-specific average losses are known, then the average line loss reduction can be calculated as a simple percentage of the DG capacity. In Texas, this kind of data would need to be compiled from a combination of transmission data (from the ISO), FERC filed data or other sources. If, for example, an average T&D line loss figure is 7% (this is comparable to other T&D utilities nationwide), then approximately 1.075 MW of energy input into the T&D system is required to serve 1.0 MW of actual load. Therefore, every 1 MW of DG can be considered to result in an average benefit of 75 kW of avoided line losses during the time it operates. This approach takes advantage of known system characteristics to attribute total line loss savings to a specified DG amount.

This reduction also has implications for capacity requirements. A 7.5% reduction in energy losses from DG use at the point of customer load translates into that much less generation, transmission and distribution capacity that would otherwise have to be built to generate and transport that energy.

4.3.3.2. Reserve Margin

Reserve margin is the amount of capacity cushion (denominated in MW) a power region requires to be available to serve as a safety margin at extremely high load times. This extra capacity allows the system generation controllers or operators to dispatch plants with an additional surety that the system will not collapse if an outage of a single transmission line or generating plant occurs. The reserve margin takes into account the instantaneous status of all available generation and transmission assets.

At this time, DG is not sufficiently proven or prevalent in the electric system to warrant explicit and separate inclusion in reserve margin calculations. Once there is a significant amount of DG installed and exporting into the Texas electric grid, and concomitant experience with operating DG, future DG can be included in reserve margin calculations. For now, customer load served by on-site DG is included in calculations of reserve margin requirements, while the DG is not counted as a generation resource.

Most system peak loads occur in only a relatively few hours per year (<300 or so). Reserve margin plants do not usually have high efficiency or low emissions due to their very low capacity factor. Customer units, such as standby generators which are configured for remote dispatch on demand, might be excellent candidates for consideration as reserve margin status and benefits. However, the PUCT will include DG capacity in calculations of installed generation capacity for purposes of market share calculations.

Small increments of DG can be added as the load grows, sized to accommodate the amount of load that exceeds the capacity limit. This contrasts with typical capacity additions that are usually large, “lumpy” capital investments. DG can therefore be more cost-effective, flexible, and a less risky way to meet load growth.

If DG is connected to the transmission system it can displace the need for incremental generation capacity, and may reduce transmission line losses.

Reserve margin capacity costs are quantified in terms of dollars per kilowatt per year ($/kW-yr), and can apply to generation and/or transmission capacity. The benefit due to DG installation is calculated by evaluating the present worth of the kW deferred. A present worth calculation assumes a certain number of megawatts installed each year, referred back to the present year.

Benefit ($) = Present Worth {(# of kW)*($/kW-yr)*(# of years)}

Example Calculation

Consider the case in which generation capacity planned for the next ten years is 1000 MW, at a budget of $500 million. Assume the capacity would be installed in equal increments of 100 MW each year.

Installing 100 MW of DG this year can defer 100 MW of capacity for one year:

Capacity cost, $/kW-yr = ($500,000,000)/((1,000,000 kW)*(10 years))
= 50 $/kW-yr

Benefit ($) = (100,000 kW)*(50 $/kW-yr)*(1 year)
= $5,000,000

4.3.3.3. Ancillary Services

Ancillary services comprise a number of valuable electrical attributes that are required for the safe, reliable and efficient operation of a power system. Typically provided by large central plants for reasons of economy and simplicity of operation, several types of ancillary services can also be provided by distributed generators. In fact, given that many DG technologies are nearly as efficient as new central generation, they may actually be more efficient in delivering ancillary service, especially when locational advantages are figured into the equation (as with line losses). It is anticipated that there will be markets for ancillary services just as there are for bulk generation; the buyer(s) of the services might be the generators, QSEs or the ISO. Identification of beneficiaries and development of economic accounting tools for ancillary services are key unresolved issues of utility restructuring.

Logistically, ancillary services could be procured from DGs that are directly controlled and dispatched by a QSE or the ISO; that is, the DGs would have communication and control equipment installed so that they could be monitored and dispatched. Alternatively, the ISO could contract with DGs to operate at certain times and with specified performance requirements, with economic penalties for non-performance.

Examples of ancillary services include:

Volt/var Control
DG can be used in lieu of capacitors or other devices to provide the reactive power (kvar) needed to improve or control voltage profiles on distribution feeders, and to generally improve overall system voltage. Capacity values of $/kvar should be readily available from the TDU for each voltage level in the system, representing the equipment cost of capacitors that the TDU would purchase for voltage correction. Improvement in system voltage profile contributes to increased stability margin as well, since the system is less susceptible to voltage collapse during contingencies.

Reliability Must Run (RMR)
DGs are located and operated in specific areas and for specific times to relieve transmission constraints.

Spinning Reserve
The DG operates at reduced load, but ready to pick up additional load if another generator (or generators) in a specified area are forced out of service.

Load Frequency Control
The DG acts as a "swing bus": it adjusts its output to compensate for normal variations in customer load, in order to keep system frequency constant.

Load Following
The DG "tracks" a particular load, i.e., it adjusts its output so that the load has minimal effect on the rest of the system.

Scheduling And Unit Commitment
Large generating plants can be uneconomical to use for cycling duty or for reliability-must-run applications where the capacity needs are small or the number of hours of operation are few. Using DGs can be more economical than committing a large plant for these purposes.

Black Start Capability
After a TDU outage, a DG can bring up local loads (forming a "micro-grid") and eventually re-synchronize with the grid, lessening the difficulty of system restoration.

4.4. Operational Protocols

The PUCT is working with the ERCOT ISO to develop operational protocols for DG interconnection to parallel the technical protocols laid out in the Rule and the Standard DG Interconnection Agreement. These protocols will cover matters such as how to schedule DG deliveries from the generator to the TDU to the ISO (i.e., inadvertent energy versus dynamic scheduling), appropriate scheduling fees, and the like. These decisions will ultimately be documented in an operational section of the Standard DG Interconnection Agreement, and will be discussed in this manual when the policy decisions have been made.

5. DG APPLICANT INFORMATION

Introduction

The Public Utility Commission of Texas (PUCT) has endeavored to make it easy for customers to interconnect their distributed generation (DG) projects with the local TDU's electric distribution system. The interconnection rules developed by the PUCT are intended to set forth the rights and responsibilities of both DG applicant and TDU.

The discussion below pertains to "distributed generation," which is limited to ten (10) MW at the point of interconnection, and the "utility distribution system" to which the DG is interconnected is at a voltage of less than 60 kV.

Existing provisions of PURA address the issue of Exempt Wholesale Generators (EWGs) and the tariffs that apply to them. Wholesale generators are in the business of selling their power on the open market, to whomever wants to buy it. They are registered with the PUCT and the Federal Energy Regulatory Commission (FERC) as competitive players in the market, are generally exempt from regulation, and are able to connect with the TDU transmission system (i.e., at ≥ the 60 kV level) at rates described in the published tariffs (see PURA Sections §35.004, §35.005, §35.006 and §35.007, and within ERCOT, PUCT Substantive Rules §25.191, §25.192, and §25.195). It is anticipated that the vast majority of customers wishing to interconnect DG systems at the distribution level will not fall into this category, and will in fact desire to connect at the distribution level. Any applicant that is an Exempt Wholesale Generator should clearly disclose such status on the application.

Texas law prohibits distribution companies (TDUs) and retail electric providers from owning or operating distributed generation facilities. TDUs are allowed to contract for DG from customers and other entities in instances where such DG services may provide cost-effective benefits to the distribution system. The DG ownership and structure options are described in Table 5-1.

5.1. DG Applicant Rights and Responsibilities

A DG applicant has the right to interconnect DG projects with the electric utility system, and electric utilities are obligated to interconnect the DG project (see PUCT Substantive Rule §25.211(d)), subject to the requirements set forth in this Manual. A DG applicant has the right to expect expeditious processing of the application by the host TDU, and to receive supporting data from the TDU for any studies or additional equipment required for interconnection. A DG applicant does not have the right to expect payment from the TDU for energy generated by the customer's DG project; it is the responsibility of the DG owner to market the energy produced from the DG facility. The DG owner has the right to sell the energy, through a Qualified Scheduling Entity (QSE), to any power generation company or retail electric provider that agrees to buy it, after January 1, 2002.

Table 5-1: DG Ownership and Structural Options

Customer Ownership	• Self-generation DG and storage • Cost-effective EE, storage • ESCO provision of DG, EE • DG for grid export
TDU Contracting (in lieu of ownership)	• T&D supplements • DG location support - EE, DG dispatch • Customer partnership DG, EE, storage (co-funding possibilities)
TDU Rebates & Incentives	• EE incentives • TDU or ISO purchase (demand-responsive bidding, interruptible rates, LM)
TDU Out-Sourcing	• Aggregation of demand reduction, DG • ESCO/DG vendor places and operates DG where wireco needs it • Third-party EE programs

A DG applicant has the responsibility to pay for the reasonable costs of system studies. A customer has the responsibility to make full disclosure of the DG project and its operation to the TDU. A DG applicant also has the responsibility of ensuring that the DG project meets all applicable national, state, and local construction and safety codes (see §25.211(b)); that operation of DG does not cause undesirable effects on other customers (see §25.211(c)); and that the necessary protection equipment is installed and operated to protect both its equipment and the TDU's system. If the DG applicant does not fulfill these obligations, the host TDU need not interconnect, or it may disconnect, the DG project.

5.2. TDU Rights and Responsibilities

A TDU must respond to applications for interconnection expeditiously, within the time periods specified in this Manual. A TDU has the right and responsibility to safeguard its system, other customers, and the general public, subject to the PUCT's rules, and must show good cause why a DG application that satisfies the PUCT's requirements should not be interconnected to its system. A TDU does not have the right to unilaterally refuse to connect a DG project. A TDU is under no obligation to purchase the energy from a customer's DG. A TDU is, however, required to assess and recognize the benefits of adding DG to the distribution system during the application process (see PUCT Rule §25.211(g)(1)(C)).

A TDU is paid to link generation to customers and to deliver power between points; it does not matter whether that power comes from central station generation at a remote location or from DG at the customer's site. All distribution users shall bear the costs of interconnecting the DG, including distribution upgrades as needed. The TDUs recover the costs of grid construction and maintenance through base rates.

If the TDU believes that although a specific DG application meets the PUCT's technical requirements for system safety and reliability, but the costs of reconfiguring the TDU system to accommodate the new DG unit appear excessive, the TDU may seek guidance from the PUCT before approving or denying the DG application. The TDU should contact the PUC's Electric Division staff at 512-936-7340 or by e-mail at ed.ethridge@puc.state.tx.us.

5.3. Interconnection Process

The interconnection process consists of the following steps:

1. Filing of an application by the DG applicant with the TDU
2. TDU review of the application
3. Response specifying the requirements for further study, if needed, and the technical requirements to interconnect
4. Approval of an agreement between the DG applicant and the TDU
5. Connection, testing and operation of the DG project

The interconnection process has been designed to specify the appropriate level of review and the associated technical and equipment requirements for each DG project. The intent is for small, low-impact DG projects to be reviewed quickly, the technical and equipment requirements to be only as complex and expensive as required for safe operation, and fees paid by the customer to be fair and justified. The larger the project and the more complex the interconnection scheme, the higher the costs, both for studying the interconnection scheme and for the necessary electrical equipment to interconnect.

For example, consider the simplest case, with the following attributes: A customer wishes to connect a pre-certified DG system smaller than 500 kW. A pre-certified system is a known collection of components that has been tested and certified either by the TDU or by a qualified third party (see PUCT rules §25.211(c)(12), §25.211(k), and Section 4 of this Manual). The line to which interconnection is desired is a radial feeder circuit, i.e., there is only one path from the interconnect point to the TDU's distribution substation (this is the most common situation). The DG will export either no power to the TDU system at all, or less than 15% of the total load on the feeder. Also, it will add no more than 25% of the short-circuit current on the feeder, as determined by the TDU's review of the application.

In this example, no further interconnection study is required and the TDU may not charge for one, and the equipment requirements are minimal and pre-specified for this case (PUCT Rule §25.212(d, e)). The TDU is required to interconnect the DG within four weeks of receipt of customer's application.

In all other cases, a TDU may need to conduct an interconnection study, and may charge the customer for the costs of the study. For example, a DG system that is not pre-certified must be evaluated to ensure that the system will operate safely on the TDU's system. Larger DG systems can have significant impacts on the TDU system, and this is the reason that a comparison of the DG size to the load on the existing system is important. An estimate of the study costs must be provided to the customer before the TDU performs the study. The study must be completed by the TDU in four weeks for a radial connection, and six weeks for a network connection. Written results must be presented to the customer, detailing the findings and including an estimate of capital upgrades required, if any. These capital upgrades are the responsibility of the customer, who must enter into a contract with the TDU to implement them. Section 4 of this Manual gives a detailed explanation of this application process.

Connecting to a networked feeder system (one in which there are multiple paths from the interconnect point to the distribution substation) poses more difficult questions of equipment and system protection, requiring more detailed technical analysis. The study may take no longer than six weeks, and a written report of TDU's findings must be supplied to the customer. Moreover, the TDU must take into account the benefits realized from the DG project in addition to the costs incurred by it (see PUCT Rule §25.211(g)(1)(C)).

In the case of a proposed network connection, additional guidelines apply. Inverter-based DG systems, and all DG systems that do not export power to the grid, will be approved without further study, unless the total distributed generation on the feeder, including the new facility, is more than 25% of total load on the network. Total load is defined as the sum of all customer loads on the feeder. If the new DG application would push total DG on the feeder over this 25% load limit, then the proposed DG facility will be subject to interconnection studies that must be completed within six weeks.

A TDU can reject a DG project on a networked system if it can demonstrate valid technical or safety reasons for denying the interconnection, but the TDU must make good-faith efforts to resolve the issue with the customer. TDUs must make reasonable efforts to accommodate DG projects that propose to export power on a networked system. Such reasonable efforts should include alternate methods of interconnection such as converting to radial service, if practical.

5.4. Frequently Asked Questions (FAQs) About DG Interconnections

The detailed guidelines and requirements for interconnecting DG are set forth in §25.211 and §25.212 of the PUCT's rules, attached to this Manual. The following are frequently asked questions (FAQs) that address the basic aspects of getting a DG project interconnected with the TDU. Consult the PUCT's rules for any topics not covered here. If you still have questions, call the PUCT's Customer Protection Division at 1-888-782-8477.

Q. What should I do first?

A. Collect as much information as you can on the DG system you intend to install. This would include size, manufacturer, model, fuel, and electrical characteristics. Obtain the application form and fill it out, describing the technical and business aspects of your proposed project. The application should then be filed with the host TDU with whose system you wish to interconnect.

Q. How can I find out whom to contact in the TDU about interconnecting my DG unit?

A. Rule 25.211(l) requires that each TDU must designate a person or persons who will serve as the TDU's contact for all matters relating to DG interconnection. Contacts as of November 1, 2000 are listed in Appendix A4. The TDU must provide convenient access through its Internet site to the names, telephone numbers, mailing addresses and e-mail addresses for its DG contact persons.

Q. What happens after my Application is filed?

A. The TDU will have its engineering staff evaluate your Application to decide whether a pre-interconnection study is necessary. A lot depends on the specifics of your DG project: how big it is, whether you will export to the grid, whether the interconnection will be on a radial or a networked feeder, and so forth. Generally, the bigger the DG and the more complex the TDU feeder situation is, the more study is required by the TDU to determine the proper interconnection scheme and protective equipment that may be needed. The TDU will tell you whether you can interconnect right away, or whether a study is required.

Q. Are pre-interconnection studies always required?

A. No. If your DG system has been pre-certified (see §25.211(k)), is under 500 kW, will not export an amount of power more than 15% of the total load on the feeder, and the TDU determines it will not add more than 25% to the short-circuit potential on the feeder, no study should be required. In addition, protective equipment will be minimal and prespecified, and interconnection fees will be the minimum amount.

Q. If a study is needed, how much time will it take?

A. For connection to a radial TDU feeder, the PUCT's rules require that the TDU complete the study in four weeks. For connection to a network system, the technical issues are more complex and the TDU has six weeks to complete the study. Most distribution systems are radial construction, but networked systems do exist in some areas, particularly in city centers.

Q. How much will it cost me to connect?

A. Each TDU has filed study fees for various ranges of DG capacity rating.

Interconnection cost depends upon the size and characteristics of the DG unit you choose to interconnect, how you intend to operate it (e.g., exporting energy into the grid, as opposed to using all the energy on-site), whether the connection will be to a radial or networked distribution system, and whether the unit will use pre-certified equipment or not.

Q. What if the TDU doesn't want to connect my DG project?

A. You have the right to connect to the TDU's system, and the TDU is obligated to connect you, with certain provisions: you must follow the procedures described in this manual; and your DG facility must meet the technical requirements of §25.212 of the PUCT's rules. The TDU would have to document the technical or business reasons for not granting your Application as filed, and is obligated to work with you to resolve the situation to your mutual satisfaction.

Q. After I'm connected, can the TDU disconnect me without my consent?

A. The TDU can disconnect you only if: you have no interconnection agreement with the TDU, or your agreement has expired or has been terminated; you have not complied with the technical requirements of PUCT Substantive Rule §25.212; there is a system emergency that requires disconnection; or maintenance or other construction work on the TDU system requires it. Rule §25.212 spells out the requirements for notice of disconnection and reconnection under such circumstances.

