Survey of Interconnection Rules

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Introduction

Among the key factors affecting the deployment of distributed generation to existing utility systems are the technical, procedural and economic requirements governing the physical interconnection and operation of generating equipment with the existing utility system. This paper addresses the regulatory context for interconnection of smaller scale distributed generation (DG). This paper is intended to highlight the critical issues in interconnection and to provide a condensed recitation of the provisions for interconnection contained in existing interconnection rules and in selected draft and model interconnection rules.

At present there are no uniform standards for interconnection in the US. This is due, in part, to the fact that jurisdiction over interconnections is split between the Federal Energy Regulatory Commission (FERC) and the various states. At the federal level, the FERC has adopted Small Generation Interconnection Procedures for facilities within its jurisdiction.[2] Meanwhile, less than half the states currently have interconnection rules in place for DG.[3] Even within states, a number of utility systems, municipal utilities and rural cooperatives, are beyond the reach of the state's utility commission and are left to adopt their own standards. While most parties agree that greater uniformity among jurisdictions is desirable (some would say crucial), a large number of inconsistencies and inadequacies remain.

In attempting to identify best practices for interconnection, judgments must necessarily be made regarding the balance of interests among DG owners and operators, the local utility and non-participant customers. To assess best practices of rules and standards in place around the country or proposed in model rules, some key criteria are:

- Degree of uniformity among other jurisdictions
- Scope
- Simplicity
- Certainty
- Impact on public and employee safety; and,
- Industry experience.

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[1] Information for Maryland and Oregon added on August 27, 2007. Original survey completed on June 20, 2006.

[2] 18 CFR Part 35, Docket No. RM02-12-000; Order No. 2006.

[3] Source: "Interconnection Rules for Distributed Generation", Interstate Renewable Energy Council (IREC) National Interconnection Project (updated March 2006).

This paper reviews the following rules, proposed rules and model rules: California, FERC, Illinois[4], Maryland, Massachusetts, Minnesota, New York, Oregon, Texas, Washington and Wisconsin. This provides some geographic and size diversity, as well variety in approaches. Also included are model interconnection rules developed by the Mid-Atlantic Distributed Resources Initiative (MADRI) and the Interstate Renewable Energy Coalition (IREC).[5]

At a high level, the topic of interconnection breaks down into four main categories: technical design requirements, the application process, interconnection process and the interconnection agreement. However, where and how the specific requirements of each of these categories are manifested is not always clear. Some jurisdictions choose to place technical requirements in their interconnection "rule" while others place them in the interconnection agreement or in a separate operating agreement. As a result, it is problematic to parse these issues purely on the basis of these categories. Instead, this review addresses the most important components of interconnection rules and procedures without regard to where the requirements are manifested.

Interconnection Rule Basics

Applicability

There is no single definition of what a "small" DG unit is. Nor is there is any convenient technological basis for distinguishing units on the basis of size for treatment under a small DG rule. Even so, the existing rules have, for the most part, been bounded at the 10 MW or the 20 MW level. In addition, special rules have been developed for smaller installation at the 1 MW level or below and for very small installations at the 25 kW or 40 kW size. The breadth of these sizes hints at some of the difficulties in developing standardized technical standards and procedures for interconnection of DG. Some jurisdictions, notably the FERC, also have rules for large installations. We have not reviewed those here.

Components of Interconnection Rules

Requirements for interconnection of DG can be organized into three basic categories:

1. Technical and engineering-based hardware requirements for interconnection;
2. Rules governing the process of interconnection; and,
3. Rules governing the operational relationships of the parties.

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[4] The Illinois rule is a draft rule and has not yet been formally adopted. It is included as an example of a rule that is currently under consideration.

[5] For convenience, each of the different existing rules, proposed rules and model rules are referenced on a "jurisdiction" basis, even though the model rules are technically not associated with any specific jurisdiction.

In each jurisdiction, these categories are addressed through a combination of industry standards, utility regulatory requirements and contracts between the parties, or left to the judgment and discretion of the utility.

Technical and Engineering-based Hardware Requirements for Interconnection

As restructuring proceeded through the late 1990s there was increasing pressure from DG manufacturers and developers, as well as utility regulators, to develop standardized interconnection rules for all distributed generation. In response to this need, the Institute of Electrical and Electronics Engineers (IEEE), which sets standards for the electric industry, initiated a multi-year process to establish standardized technical and hardware requirements for interconnection. The initial standards emerging from this process have been published as IEEE 1547. In addition, there are number of follow-on processes designed to address related issues identified during the initial IEEE 1547 process. These are:

- 1547.1 **–** Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- P1547.2 **–** Draft Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems
- P1547.3. **–** Draft Guide for Monitoring, Information Exchange and Control of Distributed Resources Interconnected with Electric Power Systems
- P1547.4 **–** Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems
- P1547.5 **–** Draft Technical Guidelines for Interconnected Electric Provider Sources Greater than 10MVA to the Power Transmission Grid
- P1547.6 **–** Draft Recommended Practice For Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks

IEEE 1547 has essentially become "law" through the passage of EPAct 2005 which cites IEEE 1547 as a reference standard. The technical content of IEEE 1547 is beyond the scope of this paper.[6] However, it important to note that IEEE 1547 is focused just on the physical interconnection, that is, the point of common coupling (PCC), between the synchronized grid (i.e. the "utility system") and the DG installation, the surrounding equipment utilized for control and automatic disconnection and the operational standards that must be met while interconnected. It does not address the processes used to accomplish interconnection, the economic relationship of the DG owner and the utility, or the operational rules governing use of the DG.

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[6] See: http://grouper.ieee.org/groups/scc21/1547/1547_index.html for further information.

IEEE 1547 has greatly increased the uniformity of basic technical requirements for interconnection of small DG. Underwriters Laboratory (UL) has also developed testing standards for some interconnection equipment, notably UL 1741 "Inverters, Converters, and Controllers for Use in Independent Power System." In essence, UL 1741 is Underwriter Laboratory's implementation of IEEE 1547.

There are numerous other IEEE, UL and ANSI standards which may come into play in an interconnection and which are utilized to varying degrees by existing and proposed interconnection rules. Our review of these standards is limited to a determination of whether a given rule explicitly cites or adopts a given standard and whether there are known or explicit exceptions to them and does not address whether any given technical standard is appropriate.

Status of Interconnection in the States, FERC and as Proposed in Model Rules

Scope and Applicability of the Rules

The threshold issue for interconnection is the determination of what technologies fall within the scope of a jurisdiction's interconnection rules. Table 1 summarizes the scope and applicability of the interconnection rules for each of our reference jurisdictions:

Table 1 Scope and Applicability of Rules

Jurisdiction	Scope	Capacity Limits
California	All jurisdictional interconnections	No size limits
FERC	All jurisdictional interconnections	Small generator rules for units <= 20 MW Large generator rules for units > 20 MW
Illinois	All jurisdictional interconnections, except those made prior to 60 business days after effective date of rule	No size limits
IREC	Customer-sited generation	<= 10 MW
MADRI	All jurisdictional interconnections operating in parallel with the utility system	<= 10MW
Maryland	All jurisdictional interconnections operating in parallel with the utility system	<= 10MW
Massachusetts	All proposed new sources of electric power without respect to generator ownership, dispatch control, or prime mover that plan to operate in parallel with the Company; if unit will never operate in parallel, rules do not apply	No size limits
Minnesota	Interconnection between a Generation System and an area electrical power system "Utility system or Area EPS"	3 phase <=10 MW Single phase systems <= 40kW
New York	New distributed generation facilities and modifications of existing DG affecting the interface at the PCC. Generation not in parallel with the utility's electrical system is not subject to requirements.	<= 2 MW
Oregon	All jurisdictional interconnections operating in parallel with the utility system	<= 10 MW
Texas	Interconnection and parallel operation of on-site distributed generation. Sales of power by DG in the wholesale market are subject to the provisions for open-access comparable transmission service for utilities in (ERCOT).	No size limits
Washington	All jurisdictional interconnections	<=25 kW
Wisconsin	All DG facilities interconnected to public utility distribution system.	<=15 MW

The stated scope of interconnection rules generally accomplishes two objectives: 1) to clearly identify the types of installations that are subjected to the rules and 2) to avoid gaps in coverage, either within the state or *vis-a-vis* the FERC. To this end, states are best served by assuring that their rules expand to cover all interconnections which are not within FERC jurisdiction. This prevents any technology, type or manufacturer from either facing uncertainties about applicability of the rules or having to undergo unnecessary one-on-one negotiations with the utility.

As can be seen from Table 1, many states limit the applicability of their rules on the basis of the nameplate capacity of the units being interconnected. This limitation is tightly linked to the related concept of developing more streamlined rules and procedures for smaller installations, with the hope of moving toward, if not achieving, plug-and-play status. Unfortunately, this may lead to larger units not having the protection of a comprehensive process for interconnection. To avoid this, it seems appropriate for states to take the extra step to provide consistent rules and procedures for all sizes of generation, even if the larger units require more studies and customization. Such an expanded scope also helps to make clear the utility's obligation to provide interconnection to all comers, consistent with engineering and safety considerations.

In one case, the IREC Model Rule, the stated justification for limitation in generation was on the basis that units larger than 10 MW are most likely to be installed for the purpose of selling into the wholesale market and would, therefore, be within the FERC rules. It is not clear that this is the case, as it may ignore a number of configurations, especially within the CHP context, where large industrial customers might install facilities larger than 10 MW and wholly consume the output on site. The IREC bias in this regard probably relates to their renewable focus, which is unlikely to reach a 10 MW size for on-site consumption.