Q. How are disputes resolved if the TDU and I disagree on what's required?

A. Complaints relating to interconnection disputes are to be handled in an expeditious manner, as provided by PUCT Rule §22.242. Complaints shall first be presented informally, by telephone or letter, to the Electric Division, which shall attempt to resolve complaints within 20 business days of the date of receipt of the complaint. In certain cases (see Rule §22.242) the informal complaint process may be bypassed and formal complaints filed directly with the Commission. The Electric Division can be contacted at 512-936-7340, Fax: 512-936-7361, or in writing at **PUCT – Electric Division**, **Attention: Ed Ethridge**, at the same address as below. Unresolved complaints shall be presented to the PUCT at the next available Open Meeting.

PUCT - Customer Protection Division
P. O. Box 13326
Austin, TX 78711-3326
1-888-782-8477
in Austin: 512-936-7120
TTY: 1-800-735-2988
Fax: 1-512-936-7003
E-mail: customer@puc.state.tx.us
Web: http://www.puc.state.tx.us/ocp/complaints/complaint.cfm

6. ENERGY EFFICIENCY AND CUSTOMER-OWNED RESOURCES

In Texas, as per Substantive Rule §25.181, renewable energy technologies installed for self-generation which do not export to the grid are classified as energy efficiency technologies rather than as DG units.

Substantive Rule §25.181(c)(25) defines renewable demand side management (DSM) technologies as equipment that uses renewable energy resources to reduce a customer's net purchases of energy (kWh) and/or electrical demand (kW).

Rule §25.181(h)(4) provides that renewable energy technologies installed for self-generation do not disqualify a DG installation from receiving incentive payments or compensation under standard offer or market incentive programs. See also Rule §25.181(1)(2)(L), which specifically states that renewable DSM technologies are allowed under standard offer programs for energy efficiency.

7. PRE-CERTIFICATION PROCESS

Refer to Appendix A7 for the commission-approved Distributed Generation Pre-certification Requirements. The document explains what is meant by pre-certification and the required tests by a nationally recognized testing laboratory (NRTL). Also, the document describes optional tests and tests that must be performed for which there is no standard to be met. References are made to the DG Rules, 25.211 and 25.212, which are included in Appendix A2.

8. INTERCONNECTION DISPUTES

PUCT Rule §22.242 provides that all complaints about utilities be presented to the office of Customer Protection Division for informal resolution within 35 days. The CPD may be contacted at the phone numbers and address given below. In certain cases the informal complaint process may be bypassed (see the Rule for specifics) and formal complaints filed directly with the Commission. Unresolved informal complaints and all formal complaints shall be presented to the PUCT at the next available Open Meeting.

Rule §25.211 amends this procedure in the case of interconnection disputes. Informal complaints are to be presented to the Electric Division, which shall attempt to resolve complaints within 20 business days of the date of receipt of the complaint. The Electric Division can be contacted at 512-936-7366, Fax: 512-936-7361, or in writing at **PUCT – Electric Division**, **Attention: Tony Marciano**, at the same address as below. Unresolved complaints shall be presented to the PUCT at the next available Open Meeting.

PUCT - Customer Protection Division
P. O. Box 13326
Austin, TX 78711-3326
1-888-782-8477
in Austin: 512-936-7120
TTY: 1-800-735-2988
Fax: 1-512-936-7003
E-mail: customer@puc.state.tx.us
Web: http://www.puc.state.tx.us/ocp/complaints/complaint.cfm

Appendix A1: Definitions

The following words, terms and acronyms, when used in this Manual shall have the following meanings, unless the context clearly indicates otherwise [Rule §25.211(c); refer to IEEE Standard 100 for certain terms]:

Applicant — A customer or entity who intends to apply or has applied to an electric utility for interconnection**.**

Application for Interconnection and Parallel Operation with the Utility System (or Application) — The standard form of application for interconnection of distributed generation projects approved by the Commission.

Closed Transition — A mode of operation in which the DG is operated in parallel with the distribution system for a brief period of time, to ensure that the load is maintained while from the utility (TDU) to the generator or vice versa.

Commission — The Public Utility Commission of Texas (PUCT).

Company — An electric utility operating a distribution system.

Customer — Any entity interconnected to the company's utility system for the purpose of receiving or exporting electric power from or to the company's utility system.

DG — Distributed generation; see also **On-Site Distributed Generation**.

Distribution Feeder — An electric line operated at voltages below 60 kV that serves to deliver power from a utility substation or other supply point to customers.

Electric Utility — A person or river authority that owns or operates equipment or facilities to produce, generate, transmit, distribute, sell or furnish electricity for compensation in the state of Texas; excluded from this definition are municipal corporations, power generation companies, exempt wholesale generators, power marketers, electric cooperatives and retail electric providers [PURA §31.002(6)].

Electric Reliability Council of Texas (ERCOT) — The area in Texas served by electric utilities, municipally owned utilities, and electric cooperatives that is not synchronously connected with electric utilities outside the state [PURA §31.002(5)].

Exempt Wholesale Generator (EWG) — A person who is engaged directly or indirectly, through one or more affiliates, exclusively in the business of owning or operating a facility for generating electric energy and selling electric energy at wholesale. An EWG must register with the Commission [PURA §35.032 and Substantive Rule 25.109] and with the FERC under 15 U.S.C. §79z-5a.

Facility — An electrical generating installation consisting of one or more on-site distributed generation units. The total capacity of a facility's individual on-site distributed generation units may exceed 10 MW; however, no more than 10 MW of a facility's capacity will be interconnected at any point in time at the point of common coupling under this section.

IEEE — The Institute of Electrical and Electronics Engineers.

Independent System Operator (ISO) — An entity, administered by ERCOT, supervising the collective facilities of a power region; the ISO is charged with nondiscriminatory coordination of market transactions, systemwide transmission planning, and network reliability [PURA §31.002(9)].

Interconnection — The physical connection of distributed generation to the utility system in accordance with the requirements of this section so that parallel operation can occur.

Interconnection Agreement — The standard form of agreement, which has been approved by the Commission. The interconnection agreement sets forth the contractual conditions under which a utility and a customer agree that one or more facilities may be interconnected with the utility's distribution system.

Inverter — A machine, device or system that changes direct-current power to alternating-current power [IEEE Std. 100].

Inverter-based Protective Function — A function of an inverter system, carried out using hardware and software, that is designed to prevent unsafe operating conditions from occurring before, during, and after the interconnection of an inverter-based static power converter unit with a utility system. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the utility system.

kV — kilovolt, an amount of voltage equal to one thousand volts.

kW — kilowatt, an amount of power equal to one thousand watts.

MW — megawatt, an amount of power equal to one million watts.

Network Service — Network service consists of two or more utility primary distribution feeder sources electrically tied together on the secondary (or low voltage) side to form one power source for one or more customers. The service is designed to maintain service to the customers even after the loss of one of these primary distribution feeder sources.

On-Site Distributed Generation (or Distributed Generation) — An electrical generating facility located at a customer's point of delivery (point of common coupling) of 10 MW or less and connected at a voltage less than 60 kV, which may be connected in parallel operation to the utility system. May include energy storage technologies as well as conventional generation technologies.

Parallel Operation — The operation of on-site distributed generation by a customer while the customer is connected to the utility's distribution system.

Point Of Common Coupling (PCC) — The point where the electrical conductors of the utility's distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the utility system takes place, such as switchgear near the meter [IEEE Std. 100].

Power Generation Company (PGC) — A person that generates electricity to be sold at wholesale. A PGC does not own a transmission or distribution system and does not have a prescribed service area, although it may be affiliated with an electric utility that does [PURA §31.002(10)].

Pre-certified Equipment — A specific generating and protective equipment system or systems that have been certified as meeting the applicable parts of this section relating to safety and reliability by an entity approved by the commission.

Pre-interconnection Study — A study or studies that may be undertaken by a utility in response to its receipt of a completed application for interconnection and parallel operation with the utility system. Pre-interconnection studies may include, but are not limited to, service studies, coordination studies and utility system impact studies.

PURA — The Public Utility Regulatory Act of 1999 (Texas).

QSE — Qualified scheduling entity. A QSE is responsible for submitting Balanced Schedules for transmission capacity for all entities for which it serves as a scheduling agent. The QSE is responsible for payment of settlement charges as set forth in Section 9 of the ERCOT Protocols Document. Each QSE shall maintain a 24-7 scheduling center for the purposes of communicating with the ISO for scheduling and Real Time operational purposes and is required to install and maintain communications and telemetry capability as prescribed by ERCOT.

Radial Service — Radial service consists of one utility primary distribution feeder source forming a single power source for one or more customers.

Retail Electric Provider (REP) — A person that sells electric energy to retail customers in Texas. A retail electric provider may not own or operate generation assets [PURA §31.002(17)].

Stabilized — A utility system is considered stabilized when, following a disturbance, the system returns to the normal range of voltage and frequency for a duration of two minutes or a shorter time as mutually agreed to by the utility and customer.

Switchgear — An enclosed metal assembly containing components for switching, protecting, monitoring and controlling electric power systems [IEEE Std. 100].

Tariff For Interconnection And Parallel Operation Of Distributed Generation — The Commission-approved tariff for interconnection and parallel operation of distributed generation including the application for interconnection and parallel operation of DG and pre-interconnection study fee schedule.

Transmission and Distribution Utility (TDU) — A person or river authority that owns or operates equipment or facilities to transmit or distribute electricity for compensation in Texas, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility" under this section, in a qualifying power region certified under PURA §39.152, but does not include a municipally owned utility or an electric cooperative [PURA §31.002(19)].

Total Load — The sum of all customer loads on a distribution feeder.

Unit — A power generator.

Utility System — A utility's distribution system below 60 kV to which the generation equipment is interconnected.

Appendix A2: Copy of PUCT's Rules, Forms and PURA 99 Excerpts

PUCT Rules §25.211 and §25.212

§25.211. Interconnection of On-Site Distributed Generation (DG).

(a) **Application.** Unless the context clearly indicates otherwise, in this section and §25.212 of this title (relating to Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation) the term "electric utility" applies to all electric utilities as defined in the Public Utility Regulatory Act (PURA) §31.002 that own and operate a distribution system in Texas. This section shall not apply to an electric utility subject to PURA §39.102(c) until the expiration of the utility's rate freeze period.

(b) **Purpose.** The purpose of this section is to clearly state the terms and conditions that govern the interconnection and parallel operation of on-site distributed generation in order to implement PURA §39.101(b)(3), which entitles all Texas electric customers to access to on-site distributed generation, to provide cost savings and reliability benefits to customers, to establish technical requirements that will promote the safe and reliable parallel operation of on-site distributed generation resources, to enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity, and to promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints. Sales of power by a distributed generator in the wholesale market are subject to the provisions of this title relating to open-access comparable transmission service for electric utilities in the Electric Reliability Council of Texas (ERCOT).

(c) **Definitions.** The following words and terms when used in this section and §25.212 of this title shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Application for interconnection and parallel operation with the utility system or application —** The standard form of application approved by the commission.

(2) **Banking** — A method of accounting for energy produced by a customer for export into the distribution system. The host control area accepts energy from the customer to meet its own energy needs during a five- to 30-day period, credits this energy to the customer's account, and subsequently produces and, in the five- to 30-day period immediately following acceptance of the energy, disburses the energy accrued under the customer's account to the receiving control area specified by the customer. Disbursement of the accrued energy shall follow a pre-arranged schedule mutually acceptable to the host control area, the receiving control area, and the DG customer. Such schedule shall attempt to keep the host control area neutral with respect to the market value of the energy transferred on behalf of the exporting customer.

(3) **Company —** An electric utility operating a distribution system.

(4) **Customer —** Any entity interconnected to the company's utility system for the purpose of receiving or exporting electric power from or to the company's utility system.

(5) **Facility** — An electrical generating installation consisting of one or more on-site distributed generation units. The total capacity of a facility's individual on-site distributed generation units may exceed ten megawatts (MW); however, no more than ten MW of a facility's capacity will be interconnected at any point in time at the point of common coupling under this section.

(6) **Interconnection —** The physical connection of distributed generation to the utility system in accordance with the requirements of this section so that parallel operation can occur.

(7) **Interconnection agreement —** The standard form of agreement, which has been approved by the commission. The interconnection agreement sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system.

(8) **Inverter-based protective function —** A function of an inverter system, carried out using hardware and software, that is designed to prevent unsafe operating conditions from occurring before, during, and after the interconnection of an inverter-based static power converter unit with a utility system. For purposes of this definition, unsafe operating conditions are conditions that, if left uncorrected, would result in harm to personnel, damage to equipment, unacceptable system instability or operation outside legally established parameters affecting the quality of service to other customers connected to the utility system.

(9) **Network service —** Network service consists of two or more utility primary distribution feeder sources electrically tied together on the secondary (or low voltage) side to form one power source for one or more customers. The service is designed to maintain service to the customers even after the loss of one of these primary distribution feeder sources.

(10) **On-site distributed generation (or distributed generation) —** An electrical generating facility located at a customer's point of delivery (point of common coupling) of ten megawatts (MW) or less and connected at a voltage less than 60 kilovolts (kV) which may be connected in parallel operation to the utility system.

(11) **Parallel operation** — The operation of on-site distributed generation by a customer while the customer is connected to the company's utility system.

(12) **Point of common coupling —** The point where the electrical conductors of the company utility system are connected to the customer's conductors and where any transfer of electric power between the customer and the utility system takes place, such as switchgear near the meter.

(13) **Pre-certified equipment** — A specific generating and protective equipment system or systems that have been certified as meeting the applicable parts of this section relating to safety and reliability by an entity approved by the commission.

(14) **Pre-interconnection study —** A study or studies that may be undertaken by a company in response to its receipt of a completed application for interconnection and parallel operation with the utility system. Pre-interconnection studies may include, but are not limited to, service studies, coordination studies and utility system impact studies.

(15) **Stabilized —** A company utility system is considered stabilized when, following a disturbance, the system returns to the normal range of voltage and frequency for a duration of two minutes or a shorter time as mutually agreed to by the company and customer.

(16) **Tariff for interconnection and parallel operation of distributed generation —** The commission-approved tariff for interconnection and parallel operation of distributed generation including the application for interconnection and parallel operation of DG and pre-interconnection study fee schedule.

(17) **Unit —** A power generator.

(18) **Utility system —** A company's distribution system below 60 kV to which the generation equipment is interconnected.

(d) **Terms of Service.**

(1) **Banking.** A company operating in ERCOT shall make banking services available to any customer upon the customer's request. This obligation continues until the ERCOT Independent System Operator begins operating ERCOT as a single control area.

(2) **Distribution line charge.** No distribution line charge shall be assessed to a customer for exporting energy to the utility system.

§25.211(d) continued

(3) **Interconnection operations and maintenance costs.** No charge for operation and maintenance of a utility system's facilities shall be assessed against a customer for exporting energy to the utility system.

(4) **Scheduling fees.** A one-time scheduling fee for each banking period may be assessed for the disbursement of banked energy. No other scheduling fees may be assessed against an exporting DG customer.

(5) **Transmission charges.** No transmission charges shall be assessed to a customer for exporting energy. For purposes of this paragraph, the term transmission charges means transmission access and line charges, transformation charges, and transmission line loss charges.

(6) **Contract reformation.** All interconnection contracts shall be conformed to meet the requirements of this section within 60 days of adoption.

(7) **Tariffs.** No later than 30 days after the effective date of this section as amended, each electric utility shall file a tariff or tariffs for interconnection and parallel operation of distributed generation, including tariffs for banking and scheduling fees, in conformance with the provisions of this section. This provision does not require a utility that filed an interconnection study fee tariff prior to the effective date of this rule as amended to refile such tariff. The utility may file a new tariff or a modification of an existing tariff. Such tariffs shall ensure that back-up, supplemental, and maintenance power is available to all customers and customer classes that desire such service until January 1, 2002. Any modifications of existing tariffs or offerings of new tariffs relating to this subsection shall be consistent with the commission-approved form. Concurrent with the tariff filing in this section, each utility shall submit:

  (A) a schedule detailing the charges of interconnection studies and all supporting cost data for the charges;

  (B) a standard application for interconnection and parallel operation of distributed generation; and

  (C) the interconnection agreement approved by the commission.

(e) **Disconnection and reconnection.** A utility may disconnect a distributed generation unit from the utility system under the following conditions:

(1) **Expiration or termination of interconnection agreement.** The interconnection agreement specifies the effective term and termination rights of company and customer. Upon expiration or termination of the interconnection agreement with a customer, in accordance with the terms of the agreement, the utility may disconnect customer's facilities.

(2) **Non-compliance with the technical requirements specified in §25.212 of this title.** A utility may disconnect a distributed generation facility if the facility is not in compliance with the technical requirements specified in §25.212 of this title. Within two business days from the time the customer notifies the utility that the facility has been restored to compliance with the technical requirements of §25.212 of this title, the utility shall have an inspector verify such compliance. Upon such verification, the customer in coordination with the utility may reconnect the facility.

(3) **System emergency.** A utility may temporarily disconnect a customer's facility without prior written notice in cases where continued interconnection will endanger persons or property. During the forced outage of a utility system, the utility shall have the right to temporarily disconnect a customer's facility to make immediate repairs on the utility's system. When possible, the utility shall provide the customer with reasonable notice and reconnect the customer as quickly as reasonably practical.

(4) **Routine maintenance, repairs, and modifications.** A utility may disconnect a customer or a customer's facility with seven business days prior written notice of a service interruption for routine maintenance, repairs, and utility system modifications. The utility shall reconnect the customer as quickly as reasonably possible following any such service interruption.

(5) **Lack of approved application and interconnection agreement.** In order to interconnect distributed generation to a utility system, a customer must first submit to the utility an application for interconnection and parallel operation with the utility system and execute an interconnection agreement on the forms prescribed by the commission. The utility may refuse to connect or may disconnect the customer's facility if such application has not been received and approved.