Design, Operating and other Technical Requirements

Application of IEEE 1547, NEC & Other Standards and Codes

Among the many applicable electrical codes and standards, IEEE 1547 is the one that most directly addresses interconnection of distributed generation facilities to the utility system. Many interconnection rules either explicitly adopt IEEE 1547 by reference or directly state (in virtually identical terms) key portions of the IEEE 1547 standards. In addition to IEEE 1547, a number of other codes and standards may also apply, depending on the laws of each state. Among these are:

- The National Electrical Code (NEC)
- The National Electric Safety Code (NESC)
- IEEE 929 "Recommended Practice for Utility Interface of Photovoltaic Systems
- American National Standards Institute (ANSI) Standard C37.90, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus
- Institute of Electrical and Electronics Engineers (IEEE) Standard 519, Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.
- Underwriters Laboratories (UL) standards including UL Standard 1741, Inverters, Converters, and Controllers for Use in Independent Power System
- Occupational Safety and Health Administration (OSHA) Standard at 29 CFR 1910.269 and
- Applicable state worker safety and health laws and regulations.

The manner in which each state addresses these standards is shown in Table 2:

Table 2 Codes and Standards Referenced by Interconnection Rules

Code or Standard	Adopted by Reference	Adopted by Reference with Exceptions or Modifications	States Virtually Same Standard in Rule	Not Adopted or Referenced[7]
IEEE 1547	WA, FERC, MA, MD, MN, NY, OR, IL, MADRI	IREC (implicit for certified unit, explicit for non-certified units), WI (non-certified equipment only)	CA (predates 1547) NY (states some standards, adopts all others by reference)[8]	TX
IEEE 929	WA, FERC, MA, MD, MN (929-2000), NY (for Inverter dynamic anti-islanding), CA			TX
IEEE 519	CA, FERC, MD, MN (519-1992), NY, TX, WA			TX
IEEE C37.90.1-1989 (R1994)	FERC, MD, MN, WA[9], NY (for equipment certification), CA (Surge Withstand Capability)			TX
IEEE C37.90.2 (1995)	FERC, MD, MN, WA	NY (Only appears in definition of "Utility Grade Relay")		CA, TX
IEEE C37.108-1989 (R2002)	FERC, MD			MN, WA, NY, CA, TX
IEEE C57.12.44-2000	FERC, MD			MN, WA, NY, CA, TX
IEEE C62.41.2-2002	FERC, MD, MN, NY (for equipment certification), CA (Surge Withstand Capability)			WA, TX

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[7] In some cases blanket references to IEEE, ANSI, etc. are used. In these cases, those sources are not individually listed as "not adopting or referenced" even if the specific standard is not identified.

[8] New York's reference to IEEE 1547-covered standards includes the following footnote:

"It is expected that IEEE Std.1547 will eventually supercede (sic) the need for explicit technical standards in New York State. However, until such time as all IEEE Std.1547 compliance standards (including testing protocols) are complete and approved, this standard will take precedence."

Although IEEE 1547 has since been formally approved, the rule has not yet been updated.

[9] Washington cites this as ANSI C37.90.

Code or Standard	Adopted by Reference	Adopted by Reference with Exceptions or Modifications	States Virtually Same Standard in Rule	Not Adopted or Referenced[7]
IEEE C62.45-1992 (R2002)	FERC, MD, MN[10], NY, CA			WA, TX
IEEE 100-2000	FERC, MD, MN			WA, NY, CA
IEEE 37.98		NY (Only appears in definition of "Utility Grade Relay")		CA
NEMA MG 1-1998 Revision 3	FERC			MN, WA, NY
NEMA MG 1-2003 (Rev 2004) Revision 1	FERC			MN, WA, NY
ANSI C84.1-1995	FERC, MD, MN			WA,CA
ANSI/IEEE C84.1-1995	MN			WA,CA
ANSI/IEEE 446-1995	MN			WA, CA
ANSI/IEEE Standard 142-1991	MN			WA,CA
ANSI C37.2		NY (Only appears in definition of "Utility Grade Relay")		CA
NEC	WA, FERC, MD, MN			CA
NEMA MG 1-1998	MD			
NEMA – MG 1-2003	MD			
NESC	MN			WA, CA
UL 1741	FERC, MA, MD, MN, CA, WA	WI (certified paralleling equipment), IREC (for certification of generators and interconnection equipment)		
OSHA 29 CFR 1910.269	WA			CA
NFPA 70 (2002)	FERC			WA
IEC[11] 255-21-1, IEC 255-22-2, IEC 255-5		NY (Only appears in definition of "Utility Grade Relay")		FERC, MN, IL, WA, WI, CA, IREC, MADRI

[10] The Minnesota rule cites this as "IEEE Std C62.42-1992 (2002)"; however, this appears to be a typographical error.

[11] International Electrotechnical Commission.

Code or Standard	Adopted by Reference	Adopted by Reference with Exceptions or Modifications	States Virtually Same Standard in Rule	Not Adopted or Referenced[7]
Blanket adoption by reference of all IEEE, ANSI or UL standards	WI (IEEE, ANSI, UL for "all installations" and for "disconnect switches"), MADRI (in interconnection agreement), MN	IREC (ANSI, UL & IEEE for Level 1; ANSI & UL in Application form for Level 2,3 & 4)		

Table 2 reflects the fact that the jurisdictions vary considerably in the detail with which they articulate codes and standards applicable to interconnections. Both the FERC and the Minnesota rules take care to articulate with great specificity the IEEE, ANSI and UL standards that must be met for interconnections. Others, most notably Texas, have only limited reference to outside standards. Even though specific requirements may be cited in the context of the rules, Minnesota, Wisconsin and the two model rules (MADRI and IREC), essentially adopt all applicable IEEE, ANSI and UL standards with some kind of blanket reference.

As general rule whether and how externally adopted standards, such as the NEC, are applicable to an interconnection is a function of statutory requirements that are outside the ordinary scope of a regulatory commission's focus. Nonetheless, the citation of such codes can be helpful to any party seeking a DG interconnection. However, not all of these standards and codes are otherwise in force through non-utility statutes. This is especially true for the IEEE standards that directly address distributed generation, such as IEEE 1547 and IEEE 929, among others. In these cases, interconnection rules need to explicitly adopt these standards in order to give them the force of law.

There is the potential for confusion or even inconsistency in those cases where the rules explicitly repeat or adopt a specific standard and adopts by reference the same standard by reference. For example, if IEEE 1547 is adopted by reference and the rule also explicitly repeats a particular standard for protective functions, such as voltage regulation, any inconsistency in language between the two introduces an immediate potential for confusion. Also, in the event IEEE 1547 is amended or revised, the same conflict could arise in the future.

Because there is widespread and increasing acceptance of these external standards, it is not unreasonable to treat them as, in fact, industry standards. In order to maintain consistency, wherever possible, the preferred approach is to externally reference existing industry standards as the controlling standard.

Technology Specific Requirements

One of the core objectives of any interconnection rule is protection of the public and the electric system from unsafe or unstable operating conditions. As a result, much of the focus of the technical standards is on the use of protection functions designed to prevent the distributed generator from energizing the electric system during a system failure or from propagating disturbances onto the electric system during normal operations.

In many the cases, the interconnection rules explicitly provide that the protective standards are designed solely to protect public (and utility employee) safety and the utility's electrical system and are not designed to protect interconnected equipment or the customer's other facilities. This is a useful distinction to make clear to the interconnecting party their obligations *vis-à-vis* the utility and the electric system.

Existing interconnection rules vary significantly in the way they address these needs, but there are basically three strategies for dealing with these issues:

- The rules themselves set forth the specific design and operating characteristics that must be met (or do so by reference to external standards);
- Provision is made for pre-certification or type testing of specific technologies which are then deemed pre-approved for interconnection; or,
- Determination of requirements is not addressed or is left to the judgment of the utility.

Inverter-based Technologies

Current state-of-the-art inverter systems are capable of performing many of the required protective functions internally, without the need for additional protective equipment. As a result, a number of the interconnection rules have developed explicit standards for inverter-based technologies. The application of these standards occurs at two levels.

First are the actual technical standards themselves. Two external standards (among others) and, in the case of photovoltaic systems a third, apply to inverter-based interconnections. They are IEEE Standard 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems," UL Standard 1741, "Inverters, Converters, and Controllers for Use in Independent Power Systems," and IEEE Standard 929, "IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems." Generally these standards set forth the nominal voltage and frequency parameter that must be met and the limits allowed for anomalies such as flicker, interference, etc., and the time allowed for disconnection when the required parameters are no longer being met or for reconnection following a system failure or automatic disconnection.

Second are the creation of safe harbor or so-called "fast track" rules and the notion of type certification (sometimes called pre-certification) which moves this technology closer to a "plug-n-play" status (here collectively referred to as "Type Certification"). Type Certification requires that the units undergo standardized testing, usually by a Nationally Recognized Testing Laboratory (NRTL), such as Underwriter's Laboratory, and that the results of those tests be made available. Type certified units typically must also be "listed" by the laboratory and the equipment labeled as such.

Table 3 Inverter-Based Technical Standards and Inverter-Based Type Certification

Topic	Technical Standards	Type Certification
California	"Utility interactive" inverters do not require separate synchronizing equipment, other than certification related standards. Non-islanding inverters < 1kVA are exempt from manual disconnect device requirement	Specific type-testing requirement, based on UL 1741 including Utility Disconnect Switch, Field Adjustable Trip Points, DC Isolation, Simulated PV Array (Input Source) requirements, Dielectric Voltage Withstand test, Power Factor, Harmonic Distortion, DC Injection, Utility Voltage and Frequency Variation Test, Reset Delay, Loss of Control circuit, Short Circuit Test and Load Transfer Test.
FERC	No specific inverter-based standards articulated, other than certification standards	No inverter-specific type certification provisions; however FERC has generic type certification rules (See Type Certification discussion below).
Illinois	No specific inverter-based standards articulated	No inverter type certification provisions.
IREC	No specific inverter-based standards articulated	Facilities must meet IEEE 1547 and UL 1741 standards & be tested and listed by a NRTL and meet definition for certification under FERC rules (Order 2006)
MADRI	No specific inverter-based standards articulated	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).
Maryland	No specific inverter-based standards articulated	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).
Massachusetts	No specific inverter-based standards articulated	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).
Minnesota	No specific inverter-based standards articulated	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).

Topic	Technical Standards	Type Certification
New York	Must disconnect for voltage or frequency trip condition; Non-certified equipment must meet IEEE 929 anti-islanding standard and IEEE 519 harmonic limits and be protected by utility grade relays; Must be designed for parallel operation; Synchronization may not result in excessive voltage deviations; Line inverter may be used if demonstrated to be isolate customer from system safely and reliably. Single phase inverters and inverter systems <= 15 kW are exempt from normal verification testing but must be verified upon initial operation and once annually thereafter	State maintains list of certified equipment. (See Type Certification discussion below)
Oregon	No specific inverter-based standards articulated	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).
Texas	Line-commutated inverters do not require synchronizing equipment. Self-commutated inverters whether of the utility-interactive type or stand-alone type may be used in parallel with the utility system only with synchronizing equipment.	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).
Washington	All inverter-based systems must meet requirements of IEEE 1547, UL 1741 and IEEE 929	No certification or type testing is provided for in the rule.
Wisconsin	No isolation by a transformer may be required for a line-commutated inverter.	No inverter-specific type certification provisions; however has generic type certification rules for any small generator (See Type Certification discussion below).

Treatment of inverter-based systems remains an area of moderate inconsistency, in terms of specified technical standards. It appears that most, if not all, of the necessary technical standards for inverter-based systems are covered by existing IEEE and UL standards, which are easily incorporated into interconnection rules. Both California and New York address detailed standards for inverter-based systems, but it should be noted that these states adopted standards for interconnection before IEEE 1547 was finalized. If and when these two states undertake additional reviews of their rules, we may see these passages replaced with adoptions by reference of the IEEE and UL standards.

One major area of contention and inter-jurisdictional inconsistency that remains relates to the need for an external, utility-accessible, disconnect switch. Utility experience with existing DG resources has been to usually require such switches. Absent an explicit exception to this in the interconnection rule, it is a near certainty that utilities will impose a disconnect switch requirement on most interconnections.

The utility argument for requiring a disconnect switch is straightforward and, on its face, seems compelling: that any time the distribution system is de-energized, to protect the safety of utility employees and the public, the utility must be able to positively ascertain that no customer-owned generation is feeding energy into the system and must have access to a switch to disconnect the generator from the system to confirm that this is the case.

Providers of appropriately designed small inverter-based systems, on the other hand, insist that their technology automatically provides this function internally and that any requirement for an external switch is redundant and an unnecessary additional cost. There is some reason to support this view, given the current status of IEEE/UL standards that already cover the automatic disconnect and reconnect functions of an inverter-based system in a published standard. They insist this is a critical issue because, for many installations, the additional cost of a disconnect switch may render the project uneconomic.

This is an area that ultimately must be resolved on the basis of the judgment of the regulators, enlightened by experience going forward. California (< 1 kW) and IREC exempt units from disconnect switches, while California (> 1 kW), Illinois (ComEd >40 kW), Maryland, Minnesota, New York, Oregon, Texas, Wisconsin and MADRI require a disconnect switch. Massachusetts leaves this issue to the discretion of the utility. [12] FERC references it only in terms of "if required" without specifying whether it is required.[13]

As will be seen below, inverter-based technology, especially for smaller units, is also likely to be well-suited for a Type Certification process and the related "fast track" processes that many jurisdictions have adopted.

Interconnection Facilities and System Modifications

The installation of DG may require construction of facilities on the utility's side of the meter or modifications to existing facilities. In most cases, the cost of such facilities or modifications is to be paid by the interconnecting customer. However, some jurisdictions have elected to exempt some types of installations from paying such costs. Occasionally, these kinds of investments may also address other existing or future system needs, in which case some form of cost allocation or sharing would be appropriate. Some jurisdictions also provide explicit financing options that allow customer to pay for such facilities over time, rather than in one up-front lump sum.

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[12] Other states (not included in our overall review) that do not require a disconnect switch are Arizona (other than APS), Colorado (but not Cooperatives), New Jersey (Class I Renewables only). Other state (not included in our overall review) that require a disconnect switch are Arizona (APS), Colorado Cooperatives, Connecticut, Delaware, Hawaii, Idaho, Indiana, Kansas, Michigan, Missouri, North Carolina and Vermont. Ohio leaves this to the discretion of the utility. Source: IREC, http://www.irecusa.org/connect/state-by-state.pdf.

[13] IREC reports FERC as not requiring a disconnect switch, but the language of the rule seems refer to an "if required" approach. Source: IREC, *id.*

Even though the customer may pay the interconnection facilities or system modifications, as a general rule, all facilities that are installed on the utility's side of the meter will be owned and operated exclusively by the utility.

For the most part, the determination of the need for system modifications is made in the context of system studies conducted during the interconnection process. The subject of the need for and cost of system studies is addressed elsewhere in this analysis.

Metering, Monitoring, Telemetry and Control

Closely related to system modifications is the imposition of additional metering, monitoring and telemetry requirements for the DG facility. There are both economic and engineering reasons for these requirements.

For economic purposes, metering may be required in order to meter energy exported from the customer's site into the utility system in order to quantify sales to the utility or into the wholesale market. Even where there are not exports into the system, the utility's tariff structure may require that the customer's energy production be accounted for separately from its load, thus requiring metering of the generation output.

For engineering purposes, the utility may want or need to meter, monitor and have access to telemetry from the DG unit to verify that it is not adversely affecting the system and is operating within the nominal parameters allowed for voltage, frequency and other criteria. Units that participate in capacity or reliability programs may require remote operational capability enabling the utility to dispatch for such purposes.

For larger DG installations, the costs of metering, monitoring, telemetry and control are not likely to be of significant concern. For smaller units, however, such costs can quickly overwhelm the economics of the installation. As a result, metering, monitoring, telemetry and control requirements have the potential to operate as barriers to the deployment of smaller technologies.

In states that have adopted net metering rules, special treatment may be afforded facilities that qualify for net metering. Often some or all of the costs of additional metering requirements may be borne by the utility. Other restrictions on the utility's ability to require additional metering requirements may also be imposed for net metered facilities.

Table 4 summarizes the treatment of system modification costs and metering, monitoring, telemetry and control requirements:

Table 4: Interconnection Facilities & System Modifications and Metering, Monitoring & Control

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
California	Facilities on Producer's side of Point of Common Coupling may be owned, operated and maintained by Producer or utility Facilities on utility's side of PCC shall be owned, operating and maintained only by utility The Electrical Corporation shall provide the Applicant with an executable version of the Interconnection Agreement, Net Energy Metering Agreement, or Power Purchase Agreement appropriate for the Applicant's Generating Facility and desired mode of operation. Where the Initial Review or Interconnection Study performed by the Electrical Corporation has determined that modifications or additions are required to be made to its Electric System, or that additional metering, monitoring, or protection devices will be necessary to accommodate a Applicant's Generating Facility, the Electrical Corporation shall also provide the Applicant with an Interconnection Facilities Financing and Ownership Agreement (IFFOA). The IFFOA shall set forth the respective parties' responsibilities, completion schedules, and estimated or fixed price costs for the required work. Customer may choose between fixed prices or an estimated & reconciled cost method for determining costs. Facilities on customer's side of PCC may be owned, operated and maintained by the customer or utility. Facilities installed on Electrical Corporation's side of PCC and Distribution System Improvements may be owned operated and maintained only by Electrical Corporation. Customer is responsible for all costs associated with Facilities owned by customer and for any costs reasonably incurred by utility in providing, operating, or maintaining Interconnection Facilities and Distribution System Improvements required solely for interconnection of customer's Generating Facility. California provides for utility financing of utility owned & operated interconnection facilities.	Metering must be done by utility Net Generation Metering may be required to determine standby charges and other non-bypassable charges and for Distribution System planning and operations, but should be least intrusive most cost-effective solution Utility must provide quarterly reports on rationale for requiring metering of Generation Facilities and size and location of each installation. Point of Common Coupling Metering: Utility may require Producer to replace customer's existing meter with bi-directional meter to separate meter power flows to and from utility or Producer can elect to install multi-metering equipment to separately record flows If greater than 1 MW utility may require telemetering equipment at Producer's expense; if connected at below 10 kV, then may be required for Generating Facilities of 250 kW or greater; all subject to least intrusive most cost-effective options. Customer must provide reasonable location for metering of generation. Customer will bear all of the costs of required metering.
FERC	Customer pays costs as determined in study processes. Modifications may occur on Transmission Provider's system and on Affected Systems.	Necessary metering installed at customer's expense and be installed in accordance with applicable ANSI standards.