(f) **Incremental demand charges**. During the term of an interconnection agreement a utility may require that a customer disconnect its distributed generation unit and/or take it off-line as a result of utility system conditions described in subsection (e)(3) and (4) of this section. Incremental demand charges arising from disconnecting the distributed generator as directed by company during such periods shall not be assessed by company to the customer. After January 1, 2002, the distribution utility shall not be responsible for the provision of generation services or their related charges.

(g) **Pre-interconnection studies for non-network interconnection of distributed generation.** A utility may conduct a service study, coordination study or utility system impact study prior to interconnection of a distributed generation facility. In instances where such studies are deemed necessary, the scope of such studies shall be based on the characteristics of the particular distributed generation facility to be interconnected and the utility's system at the specific proposed location. By agreement between the utility and its customer, studies related to interconnection of DG on the customer's premise may be conducted by a qualified third party.

(1) **Distributed generation facilities for which no pre-interconnection study fees may be charged.** A utility may not charge a customer a fee to conduct a pre-interconnection study for pre-certified distributed generation units up to 500 kW that export not more than 15% of the total load on a single radial feeder and contribute not more than 25% of the maximum potential short circuit current on a single radial feeder.

(2) **Distributed generation facilities for which pre-interconnection study fees may be charged.** Prior to the interconnection of a distributed generation facility not described in paragraph (1) of this subsection, a utility may charge a customer a fee to offset its costs incurred in the conduct of a pre-interconnection study. In those instances where a utility conducts an interconnection study the following shall apply:

(A) The conduct of such pre-interconnection study shall take no more than four weeks;

(B) A utility shall prepare written reports of the study findings and make them available to the customer;

(C) The study shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed generation to the company's utility system; and

(D) The customer shall receive an estimate of the study cost before the utility initiates the study.

(h) **Network interconnection of distributed generation.** Certain aspects of secondary network systems create technical difficulties that may make interconnection more costly to implement. In instances where customers request interconnection to a secondary network system, the utility and the customer shall use best reasonable efforts to complete the interconnection and the utility shall utilize the following guidelines:

(1) A utility shall approve applications for distributed generation facilities that use inverter-based protective functions unless total distributed generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration.

(2) A utility shall approve applications for other on-site generation facilities whose total generation is less than the local customer's load unless total distributed generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration.

(3) A utility may postpone processing an application for an individual distributed generation facility under this section if the total existing distributed generation on the targeted feeder represents more than 25% of the total load of the secondary network under consideration. If that is the case, the utility should conduct interconnection and network studies to determine whether, and in what amount, additional distributed generation facilities can be safely added to the feeder or accommodated in some other fashion. These studies should be completed within six weeks, and application processing should then resume.

(4) A utility may reject applications for a distributed generation facility under this section if the utility can demonstrate specific reliability or safety reasons why the distributed generation should not be interconnected at the requested site. However, in such cases the utility shall work with the customer to attempt to resolve such problems to their mutual satisfaction.

(5) A utility shall make all reasonable efforts to seek methods to safely and reliably interconnect distributed generation facilities that will export power. This may include switching service to a radial feed if practical and if acceptable to the customer.

(i) **Pre-Interconnection studies for network interconnection of distributed generation.** Prior to charging a pre-interconnection study fee for a network interconnection of distributed generation, a utility shall first advise the customer of the potential problems associated with interconnection of distributed generation with its network system. For potential interconnections to network systems there shall be no pre-interconnection study fee assessed for a facility with inverter systems under 20 kW. For all other facilities the utility may charge the customer a fee to offset its costs incurred in the conduct of the pre-interconnection study. In those instances where a utility conducts an interconnection study, the following shall apply:

(1) The conduct of such pre-interconnection studies shall take no more than four weeks;

(2) A utility shall prepare written reports of the study findings and make them available to the customer;

(3) The studies shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed generation to the utility's system; and

(4) The customer shall receive an estimate of the study cost before the utility initiates the study.

(j) **Communications concerning proposed distributed generation projects.** In the course of processing applications for interconnection and parallel operation and in the conduct of pre-interconnection studies, customers shall provide the utility detailed information concerning proposed distributed generation facilities. Such communications concerning the nature of proposed distributed generation facilities shall be made subject to the terms of §25.84 of this title (Relating to Annual Reporting of Affiliate Transactions for Electric Utilities), §25.272 of this title (Relating to Code of Conduct for Electric Utilities and their Affiliates), and §25.273 (Relating to Contracts between Electric Utilities and their Competitive Affiliates). A utility and its affiliates shall not use such knowledge of proposed distributed generation projects submitted to it for interconnection or study to prepare competing proposals to the customer that offer either discounted rates in return for not installing the distributed generation, or offer competing distributed generation projects.

(k) **Equipment pre-certification**.

(1) **Entities performing pre-certification.** The commission may approve one or more entities that shall pre-certify equipment as defined pursuant to this section.

(2) **Standards for entities performing pre-certification.** Testing organizations and/or facilities capable of analyzing the function, control, and protective systems of distributed generation units may request to be certified as testing organizations.

(3) **Effect of pre-certification.** Distributed generation units which are certified to be in compliance by an approved testing facility or organization as described in this subsection shall be installed on a company utility system in accordance with an approved interconnection control and protection scheme without further review of their design by the utility.

(l) **Designation of utility contact persons for matters relating to distributed generation interconnection.**

(1) Each electric utility shall designate a person or persons who will serve as the utility's contact for all matters related to distributed generation interconnection.

(2) Each electric utility shall identify to the commission its distributed generation contact person.

(3) Each electric utility shall provide convenient access through its internet web site to the names, telephone numbers, mailing addresses and electronic mail addresses for its distributed generation contact person.

(m) **Time periods for processing applications for interconnection with the utility system.** In order to apply for interconnection the customer shall provide the utility a completed application for interconnection and parallel operation with the utility system. The interconnection of distributed generation to the utility system shall take place within the following schedule:

(1) For a facility with pre-certified equipment, interconnection shall take place within four weeks of the utility's receipt of a completed interconnection application.

(2) For other facilities, interconnection shall take place within six weeks of the utility's receipt of a completed application.

(3) If interconnection of a particular facility will require substantial capital upgrades to the utility system, the company shall provide the customer an estimate of the schedule and customer's cost for the upgrade. If the customer desires to proceed with the upgrade, the customer and the company will enter into a contract for the completion of the upgrade. The interconnection shall take place no later than two weeks following the completion of such upgrades. The utility shall employ best reasonable efforts to complete such system upgrades in the shortest time reasonably practical.

§25.211(m) continued

(4) A utility shall use best reasonable efforts to interconnect facilities within the time frames described in this subsection. If in a particular instance, a utility determines that it can not interconnect a facility within the time frames stated in this subsection, it will notify the applicant in writing of that fact. The notification will identify the reason or reasons interconnection could not be performed in accordance with the schedule and provide an estimated date for interconnection.

(5) All applications for interconnection and parallel operation of distributed generation shall be processed by the utility in a non-discriminatory manner. Applications will be processed in the order that they are received. It is recognized that certain applications may require minor modifications while they are being reviewed by the utility. Such minor modifications to a pending application shall not require that it be considered incomplete and treated as a new or separate application.

(n) **Reporting requirements.** Each electric utility shall maintain records concerning applications received for interconnection and parallel operation of distributed generation. Such records will include the date each application is received, documents generated in the course of processing each application, correspondence regarding each application, and the final disposition of each application. By March 30 of each year, every electric utility shall file with the commission a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report shall list the new distributed generation facilities interconnected with the system since the previous year' report, any distributed generation facilities no longer interconnected with the utility's system since the previous report, the capacity of each facility, and the feeder or other point on the company's utility system where the facility is connected. The annual report shall also identify all applications for interconnection received during the previous one-year period, and the disposition of such applications.

(o) **Interconnection disputes.** Complaints relating to interconnection disputes under this section shall be handled in an expeditious manner pursuant to §22.242 (relating to Complaints). In instances where informal dispute resolution is sought, complaints shall be presented to the Electric Division. The Electric Division shall attempt to informally resolve complaints within 20 business days of the date of receipt of the complaint. Unresolved complaints shall be presented to the commission at the next available open meeting.

§25.212. Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation.

(a) **Purpose.** The purpose of this section is to describe the requirements and procedures for safe and effective connection and operation of distributed generation.

(1) A customer may operate 60 Hertz (Hz), three-phase or single-phase generating equipment, whether qualifying facility (QF) or non-QF, in parallel with the utility system pursuant to an interconnection agreement, provided that the equipment meets or exceeds the requirements of this section.

(2) This section describes typical interconnection requirements. Certain specific interconnection locations and conditions may require the installation and use of more sophisticated protective devices and operating schemes, especially when the facility is exporting power to the utility system.

(3) If the utility concludes that an application for parallel operation describes facilities that may require additional devices and operating schemes, the utility shall make those additional requirements known to the customer at the time the interconnection studies are completed.

(4) Where the application of the technical requirements set forth in this section appears inappropriate for a specific facility, the customer and utility may agree to different requirements, or a party may petition the commission for a good cause exception, after making every reasonable effort to resolve all issues between the parties.

(b) **General interconnection and protection requirements.**

(1) The customer's generation and interconnection installation must meet all applicable national, state,

and local construction and safety codes.

(2) The customer's generator shall be equipped with protective hardware and software designed to prevent the generator from being connected to a de-energized circuit owned by the utility.

(3) The customer's generator shall be equipped with the necessary protective hardware and software designed to prevent connection or parallel operation of the generating equipment with the utility system unless the utility system service voltage and frequency is of normal magnitude.

(4) Pre-certified equipment may be installed on a company's utility systems in accordance with an approved interconnection control and protection scheme without further review of their design by the utility. When the customer is exporting to the utility system using pre-certified equipment, the protective settings and operations shall be those specified by the utility.

(5) The customer will be responsible for protecting its generating equipment in such a manner that utility system outages, short circuits or other disturbances including zero sequence currents and ferroresonant over-voltages do not damage the customer's generating equipment. The customer's protective equipment shall also prevent unnecessary tripping of the utility system breakers that would affect the utility system's capability of providing reliable service to other customers.

(6) For facilities greater than two megawatts (MW), the utility may require that a communication channel be provided by the customer to provide communication between the utility and the customer's facility. The channel may be a leased telephone circuit, power line carrier, pilot wire circuit, microwave, or other mutually agreed upon medium.

(7) Circuit breakers or other interrupting devices at the point of common coupling must be capable of interrupting maximum available fault current. Facilities larger than two MW and exporting to the utility system shall have a redundant circuit breaker unless a listed device suitable for the rated application is used.

(8) The customer will furnish and install a manual disconnect device that has a visual break that is appropriate to the voltage level (a disconnect switch, a draw-out breaker, or fuse block), and is accessible to the utility personnel, and capable of being locked in the open position. The customer shall follow the utility's switching, clearance, tagging, and locking procedures, which the utility shall provide for the customer.

(c) **Prevention of interference.** To eliminate undesirable interference caused by operation of the customer's generating equipment, the customer's generator shall meet the following criteria:

(1) **Voltage.** The customer will operate its generating equipment in such a manner that the voltage levels on the utility system are in the same range as if the generating equipment were not connected to the utility's system. The customer shall provide an automatic method of disconnecting the generating equipment from the utility system if a sustained voltage deviation in excess of +5.0 % or –10% from nominal voltage persists for more than 30 seconds, or a deviation in excess of +10% or –30% from nominal voltage persists for more than ten cycles. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized.

(2) **Flicker.** The customer's equipment shall not cause excessive voltage flicker on the utility system. This flicker shall not exceed 3.0% voltage dip, in accordance with Institute of Electrical and Electronics Engineers (IEEE) 519 as measured at the point of common coupling.

(3) **Frequency**. The operating frequency of the customer's generating equipment shall not deviate more than +0.5 Hertz (Hz) or –0.7 Hz from a 60 Hz base. The customer shall automatically disconnect the generating equipment from the utility system within 15 cycles if this frequency tolerance cannot be maintained. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized.

(4) **Harmonics.** In accordance with IEEE 519 the total harmonic distortion (THD) voltage shall not exceed 5.0% of the fundamental 60 Hz frequency nor 3.0% of the fundamental frequency for any individual harmonic when measured at the point of common coupling with the utility system.

(5) **Fault and line clearing.** The customer shall automatically disconnect from the utility system within ten cycles if the voltage on one or more phases falls below -30% of nominal voltage on the utility system serving the customer premises. This disconnect timing also ensures that the generator is

disconnected from the utility system prior to automatic re-close of breakers. The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized. To enhance reliability and safety and with the utility's approval, the customer may employ a modified relay scheme with delayed tripping or blocking using communications equipment between customer and company.

(d) **Control, protection and safety equipment requirements specific to single phase generators of 50 kilowatts (kW) or less connected to the utility's system**. Exporting to the utility system may require additional operational or protection devices and will require coordination of operations with the host utility. The necessary control, protection, and safety equipment specific to single-phase generators of 50 kW or less connected to secondary or primary systems include an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a synchronizing check for synchronous and other types of generators with stand-alone capability.

(e) **Control, protection and safety equipment requirements specific to three-phase synchronous generators, induction generators, and inverter systems.** This subsection specifies the control, protection, and safety equipment requirements specific to three phase synchronous generators, induction generators, and inverter systems. Exporting to the utility system may require additional operational or protection devices and will require coordination of operations with the utility.

(1) **Three phase synchronous generators.** The customer's generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The customer is solely responsible for properly synchronizing its generator with the utility. The excitation system response ratio shall not be less than 0.5. The generator's excitation system(s) shall conform, as near as reasonably achievable, to the field voltage versus time criteria specified in American National Standards Institute Standard C50.13-1989 in order to permit adequate field forcing during transient conditions. For generating systems greater than two MW the customer shall maintain the automatic voltage regulator (AVR) of each generating unit in service and operable at all times. If the AVR is removed from service for maintenance or repair, the utility's dispatching office shall be notified.

(2) **Three-phase induction generators and inverter systems.** Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured on the utility system side at the point of common coupling is within the visible flicker stated in subsection (c)(2) of this section. Otherwise, the customer may be required to install hardware or employ other techniques to bring voltage fluctuations to acceptable levels. Line-commutated inverters do not require synchronizing equipment. Self-commutated inverters whether of the utility-interactive type or stand-alone type shall be used in parallel with the utility system only with synchronizing equipment. Direct-current generation shall not be operated in parallel with the utility system.

(3) **Protective function requirements.** The protective function requirements for three phase facilities of different size and technology are listed below.

(A) Facilities rated ten kilowatts (kW) or less must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a manual or automatic synchronizing check (for facilities with stand alone capability).

(B) Facilities rated in excess of ten kW but not more than 500 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, a manual or automatic synchronizing check (for facilities with stand alone capability), either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, and reverse power sensing if the facility is not exporting (unless the generator is less than the minimum load of the customer).

(C) Facilities rated more than 500 kW but not more than 2,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check (for facilities with stand alone capability) and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer). If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility.

(D) Facilities rated more than 2,000 kW but not more than 10,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, an automatic synchronizing check and AVR for facilities with stand alone capability, and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer). If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility. A telemetry/transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

(f) **Facilities not identified.** In the event that standards for a specific unit or facility are not set out in this section, the company and customer may interconnect a facility using mutually agreed upon technical standards.

(g) **Requirements specific to a facility paralleling for sixty cycles or less (closed transition switching).** The protective devices required for facilities ten MW or less which parallel with the utility system for 60 cycles or less are an interconnect disconnect device, a generator disconnect device, an automatic synchronizing check for generators with stand alone capability, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and either a ground over-voltage trip or a ground over-current trip depending on the grounding system, if required by the utility.

(h) **Inspection and start-up testing.** The customer shall provide the utility with notice at least two weeks before the initial energizing and start-up testing of the customer's generating equipment and the utility may witness the testing of any equipment and protective systems associated with the interconnection. The customer shall revise and re-submit the application with information reflecting any proposed modification that may affect the safe and reliable operation of the utility system.

(i) **Site testing and commissioning.** Testing of protection systems shall include procedures to functionally test all protective elements of the system up to and including tripping of the generator and interconnection point. Testing will verify all protective set points and relay/breaker trip timing. The utility may witness the testing of installed switchgear, protection systems, and generator. The customer is responsible for routine maintenance of the generator and control and protective equipment. The customer will maintain records of such maintenance activities, which the utility may review at reasonable times. For generation systems greater than 500 kW, a log of generator operations shall be kept. At a minimum, the log shall include the date, generator time on, and generator time off, and megawatt and megavar output. The utility may review such logs at reasonable times.

(j) **Metering.** Consistent with Chapter 25, Subchapter F of this title (relating to Metering), the utility may supply, own, and maintain all necessary meters and associated equipment to record energy purchases by the customer and energy exports to the utility system. The customer shall supply at no cost to the utility a suitable location on its premises for the installation of the utility's meters and other equipment. If metering at the generator is required in such applications, metering that is part of the generator control package will be considered sufficient if it meets all the measurements criteria that would be required by a separate stand alone meter.

Form of Tariff for Interconnection and Parallel Operation of DG

Distributed Generation Interconnection

Availability

Company shall interconnect distributed generation as described in PUC Substantive Rules §25.211 and §25.212 pursuant to the terms of the Agreement for Interconnection and Parallel Operation of Distributed Generation which is incorporated herein.

Application

A person seeking interconnection and parallel operation of distributed generation with Company must complete and submit the Application for Interconnection and Parallel Operation of Distributed Generation with the Utility System, which is incorporated herein.

Definitions

1) Non-Peak Hours - ____________________________________.

2) Peak Hours - ____.