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
Illinois	Customer will bear the cost at no more than the estimated binding maximum cost in facilities study agreement. Customer may be credited for costs or such costs may be offset by mutual agreement with subsequent interconnection customers. An interconnection provider may propose to group facilities for more than one interconnection customer to minimize costs, but customer may require the installation of facilities required for its own system and pay the costs of those facilities.	Any metering necessitated by the use of the small resource shall be installed in accordance with state regulatory requirements
IREC	Customer pays for cost of Interconnection Facilities. If Facilities Study was performed, utility must identify Interconnection Facilities necessary to safely interconnect the Small Generator Facility with the Distribution System, the cost of those facilities, and the time required to build and install facilities. Customer pays its share of reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its Interconnection Equipment, and (2) operating, maintaining, repairing, and replacing utility's Interconnection Facilities. Utility designs, procures, constructs, installs, and owns any Distribution Upgrades. Actual costs of the Distribution Upgrades, including overheads, are directly assigned to Customer.	Rule does not address metering requirements other than requiring utility access to meter
MADRI	Utility must construct, own, operate, and maintain distribution system and Interconnection Facilities in accordance with IEEE 1547, NEC and other applicable standards. Utility may propose to interconnect more than one Small Generator Facility at a single Point of Interconnection in order to minimize costs and may not unreasonably refuse to do so. However, the Customer may elect to pay the entire cost of separate Interconnection Facilities. Each party must operate, maintain, repair, inspect, and be fully responsible for own facilities and for safe installation, maintenance, repair and condition of their respective lines and appurtenances on their side of Interconnection and must provide facilities that adequately protect the other party's facilities, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of facilities is delineated in Interconnection Agreement. Customer must pay for the cost of the Interconnection Facilities. If a Facilities Study was performed, utility must identify its Interconnection Facilities necessary to safely interconnect the Small Generator Facility with the system, the cost of those facilities, and the time required to build and install those facilities. Customer pays its share of all reasonable expenses of owning, operating, maintaining, repairing, and replacing customer's Interconnection Equipment, and utility's Interconnection Facilities.	Suitable EDC metering equipment required under applicable tariffs must be installed and tested in accordance with applicable ANSI standards. The Interconnection Customer shall be responsible for the cost of the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment Metering is as required by tariff governing sale or exchange of power

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
Maryland	The EDC shall construct, own, operate, and maintain its Interconnection Facilities in accordance with this Agreement, IEEE Standard 1547, the National Electrical Safety Code and applicable standards promulgated by the Maryland Public Service Commission. The Interconnection Customer shall construct, own, operate, and maintain its Small Generator Facility in accordance with this Agreement, IEEE Standard 1547, the National Electrical Safety Code, the National Electrical Code and applicable standards promulgated by the Maryland Public Service Commission. Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. The Interconnection Customer agrees to design, install, maintain and operate its Small Generator Facility so as to minimize the likelihood of causing an Adverse System Impact on an electric system that is not owned or operated by the EDC.	The Interconnection Customer shall be responsible for the cost of the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 5 and 6 of the interconnection Agreement. EDC monitoring and control of small generator facilities shall be permitted only if the nameplate rating is greater than 2 MW. Any monitoring and control requirements shall be consistent with the EDC's written and published requirements and must be clearly identified as part of an interconnection agreement executed by the interconnection customer and the EDC.
Massachusetts	Company will build and own, as part of the Company EPS, all facilities necessary to interconnect the system with the Facility up to and including terminations at the PCC. The Interconnecting Customer shall pay all System Modification costs.	Customer pays reasonable and necessary costs for purchase, installation, operation, maintenance, testing, repair and replacement of metering and data acquisition equipment. Interconnecting Customer's metering (and data acquisition, as required) equipment must conform to rules and applicable operating requirements. Company furnishes, reads and maintains all revenue metering equipment. Customer furnishes and maintains all meter mounting equipment. Company owns the meter and Customer pays monthly charge for taxes, maintenance, reading and billing costs, allowable return on invoice cost of meter and depreciation of the meter. For QFs or On-Site Generating Facility, Customer may own meter and pay monthly charge for maintenance and reading and billing costs and is responsible for purchasing and installing software, hardware and/or other technology required by Company to read meter. Customer must provide suitable space for metering and communication equipment at no cost to the Company. Metering must be routinely tested by the Company at Customer's expense. If metering equipment found to be inaccurate Company must repair or replace meter at Company's expense, if the Company owns the meter, or at Customer's expense, if Customer owns the meter. If Metering Point and the Point of Receipt or Point of Delivery not the same, the metering must account for losses between the Metering Point and Point of Receipt or Delivery. Losses between the Metering Point and Point of Receipt will be reflected pursuant to applicable Company, NEPOOL or ISO-NE criteria, rules or standards.

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
		Type of metering is dependent on the size and how and if the Facility plans to export power or net meter. For those that will export power or net meter, the available equipment options and associated requirements are: -**Net Metering** <= 60 kW, unless the Interconnecting Customer elects another form of metering, the Facilities will be equipped with net metering in which standard distribution class meter is installed and is enabled to run in a normal direction during periods of net consumption and to run backwards during periods of net generator output and shall meet ANSI C12.1 Metering Accuracy Standards and ANSI C57.13 accuracy requirements for instrument transformers. See 220 CMR 11.04 (7)(c). - **Bi-directional, non-interval meter without remote access** in which a distribution class meter with multiple registers is installed. One set of registers records energy flows from the Company to the Facility and second set of registers records energy flows from the Facility to the Company on a mutually exclusive basis and which record total flows only and not flows during specific intervals and shall meet ANSI C12.1 Metering Accuracy Standards and ANSI C57.13 accuracy requirements for instrument transformers. - **Bi-directional, interval meter with remote access –**Same register controls as without remote access. In addition, meters must be equipped with remote access capability that may include communication to the extent required by applicable NEPOOL standards and shall meet the requirements contained in NEPOOL Operating Procedure No. 18, "Metering and Telemetering Criteria" and the Company's "Policy and Practices for Metering and Telemetering Requirements for New or Modified Interconnections." Customer is responsible for providing necessary telephone lines and for all communication required by ISO-NE, Customer maintains all communication and transducer equipment in accordance with ISO-NE criteria, rules and standards. Customer may elect to have Company purchase, own and maintain all communication equipment at the Customer's expense. Customer must provide, install and own Company-approved or -specified test switches. **Units over 60 kW:** Will be equipped with a bi-directional meter. Such meter will have remote access capability and may be an interval meter. **Units over 1 MW**: Shall be equipped with bi-directional, interval meters with remote access. In addition, Facilities which are 5 MW or greater are required by NEPOOL Operating Procedure No. 18 to provide communication equipment and to supply accurate and reliable information to system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status and all other information deemed necessary by ISO¬NE and the NEPOOL Satellite (REMVEC).
Minnesota	Standard describes the modifications which could be necessary to the Area EPS for different types of Generation Systems, but if unique interconnections require additional and/or different protective devices,	**< 40 kW All sales to Area EPS** Metering: Bi-Directional metering at PCC Remote Monitoring: Not required

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
	system modifications and/or additions, the utility will provide the final determination of the required modifications and/or additions and such special requirements will be identified by the utility during the application review process.	Remote Control: Not required **< 40 kW Sales to other than Area EPS** Separate meter generation and load Remote Monitoring: Customer supplied direct dial phone line. Remote Control: Not Required **40 - 250kW limited parallel operation** Metering: Detented Metering at PCC Remote Monitoring: Not required Remote Control: Not required **40 - 250kW extended parallel operation** Separate meter generation and load Remote Monitoring: Customer supplied phone line. Area EPS supplied monitoring equipment Remote Control: Not Required **250 - 1000 kW limited parallel operation** Metering: Detented Metering at PCC Remote Monitoring: Customer supplied phone line and monitoring points available. See "B (i)" below Remote Control: Not Required **250 - 1000 kW extended parallel operation** Separate meter generation and load Remote Monitoring: Required Area EPS remote monitoring system See B (i) Remote Control: Not Required **>1000 kW limited parallel operation** Metering: Detented Metering at PCC Remote Monitoring: Required Area EPS SCADA system. See B (i) Remote Control: Not required **>1000 kW extended parallel operation** Separate meter generation and load Remote Monitoring: Required Area EPS SCADA system See B (i) Remote Control: Direct Control via SCADA of interface breaker. "Detented" = Detented meter records power flow in only one direction. **> 40kW in size and selling power** separate metering of generation & load **QFs <= 40kW** net metering is allowed **B) i) Remote Monitoring or SCADA** - (1) Real and reactive power, (2) Phase voltage, (3) Status (open/close) of DG and breaker(s) or transfer switch, (4) Customer load (kW and kVAR), (5) Control of interconnection breaker - if required by the Area EPS operator. Customer must provide communications medium.

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
New York	Company designs, constructs and installs Dedicated Facilities. Customer pays incremental capital cost of Dedicated Facilities attributable to the Customer's Unit. All costs associated with the operation and maintenance of the Dedicated Facilities after the Unit first produces energy is responsibility of the Company.	Case-by-case review to determined need for additional metering or modifications to existing metering consistent with metering requirements adopted by the Commission. Net metering customer-generators may opt for single bi-directional meter or two separate meters for consumption and generation. For photovoltaic, net metering residential applicants, at least one meter in a two meter arrangement may be, at the customer's option, non-demand, non-time of use. Customer is responsible for the cost of installing meter box and socket. The single bi-directional meter option is not available to demand billed applicants. For non-demand billed applicants, a single bi-directional meter may be employed.
Oregon	Estimates of the additional costs must be based on the scope of work determined and documented as a result of the applicable feasibility, facilities and system impact studies conducted and the estimated hours needed to complete the evaluation using an engineering cost not to exceed $100 per hour (a factor that may be escalated annually, at the EDC's election, for inflation at the CPI index). (1) Minor T&D System Modifications: Modifications to the existing T&D Systems identified by the EDC under a Level 2 or Level 3 review; such as changing meters, fuses, or relay settings; are deemed Minor Modifications. It is at the EDC's sole discretion to decide what constitutes a Minor Modification. The Applicant must bare the costs of making such Minor Modifications as may be necessary to gain approval of an Application. (2) Interconnection Facilities: The EDC must identify under the review procedures of a Level 2 review or under a Level 4 Facilities Study, the Interconnection Facilities necessary to safely interconnect the Small Generator Facility with the EDC. The EDC must itemize the Interconnection Facilities for the Applicant including the cost of the facilities and the time required to build and install those facilities. The Interconnection Customer is responsible for the cost of the Interconnection Facilities. (3) Interconnection Equipment: The Interconnection Customer is responsible for all reasonable expenses, including overheads, associated with owning, operating, maintaining, repairing, and replacing its Interconnection Equipment. (4) System Upgrades: The EDC must design, procure, construct, install, and own any System Upgrades. The actual cost of the System Upgrades, including overheads, is directly assigned to the Applicant. An Interconnection Customer may be entitled to financial compensation from other EDC Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation is not governed by this rule. (5) Adverse System Impact: The EDC is responsible for identifying	Metering and Monitoring (l) Metering: The Interconnection Customer is responsible for the cost of the purchase, installation, operation, maintenance, testing, repair, and replacement of any special metering and data acquisition equipment deemed necessary by the terms of the (separate) Power Purchase Agreement except as provided in OAR 860-039-0005 through 860-039-0080 for a Net Metering Facility. The EDC must install, maintain and operate the metering equipment. Parties must be granted unrestricted access to such equipment as may be necessary for the purposes of conducting routine business. (2) Monitoring: Small Generator Facilities approved and interconnected to the EDC under a Level 1, Level 2 or Level 3 Interconnection Application, and under a Level 4 Interconnection Application, up to an Electric Nameplate Capacity rating of 3 MW, except as noted herein, are not required to provide for remote monitoring of the electric output by the EDC. Level 4 Interconnection Applications with Electric Nameplate Capacities greater than 3 MW or Level 3 Interconnection Applications where the aggregated generation on the circuit, including the Applicant's Small Generator Facility, would exceed 50 percent of the line section annual peak load may be required to provide remote monitoring at the EDC's discretion. For Small Generator Facilities required to provide remote monitoring pursuant to provisions this subsection, the data acquisition and transmission to a point where it can be used by the EDC's control system operations must meet the performance based standards described in section (3) of this rule. Any data acquisition and telemetry equipment required by this rule must be installed, operated and maintained at the Interconnection Customer's expense. (3) Telemetry is the remote communication from a Small Generator Facility to a point on the EDC's communication network where the data can be assimilated into the EDC's grid operations if desired. (a) Parties may mutually agree to waive or modify any of the telemetry requirements contained in section (3) of this rule. (b) The communication must take place via a Private Network Link using a Frame Relay or Fractional T-1 line or other such suitable device. Dedicated

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
	Adverse System Impacts on any Affected Systems and for determining what mitigation activities or upgrades may be required to accommodate a Small Generator Facility. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, must be directly assigned to the Applicant. The Applicant may be entitled to financial compensation from other EDCs, or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Applicant, only to the extent as may be provided for by the Commission. (6) Billings: The EDC may require a deposit of not more than 50 percent of the cost estimate, not to exceed $1000, to be paid in advance by the Applicant for studies or Interconnection Facilities necessary to complete an Application and to interconnect to the T&D System. Progress billing, final billing and payment schedules must be agreed to by Parties prior to commencing work.	Remote Terminal Units, from the Interconnected Small Generator Facility to an EDC's substation and Energy Management System are not required. (c) A single communication circuit from the Small Generator Facility to the EDC is sufficient. (d) Communications protocol must be DNP 3.0 or other standard used by the EDC. (e) The Small Generator Facility must be capable of sending telemetric monitoring data to the EDC at a minimum rate of every 2 seconds (from the output of the Small Generator Facility's telemetry equipment to the EDC's Energy Management System). (f) The minimum data points that a Small Generator Facility is required to provide telemetric monitoring to the EDC on are: (A) Net real power flowing out or into the Small Generator Facility (analog); (B) Net reactive power flowing out or into the Small Generator Facility (analog); (C) Bus bar voltage at the point of common coupling (analog); (D) Data Processing Gateway (DPG) Heartbeat (used to certify the telemetric signal quality); and (E) On-line or off-line status (digital). (g) If an Interconnection Customer operates the equipment associated with the high voltage switchyard interconnecting the Small Generator Facility to the T&D System, and is required by this rule to provide monitoring and telemetry, the Interconnection Customer must provide the following monitoring to the EDC in addition to provisions in subsection (e) above: (A) Switchyard Line and Transformer MW and MVAR values; (B) Switchyard Bus Voltage; and (C) Switching Devices Status
Texas	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. >2 MW 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.	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, 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. **> 2MW** A telemetry/transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

Jurisdiction	Interconnection Facilities & System Modifications	Metering, Monitoring, Telemetry and Control
Washington	Customer must pay for dedicated transformer and related facilities on a compensatory basis, including costs of transformers, production meters, and electrical company testing, qualification, and approval of non-UL 1741 listed equipment. The generator shall be responsible for any costs associated with any future upgrade or modification to its interconnected system required by modifications in the electrical company's electric system.	**Net metering**: Utility installs, owns and maintains a kilowatt-hour meter, or meters as the installation may determine. Customer provide space for metering, transformer enclosure (if required), meter socket(s) and junction box. Utility may approve other generating sources for net metering but is not required to do so. **Production metering**: Utility may require separate metering for production to record all generation produced and that may be billed separately from any net metering or customer usage metering. All costs associated with the installation of production metering will be paid by the customer.
Wisconsin	If the applicant agrees, in writing, to pay for any required distribution system construction and modifications, the public utility shall complete the distribution system upgrades The public utility may recover from the applicant an amount up to the actual cost, for labor and parts, of any distribution system upgrades required.	> 200 kW to <= 15 MW Utility may require that the facility owner provide telemetry equipment whose monitoring functions include transfer−trip functionality, voltage, current, real power (watts), reactive power (vars), and breaker status. Utility may require equipment, such as other protective devices, supervisory control and alarms, telemetry and associated communications channel. The public utility shall advise the applicant of any communications requirements after a preliminary review of the proposed installation.

Table 4 reveals the diversity in detail that different rules have utilized to address both system modification requirements and associated metering, telemetry and control requirements. In some cases, IREC for example, metering is left largely unaddressed, while in other, Minnesota and New York for examples, there are extensive provisions addressing the types of metering required, responsibilities for installation, ownership, maintenance and repair.

Likewise, while most of these rules require the customer to pay the cost of system upgrades, some rules address this requirement with a simple statement to that effect, while others provide a more elaborate description of the manner in which costs are calculated, allocated and recovered. One state, California, includes explicit requirements providing for the financing of utility owned investments that must be paid by the customer, allowing the cost recovery to occur over time.

Facilities and metering requirements also vary by size of the installation, the nature of the operations (extended parallel operation or not) and purpose of the installation (sales to the utility or to others, etc.).

Ideally, the disparity among these rules would be reconciled into a more common scheme; however, this may be problematic because, especially in the case of the metering requirements, the need for different metering schemes is closely tied to other tariff and service obligations in each of the jurisdictions.

Application Process

The process required to allow generation to be interconnected to the system can be as important to the successful deployment of DG as the technical requirements. The process includes several components:

- A written application
- Application Fees
- Determination of the need for studies and determination of the cost of those studies; and,
- Determination of the need for system modifications or upgrades and determination of the costs for those modifications or upgrades.

A clear, understandable and simple process for interconnection should be one of the objectives of an interconnection rule. A common approach among the jurisdictions is for the application process to define some number of system types and configurations, primarily smaller systems, that can be processed on a simplified, or “fast track” basis.[14] While there is usually a strong correlation between system size and the simplicity of the process, the jurisdictions exhibit little consistency in adopting the size points used to qualify systems for fast track approval. Table 5 summarizes the different processes used by the various jurisdictions:

[14] Here, unless the context requires specificity, collectively referred to as “fast track.”

Table 5: Types of Review Processes and Fast Track Approvals

Jurisdiction	Processes/Types of Review
California	California has an “Initial Review” and a “Supplemental Review.” If the project fails the screens for these reviews, then the process moves to an “Interconnection Study.”
FERC	FERC has a “Fast Track Process” for systems nor larger than 2 MW and “10 kW Inverter Process” for small inverter-based systems. The “Fast Track Process” includes an “Initial Review” and a “Supplemental Review” process. Projects not meeting screens of the Fast Track Process or of the 10 kW Inverter Process” move into the “Study Process” which includes provisions for a “System Impact Study” and a “Facilities Study”
Illinois	Illinois has an “Initial Review” which applies “Primary Screening Criteria” and then, if necessary, “Secondary Screening Criteria.” Facilities that fail these screening steps, then move to a “Scoping Meeting” to determine whether a “Feasibility/Impact Study” should be performed. The Feasibility Study may lead to a Transmission Impact Study (if transmission and distribution not owned by same owner, then process may invoke the FERC interconnection notification protocols and the transmission study will proceed under the FERC tariff). The Feasibility Study may also lead to a Facilities Study.
IREC	IREC procedures are organized into four “levels.” Level 1 is for certified, inverter-based systems <=10 kW on a radial system (or on a spot network under certain conditions). Level 2 is for certified generating facilities <=2 MW that pass certain specified screens Level 3 is for certified generating facilities <=10MW that pass certain screens , do not export power beyond the PCC Level 4 is for all facilities <=10 MW that do not qualify for Levels 1, 2 or 3. IREC assumes all units larger than 10 MW will be FERC jurisdictional. Level 4 includes a Scoping Meeting/Discussion and may include a Feasibility Study, an Impact Study and a Facilities Study.
MADRI	MADRI procedures are organized into four “levels.” Level 1 is for certified, inverter-based systems <= 10 kVA. Level 2 is for certified, inverter-based systems that are <= 2 MVA or systems that did not pass a Level 1 review. Level 3 is for systems <= 10 MVA which do not qualify for or did not pass the Level 1 or Level 2 reviews Level 3A is for systems that do not qualify for Level 1 or Level 2 review and do not export power to the system.
Maryland	Maryland procedures are organized into four “levels.” Level 1 is for certified, inverter-based systems <= 10 kVA. Level 2 is for certified, inverter-based systems that are <= 2 MVA or systems that did not pass a Level 1 review. Level 3 is for systems <= 10 MVA which do not qualify for or did not pass the Level 1 or Level 2 reviews Level 4 is for systems that do not qualify for Level 1 or Level 2 review and do not export power to the system.
Massachusetts	Massachusetts has three processes: Simplified Process: For Facilities that are 10 kW or less, qualified, and inverter-based. Expedited Process: For certified Facilities, using a set of technical screens to determine grid impact. Standard Process: for Facilities that do not qualify for Simplified or Expedited treatment.
Minnesota	Minnesota uses a single screening process to determine if some units can by-pass the study process. Units <= 40 kW are exempted from some requirements of interconnection rule.
New York	New York provides a simplified process for systems <= 15 kW and provides for Type Pre-certification. New York maintains its own list of certified systems.