Pricing

Standby

Maintenance

Supplemental

Terms and Conditions of Service

The terms and conditions under which interconnection of distributed generation is to be provided are contained in Commission Substantive Rules §25.211 and §25.212, which are incorporated herein by reference, and in the Agreement for Interconnection and Parallel Operation of Distributed Generation, which is incorporated herein. The rules are subject to change from time to time as determined by the Commission, and such changes shall be automatically applicable hereto based upon the effective date of any

Commission order or rule amendment.

Studies and Services

Pre-interconnection studies may be required and conducted by Company. Other services may be provided as requested by the customer and provided pursuant to negotiations and agreement by the customer and Company and may be subject to approval by the Commission.

Pre-Interconnection Study Fee Schedule

Prescribed Form Application for Interconnection and Parallel Operation of Distributed Generation with the Utility System

Customers seeking to interconnect distributed generation with the utility system will complete and file with the company the following Application for Parallel Operation:

APPLICATION FOR INTERCONNECTION AND PARALLEL OPERATION OF DISTRIBUTED GENERATION WITH THE UTILITY SYSTEM

Return Completed Application to: [Company name]
[Attention: Manager, Distribution Planning
[Company address]
[Company address]

Customer's Name: ____

Address:____

Contact Person: ____

Telephone Number: ____

Service Point Address: ____

Information Prepared and Submitted By: ____________________________________
(Name and Address) ____

Signature ______________________________________

The following information shall be supplied by the Customer or Customer's designated representative. All applicable items must be accurately completed in order that the Customer's generating facilities may be effectively evaluated by the (Company) _____________for interconnection with the utility system.

GENERATOR

Number of Units: ____

Manufacturer: ____

Type (Synchronous, Induction, or Inverter): ____________________________________

Fuel Source Type (Solar, Natural Gas, Wind, etc.): ______________________________

Kilowatt Rating (95 F at location) ____

Kilovolt-Ampere Rating (95 F at location): ____________________________________

Power Factor: ____

Voltage Rating: ____

Ampere Rating: ____

Number of Phases: ____

Frequency: ____

Do you plan to export power: _____________Yes / _______________No

If Yes, maximum amount expected: ____

Pre-Certification Label or Type Number: ______________________________________

Expected Energizing and Start-up Date: ____

Normal Operation of Interconnection: (examples: provide power to meet base load, demand management, standby, back-up, other (please describe))______________________________

One-line diagram attached: __________Yes

Has the generator Manufacturer supplied its dynamic modeling values to the Host Utility? _______Yes

[Note: Requires a Yes for complete application. For Pre-Certified Equipment answer is Yes.]

Layout sketch showing lockable, "visible" disconnect device:
_____________Yes

[COMPANY NAME]	[CUSTOMER NAME]
BY: _________________________	BY: _________________________
TITLE: _______________________	TITLE: _______________________
DATE: _______________________	DATE: ________________________

AGREEMENT FOR INTERCONNECTION AND PARALLEL OPERATION OF DISTRIBUTED GENERATION

This Interconnection Agreement ("Agreement") is made and entered into this ________ day of ________________, 19__, by ______________________________, ("Company"), and ____ ("Customer"), a _____________________________________ [specify whether corporation, and if so name state, municipal corporation, cooperative corporation, or other], each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties". In consideration of the mutual covenants set forth herein, the Parties agree as follows:

1. **Scope of Agreement** -- This Agreement is applicable to conditions under which the Company and the Customer agree that one or more generating facility or facilities of ten MW or less to be interconnected at 60 kV or less ("Facility or Facilities") may be interconnected to the Company's utility system, as described in Exhibit A.

2. **Establishment of Point(s) of Interconnection** -- Company and Customer agree to interconnect their Facility or Facilities at the locations specified in this Agreement, in accordance with Public Utility Commission of Texas Substantive Rules § 25.211 relating to Interconnection of Distributed Generation and § 25.212 relating to Technical requirements for Interconnection and Parallel Operation of On-Site Distributed Generation, (16 Texas Administrative Code §25.211 and §25.212) (the "Rules") or any successor rule addressing distributed generation and as described in the attached Exhibit A (the "Point(s) of Interconnection").

3. **Responsibilities of Company and Customer** -- Each Party will, at its own cost and expense, operate, maintain, repair, and inspect, and shall be fully responsible for, Facility or Facilities which it now or hereafter may own unless otherwise specified on Exhibit A. Customer shall conduct operations of its facility(s) in compliance with all aspects of the Rules, and Company shall conduct operations on its utility system in compliance with all aspects of the Rules, or as further described and mutually agreed to in the applicable Facility Schedule. Maintenance of Facilities or interconnection facilities shall be performed in accordance with the applicable manufacturer's recommended maintenance schedule. The Parties agree to cause their Facilities or systems to be constructed in accordance with specifications equal to or greater than those provided by the National Electrical Safety Code, approved by the American National Standards Institute, in effect at the time of construction.

Each Party covenants and agrees to design, install, maintain, and operate, or cause the design, installation, maintenance, and operation of, its distribution system and related Facilities and Units so as to reasonably minimize the likelihood of a disturbance, originating in the system of one Party, affecting or impairing the system of the other Party, or other systems with which a Party is interconnected.

Company will notify Customer if there is evidence that the Facility operation causes disruption or deterioration of service to other customers served from the same grid or if the Facility operation causes damage to Company's system.

Customer will notify Company of any emergency or hazardous condition or occurrence with the Customer's Unit(s) which could affect safe operation of the system.

4. *Limitation of Liability and Indemnification*

a. *Notwithstanding any other provision in this Agreement, with respect to Company's provision of electric service to Customer, Company's liability to Customer shall be limited as set forth in ______ of Company's PUC-approved tariffs and terms and conditions for electric service, which is incorporated herein by reference.*

b. *Neither Company nor Customer shall be liable to the other for damages for any act that is beyond such party's control, including any event that is a result of an act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, a curtailment, order, or regulation or restriction imposed by governmental, military, or lawfully established civilian authorities, or by the making of necessary repairs upon the property or equipment of either party.*

c. Notwithstanding Paragraph 4.b of this Agreement, Company shall assume all liability for and shall indemnify Customer for any claims, losses, costs, and expenses of any kind or character to the extent that they result from Company's negligence in connection with the design, construction, or operation of its facilities as described on Exhibit A; provided, however, that Company shall have no obligation to indemnify Customer for claims brought by claimants who cannot recover directly from Company. Such indemnity shall include, but is not limited to, financial responsibility for: (a) 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 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 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.

d. Notwithstanding Paragraph 4.b of this Agreement, Customer shall assume all liability for and shall indemnify Company for any claims, losses, costs, and expenses of any kind or character to the extent that they result from Customer's negligence in connection with the design, construction or operation of its facilities as described on Exhibit A; provided, however, that Customer shall have no obligation to indemnify Company for claims brought by claimants who cannot recover directly from Customer. Such indemnity shall include, but is not limited to, financial responsibility for: (a) 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 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 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.

e. Company and Customer shall each be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of delivery. The Company does not assume any duty of inspecting the Customer's lines, wires, switches, or other equipment and will not be responsible therefor. Customer assumes all responsibility for the electric service supplied hereunder and the facilities used in connection therewith at or beyond the point of delivery, the point of delivery being the point where the electric energy first leaves the wire or facilities provided and owned by Company and enters the wire or facilities provided by Customer.

f. For the mutual protection of the Customer and the Company, only with Company prior authorization are the connections between the Company's service wires and the Customer's service entrance conductors to be energized.

5. **Right of Access, Equipment Installation, Removal & Inspection**– Upon reasonable notice, the Company may send a qualified person to the premises of the Customer at or immediately before the time the Facility first produces energy to inspect the interconnection, and observe the Facility's commissioning (including any testing), startup, and operation for a period of up to no more than three days after initial startup of the unit.

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.

6. **Disconnection of Unit –** Customer retains the option to disconnect from Company's utility system. Customer will notify the Company of its intent to disconnect by giving the Company at least thirty days' prior written notice. Such disconnection shall not be a termination of the agreement unless Customer exercises rights under Section 7.

Customer shall disconnect Facility from Company's system upon the effective date of any termination under Section 7.

Subject to Commission Rule, for routine maintenance and repairs on Company's utility system, Company shall provide Customer with seven business days' notice of service interruption.

Company shall have the right to suspend service in cases where continuance of service to Customer will endanger persons or property. During the forced outage of the Company's utility system serving customer, Company shall have the right to suspend service to effect immediate repairs on Company's utility system, but the Company shall use its best efforts to provide the Customer with reasonable prior notice.

7. **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 within 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.

8. **Governing Law and Regulatory Authority** -- This Agreement was executed in the State of Texas 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, 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.

9. **Amendment** --This Agreement may be amended only upon mutual agreement of the Parties, which amendment will not be effective until reduced to writing and executed by the Parties.

10. **Entirety of Agreement and Prior Agreements Superseded** -- This Agreement, including all attached Exhibits and Facility Schedules, which are expressly made a part hereof for all purposes, constitutes the entire agreement and understanding between the Parties with regard to the interconnection of the facilities of the Parties at the Points of Interconnection expressly provided for in this Agreement. The Parties are not bound by or liable for any statement, representation, promise, inducement, understanding, or undertaking of any kind or nature (whether written or oral) with regard to the subject matter hereof not set forth or provided for herein. This Agreement replaces all prior agreements and undertakings, oral or written, between the Parties with regard to the subject matter hereof, including without limitation ____ [specify any prior agreements being superseded], and all such agreements and undertakings are agreed by the Parties to no longer be of any force or effect. 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.

11. **Notices** -- Notices given under this Agreement are deemed to have been duly delivered if hand delivered or sent by United States certified mail, return receipt requested, postage prepaid, to:

(a) If to Company:

____
____
____
____

(b) If to Customer:

____
____
____
____

The above-listed names, titles, and addresses of either Party may be changed by written notification to the other, notwithstanding Section 10.

12. **Invoicing and Payment --** Invoicing and payment terms for services associated with this agreement shall be consistent with applicable Substantive Rules of the PUCT.

13. **No Third-Party Beneficiaries** -- This Agreement is not intended to and does not create rights, remedies, or 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 the Parties, their successors in interest and, where permitted, their assigns.

14. **No Waiver** -- 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 upon the Parties.

15. **Headings** -- The descriptive headings of the various articles and sections of this Agreement have been inserted for convenience of reference only and are to be afforded no significance in the interpretation or construction of this Agreement.

16. **Multiple Counterparts** -- This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

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

LIST OF FACILITY SCHEDULES AND POINTS OF INTERCONNECTION

Facility Schedule No.	Name of Point of Interconnection

[Insert Facility Schedule number and name for each Point of Interconnection]

FACILITY SCHEDULE NO.

[The following information is to be specified for each Point of Interconnection, if applicable.]

1. Name:

2. Facility location:

3. Delivery voltage:

4. Metering (voltage, location, losses adjustment due to metering location, and other):

5. Normal Operation of Interconnection:

6. One line diagram attached (check one): ______ Yes /_______ No

7. Facilities to be furnished by Company:

8. Facilities to be furnished by Customer:

9. Cost Responsibility:

10. Control area interchange point (check one): ______ Yes /_______ No

11. Supplemental terms and conditions attached (check one): _____ Yes / ______ No

[COMPANY NAME]	[CUSTOMER NAME]
BY:______________________________	BY:____________________________________
TITLE:___________________________	TITLE:__________________________________
DATE:____________________________	DATE:__________________________________

Definition of "electric utility" from PURA §31.002(6)
Also see Definitions A-1

FILE: PURA31.002(6)

ATTACHMENT G

EXCERPT FROM PUBLIC UTILITY REGULATORY ACT, 1999, SEC. 31.002 DEFINITIONS, (6)

(6) "Electric utility" means a person or river authority that owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state. The term includes a lessee, trustee, or receiver of an electric utility and a recreational vehicle park owner who does not comply with Subchapter C, Chapter 184, with regard to the metered sale of electricity at the recreational vehicle park. The term does not include:

(A) a municipal corporation;

(B) a qualifying facility;

(C) a power generation company;

(D) an exempt wholesale generator;

(E) a power marketer;

(F) a corporation described by Section 32.053 to the extent the corporation sells electricity exclusively at wholesale and not to the ultimate consumer;

(G) an electric cooperative;

(H) a retail electric provider;

(I) this state or an agency of this state; or

(J) a person not otherwise an electric utility who:

(i) furnishes an electric service or commodity only to itself, its employees, or its tenants as an incident of employment or tenancy, if that service or commodity is not resold to or used by others;

(ii) owns or operates in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electric energy to an electric utility, if the equipment or facilities are used primarily to produce and generate electric energy for consumption by that person; or

(iii) owns or operates in this state a recreational vehicle park that provides metered electric service in accordance with Subchapter C, Chapter 184.

Appendix A3: Summary of DG Technologies

This Appendix provides brief descriptions of leading DG technologies. For context, it includes generic cost and performance information. Readers should note that for any given situation it is important to consult with vendors or their agents or dealers regarding actual price. To assist, this Appendix includes a list of links to World Wide Web sites for many leading DG equipment vendors.

Introduction

Distributed generation (DG) systems may be comprised of one or more primary technologies such as internal combustion engines, combustion turbines, photovoltaics, and batteries. Innumerable combinations of DG technology/fuel options are possible, to take advantage of synergies between individual technologies, making them as robust and/or cost-effective as possible.[4]

Most DG systems operate on gaseous or liquid hydrocarbon fuel to produce electricity as needed; natural gas fuel is piped in; diesel fuel is stored on-site. Battery systems store electric energy from the grid for use when needed. Renewable energy DGs use solar or wind energy as fuel.

One important DG type category is the duty cycle for the DG is used: 1) for "peaking" duty cycle applications DGs only operate for a small portion of the year, usually between 50 – 600 hours annually, and 2) for "baseload" duty cycle DGs operate for many hours per year for.

Peaking duty distributed generation tends to have relatively low installed cost and can take on load in just a few minutes (or less). It tends to be relatively inefficient and have significant air emissions per hour operated. Peak duty cycle DGs usually operate for just a few hundred hours between overhauls. Typical installed costs range from about \$200 – \$500/kW and non-fuel operating cost ranges from 1¢ - 5¢/kWh.

Primary distributed generation technologies used for baseload duty cycle (when compared to peaking duty cycle described above) tend to be fuel efficient, reliable, and clean burning combustion-based options. Typical installed costs range from about \$400 – \$800/kW and non-fuel operating cost ranges from ½¢ - 3¢/kWh.

[4] Perhaps one of the best examples is an uninterruptible power supply (UPS) that can carry a facility's load for several minutes combined with a diesel engine generator that takes a few minutes to come on line. Batteries are an expensive way to store/provide a significant amount of electric energy. So in this case the synergy is that once running, the diesel generator provides much lower cost energy.

Most types of distributed generation can provide useful and valuable thermal energy. To do so, additional equipment (e.g., pipes and pumps) is added to the generation system so that during electricity generation otherwise wasted heat energy is captured and used to heat water or air, or for processes. This concept is often referred to as combined heat and power (CHP) or cogeneration. Depending on type of generator used, existing thermal energy infrastructure in the facility, and many other project-specific factors, equipment for CHP can add 25% - 100% to the installed cost for a generation-only system.

Important "enabling" subsystems include:

- power conditioning equipment such as electricity generator, transformer, and inverters
- controls
- communications
- fuel handling and/or fuel storage
- emission controls
- sound attenuation enclosures.

Internal Combustion/Reciprocating Engine Generators

An internal combustion reciprocating (piston-driven) engine generator set (genset) includes an internal combustion engine as prime mover coupled with an electric generator and often control and power conditioning subsystems. Sound attenuation enclosures may be also needed.

Most engines are one of two types:

1) compression ignition of fuel — the diesel cycle in which fuel combustion occurs as fuel is compressed causing heat leading to ignition.
2) "spark-ignited" combustion of fuel — the Otto cycle characterized by how fuel spark ignition of fuel (gasoline fueled automobile engines employ the Otto cycle).

These are described in more detail below.

Diesel Engine Generators

Diesel engine generator sets (gensets) consists of a diesel cycle reciprocating engine prime mover, burning diesel fuel, which is coupled to an electric generator. The diesel engine operates at a relatively high compression ratio and at relatively low rpm (compared to Otto cycle/spark engines and to combustion turbines described below).

Diesel engine gensets are very common, especially in areas where grid power is not available or is unreliable. They are manufactured in a wide range of sizes up to 15 MW; however, for typical distributed energy applications multiple small units, rather than one large unit, are installed for added reliability.

These power plants can be cycled frequently and operate as peak load power plants or as load-following plants. In some cases, usually at sites not connected to a power grid, diesel gensets are used for baseload operation (sometimes referred to as "village" power). Diesel gensets are proven, cost-effective, and extremely reliable, and should have a service life of 20 to 25 years if properly maintained.

Installed cost for diesel engines varies significantly. Used/refurbished models can cost as little as $200/kW and newer, more robust, more efficient machines costing $500/kW or more. Depending on duty cycle and engine design, non-fuel O&M for diesel gensets operating on diesel fuel can vary widely, typically ranging from 2.5¢/kWh - 4¢/kWh, with an allowance for overhauls. Frequent cycling increases O&M costs considerably. Though fuel conversion efficiency for diesels engines can exceed 43% (fuel input of about 7,900 Btu/kWh$_e$, HHV), typical heat rates range widely from 8,000 Btu/kWh$_e$ to 10,000 Btu/kWh$_e$ (HHV).