Jurisdiction	Processes/Types of Review
Oregon	Oregon procedures are organized into four “levels.” Level 1 is for certified, inverter-based systems <= 10 kVA. Level 2 is for certified, inverter-based systems that are <= 2 MVA or systems that did not pass a Level 1 review. Level 3 is for systems <= 10 MVA which do not qualify for or did not pass the Level 1 or Level 2 reviews Level 4 is for systems that do not qualify for Level 1 or Level 2 review and do not export power to the system.
Texas	Texas has an equipment pre-certification procedure, but no “small system” fast track approval. Pre-certification exempts units from further review of the system design. “Pre-interconnection” studies may be conducted by the utility, apparently at the utility’s discretion. No study fees may be charged for systems <= 500 kW on a non-network connection.
Washington	Washington has no fast track process per se. Washington’s rule only applies to systems <= 25 kW. Rule prescribes specific technical standards to be met. Rule is silent regarding studies.
Wisconsin	Utility determines whether an engineering review is required. Rules provide for “certified paralleling equipment.” Certified equipment is exempt from system design review, but not engineering studies.

Fee structures, timelines for “standard” processes and fast track processes and type certification and testing are all closely related. Table 6 summarizes the requirements for these items:

Table 6: Fees, Timelines and Type Certification & Testing

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
California	Initial review: Net Metered systems: No fee All others: $800 (one-half refunded if application rejected). Supplemental Review: Net Metered Systems: No Fee All others: $600	Initial contact (sending info to applicant): 3 days[15] Review Application for completeness (acknowledge receipt of application & identify deficiencies): 10 days Initial Review (application of Simplified Interconnection screen & if eligible provision of Interconnection Agreement, else Notice to Applicant and commencement of Supplemental Review): 10 days Completion of Supplemental Review: 20 days	Same as Standard up to completion of screening step. Initial contact (sending info to applicant): 3 days Review Application for completeness (acknowledge receipt of application & identify deficiencies): 10 days Initial Review (application of Simplified Interconnection screen & provision of Interconnection Agreement): 10 days	California provides for Type Testing, Production Testing, Commissioning Testing and Periodic Testing. Procedures rely heavily on Underwriters Laboratory (UL), Institute of Electrical and Electronic Engineers (IEEE), and International Electrotechnical Commission (IEC) documents—most notably UL 1741 and IEEE 929, as well as the testing described in May 1999 New York State Public Services Commission Standardized Interconnection Requirements. Rule is meant to be consistent with ANSI/IEEE 1547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems. Tests are intended to provide assurance that the Generating Facility’s equipment will not

[15] All references to “days” are to business days, unless otherwise noted.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
				adversely affect Distribution System and will cease providing power to Distribution System under abnormal conditions. Tests developed assuming a low level of DG penetration or number of connections to Distribution System. At high levels of DG penetration, additional requirements and corresponding test procedures may needed. Rule includes criteria for certifying Generators or inverters which are then considered suitable for Interconnection will be required to repeat the design review or require retesting Certification is not a prerequisite to interconnect **Certified Equipment** Equipment Type Tested and Production Tested and approved (e.g., “Listed”) by NRTL is considered to be Certified Equipment Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. Type Testing may be done in the manufactures’ factory or test laboratory, or in the field. At the discretion of the testing laboratory, field-certification

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
				may apply only to the particular installation tested. In such cases, some or all of the tests may need to be repeated at other installations. When equipment is Certified by a NRTL, the NRTL shall provide to the manufacturer, at a minimum, a Certificate with the specifically detailed information. **Type Testing** Testing provides basis for determining equipment meets specifications for being designated as Certified Equipment. The requirements described in this Section cover only issues related to Interconnection and not equipment safety or other issues. Rule defines the test criteria by Generator or inverter technology. While UL 1741 is specifically for inverters, requirements are readily adaptable to synchronous and induction generators, as well as single/multi-function controllers and protection relays. Until a universal test standard is developed, utility or NRTL must adapt the procedures in rule for a Generating Facility and/or Interconnection Facilities or associated equipment

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
				performance and its control and Protective Functions. Rule details specific test that must be conducted.
FERC	Application Fees: For Fast Track applications: Non-refundable fee of $500. For all others: Deposit not to exceed $1,000 towards cost of feasibility study. Supplemental Review: Actual costs incurred by Transmission Provider – Deposit required Feasibility Study: Actual costs. Deposit of lesser of 50% of cost estimate or $1,000 may be required. System Impact Study: Actual costs. Deposit of "good faith estimated costs" may be required. Facilities Study: Actual costs. Deposit of "good faith estimated costs" may be required.	Request for Pre-application Determination of applicability of FERC rules: 15 days Acknowledgement of receipt of Interconnection Request: 3 days Notification of completeness of request/identification of required additional information: 10 days Customer supplies required information or seeks extension: 10 days	Initial Review (application of Fast Track screens & notice of results): 15 days If passes screens (or fails but can be safely, reliably, etc. connected), provision of executable interconnection agreement: 5 days Customer Options Meeting (if fails screen): 10 days Customer agrees to supplemental review: 15 days Customer pays/Utility refunds review costs in excess of deposit/deposit in excess of costs: 20 days Supplemental review completed: 5 days after receipt of deposit If customer facility changes required, utility provides interconnection agreement after customer agrees to pay for changes: 5 days If system modifications required, utility provides interconnection agreement after customer agrees to pay for modifications: 10 days If fails Supplemental Review, process continues with Standard Process "Study Process"	Small Generating Facility equipment considered certified for interconnected operation if (1) tested in accordance with industry standards for continuous utility interactive operation in compliance with appropriate codes and standards referenced below by OSHA recognized Nationally Recognized Testing Laboratory (NRTL) , (2) it has been labeled and is publicly listed by NRTL at the time of the interconnection application, and (3) NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL. Certified equipment requires no further type-test review, testing, or additional equipment to meet

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
				the requirements of this interconnection procedure If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then Customer must show that generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment. Provided the generator or electric source, when combined with equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required An equipment package does not include equipment provided by the utility. Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of generator is considered certified.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
Illinois	Utility to file tariff for initial review fee (with supporting cost information). Study fees are actual costs. 50% deposit of estimated costs may be required.	Notification of receipt of Application: 3 days Notification of whether application is complete, including details of required information: 10 days Initial Review of application (application of Primary and Secondary Screens, along with copies of analysis and data): 15 days If passes screens (or fails one or both screens but can be safely, reliably, etc. interconnected) utility tenders executable interconnection agreement within 5 day of determination. If fails Primary Screen, passes Secondary Screen but cannot safely, reliably, etc. connect, utility identifies small resource modifications or system modifications necessary for interconnection: 10 days Customer pays for system or facility modifications: 30 days Utility tenders executable interconnection agreement after customer agrees to modifications: 10 days If fails both screens and not determined to safe, reliable, etc., scoping meeting held at request of either party: 10	Same as standard process up through screening process: Notification of receipt of Application: 3 days Notification of whether application is complete, including details of required information: 10 days Initial Review of application (application of Primary and Secondary Screens, along with copies of analysis and data): 15 days Is passes screens (or fails one or both screens but can be safely, reliably, etc. interconnected) utility tenders executable interconnection agreement within 5 day of determination. If fails Primary Screen, passes Secondary Screen but cannot safely, reliable, etc. connect, utility identifies small resource modifications or system modifications necessary for interconnection: 10 days Customer pays for system or facility modifications: 30 days Utility tenders executable interconnection agreement after customer agrees to modifications: 10 days	None.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
		days Utility provides executable facility/impact study agreement (with outline of scope & costs): 5 days Customer returns executed feasibility/impact study agreement: 15 days Customer pays required deposit for studies: 15 days Customer pays balance / utility refunds excess after invoice for study costs: 20 days Feasibility/Impact Study: Deposit for 50% of costs: 15 days after receipt of study agreement. Balance of costs/Refund of overpayment: 20 days after invoice Study Report: 45 days from date of study agreement For distribution connections with transmission impacts: utility notifies transmission provider and provide customer with transmission study agreement: 5 days Customer returns executed transmission study agreement and deposit: 30 days Customer pays balance of costs/receives refund of excess for transmission study: 20 days Utility coordinates		

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
		transmission study and "attempts" to deliver results to customer: 45 days after receipt of agreement and deposit Customer notifies utility of intent to proceed: 30 days after receipt of transmission study results Facilities Study: Customer returns executed facilities study agreement and deposit for 50% of costs: 30 days after receipt of feasibility/impact study report. Facilities study completed: 45 days after receipt of facilities study agreement If utility can't meet deadline notification to customer within 3 day of deadline and notice to Commission w/in 7 days after notice to customer.		
IREC	Level 1: $50 Level 2: $50 plus $1/kW Level 3: $100 plus $1.50/kW Level 4: $100 plus $2/kW, plus charges for actual time spend on interconnection study. System Modification Study (for systems that fail Level 2 screening): Actual costs. Level 4 studies: Feasibility Study, Impact Study, Facilities Study: Actual Costs	Level 4: Utility acknowledges receipt of application and identifies additional information requirements: 3 days Customer cures application deficiencies and gets in queue: 10 days Initial Review (including scoping meeting): 10 days after application complete At customer request, utility provides cost estimate for Feasibility Study: 5 days Time for Feasibility Study: No	Level 1: Utility acknowledges receipt of application and identifies additional information requirements: 3 days Customers cure application deficiencies: 10 days Utility completes processing of application: 10 days after application is complete Utility sends partially executed interconnection agreement: 3 days Customer returns executed agreement: 5 days prior to	In order to qualify as "certified" for any interconnection procedures, generators shall comply with IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems, or IEEE 929 for inverters less than 10 kW And UL 1741 Inverters, Converters and Controllers for Use in Independent Power Systems, as applicable Interconnection Equipment is considered certified if it has

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
		pre-determined limit Utility provides Impact Study Agreement for execution: 10 days after Feasibility Study No time limit for engineering review of non-certified equipment for IEEE 1547 compliance Utility sends Interconnection Agreement: 5 days after completion of Impact and/or Facilities Study. Customer executes and returns Interconnection Agreement: 30 days after receipt of agreement from utility	commencement of operations Customer provides 5 day notice for any required utility inspections. If not notice to customer, application deemed approved: 20 days after acknowledgement of receipt of application by utility. Level 2: Utility acknowledges receipt of application and identifies additional information requirements: 3 days Customer cures application deficiencies: 10 days Utility completes processing of application: 15 days after application is complete If passes screens utility provides partially executed interconnection agreement: 3 days Customer returns executed agreement 3 days of receipt or 10 days prior commencement of operations. Customer provides 5 day notice for any required inspections. Customer may not delay return of interconnection beyond 90 days beyond date shown for initial operations in application. Level 3: Utility acknowledges receipt of application and identifies additional information requirements: 3 days Customers cures applications	been tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous interactive operation with a utility grid and meets definition for Certification in FERC Order 2006.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
			deficiencies: 10 days Utility completes processing of application: 17 days after application is complete If passes screens, utility provides partially executed interconnection agreement w/in 3 days. Customer returns executed agreement 3 days of receipt or 10 days prior commencement of operations. Customer provides 5 day notice for any required inspections. Customer may not delay return of interconnection beyond 90 days beyond date shown for initial operations in application.	

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
MADRI	Does not include specific fees. Recommends a nominal (small) fee for Level 1 systems and cost-based fees for Levels 2, 3 & 4. All study fees are intended to be cost-based.	Level 3: Utility acknowledges receipt and identifies missing information in application: 10 days Customer provides information necessary to complete application: 10 days Scoping Meeting: 10 days after customer notified application is complete If at Scoping Meeting, parties agree Feasibility Study required, utility provides Feasibility Study Agreement: 5 days If no Feasibility Study required, utility provides executable Interconnection Impact Study Agreement w/ study cost estimate: 5 days If no Feasibility or System Impact Study required: utility provides executable Interconnection Facilities Study agreement: 5 days If Feasibility Study show distribution system impact, utility provide executable Interconnection System Impact Study Agreement: 5 days. Utility provides Interconnection System Impact Study report and executable Interconnection Facilities Study Agreement: 5	Level 1: Utility acknowledges receipt and identifies missing information in application: 10 days Utility applies screens for Level and notifies customer: 15 days Notice to utility for witness test: 10 days, unless utility fails to conduct test, in which case test is deemed waived. Level 2: Utility acknowledges receipt and identifies missing information in application: 10 days Utility applies screens for Level and notifies customer: 20 days Utility conduct witness test: 10 days after receipt of Certificate of Completion Utility provide executable agreement: 5 days after determination project passes screens or can be interconnected safely and reliably. Customer executes agreement: 30 days (or mutually agreed deadline) after receipt of executable agreement. If not returned w/in 30 days or agreed time, deemed withdrawn. Level 3A: If < 10 kVA, certified, has reverse power relays (no flow onto system), aggregate generation <5% of Area Network's maximum load or 50 kVA and no system	Same as FERC

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
		days after study completed Upon completion of Interconnection Facilities Study Agreement and agreement by customer to pay costs of Interconnection Facilities and Distribution Upgrades, utility provides Standard Small Generator Interconnection Agreement: 5 days. Utility Witness Test: Within 10 days after receipt by utility of Certificate of Completion; deemed waived if not conducted within 10 days Customer executes Interconnection Agreement: 30 days after receipt (unless later date mutually agreed)	modifications required, then application completeness review and Interconnection Request review, same as Level 1, except utility has 20 days to conduct Area Network Impact Study. If potential Adverse System Impacts, at utility discretion system inappropriate for interconnection and deny request, but customer may submit under Level 3 review without losing position in queue. If >10 kVA and <= 50 kVA and certified inverter system and utilizes reverse power relays (no flow onto system), aggregate generation < 5% of Area Network's maximum load or < 50 kVA, review is same as Level 2, except utility has 25 days for Area Network Impact Study. Utility conducts witness test: within 10 days of receipt of Certificate of Completion, else deemed waived. Utility provides executable Interconnection Agreement: No time limit stated Customer returns executed Interconnection Agreement: 30 days	

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
Maryland	To be commission approved in separate tariff/process	Level 4 Interconnection : Utility acknowledges receipt and identifies missing information in application: 10 days Customer provides information necessary to complete application: 10 days Scoping Meeting: 10 days after customer notified application is complete If at Scoping Meeting, parties agree Feasibility Study required, utility provides Feasibility Study Agreement: 5 days If no Feasibility Study required, utility provides executable Interconnection Impact Study Agreement w/ study cost estimate: 5 days If no Feasibility or System Impact Study required: utility provides executable Interconnection Facilities Study agreement: 5 days If Feasibility Study shows distribution system impact, utility provide executable Interconnection System Impact Study Agreement: 5 days. Utility provides Interconnection System Impact Study report and executable Interconnection Facilities Study Agreement: 5	Level 1: Utility acknowledges receipt and identifies missing information in application: 10 days Utility applies screens for Level and notifies customer: 15 days Utility conduct witness test:20 day notice to utility of commissioning test, then EDC has 10 days to conduct witness date, else waived Level 2: Utility acknowledges receipt and identifies missing information in application: 10 days Utility applies screens for Level and notifies customer: 20 days Utility conduct witness test:20 day notice to utility of commissioning test, then EDC has 10 days to conduct witness date, else waived Utility provide executable agreement: 5 days after determination project passes screens or can be interconnected safely and reliably. Customer executes agreement: 30 days (or mutually agreed deadline) after receipt of executable agreement. If not returned w/in 30 days or agreed time, deemed withdrawn. Level 3: If < 10 kVA, certified, has reverse power relays (no flow onto system), aggregate	Basically same as FERC, but adds a field certification category for units that once passed a Level 4 review.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
		days after study completed Upon completion of Interconnection Facilities Study Agreement and agreement by customer to pay costs of Interconnection Facilities and Distribution Upgrades, utility provides Standard Small Generator Interconnection Agreement: 5 days. Utility Witness Test: Applicant provides 20 days notice of commissioning test. EDC provides 10 days notice if it elects to perform witness test; deemed waived if not conducted within 10 days Customer executes Interconnection Agreement: 30 days after receipt (unless later date mutually agreed)	generation <5% of Area Network's maximum load or 50 kVA and no system modifications required, then application completeness review and Interconnection Request review, same as Level 1, except utility has 20 days to conduct Area Network Impact Study. If potential Adverse System Impacts, at utility discretion system inappropriate for interconnection and deny request, but customer may submit under Level 3 review without losing position in queue. If >10 kVA and <= 50 kVA and certified inverter system and utilizes reverse power relays (no flow onto system), aggregate generation < 5% of Area Network's maximum load or < 50 kVA, review is same as Level 2, except utility has 25 days for Area Network Impact Study. Utility conduct witness test:20 day notice to utility of commissioning test, then EDC has 10 days to conduct witness date, else waived Utility provides executable Interconnection Agreement: No time limit stated Customer returns executed Interconnection Agreement: 30 days	

<table>
<tr><th>Jurisdiction</th><th>Fee Structure</th><th>Application Process
Standard Process & Timing</th><th>Application Fast Track
Process & Timing</th><th>Type Certification
And Testing</th></tr>
<tr><td rowspan="2">Massachusetts</td><td rowspan="2">Simplified Process on radial system: No fee (unless System Modification required)
Expedited Process: $3/kW (minimum of $300 and maximum of $2500), plus $125/hr up to 10 hours ($1,250) for Supplemental Review plus actual costs for system modifications.
All study fees are based on costs.</td><td colspan="2">Utility clock always stops when waiting for customer to act. If customer fails to act for longer of one-half the time allotted for utility to act or 15 days, utility may terminate process and customer must reapply, unless extended by mutual agreement. Company must retain completed work for one year in case of re-application.</td><td rowspan="2">Recognizes certification by California or New York.
Qualifies for Expedited Process if shown to meet requirements of UL 1741 or IEEE Standard 1547-2003
Considered certified if previous determined by utility to be in compliance with applicable UL/IEEE standards</td></tr>
<tr><td>Standard Process:
Utility acknowledges receipt of application: 3 days
Utility completes review for completeness and notifies customer: 10 days
Maximum time for Standard Process: 125 if customer goes directly to Standard Process or 150 days if customer goes from Expedited Process to Standard Process.</td><td>Simplified Process:
Utility acknowledges receipt of application: 3 days
Utility completes review for completeness and notifies customer: 10 days
Utility must complete witness test within 10 days of receipt of Certificate of Completion (no timelines set for intervening steps).
After witness test, company notifies customer that interconnection is authorized
Provide information describing clearly what is required for approval: No deadline stated
Maximum time for Simplified Process: 15 days or, if on spot network, 40 days if load data available or 100 days if it is not.
Expedited Process:
Utility acknowledges application receipt: 3 days
Utility completes review for completeness and notifies customer: 10 days
Maximum time for Expedited Process 40 days if not Supplemental Review or 60 days with Supplemental Review</td></tr>
</table>