"Dual Fuel" Diesel Engine Generators

A dual-fuel engine is a diesel (cycle) engine modified to use *mostly* natural gas. Diesel cycle engines cannot operate on natural gas alone because natural gas will not combust under pressure like diesel fuel does, so they must operate in what is called "dual fuel" mode. For that, natural gas is mixed with a small portion of diesel fuel so that the resulting fuel mixture (i.e., 5 – 10% diesel fuel) *does* combust under pressure. This requires de-rating of and modest modifications to a diesel cycle engine. (Note: for the same displacement a diesel engine operating on natural gas generates less power than the same sized engine operating on diesel fuel only).

Although diesel engines are common, dual fuel versions are not. But because the underlying technology is commercial and well known, in theory natural gas fired versions (for power generation) could become much more common in sizes ranging from kilowatts to megawatts. For distributed energy systems small multiple unit systems would probably be installed, rather than one single large unit, to improve electric service reliability.

Dual fuel gensets can be cycled frequently to provide peaking power or "load-following" or they can be used for baseload or cogeneration applications. They employ mostly well-proven technology and are very reliable. Service life should be at least 20 to 25 years if properly maintained.

Non-fuel O&M cost is similar to that for diesel gensets. It typically ranges from 2 - 4 ¢/kWh including allowance for overhauls. Typical heat rates (HHV) also have a wide range, from 8,200 Btu/kWh$_e$ to 10,000 Btu/kWh$_e$.

Spark Ignited/Otto Cycle Engine Generators

Spark-ignited combustion (Otto cycle) reciprocating engines are very common. They range in power output of less than a horsepower to megawatts. Perhaps the most familiar use for these engines is for automobiles. For stationary power applications including DG a system includes the engine, internal combustion engine as prime mover coupled with an electric generator. The engine prime mover is usually one of two types:

Although spark-ignition engines designed to use gasoline are common, natural gas fueled versions are not so common. However, because the underlying technology is commercial and well known, in theory, natural gas fired versions (for power generation) could become much more common for a variety of applications and load sizes.

Natural gas-fueled reciprocating engine gensets can be cycled frequently to provide peaking power or “load-following” or they can be used for baseload or cogeneration applications. They employ mostly well-proven technology and are very reliable. Service life should be at least 20 to 25 years if properly maintained.

Installed cost tends to range between $400/kW – $600/kW. O&M cost is similar to and possibly somewhat lower than that for diesel gensets. It typically ranges from 2¢/kWh – 4.5¢/kWh. Typical heat rates (HHV) also have a wide range, from 8,800 to 10,500 Btu/kWh.

Combustion Turbines

Combustion turbines (also called gas turbines) burn gaseous or liquid fuel to produce electricity in a relatively efficient, reliable, cost-effective, and in some instances clean manner. Generically, combustion turbines s are "expansion turbines" which derive their motive power from the expansion of hot gasses—heated with fuel—through a turbine with many blades. The resulting high-speed rotary motion is converted to electricity via a connected generator using the Brayton heat cycle. A full generation system consists of the turbine itself, a compressor, a combustor, power conditioning equipment (usually electricity generator and transformer), a fuel handling subsystem, and possibly other subsystems. They may also include a sound attenuation enclosure.

Combustion turbine generation systems are commonplace as electricity generators and are available in sizes from hundreds of kilowatts to very large units rated at hundreds of megawatts. Combustion turbine systems have a moderate capital cost, but they often are used to burn relatively high cost distillate oil or natural gas. Combustion turbine generation systems should have a minimum service life of 25 - 30 years if properly maintained and depending on how and how often they are used.

Depending on the size, type, and application, full-load heat rates (HHV) for commercial equipment can range from 8,000 Btu/kWh to 14,000 Btu/kWh. Non-fuel O&M costs are relatively low – typically ranging from ½ ¢/kWh - 5 ¢/kWh. Variation is a function of criteria such as turbine size, turbine age, turbine materials, turbine complexity/simplicity, reliability required, availability of components, and maintenance protocol/frequency.

Combustion turbines can start and stop quickly and can respond to load changes rapidly making them ideal for peaking and load-following applications. In many industrial cogeneration applications they would also make excellent sources of baseload power, especially at sizes in the 5 to 50 MW range.

"Conventional" Combustion Turbine Generators

Conventional combustion turbine generators vary significantly in price, size, and are designed for a wide range of duty cycles. Typical sizes range from 1 to 300 MW. Smaller turbines used for stationary power generation are often those developed for transportation applications, especially for marine vessels and airplanes. (Note that for those applications reliability and in some cases fuel efficiency are important performance criteria.)

Installed costs range from as low as $300/kW for refurbished units and lighter duty machines to 700 - $800/kW for heavier duty/more efficient versions, with non-fuel O&M ranging from .75¢/kWh - 4¢/kWh depending in large part on the intended duty cycle and on maintenance practices.

Microturbine Generators

Microturbines are small versions of traditional gas turbines, with very similar operational characteristics. They are based on designs developed primarily for transportation-related applications such as turbochargers and power generation in aircraft. In general, electric generators using microturbines as the prime mover are designed to be very reliable with simple designs, some with only one moving part. Typical sizes are 20 to 300 kW.

Microturbines are "near-commercial" with many demonstration and evaluation units in the field. Several companies, some of which are very large, are committed to making these devices a viable, competitive generation option. One key characteristic of microturbines is that their simple design lends itself to mass production—should significant demand materialize. For the most part, prices too are still being established. Possibly the key driver will be manufacturing scale. Installed price is currently in the range of about $1,000/kW – 1,500/kW.

Definitive data on reliability, durability, and non-fuel O&M costs are just being developed though based on simplicity and in some cases well-proven designs non-fuel O&M could be similar to that of conventional combustion turbines.

Fuel efficiency tends to be somewhat or even significantly lower than that of larger combustion turbines and internal combustion reciprocating engines, ranging from 10,000 Btu/kWh_e –15,000 Btu/kWh_e. Note, however, that if microturbines are used in situations involving use of steam and/or hot water, then they can generate electricity and thermal energy (combined heat and power, CHP) cost-effectively due to a) the temperatures involved and b) the large amount of waste heat produced.

Advanced Turbine System (ATS) Generators

The Advanced Turbine System (ATS) was developed as a small, efficient, clean, low-cost, power generation prime mover by Solar Turbines in conjunction with the U.S. Department of Energy. It employs the latest combustion turbine design philosophy and state-of-the-art materials. It generates 4.2 MW. Fuel requirements are about 8,800 – 9,000 Btu/kWh (LHV). Installed cost is expected to be about $400/kW, with non-fuel O&M expected to be below ½¢ per kWh generated.

Fuel Cells

Fuel cells are energy conversion devices that convert hydrogen (H_2) or high-quality (hydrogen-rich) fuels like methane into electric current without combustion and with minimal environmental impact. Due in part to how fuel cells convert fuel to electricity (i.e., without combustion) conversion is relatively efficient and fuel cells' emissions of key air pollutants are much lower than for combustion technologies, especially nitrogen oxides (NO_x). Fuel cells are very modular (from a few watts to one MW).

Fuel cells are often categorized by the type of electrolyte used. The most common electrolyte for fuel cells used for stationary power is phosphoric acid; others include solid oxide and molten carbonate. Another promising type of fuel cell utilizes a proton exchange membrane, hence the name PEM fuel cell.

A fuel cell system consists of a fuel processor, the chemical conversion section (the fuel cell "stack"), and a power conditioning unit (PCU) to convert the direct current (DC) electricity from the fuel cell's stack into alternating current (AC) power for the grid or for loads and for supporting hardware such as gas purification systems.

Unless hydrogen is used as the fuel, prior to entering the fuel cell stack, the raw fuel (e.g., natural gas) must be dissociated into hydrogen and a supply of oxygen from air must be available. Within the fuel cell stack, the hydrogen and oxygen react to produce a voltage across the electrodes, essentially the inverse of the process which occurs in a water electrolyzer.

There are hundreds of fuel cells in service worldwide and the number of units in service is growing rapidly. Advocates are awaiting expected manufacturing advances that will reduce fuel cells' equipment cost and improve its efficiency such that they produce very low cost energy. Typical plant unit sizes (which can be aggregated into any plant output rating needed) are expected to range widely from a few kW to 200 kW.

Currently available fuel cells based on phosphoric-acid electrolytes have heat rates (HHV) of 9,500 Btu/kWh$_e$ – 10,000 Btu/kWh$_e$ and cost about $3000/kW installed. Non-fuel O&M for installed devices is about 2.5¢/kWh – 3¢/kWh.

Advanced fuel cells systems are expected to have efficiencies of ranging from 40% to perhaps as high as 55%. (6,300 Btu/kWh$_e$ - 8,500 Btu/kWh$_e$) over the next 5 years and ultimately to cost less than $1000/kW installed.

Energy Storage Systems

Energy storage systems used for DG applications include devices that store energy: a) electrochemically or b) as mechanical energy, and which "discharge" electricity for use when needed. Battery energy storage systems consist of the battery and a power conditioning unit (PCU) sub-system to convert grid power from alternating current (AC) power to direct current (DC) power during battery charging, and to convert battery power from DC to AC power during battery discharge.

Most batteries can change their rate of discharge/storage in milliseconds.

Note that there are two key elements to energy storage plant cost (unlike generators with just one). They are: 1) *output* rated in Watts (or Volt-amps) indicating the *rate* at which the system can "discharge: (i.e. provide energy to a load) and 2) the *energy storage capacity*, the amount of energy that can be stored (rated in kiloWatt-hours).

Storage is used for a variety of applications, such as:

- increase reliability—for longer duration power outages
- reduce impacts from an electric supply's poor power quality—for shorter duration electric service disruptions
- to take advantage of "buy low-sell high" (energy cost reduction) opportunities or of peak shaving (electric demand reduction) opportunities
- to reduce peak demand on a local electricity infrastructure

Electrochemical batteries are by far the most common type of battery, primarily these are the "lead-acid" type, though other types are emerging as competitive options. They are proven, reliable, and highly modular. A robust international industry exists to support use of electrochemical batteries. Off the shelf and, in the future, "advanced" battery systems will be viable for distributed energy systems.

Plant costs range from about $200 - $300 per kW of maximum <u>power</u> output/discharge, and about the same to somewhat higher installed cost for each kWh of <u>energy</u> storage “reservoir” capacity ($200/kWh - $400/kWh of storage capacity). O&M for electrochemical includes replacement of battery cells and secondarily periodic watering of the cells and periodic maintenance of the PCU. Non-fuel O&M ranges from .75¢/kWh – 1.5 ¢/kWh. “Round-trip” energy efficiency (AC to DC to AC, or charge-discharge) usually ranges from 65% - 75%.

There may be limited hazardous emissions from battery charging and some batteries contain hazardous material(s).

Superconducting magnetic energy storage (SMES), flywheels, “supercapacitors” are emerging alternatives to electrochemical batteries. These devices tend to be more efficient. SMES units may be superior for larger scale applications. SMES units are being used commercially in the U.S. to stabilize voltage on transmission lines. Flywheels and supercapacitors are more modular and tend to be relatively light.

In addition be being a discreet system type, often energy storage is a key subsystem within systems employing other types of DG. Depending on the type of system, energy storage does one or more of the following: a) provide power for loads during engine start-up, b) provide electric energy needed to start the engine itself, or c) store electric energy from the DG system (or even the utility grid) for later use.

Uninterruptible Power Systems (UPS)

UPSs are connected to specific equipment, buildings or entire facilities with critical loads to provide protection from power fluctuations lasting from just a few milliseconds to a few minutes. Specifically they provide: a) filtered/high quality power on a continuous basis and/or b) energy for use during power outages lasting several minutes. Often they have sufficient energy to power loads long enough to allow orderly shutdowns (e.g. of information or process equipment).

UPSs can either be stand-by or in-line. Stand-by devices monitor the line (power source) and provide energy as needed when problems are detected. In-line systems are connected between the power source and the load and thus can provide very complete, continuous filtering of grid power, although “throughput” losses can be as high as 40%.

Photovoltaics (PV)

Photovoltaics are semiconductor devices which convert sunlight directly to DC electricity; power conditioners (inverters) are used to convert the DC to standard AC power. Photovoltaic cells are thin layers of semiconductor (usually crystalline silicon). The cells are integrated in series and parallel into a module which is easily mountable on a structure. Modules can be attached to fixed surfaces, accepting output variations due to the sun’s position, or they can be made to track the sun for maximum output.

Photovoltaic systems using crystalline silicon are readily available. However, PV lifecycle and equipment costs are not competitive with more conventional generation technology for large-scale generation applications. Conversely, PV *is* cost-effective in a growing number of circumstances for applications requiring low power and/or small amounts of energy. Therefore remote installations and niche applications (e.g., power for communications systems, roadside emergency cellular phones, and off-grid homes) are the most common applications for PV.

Photovoltaic energy production can vary dramatically from one day to the next—due mostly to weather, and from one region to the next—due mostly to differences in latitude and weather. Frequently, battery storage and/or diesel genset systems are integrated with photovoltaics to carry loads through times when sunlight does not provide enough energy.

PV systems can cost between $5,000 - $10,000/kW installed, with variation driven mostly by system maximum output and cost for subsystems used such as inverters, integrated engine-generator, battery energy storage.

Controls

Control subsystems perform a variety of tasks within a DG system including: 1) engine start up and shut down, 2) managing how/how much fuel is used, 3) energy storage charge/discharge control, 4) communications between DG subsystems and with external systems, 5) monitoring and recording key performance and operational parameters, and 6) system diagnostics.

Power Conditioning

Unless a DG system provides power in the form needed by loads, some type of power conditioning is required. For example, fuel cells, photovoltaics and battery systems produce direct current electricity. Power conditioning equipment called inverters are used to convert DC electricity to alternating current (AC) electricity used by most types of electricity-using equipment.

Reciprocating engines and combustion turbines create “rotational” mechanical power that must be converted to electricity. To do that the engine is attached to a generator. Generators create electricity via electromagnetism using coils of wire and magnets (electricity is created by the motion of the wire coils or magnets relative to each other).
Generators used with combustion turbine and reciprocating engine based DG systems usually produce electricity at frequencies and voltages that may have to be modified being used by loads. Step-up or step-down transformers are used to increase/decrease voltage respectively.

Data Caveats

Cost and performance information presented herein is based on data from various sources. In many cases manufacturers supplied their best current data or they developed estimations based on projected costs or fuel efficiency. Installed cost for actual distributed generation projects are usually quite site-specific.

Wind

A wind generation system (a.k.a. wind turbine) converts the kinetic energy in wind (moving air) into mechanical work and then to electric energy. Key subsystems include: airfoil shaped blades; a rotor (to which blades are attached) that converts wind energy to rotational shaft energy; a drive train, usually including a gearbox; a tower that supports the rotor and drive train, a generator that converts mechanical energy to electricity, and power conditioning that converts the electricity generated into a form (Voltage and current frequency) used by the grid. Systems also include other equipment such as electrical wires, ground support equipment, interconnection gear, and controls.

During generation wind passes over both surfaces of the airfoil shaped blade; air passes over the longer (upper) side of the airfoil more rapidly than it moves past the underside, creating a lower-pressure area above the airfoil. The pressure differential between top and bottom surfaces results in a force called aerodynamic lift (the same phenomenon that causes aircraft wing use this phenomenon to “lift” an airplane).

Wind turbine electric power output varies with wind speed. The "rated wind speed" is the wind speed at which the "rated power" is achieved and generally corresponds to the point at which the conversion efficiency is near its maximum. In many systems power output during times when wind speed exceeds the rated wind speed, turbine speed is maintained at a constant level, allowing more stable system control. Note that at lower wind speeds, the power output drops off sharply as turbine output is a function of the cube of the wind speed (e.g.; power available in the wind increases eight times for every doubling of wind speed).

Individual wind generation systems range in electrical output from a few Watts to over 1 MW and can be used for applications including small/residential electricity production to utility scale power generation. In both cases power from the turbine must be converted to the form used by the grid before being transferred to the grid (i.e., the process called power conditioning).

For large scale applications turbines are often constructed in “wind farms” whose total output can range from tens to hundreds of MW.

Distributed Power Equipment and Services Vendors	
Batteries and UPSs	
American Superconductor	http://www.amsuper.com
General Electric (GE) Industrial Systems	http://www.geindustrial.com/
GNB	http://www.gnb.com/
Powercell	http://www.powercell.com/
Fuel Cells	
Avista Labs	http://www.avistalabs.com
Ballard Power Systems	http://www.ballard.com
DCH Technology	http://www.dch-technology.com
Dais Analytic	http://www.daisanalytic.com
FuelCell Energy	http://www.fce.com
GE MicroGeneration	http://www.gemicrogen.com
H Power Corp.	http://www.hpower.com
IdaTech (Northwest Power Systems)	http://www.idatech.com
International Fuel Cells (United Technologies)	http://www.internationalfuelcells.com
Matsushita Electric Industry	http://www.mei.co.jp
NuPower (Energy Partners, Inc.)	http://www.energypartners.org
Plug Power	http://www.plugpower.com
Proton Energy Systems	http://www.protonenergy.com
Sanyo	http://www.sanyo.co.jp
Siemens Westinghouse	http://www.spcf.siemens.com
Sure Power	http://www.hi-availability.com
Microturbines	
AeroVironment	http://www.aerovironment.com/
Capstone	http://www. capstoneturbine.com
Elliott Energy Systems/MagneTek	http://www.magnatek.com/
GE Power Systems	http://www.ge.com
Honeywell Parallon Power Systems	http://www.parallon75.com/
Ingersoll-Rand Energy Systems	http://www.ingersoll-rand.com/energystystems
Solo Energy Corp.	
Turbec AB	
PowerPac (Elliot Microturbine Systems)	http://www.powerpac.com/turbine.html
Williams Distributed Power Services	http://www.williamsgen.com
Photovoltaics	
Amonix	http://www.amonix.com/

Applied Power	http://www.appliedpower.com/
ASE Americas	http://www.asepv.com
AstroPower	http://www.astropower.com
BP Solarex	http://www.solarex.com
Ebara Solar	http://www.ebara.co.jp
Energy Conversion Devices	http://www.ovonic.com/
Evergreen Solar	http://www.evergreensolar.com
Kyocera	http://www.kyocera.com
PowerLight	http://www.powerlight.com/
Photowatt International	http://www.photowatt.com
Sharp	http://www.sharp-usa.com
Shell Renewables	http://www.shell.com
Siemens Solar	http://www.siemenssolar.com
Solar Electric Light Company	http://www.selco-intl.com
Solarex	http://www.solarex.com/
Internal Combustion Engines	
Caterpillar	http://www.cat.com
Cooper Energy Services	http://www.cooperenergy.com
Cummins Energy Company	http://www.cummins.com
Detroit Diesel	http://www.detroitdiesel.com
Honda	http://www.honda.com
Jenbacher Energie-systeme AG	http://www.jenbacher.com
Kohler Generators	http://www.kohlergenerators.com
MAN B&W Diesel	http://www.manbw.dk
SenerTec	http://www.senertec.de
Wartsila Diesel	http://www.wartsila-nsd.com
Waukesha Engine	http://www.waukeshaengine.com
Stirling Engines	
BG Technology	http://www.bgtech.co.uk
SIG Swiss Industrial Company	http://www.sig-group.com
Sigma Elektroteknisk A.S.	http://www.sigma-el.com
Solo Kleinmotoren GmbH	http://www.solo-germany.com
Stirling Technology Company	http://www.stirlingtech.com
Stirling Technology, Inc.	http://www.stirling-tech.com
Sunpower, Inc.	http://www.sunpower.com
Tamin Enterprises	http://www.tamin.com
Whisper Tech Ltd.	http://www.whispertech.co.nz
Wind Turbines	
Bergey WindPower	http://www.bergey.com
Bonus Energy A/S	http://www.bonus.dk

Dewind Technik	http://www.dewind.de
Ecotecnia	http://www.icaen.es/icaendee/ent/ecotech.htm
Enercon	http://www.enercon.de
Enron Wind	http://www.wind.eneron.com
Gamesa Eolica	http://www.gamesa.es
Mitsubishi Heavy Industries	http://www.mhi.co.jp
NEG Micon	http://www.neg-micon.dk
Nordex	http://www.nordex.dk
Nordic Windpower	http://www.nwp.se
Vesta Wind Systems A/S	http://www.vestas.com
Controls	
Encorp	http://www.encorp.com/
GE Zenith Controls	http://www.zenithcontrols.com/
Woodward Industrial Controls	http://www.woodward.com/
Combined Heat and Power	
Asea Brown Boveri	http://www.abb.com
Inverters and Power Conditioning Systems	
Advanced Energy Systems	http://www.advancedenergy.com/
AeroVironment	http://www.aerovironment.com/
Heart Interface	http://www.heartinterface.com/
Omnion Power Engineering	http://www.omnion.com/
Trace Engineering	http://www.traceengineering.com/
Trace Technologies	http://www.tracetechnologies.com/
MajorPower	http://www.majorpower.com/
California Energy Commission Inverter Buy-down Program	http://www.energy.ca.gov/greengrid/certified_inverters.html
Organizations	
Distributed Power Coalition of America	http://www.dpc.org/

Appendix A4: Texas Utility Contacts

Updated November 1, 2000

Company Name	Telephone	Fax	Web Site	Contact
American Electric Power	918-594-4142		www.aep.com	Bernard Ross
Austin Energy	512-322-6514	512-322-6037	www.electric.austin.tx.us	Ed Clark
Bailey County Electric Cooperative Association	806-272-4504	806-272-4509		Duane Lloyd
Baird, City Of				
Bandera Electric Cooperative, Inc.	830-796-3741	830-460-3030		J.R. Vander Zee
Bartlett Electric Cooperative, Inc.	254-527-3551	254-527-3221		Lawrence Karl
Bartlett, City Of (Bartlett Municipal Light Department)	254-527-3557	254-527-4280		Mike Williams
Bastrop, City Of (Bastrop Electric Department)	512-321-3941	512-321-6684		Joann Wilcoxen
Belfalls Electric Cooperative, Inc.	254-583-7955	254-583-7954		Joe Marek
Bellville, City Of	409-865-3136	409-865-9485		John Mumme
Big Country Electric Cooperative, Inc. (Midwest E. C.)	915-776-2244	915-776-2246		Jerry L. Stapp
B-K Electric Cooperative, Inc. (See Tri-County E.C.)				
Bluebonnet Electric Cooperative, Inc.	409-542-3151	409-542-1187	www.bluebon.net/bechome.html	David W. Peterson
Boerne Utilities (Boerne, City Of)	830-249-9511	830-249-9264		Ronald C. Bowman
Bowie Utilities (Bowie, City Of)	940-872-1114	940-872-5702		Ronnie Parkinson
Bowie-Cass Electric Cooperative, Inc.	903-846-2311	903-846-2406	www.bcec.com	W.D. Heldt
Brady Water & Light Works (Brady, City Of)	915-597-2152	915-597-2068		Gary Broz
Brazos Electric Power Cooperative, Inc.	254-750-6500	254-750-6290		Clifton B. Karnei
Brazos River Authority	254-776-1441	254-772-5780		Gary Gwyn
Brenham, City Of	409-836-7911	409-836-7605		Ron Bottoms
Bridgeport, City Of	940-683-5906	940-683-5995		Doug Whitehead
Brownfield Power & Light	806-637-4547	806-637-9369		Richard Fletcher
Brownsville Public Utilities Board	956-982-6260	956-982-6269		Don Ouchley
Btu, Rural Electric Division	409-821-5715	409-821-5795		Dan Wilkerson
Burnet Utilities (Burnet, City Of)	512-756-4858	512-756-8560		Johnny Sartain
Caldwell, City Of	409-567-3271	409-567-9233		William L. Broaddus
Canadian, City Of				
Cap Rock Electric Cooperative, Inc.	800-442-8688	915-684-0333		David W. Pruitt

Company Name	Telephone	Fax	Web Site	Contact
Castroville, City Of	830-538-2224	830-538-9366		Bruce A. Alexander
Central And South West Corp. (See AEP)	918-594-4142		www.aep.com	Bernard Ross
Central Power & Light Company	361-881-5300	361-881-5331		Gonzalo Sandoval
Central Texas Electric Cooperative, Inc.	830-997-2126	830-997-9034		Robert A. Loth III
Cherokee County Electric Cooperative Association	903-683-2248	903-683-5012		Greg Jones
City Of Austin Electric Utility				
City Public Service Of San Antonio	210-978-2000	210-978-3055	www.citypublicservice.com	Mrs. Jamie A. Rochelle
Cogen Power, Inc.				
Coleman County Electric Cooperative, Inc.	915-625-2128	915-625-4600		James C. Barr
Coleman, City Of	915-625-5114	915-625-5837		David S. Sooter
College Station, City Of	409-764-3688	409-764-3452		J.C. Woody
Comanche County Electric Cooperative Association	800-915-2533	915-356-3038		Ronnie Robinson
Commerce, City Of				
Community Public Service				
Concho Valley Electric Cooperative, Inc.	915-655-695	915-655-6950		Alton Rollans
Cooke County Electric Cooperative Association	800-962-0296	940-759-2285		Philip E. Slater
Coserv Electric (Formerly Denton County E.C.)	800-274-4014	940-497-6525	www.dcec.com/	Bill McGinnis
Crosbyton, City Of				
Cuero Electric Utility (Cuero, City Of)	361-275-6114	361-275-5655		John M. Trayhan
Dallas Power And Light Company				
Deaf Smith Electric Cooperative, Inc.	806-364-1166	806-364-5481		Steve Louder
Deep East Texas Electric Cooperative, Inc.	409-275-2314	409-275-2135		Mike Elder
Denton Municipal Utilities (Denton, City Of)	940-349-8487	940-349-7334		Sharon W. Mays
Dewitt County Electric Cooperative, Inc.	361-275-2334	361-275-5662		Jim Springs
Dickens Electric Cooperative, Inc.	806-271-3311	806-271-3746		Ron Golden
East Texas Electric Cooperative, Inc.	409-560-9532	409-560-9215		John H. Butts
El Paso Electric Company	915-543-5951	915-543-5711	www.epelectric.com	James S. Haines, Jr.
Electra, City Of (Electra Electric Department)	940-495-2432	940-495-3025		Danny Neff
Entergy Gulf States, Inc. (Gulf States Utilities)	800-368-3749	409-827-5438	www.entergy.com	Joe Domino
Erath County Electric Cooperative Association	254-965-3153	254-965-4387	www.erathelectric.com/	Zeb S. Deck Jr.

Company Name	Telephone	Fax	Web Site	Contact
Fannin County Electric Cooperative, Inc.	903-583-2117	903-583-7384		Ronald G. Odom
Farmers Electric Cooperative (Tx) (See Fec)				
Farmers Electric Cooperative, Inc. Of New Mexico	505-769-2116	505-769-2118		Lance Adkins
Farmersville, City Of	972-782-6151			Alan Hein
Fayette Electric Cooperative, Inc.	800-874-8290	409-968-6752		Gary Don Nietsche
Fec Electric Cooperative, Inc.	903-455-1715	903-455-8125		Lawson White
Flatonia, City Of	361-865-3548	361-865-2817		Doris Walker
Floresville Electric Light & Power System	830-216-7000	830-393-0362		David K. McMillan
Floydada, City Of	806-983-2834	806-983-5542		Connie Galloway
Fort Belknap Electric Cooperative, Inc.	940-564-3526	940-564-3247		Mark A. Stubbs
Fredericksburg, City Of	830-997-7521	830-997-1861		Jerry Bain
Garland Power & Light System	972-205-2650	972-205-2636		Robert E. Corder
Garrison Electric Department (Garrison, City Of)	409-347-2201			Melvis Bell
Gate City Electric Cooperative, Inc.	940-937-2565	940-937-2698		James C. Driver
Georgetown Community Owned Utilities	512-930-3555	512-930-3509		Jim Briggs
Giddings, City Of	409-542-2311	409-542-0950		D. E. Sosa
Golden Spread Electric Cooperative, Inc.	806-379-7766	806-374-2922		Robert W. Bryant
Goldsmith, City Of	915-827-3404	915-827-3404		Jean Lucas
Goldthwaite Utilities (Goldthwaite, City Of)	915-648-3186	915-648-2570		Dale Allen
Gonzales, City Of (Gonzales Electric System)	830-672-2815	830-672-2813		E.T. Gibson
Granbury, City Of (Granbury Municipal Electric Department)	817-573-1115	817-573-7678		Robert D. Brockman
Grayson-Collin Electric Cooperative, Inc.	903-482-5231	903-482-5906		David McGinnis
Greenbelt Electric Cooperative, Inc.	806-447-2536	806-447-2434		Stan McClendon
Greenville Electric Utility	903-457-2800	903-457-2893		Tom Darte
Guadalupe Valley Electric Cooperative, Inc.	830-672-2871	830-672-9841		Marcus W. Pridgeon
Guadalupe-Blanco River Authority	830-379-5822	830-379-9718		Bill West
Gulf States Utilities Company (See Entergy Gulf States, Inc.)				
Hall County Electric Cooperative (See Lighthouse E.C.)				
Halletsville Municipal Utilities (Halletsville, City Of)	361-798-3681	361-798-5324		Ervin Kolacny
Hamilton County Electric Cooperative Association	254-386-3123	254-386-8757		John Hartgraves

Company Name	Telephone	Fax	Web Site	Contact
Harmon Electric Association, Inc.	580-688-3342	580-688-2981		Dwight Bowen
Hearne Municipal Electric System (Hearne, City Of)	409-279-3461	409-279-2431		Robert Penney
Hemphill, City Of	409-787-2251	409-787-2259		Frank Coday
Hempstead, City Of (Hempstead Electric Department)	409-826-2486	409-826-6703		James Vines
Hilco Electric Cooperative, Inc.	254-687-2331	254-687-2428		Gerald W. Lemons
Hill County Electric Cooperative, Inc. (See Hilco)				
Hondo, City Of (Hondo Electric System)	830-426-3378	830-426-5189		Rudy DeLeon
Houston County Electric Cooperative, Inc.	409-544-5641	409-544-4628		Edd Hargett
Houston Lighting And Power Co. (See Reliant Energy)			www.hlp.com	
Hunt-Collin Electric Cooperative, Inc.(See Cap Rock E.C.)				
J-A-C Electric Cooperative, Inc.	940-895-3311	940-895-3321		Sarah Sears
Jackson Electric Cooperative, Inc.	361-782-7193	361-782-3252	/www.ykc.com/jec/	Roy Griffin
Jasper Light & Power System (Jasper, City Of)	409-384-4651	409-384-3790		Kerry Lacy
Jasper-Newton Electric Cooperative, Inc.	800-231-9340	409-423-2264		Fred Solly
Jcec (Johnson County Electric Cooperative)	817-556-4000	817-556-4068		Hollis E. Joslin
Johnson County Electric (See Jcec)				
Karnes Electric Cooperative, Inc.	800-780-2347	830-780-2347	www.karnesec.org	Leroy T. Skloss
Kaufman County Electric Cooperative, Inc.				
Kerrville Public Utility Board	830-257-3050	830-257-8078		Bill Taylor
Kimble Electric Cooperative, Inc.	915-446-2625	915-446-3482		Hubert D'Spain
Kirbyville Light & Power Company	409-423-4659	409-423-3664		C. B. Herndon
La Grange Utilities (La Grange, City Of)	409-968-3127	409-968-5743		Frank D. Menefee, Jr
Lamar County Electric Cooperative Association	903-784-4303	903-784-7084		Don McCaskill
Lamb County Electric Cooperative, Inc.	806-385-5191	806-385-5197		Delbert Smith
Lampasas Public Utilities (Lampasas, City Of)	512-556-6831	512-556-2074		Michael H. Talbot
Lea County Electric Cooperative, Inc.	505-396-3631	505-396-3634		Michael Dreyspring
Lexington, City Of (Lexington Municipal Electric Department)	409-773-2221	409-773-4878		Patrick Jatzlau
Liberty Municipal Electric System (Liberty, City Of)	409-336-6872	409-336-9846		Don Ivy

Company Name	Telephone	Fax	Web Site	Contact
Lighthouse Electric Cooperative, Inc.	806-983-2814	806-983-2804		Billy C. Harbin
Limestone County Electric Cooperative, Inc.				
Livingston Municipal Electric System (Livingston, City Of)	409-327-4311	409-327-7784		Sam Gordon
Llano Utilities (Llano, City Of)	915-247-4158	915-247-4150		Frank Salvato
Lockhart Utilities (Lockhart, City Of)	512-398-3461	512-398-5103		Hector Garcia
Lone Star Municipal Power Agency				C. B. Herndon
Lone Wolf Electric Cooperative, Inc.				
Lower Colorado River Authority	512-473-3200	512-473-3298	www.lcra.org	Joseph J. Beal
Lubbock Power & Light System (Lubbock, City Of)	806-775-2500	806-775-3112		Derrell Oliver
Luling Utilities (Luling, City Of)	830-875-2481	830-875-2038		Lamar Schulz
Lyntegar Electric Cooperative, Inc.	806-998-4588	806-998-4724		Wilton J. Payne
Magic Valley Electric Cooperative, Inc.	956-565-2451	956-565-4182		Bob Merett
Mason Utilities (Mason, City Of)	915-347-6449	915-347-5955		Mark Hahn
Mcculloch Electric Cooperative, Inc.	800-266-1774	915-597-3307	www.lotsofwatts.com	Jeanagayle Behrens
Mclennan COUNTY ELECTRIC COOPERATIVE, INC.	254-840-2871	254-840-4250		Rick Haile
Medina Electric Cooperative, Inc.	830-741-4384	830-426-2796		Larry Oefinger
Mid-South Electric Cooperative Association	409-825-5100	409-825-5166		Kenneth D. Camp
Mid-Tex Generation And Transmission Electric Coop.	915-776-3909	915-776-2246		Jerry Stapp
Midwest Electric Cooperative, Inc. (See Big Country)				
Moulton, City Of (Moulton Electric Department)	361-596-4621	361-596-7075		Michael J. Slobojan
Navarro County Electric Cooperative, Inc.	903-874-7411	903-874-8422		Billy J. Gillespie
Navasota Valley Electric Cooperative, Inc.	800-443-9462	409-828-5563		James E. Calhoun
New Braunfels Utilities (New Braunfels, City Of)	830-629-8400	830-629-8467		Paula J. DiFonzo
New Century Energies	806-378-2121	806-378-2517		Bill D. Helton
Newton Municipal Utilities (Newton, City Of)	409-379-4656	409-379-5065		Melvin Forward
North Plains Electric Cooperative, Inc.	806-435-5482	806-435-7225		Pat McAlister
Northeast Texas Electric Cooperative, Inc.	903-757-3282	903-757-3297		Gary L. Dockham
Nueces Electric Cooperative, Inc.	800-632-9288	361-387-4139		John Sims
O'donnell Telephone Company, Inc.				

Company Name	Telephone	Fax	Web Site	Contact
Panola-Harrison Electric Cooperative, Inc.	903-935-0154	903-935-3361		Victor Schwartz, Jr.
Pedernales Electric Cooperative, Inc.	830-868-7155	830-868-4999		Bennie Fuelberg
Pineland, City Of	409-584-2390			Gail Kilcrease
Plains, City Of	806-456-2288	806-456-4341		David Brunson
Public Service Company Of Oklahoma	918-599-2000	918-599-2881		T.D. "Pete" Churchwell
Rayburn Country Electric Cooperative, Inc.	972-771-1336	972-771-3046	www.rayburnelectric.com	John Kirkland
Reliant Energy HL&P (Houston Lighting & Power)	713-207-6616	713-207-9164	www.hlp.com	Reginald Comfort
Rio Grande Electric Cooperative, Inc.	830-563-2444	830-563-2006		Daniel G. Laws
Rita Blanca Electric Cooperative, Inc.	806-249-4506	806-249-5620		Aubrey L. Neff
Robertson Electric Cooperative				
Robstown Utility System (Robstown, City Of)	361-387-3554	361-387-9353		Ernest R. Gaza
Rusk County Electric Cooperative, Inc.	903-657-4571	903-657-5377		Jesse Bankhead
Sabine River Authority	409-746-3200	409-746-3749		Jerry L. Clark
Sam Houston Electric Cooperative, Inc.	800-458-0381	409-328-1207		H. E. Striedel
Sam Rayburn Dam Electric Cooperative, Inc.	409-327-5711	409-328-1207		H.E. Striedel
Sam Rayburn G & T Electric Cooperative, Inc.	409-560-9532	409-560-9215		John H. Butts
Sam Rayburn Municipal Power Agency	409-327-5303	409-327-7045		Bert B. Ogletree, Jr
San Antonio City Public Service Board				
San Augustine, City Of (San Augustine Light & Water Dept.)	409-275-2121	409-275-9146		Alton Shaw
San Bernard Electric Cooperative, Inc.	409-865-3171	409-865-9706		John Q. Adams
San Marcos Electric Utility (San Marcos, City Of)	512-396-2541	512-396-2683		Robert L. Higgs
San Miguel Electric Cooperative, Inc.	830-784-3411	830-784-3411		Marshall B. Darby
San Patricio Electric Cooperative, Inc.	888-740-2220	361-364-3467		F.D. "Buddy" McDowell
San Saba, City Of	915-372-5144	915-372-3989		Joe Ragsdale
Sanger Electric System (Sanger, City Of)	940-458-7930	940-458-4180		Jeff Morris
Schulenburg, City Of (Schulenburg Utilities Dept.)	409-743-4126	409-743-4760		Ronald G. Brossmann
Seguin Electric System (Seguin, City Of)	830-379-3212	830-401-2499		Douglas A. Faseler
Sentry Power And Light Company, Inc.				
Seymour, City Of	940-888-3148	940-888-8882		Dick Wirz

Company Name	Telephone	Fax	Web Site	Contact
Shiner Light & Water Utilities (Shiner, City Of)	361-594-3362	361-594-3566		Norma Goetz
Smithville, City Of (Smithville Utilities Dept.)	512-237-3267	512-237-4549		Bob Miller
South Plains Electric Coop. (Merged With Dickens E.C.)	806-775-7732	806-775-7796		J.C. Roberts
South Texas Electric Cooperative, Inc.	361-575-6491	361-576-1433		David L. Grubbs
Southwest Arkansas Electric Cooperative Corp.	501-772-2743			Wayne Whitaker
Southwest Rural Electric Association, Inc.	580-667-5281	580-667-5284		Ray Beavers
Southwest Texas Electric Cooperative, Inc.	915-853-2544	915-853-3141		Jim Martin
Southwestern (Nm) Electric Cooperative, Inc.	505-374-2451	505-374-2030		Ann Garcia
Southwestern Electric Power Company (Headquarters) (See AEP)	918-594-4142			Bernard Ross
Southwestern Electric Power Company (Texas Division) (See AEP)	918-594-4142			Bernard Ross
Southwestern Electric Service Company	214-812-4887	214-741-5637		John Barton
Southwestern Public Service	303-571-3542	303-571-3524		Lynn /worrell
Stamford Electric Cooperative (See Big Country)				
Swisher Electric Cooperative, Inc.	800-530-4344	806/995-2249		Charles Castleberry
Taylor Electric Cooperative, Inc.	800-992-0086	915/928-5216		Tommie Cutler
Texas Electric Service Company				
Texas Municipal Power Agency	409-873-2013	409-873-1183		Ed Wagoner
Texas Power And Light				
Texas Utilities Electric Company (TXU)	214-875-2643	214-875-2953	www.txu.com	Mike Murphy
Texas-New Mexico Power Company	817-731-0099	817-377-5521	www.tnpe.com	Kevern R. Joyce
Tex-La Electric Cooperative Of Texas, Inc.	409-560-9632	409-560-9215		John H. Butts
Timpson, City Of (Timpson Light & Water Dept.)	409-254-2421			Tommy Sparks
Toledo Bend Project	409-565-2273			Jim Washburn
Tri-County Electric Cooperative, Inc.	817-444-3201	817-444-3542		A. Craig Knight
Trinity Valley Electric Cooperative, Inc.	800-766-9576	972-932-6466		Jack Schwartz
Tulia Municipal Power & Light (Tulia, City Of)	806-995-3547	806-995-2331		Steve Stout
TXU (See Texas Utilities Electric Company)				
Upshur-Rural Electric Cooperative, Inc.	903-843-2536	903-843-2736		John C. Dugan
Victoria Electric Cooperative, Inc.	361-573-2428	361-573-5753		Winston Low

Company Name	Telephone	Fax	Web Site	Contact
Waelder, City Of (Waelder Electric Dept.)	361-665-7331			Sandra Shows
Weatherford Municipal Utility System (Weatherford, City Of)	817-598-4250	817-598-4138		J. R. Dickason
Weimar Electric Utilities (Weimar, City Of)	409-725-8554	409-725-8488		Francis E. Parks
West Texas Municipal Power Agency	806-767-2501	806-763-9711		Ty Cooke
West Texas Utilities Company (See AEP)	918-594-4142			Bernard Ross
Western Farmers Electric Cooperative, Inc.	405-247-3351	405-247-4444		J. D. Pendergrass
Wharton County Electric Cooperative, Inc.	409-543-6271	409-543-6259		Donald D. Naiser, PE
Whitesboro Electric Utility (Whitesboro, City Of)	903-564-3311	903-564-6015		Charles Whitecotton
Winters, City Of				
Wise Electric Cooperative, Inc.	888-627-9326	940-627-6540		Loyd L. Jackson
Wood County Electric Cooperative, Inc.	903-763-4567	903-763-5693		Debbie Robinson
Yoakum, City Of	361-293-6321	361-293-3318		A. J. Veselka

Appendix A5: Internet Links

This appendix is a compilation of links for the documents referenced throughout the manual. It also includes the web addresses for all electric utility distribution companies in Texas.

Public Utilities Commission of Texas	Web: www.puc.state.tx.us/

Texas' Public Utility Regulatory Act (PURA) of 1999
www.puc.state.tx.us/rules/statutes/index.cfm

Substantive Rules - Chapter 25
www.puc.state.tx.us/rules/subrules/electric/index.cfm

§25.211 Interconnection of On-Site Distributed Generation
www.puc.state.tx.us/rules/subrules/electric/25.211/25.211.pdf

§25.212 Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation
www.puc.state.tx.us/rules/subrules/electric/25.212/25.212.pdf

Institute of Electrical and Electronics Engineers (IEEE)	Web: http://www.ieee.org

IEEE Standard 519.
http://standards.ieee.org/reading/ieee/std/staticp/519-1992.pdf

IEEE Standard 100
http://standards.ieee.org/reading/ieee/std/switchgear/C37.09g-1991.pdf

Reliability Standard 1366
http://standards.ieee.org/reading/ieee/std/td/1366-1998.pdf

Links for Electric Distribution Companies in Texas

Austin Energy
www.electric.austin.tx.us/

City Public Service Company of San Antonio
www.citypublicservice.com/

CSE- CPL, SWP &WTU Now AEP
WWW.AEP.COM

El Paso Electric Co.
www.epelectric.com

Entergy
www.entergy.com

Houston Lighting & Power Co.
www.hlp.com

LCRA
www.lcra.org

Texas-New Mexico Power
www.tnpe.com

TXU
www.txu.com

Texas Electric Cooperatives
www.texas-ec.org

Appendix A6: Additional Safety and Performance References

The following standards may be useful in the specification, design, and evaluation of a DG system. Many of these documents are the standards used by utilities to design and operate the distribution system. While most are not necessary for designing the typical DG interconnection, any of them may be relevant for a particular application. One or more of these documents will likely provide the basis of a utility's application rejection or claim for additional requirements. In such cases, specific sections of applicable documents should be referenced.

Secondary Safety and Performance standards for DG:

- ANSI/IEEE Std. 100-1996, IEEE Standard Dictionary of Electrical and Electronic Terms
- ANSI/IEEE Std. 493-1900 IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems (IEEE Gold Book).
- ANSI/IEEE Std. 1100-1992 IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (IEEE Emerald Book).
- ANSI/IEEE Std. 1159-1995 IEEE Recommended Practice for Monitoring Electric Power Quality.
- ANSI/IEEE Std. 1250-1995 IEEE Guide for Service to Equipment Sensitive to Momentary Voltage Disturbances. .
- ANSI/IEEE Std. C37.04 ANSI/IEEE Standard Rating Structure for AC High-voltage Circuit Breakers Rated on a Symmetrical Current Basis
- ANSI/IEEE Std. C37.06 ANSI/IEEE Standard for AC High-voltage Circuit Breakers Rated on Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities
- ANSI/IEEE Std. C37.108-1989 IEEE Guide for the Protection of Network Transformers.
- ANSI/IEEE Std. C37.13 ANSI/IEEE Standard for Low-voltage AC Power Circuit Breakers Used in Enclosures
- ANSI/IEEE Std. C37.14 ANSI/IEEE Standard for Low-voltage DC Power Circuit Breakers Used in Enclosures
- ANSI/IEEE Std. C37.16 ANSI/IEEE Standard for Low-voltage Power Circuit Breakers and AC Power Circuit Protectors – Preferred Ratings, Related Requirements, and Application
- ANSI/IEEE Std. C37.18 ANSI/IEEE Standard Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery
- ANSI/IEEE Std. C37.2 IEEE Standard Electrical Power System Device Function Numbers
- ANSI/IEEE Std. C37.27 ANSI/IEEE Standard Application Guide for Low-voltage AC Nonintegrally Fused Power Circuit Breakers (Using Separately Mounted Current-Limiting Fuses)
- ANSI/IEEE Std. C37.29 ANSI/IEEE Standard for Low-voltage AC Power Circuit Protectors Used in Enclosures

- ANSI/IEEE Std. C37.50 ANSI Standard Test Procedures for Low-voltage AC Circuit Breakers Use In Enclosures
- ANSI/IEEE Std. C37.51 ANSI Standard Conformance Test Procedure for Metal Enclosed Low-voltage AC Power Circuit-Breaker Switchgear Assemblies
- ANSI/IEEE Std. C37.52 ANSI Standard Test Procedures for Low-voltage AC Power Circuit Protectors Used in Enclosures
- ANSI/IEEE Std. C37.95 IEEE Guide for Protective Relaying of Utility Consumer Interconnections
- ANSI/IEEE Std. C57.12 IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformers
- ANSI/IEEE Std. C57.12.13 Conformance Requirements for Liquid Filled Transformers Used in Unit Installations including Unit Substations.
- ANSI/IEEE Std. C57.12.40-1994 American National Standard for Secondary Network Transformers - Subway and Vault Types (Liquid Immersed) - Requirements.
- ANSI/IEEE Std. C57.12.44-1994 IEEE Standard Requirements for Secondary Network Protectors.
- ANSI/IEEE Std. C84.1-1995, Electric Power Systems and Equipment - Voltage Ratings (60Hertz)
- IEC 1000-3-3 Limitation of voltage fluctuations and flicker in low-voltage supply systems for equipment with rated current less than 16A
- IEC1000-3-5 Limitation of voltage fluctuations and flicker in low-voltage supply systems for equipment with rated current greater than 16A
- UL 1008 Transfer Switch Equipment

Other UL standards apply to distributed generation systems but do not directly address interconnection safety. UL 2200 is the Standard For Safety for Stationary Engine Generator Assemblies. These requirements cover stationary engine generator assemblies rated 600 volts or less that are intended for installation and use in non-hazardous locations in accordance with NEC. These requirements do not cover generators for use in hazardous locations, which is covered by the Standard for Electric Motors and Generators for Hazardous (Classified) Locations, UL 674. These requirements also do not cover uninterruptible power system (UPS) equipment, which are covered by the Standard for Uninterruptible Power Supply Equipment, UL 1778.

Standards Organizations:

National Fire Protection Association (NFPA)	1 Batterymarch Park Quincy, MA 02269-9101 Phone (617) 770-3000, Fax: (617) 770-0700 Web: http://www.nfpa.org

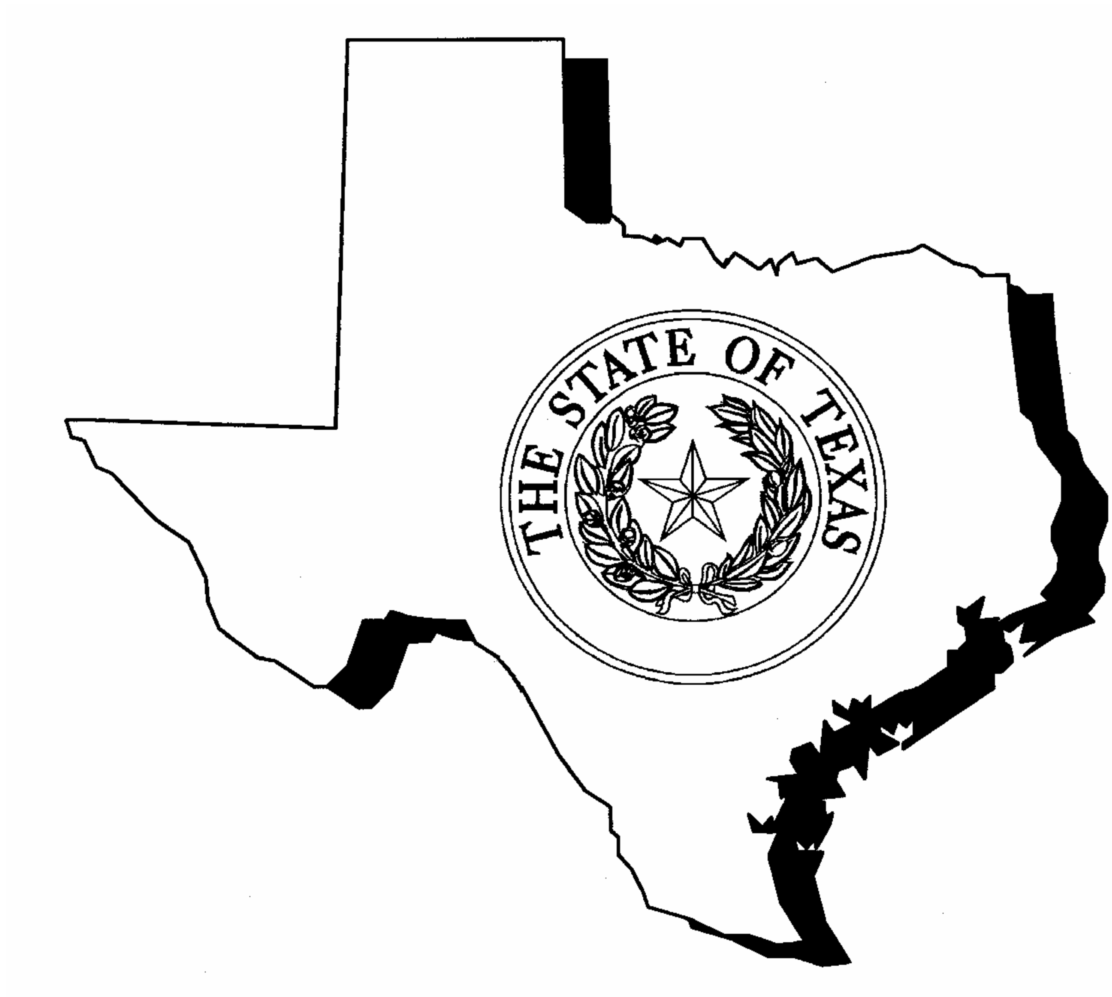
Underwriters Laboratories (UL)	333 Pfingsten Road Northbrook, IL 60062-2096 Phone: (847) 272-8800, Fax: (847) 272-8129 Web: http://www.ul.com/
Institute of Electrical and Electronics Engineers (IEEE)	445 Hoes Lane, PO Box 459 Piscataway, NJ 08855-0459 Phone: (800) 678-4333 Web: http://www.ieee.org

National Renewable Energy Laboratory	1617 Cole Boulevard Golden, CO 80401 Phone: (303) 275-3000, Fax: (303) 275-4053 Web: http://www.nrel.gov
Sandia National Laboratories, **Photovoltaic Systems Assistance Center**	P.O. Box 5800, Division 6218 Albuquerque, NM 87185 Phone: (505) 844-8161, Fax: (505) 844-6541 Web: http://www.sandia.gov/Renewable_Energy/photovoltaic/pv.html

Appendix A7: Pre-Certification Requirements

02/01/01 Version

TEXAS PUBLIC UTILITY COMMISSION REQUIREMENTS FOR PRE-CERTIFICATION OF DISTRIBUTED GENERATION EQUIPMENT BY A NATIONALLY RECOGNIZED TESTING LABORATORY



PROJECT NO. 22318
PUBLIC UTILITY COMMISSION OF TEXAS
FEBRUARY 2001

PUC PROJECT NO. 22318

REQUIREMENTS FOR PRE-CERTIFICATION OF DISTRIBUTED GENERATION EQUIPMENT BY A NATIONALLY RECOGNIZED TESTING LABORATORY

TABLE OF CONTENTS

A1 INTRODUCTION

According to Substantive Rule 25.211(k)(3) distributed generation units (DG packages) that are certified to be in compliance by an approved testing facility or organization shall be installed on a company utility system in accordance with an approved interconnection control and protection scheme without further review of their design by the utility. To ensure that the pre-certified DG package is compatible with the utility's system, the utility shall determine the interconnection and control scheme required and shall review and approve the electrical configuration for each DG installation. DG packages that have not been pre-certified may still be interconnected subject to utility review in accordance with Substantive Rules 25.211 and 25.212. Refer to Appendix 1. In this document, a DG package is defined as including the generating unit, the protection and control system and generator breaker. This document does not preclude on-site testing requirements defined in Substantive Rules 25.211 and 25.212.

A2 This document describes the test requirements for pre-certification of distributed generation (DG) that will be interconnected to an electric utility distribution system in Texas. Pre-certified equipment is defined by the Public Utility Commission of Texas (PUCT) Substantive Rule 25.211(c)(13) as "A specific generating and protective equipment system or systems that have been certified as meeting the applicable parts of this section relating to safety and reliability by an entity approved by the commission."

A3 The purpose of pre-certifying a DG package is to certify that the DG package design meets the minimum technical requirements of PUCT substantive rules 25.211 and § 25.212 and forms, which are included in Appendix 1 to this document.

A4 Section B contains the minimum documentation requirements for pre-certification of a DG package.

A5 Section C contains the capability requirements through type testing of DG packages described in the technical requirements in PUCT Substantive rule §25.212. These requirements are intended to form the basis for a set of specific minimum requirements for a DG package of a given size and configuration to be "pre-certified" as defined in the rule.

A6 Section D contains additional labeling required of the commission-approved certifying entity, the nationally recognized testing laboratory (NRTL).

B1 DOCUMENTATION REQUIRED

B2 The NRTL shall provide by whom and the date it has received its accreditation.

B3 The NRTL shall provide the effective date of pre-certification of each DG package and when re-certification will be required.

B4 Package Description: The entity requesting pre-certification shall provide to the NRTL a complete description of the DG package. The description shall include model numbers, sizes and ratings. The description shall also include software or firmware versions and date of revision.

B5 Drawings: The entity requesting pre-certification shall provide to the NRTL a one-line diagram of the DG package's major components and all protective functions. Major components to be included as a minimum are the generator, step-up or step-down transformer (if provided), switching device (e.g., circuit breaker), visible disconnect device, protective functions and control functions. The major components listed here may be any combination of discrete devices and packaged devices.

B6 Applicable Standards: The NRTL shall provide in the pre-certification test report a description of all the national or international standards applied in the pre-certification testing process.

B7 Test Procedures: The NRTL shall provide in the pre-certification test report a description of all test procedures applied in the pre-certification testing process. The description shall explain how each of the requirements in PUCT Substantive Rule § 25.212 is met by the tests.

B8 Traces: The NRTL shall provide in the pre-certification test report waveform traces for voltage and frequency tests. At a minimum, the traces shall show 15 cycles prior to and following the initiation of the fault or abnormal condition, clearly indicating the interruption of current. A trace of the normal output voltage waveform shall also be provided with the pre-certification test report.

C1 TECHNICAL REQUIREMENTS

C1.1 Technical requirements for DG installations as defined by PUCT Substantive Rule § 25.212 are divided into three groups for purposes of this document.

C1.2 Equipment and Functions that shall be pre-certified:
In order for a DG package to be pre-certified, the NRTL shall verify that the DG package meets these requirements under all reasonably expected operating and installation conditions. *Example*- the range of operation for over and under voltage relays is stated and will be the same regardless of point of interconnection.

C1.3 Equipment and Functions that may be pre-certified:
Certification of some equipment and functions may be of value, if included in the DG package, but are not required under the Substantive Rules for an installation. *Example* - Monitoring capability.

C1.4 Equipment and Functions to be pre-certified for which there is not a standard to be met:
In addition, there are certain attributes of distributed generation technologies (see sections C4 and D) that shall be quantified in the certification process. The resulting measured values shall be certified, but certification of the DG package will not be contingent upon their meeting a standard or being within any limits.

C1.5 All equipment outputs and functions will be tested as part of the pre-certification process. Each numerical test value must be within the tolerance limits specified for a minimum of three tests. Tests verifying specific functions will be performed through a minimum of 5 tests to verify that the unit responds in the manner prescribed. Tests requiring waveform plots will be recorded in the NRTL's standard test format, and all waveform plots will be supplied with the test documentation. Tables 2 and 3 specify which of the specific requirements apply to the different sizes of DG package in order to be pre-certified.

C2 REQUIRED TESTS FOR EQUIPMENT AND FUNCTION PRE-CERTIFICATION:

C2.1 **Rule 25.212 (b) (2): The customer's generator shall be equipped with protective hardware and software designed to prevent the generator from being connected to a de-energized circuit owned by the utility.**

Rule 25.212 (b) (3): The customer's generator shall be equipped with the necessary protective hardware and software designed to prevent connection or parallel operation of the generating equipment with the utility system unless the utility system service voltage and frequency is of normal magnitude.
Tests will be performed of the interconnection control logic to determine that closing of the generator interconnection device will not occur when the utility voltage is outside of the ranges of normal magnitude and frequency as specified in the Rules and shown in Table 1 below. Verification will be obtained by attempting to close the generator interconnection contacts with a test voltage applied that is 106 % of the nominal voltage, again with a test voltage that is 89 % of nominal voltage, and with zero voltage. Verification will also be obtained by attempting to close the generator interconnection contacts with a test voltage applied that is of normal magnitude and frequency greater than 60.5 Hz but less than

60.6 Hz and again with a test voltage of normal magnitude and frequency that is less than 59.3 Hz but greater than 59.2 Hz.

Table 1: Voltage/Frequency Disturbance Delay & Trip Times

Range		Delay to Trip and Trip Time	
Percentage	Voltage[1]	Seconds	Cycles[2]
<70%	<84	0.166	10 (Delay) & 10 (Trip)
70%-90%	84 – 108	30.0 & 0.166	1800 (Delay) & 10 (Trip)
90% - 105%	108 – 126	Normal Operating Range	
105% - 110%	126 – 132	30.0 & 0.166	1800 (Delay)& 10 (Trip)
>110%	>132	0.166	10 (Delay) & 10 (Trip)
	Frequency (Hz)		
	<59.3	0.25	15 (Trip)
	59.3 – 60.5	Normal Operating Range	
	>60.5	0.25	15 (Trip)

[1] Voltage shown based on 120V, nominal.

[2] Trip times for voltage excursions were added for completeness by the PUCT Project No. 22318 Pre-certification Working Group as the intent of 25.212.

C2.2 **Rule 25.212 (c) (1): Voltage. The customer will operate its generating equipment in such a manner that the voltage levels on the utility system are in the same range as if the generating equipment were not connected to the utility's system. The customer shall provide an automatic method of disconnecting the generating equipment from the utility system if a sustained voltage deviation in excess of +5.0 % or –10% from nominal voltage persists for more than 30 seconds, or a deviation in excess of +10% or –30% from nominal voltage persists for more than ten cycles.**
The application of protective functions and disconnect devices in the design of the DG package will be tested to determine that they will reliably disconnect the unit when the voltage at the point of common coupling is outside the specified ranges for the specified maximum time periods. Refer to Table 1 above. The DG package will be operated in an interconnected mode at normal frequency and voltage and then the voltage will be adjusted to a level outside of the prescribed limits at a rate of change appropriate to the test. The generator disconnect device will be verified as having opened and the current essentially decayed to zero within the prescribed time limit.

C2.3 **Rule 25.212 (c) (3): Frequency. The operating frequency of the customer's generating equipment shall not deviate more than +0.5 Hertz (Hz) or –0.7 Hz from a 60 Hz base. The customer shall automatically disconnect the generating equipment from the utility system within 15 cycles if this frequency tolerance cannot be maintained.**
The application of protective functions or disconnect devices in the design of the DG package will be tested to determine that they will reliably operate to disconnect the unit when the frequency at the point of common coupling is outside the specified ranges for the specified maximum time periods. Refer to Table 1 above. The DG package will be operated in an interconnected mode at normal frequency and voltage and then the frequency will be adjusted to a level outside of the prescribed limits at a rate of change appropriate to the test. The generator disconnect device will be verified as having opened and the current essentially decayed to zero within the prescribed time limit.

C2.4 **Rule 25.212 (c) (4): Harmonics. In accordance with IEEE 519, the total harmonic distortion (THD) voltage shall not exceed 5.0% of the fundamental 60 Hz frequency nor 3.0% of the fundamental frequency for any individual harmonic when measured at the point of common coupling with the utility system.** Tests will be performed for the THD of the current waveform and harmonic current contribution from individual odd order harmonics "h" for $3 \leq h \leq 35$. Measurements shall be made at rated output into a simulated utility interconnection with a voltage distortion of less than 2 %.

C2.5 **Rule 25.212 (c) (5): Fault and line clearing. The customer shall automatically disconnect from the utility system within ten cycles if the voltage on one or more phases falls below -30% of nominal voltage on the utility system serving the customer premises.** This disconnect timing also ensures that the generator is disconnected from the utility system prior to automatic re-close of breakers. See requirements in Table 1 and C2.2 above.

C2.6 **Rule 25.212 (e) (1): Three-phase synchronous generators. The customer's generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The customer is solely responsible for properly synchronizing its generator with the utility. The excitation system response ratio shall not be less than 0.5. The generator's excitation system(s) shall conform, as near as reasonably achievable, to the field voltage versus time criteria specified in American National Standards Institute Standard C50.13-1989 in order to permit adequate field forcing during transient conditions.**
A test of the generator breaker will be performed including assessment of its suitability as a disconnect device with fault clearing capability consistent with the size and type of generating unit. The manual control of the generator breaker and its automatic operation through the relay function requirements contained in 25.211 and 25.212 shall be tested to be reliable and of quality design and workmanship.

Additionally, the excitation system voltage time response shall be determined based on a starting point of full rated load output at unity power factor and rated terminal voltage with a step change to 75% of rated terminal voltage (as seen by the excitation system control). The excitation system voltage response ratio shall be determined based on the first half-second of this response and verified to be at least 0.5. In addition, the field voltage versus time criteria specified in ANSI C50.13-1989 will be verified as having been met.

C2.7 **Rule 25.212 (e) (1): The customer is solely responsible for properly synchronizing its generator with the utility.**
A test of the synchronizing relay or other scheme may be performed including its design reliability and control of the generator interconnect device. The synchronizing feature of the DG package shall be tested by the NRTL to verify that the generator interconnect device will not close (allowing for breaker closure time) until the DG has synchronized properly with the utility, using procedures acceptable to the PUCT.

C2.8 **Rule 25.212 (e) (2): Self-commutated inverters whether of the utility-interactive type or stand-alone type shall be used in parallel with the utility system only with synchronizing equipment.**
Inverter based outputs that use the utility power for startup shall be tested by the NRTL for impacts on the utility system during start up to verify that the DG has synchronized properly with the utility, using procedures acceptable to the PUCT.

C3 OPTIONAL TESTS FOR EQUIPMENT AND FUNCTION PRE-CERTIFICATION:

C3.1 **Rule 25.212 (b) (8): The customer will furnish and install a manual disconnect device that has a visual break that is appropriate to the voltage level (a disconnect switch, a draw-out breaker, or fuse block), and is accessible to the utility personnel, and capable of being locked in the open position.**
A manual disconnect device if integrated in the DG package configuration shall be verified as providing the necessary visible air gap suitable for the rated voltage. In addition, its configuration in the electrical circuitry of the DG package shall be verified and the locking mechanism determined to be secure for use with a padlock having a shank diameter of not more than 0.375 inches and also suitable for wire or plastic tags.

C3.2 **Rule 25.212 (c) (5): To enhance reliability and safety and with the utility's approval, the customer may employ a modified relay scheme with delayed tripping or blocking using communications equipment between the customer and the utility company.**
The DG package design and wiring shall be reviewed and tested to determine the type of input required to prevent tripping of the generator breaker under specific conditions. The design shall be certified as to which relay functions can be selected and the range of time delay or full blocking. In addition, the interface such as contacts, RTU protocol or some other communications shall be verified.

C3.3 **Rule 25.212 (e) (3) (C): If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility.**
The DG package design and wiring shall be reviewed and tested to determine that the under frequency relay function may be disabled based on an auxiliary input from the point of common coupling.

C4 TESTS FOR EQUIPMENT AND FUNCTION PRE-CERTIFICATION FOR WHICH THERE IS NOT A STANDARD TO BE MET:

C4.1 Verify maximum continuous electrical output at ISO conditions for DG units. Tests will be performed at test site conditions and calculated to ISO conditions.

C4.2 Verify maximum emergency output at ISO conditions for DG units, if available. Tests will be performed at test site conditions and calculated to ISO conditions.

C4.3 Fuel conversion efficiency expressed in percentage or as a heat rate at maximum continuous output and at 50 % and 75 % of maximum continuous output. Tests will be performed at test site conditions and calculated to ISO conditions.

C4.4 Audible (20 Hz to 20 kHz) noise level in dBa measured at 1 meter and 10 meters from the unit.

C4.5 Stack emissions of NO_X, SO_X and CO_2 measured in parts per million measured at maximum continuous output and ISO conditions. Tests will be performed at test site conditions and calculated to ISO conditions.

C4.6 Maximum leading and maximum lagging power factor at rated output power and voltage.

C4.7 Maximum fault current interrupting capability of the generator main power circuit breaker at rated voltage.

C4.8 The generator rated maximum short circuit current output for 3-phase and phase-to-ground faults will be verified for non-inverter output based DG packages. Modeling of machine parameters and computation of fault current levels shall be acceptable for units with short circuit duties that could be damaging to the unit. Equipment that is part of the DG package that could have an impact on short circuit duty such as grounding resistors and excitation systems shall also be documented. Measured or calculated fault current magnitudes shall be for one-half cycle after the fault is applied.

D1 LABELING REQUIREMENTS

D1.1 The results from the tests of the functionality of the requirements in Sections C4.1, C4.2, C4.3, C4.4, and C4.5 must be shown on a label sufficiently durable for outdoor use to be affixed on each DG package as applicable.
Labeling shall specify that the DG package has been pre-certified in compliance with PUCT Substantive Rules 25.211 and 25.212.

TABLES: The following Tables 2 and 3 outline the specific functional requirements for different types and sizes of DG packages as indicated by "X". References are to paragraphs in this document.

TABLE 2

Control, Protection and Safety Equipment[1,3]
Single-Phase Connected to Secondary or Primary System

	Generator Size	
	Reference	**50 kW or Less**
Interconnect Disconnect Device	**C2.1**	**X**
Generator Disconnect Device	**C2.1**	**X**
Over-Voltage Trip	**C2.2**	**X**
Under-Voltage Trip	**C2.2**	**X**
Over/Under Frequency Trip	**C2.3**	**X**
Synchronizing Check[2]	**C2.7**	**Manual or Automatic**

Notes:

1. See the OEM Control, Protection and Safety Equipment Guidelines publication for discussion and one-lines for acceptable installations.
2. For synchronous and other type of generators with stand-alone capability.
3. Exporting to the host electrical utility system may require additional operational/protection devices and will require coordination of operations with the utility.

TABLE 3

Control, Protection and Safety Equipment[1,6]
Three-Phase Connected to Secondary or Primary System

		Generator Size			
	Ref.	10 kW - or less	11 - 500 kW	501 - 2,000 kW	2,001 - 10,000 kW
Interconnect Disconnect Device	C2.1	X	X	X	X
Generator Disconnect Device	C2.1	X	X	X	X
Over-Voltage Trip	C2.2	X	X	X	X
Under-Voltage Trip	C2.2	X	X	X	X
Over/Under Frequency Trip	C2.3	X	X	X	X
Ground Over-Voltage Trip Or Ground Over-Current Trip[7]	C2.5		X	X	X
Synchronizing Check[2]	C2.7, C2.8	Manual or Automatic	Manual or Automatic	Automatic	Automatic
Power Direction[3]	C3.3		X	X[4]	X[4]
Telemetry/transfer Trip	C3.2				X[5]
Automatic Voltage Regulation (AVR)[2]	C2.6				X

Notes:
1. See the OEM Control, Protection and Safety Equipment Guidelines publication for discussion and one-line diagrams for acceptable installations.
2. For synchronous and other type of generators with stand-alone capability.
3. If NOT exporting and generator is less than minimum load of the customer, or if always exporting, then not required except as noted.
4. If exporting, blocks under-frequency trip with agreement of host utility.
5. May be required as part of a transfer tripping/blocking protective scheme.
6. Exporting to the host electrical system may require additional operational/protection devices and will require coordination of operations with the host utility.
7. Selection depends on grounding system, if required by host utility.

REVISIONS TO THE MANUAL

Date of Revision	Description
01-25-01	Revised Table 3-1 to add trip times and label delay and trip times; revised Table 1 in Pre-certification Requirements to make consistent with Table 3-1 in manual.
02-01-01	Revised C2.1 in Pre-certification Requirements document change test voltages from 89.9% to 89% and from 105.1% to 106% after late comments received on 01-26-01.
02-23-01	Added credit to the U.S. Dept. of Energy Office of Energy Efficiency and Renewable Energy on the cover sheet and on the Introduction page.
03-15-01	Deleted "retail electric customer," from last sentence of first paragraph of Chapter 5.1.
05-05-02	Edited the contacting person for the electric division on page 8-1 from Ed Ethridge to Tony Marciano at 512-936-7366.