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
Minnesota	**Application Fees** **Open Transfer:** All sizes: $0 **Quick Closed:** <=20 kW $0 >20 kW to <= 500 kW: $100 >500kW to <= 1 MW: $250 > 1 MW: $500 **Soft Loading:** <= 20 kW: $100 >20 kW to <=250kW: $250 >250 kW to <=1 MW: $500 > 1 MW: $1000 **Extended Parallel (Pre-certified):** <= 20 kW: $0 >20 kW to <=250kW: $250 >250 kW to <=1 MW: $1000 > 1 MW: $1500 **Other Extended Parallel:** <= 20 kW: $100 >20 kW to <=250kW: $500 >250 kW: $1500 **Maximum Study Fees** <= 20 kW: $100 >20 kW to <=250kW: $250 >250 kW to <=1 MW: $500 > 1 MW: $1000 < 20 kW: $0 20kW to 100 kW: $500 100 kW to 250 kW: $1000 > 250 kW: Actual Costs	In Step 2 (Preliminary Review): Utility completes Preliminary Review: within 15 days of receipt of application. Utility notifies customer if additional information needed to complete application and no further review occurs until missing information is submitted. Either party may request Scoping Meeting within 15 day period allowed for Step 2. Utility then has 5 days after scoping meeting to complete formal response required in Step 2. Engineering Studies: <20kW: 20 days 20kW-250kW: 30 days 250kW-1MW: 40 days >1MW: 90 days Step 7-Final Design Review: After provision of information required in “Go-No Go” step, utility has 15 days to provide estimated time table for final review. Final design review may not take longer than 15 days (excepting days when waiting for customer to provide information. Total day limit for Step 7 is 30 days. After completion of “acceptance tests” utility has 3 days to provide written approval for normal operation.		Equipment considered certified for interconnected operation if tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. Equipment presently listed as having met type-testing requirements of UL 1741 and IEEE 929 must be accepted for interconnection without additional protection system requirements. Equipment includes all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package which includes a generator or other electric source, it shall not require further design review, testing or additional equipment. If the equipment includes only interface components (switchgear, inverters, or other interface devices), then the Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
				package and consistent with listing specified for the package. Provided the generator and equipment package are consistent with listing, no further design review, testing or additional equipment may be required to meet the certification requirements A certified equipment package does not include equipment provided by utility. The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Area EPS. An application will still need to be submitted and an interconnection review may still need to be performed, to determine the compatibility of the Generation System with the Area EPS.
New York	<= 15 kW: No fee >=15 kW: Non-refundable $350 fee (one-half refunded for net meting customers, unless applied toward dedicated transformer) Fee is applied toward utility's cost of interconnection. Other costs: <= 15 kW utility cannot charge for cost estimate	Initial Inquiry (utility provides application form, information, etc.): 3 days Application review for completeness: 5 days Preliminary review of application: 5 days For Aggregate systems >300 kW <= 2MW, result of preliminary review provided: 15 days		The New York PSC maintains its own list of certified equipment. Testing and standards are similar, if not identical to UL 1741 and applicable IEEE standards.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
	(CESIR) If not to be net-metered, customer pays costs associated of modifications to the utility system, administration, metering, and on-site verification testing; If net-metered and either a Farm Wind or Residential Wind >10 kW, customer pays (i) one-half of costs of modifications to the utility system, administration, metering, and on-site verification testing, and (ii) cost of any dedicated transformer(s) up to the maximum (see below); If net-metered (but not Farm Wind or Residential Wind >10kW covered above) customer not responsibility for costs (i) above, and customer responsible for actual cost of dedicated transformer(s) up to the maximum (see below); If net-metered, if utility determines dedicated transformer(s) necessary to protect the safety and adequacy of electric service provided to other customers, customer pays costs of dedicated transformer(s). Maximum costs are: Residential Solar <=10kW: $350	Completion of Coordinated Electric System Interconnection Review (CESIR): 20 day for systems <=300 kW and 60 days for systems > 300kW		

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
	Residential or Farm Wind <=25kW: $750 Farm Wind >25kW to <=126kW: $1,000 Farm Waste <=400kW: $3,000			
Oregon	Level 1: $100 Level 2: $500 Level 3: $1000 Level 4: $1000	Level 4 Interconnection : Utility acknowledges receipt and identifies missing information in application: 10 days Customer provides information necessary to complete application: 10 days Scoping Meeting: 10 days after customer notified application is complete If at Scoping Meeting, parties agree Feasibility Study required, utility provides Feasibility Study Agreement: 15 days If no Feasibility Study required, utility provides executable Interconnection Impact Study Agreement w/ study cost estimate: 5 days If no Feasibility or System Impact Study required: utility provides executable Interconnection Facilities Study agreement: 5 days If Feasibility Study shows distribution system impact, utility provides executable Interconnection System Impact Study Agreement: 5	Level 1: Utility acknowledges receipt and identifies missing information in application: 10 days Utility applies screens for Level and notifies customer: 15 days Notice to utility for witness test: 10 days, unless utility fails to conduct test, in which case test is deemed waived. Level 2: Utility acknowledges receipt and identifies missing information in application: 10 days Utility applies screens for Level and notifies customer: 20 days Notice to utility for witness test: 10 days, unless utility fails to conduct test, in which case test is deemed waived. Customer executes agreement: 30 days (or mutually agreed deadline) after receipt of executable agreement. If not returned w/in 30 days or agreed time, deemed withdrawn. Level 3: If < 10 kVA, certified, has reverse power relays (no flow onto system), aggregate generation <5% of Area	Basically same as FERC, but adds a field certification category for units that once passed a Level 4 review.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
		days. Utility provides Interconnection System Impact Study report and executable Interconnection Facilities Study Agreement: 5 days after study completed Upon completion of Interconnection Facilities Study Agreement and agreement by customer to pay costs of Interconnection Facilities and Distribution Upgrades, utility provides Standard Small Generator Interconnection Agreement: 5 days. Utility Witness Test: Within 10 days after receipt by utility of Certificate of Completion; deemed waived if not conducted within 10 days Customer executes Interconnection Agreement: 30 days after receipt (unless later date mutually agreed)	Network's maximum load or 50 kVA and no system modifications required, then application completeness review and Interconnection Request review, same as Level 2, except utility has 25 days to conduct, at its own expense, Interconnection Feasibility Study. If potential Adverse System Impacts, at utility discretion system inappropriate for interconnection and deny request, but customer may submit under Level 3 review without losing position in queue. If >10 kVA and <= 50 kVA and certified inverter system and utilizes reverse power relays (no flow onto system), aggregate generation < 5% of Area Network's maximum load or < 50 kVA, review is same as Level 2, except utility has 25 days for Area Network Impact Study. Notice to utility for witness test: 10 days, unless utility fails to conduct test, in which case test is deemed waived. Utility provides executable Interconnection Agreement: No time limit stated Customer returns executed Interconnection Agreement: 30 days	

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
Texas	Radial Connection: Pre-interconnection study: Pre-certified equipment <=500 kW w/ no export >15% of feeder load and <=25% short circuit: No fee Otherwise: customer pays cost of pre-interconnection study Network connection: For inverter systems <20kW: No fee Otherwise customer pays cost of pre-interconnection study	Processing of application: For non-certified equipment, within six weeks of utility's receipt of completed application. No timeline for utility construction of system upgrades, but utility has "best reasonable efforts" standard of conduct. Interconnection to be completed within two weeks following completion of upgrades.	Processing of application: For pre-certified equipment: within four weeks of utility's receipt of completed application No timeline for utility construction of system upgrades, but utility has "best reasonable efforts" standard of conduct. Interconnection to be completed within two week following completion of upgrades.	Pre-certified equipment is defined as specific generating and protective equipment system or systems that have been certified as meeting the applicable parts of rule relating to safety and reliability by an entity approved by the commission. Entities performing pre-certification. The commission may approve one or more entities that may pre-certify equipment 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. 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.
Washington	Utility may charge application of no more than $100 Customer pays other costs on a "compensatory" basis	The electrical company will process the application and provide interconnection in a time frame consistent with the average of other service connections.		None.

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
Wisconsin	<=20kw: Application fee: None Engineering review fee: None Distribution System Study fee: None >20kw and <=200kW: Application fee: $250 Engineering review fee: Max. $500 Distribution System Study fee: Max. $500 >200kw and <= 1 MW: Application fee: $500 Engineering review fee: Cost-based Distribution System Study fee: Cost-based >1MW and <=15<MW: Application fee: $1000 Engineering review fee: Cost-based Distribution System Study fee: Cost-based	Utility provides information including application after initial contact: 5 days Notification of completeness of application: 10 days Application review within 10 days of determination application is complete		"Certified equipment" means a generating, control or protective system that has been certified by a nationally recognized testing laboratory as meeting acceptable safety and reliability standards. Certified paralleling equipment must conform to UL 1741 (January 17, 2001 Revision) or an equivalent standard as determined by the commission. DG paralleling equipment that a nationally recognized testing laboratory certifies as meeting the applicable type testing requirements of UL 1741 (January 17, 2001 revision) is acceptable for interconnection, without additional protection systems, to the distribution system. The applicant may use certified paralleling equipment for interconnection to a distribution system without further review or testing of the equipment design by the public utility, but the use
		If needed Engineering Study completed: Category 4: 40 days Distribution System Study completed and results provided to customer: Category 4: 60 days, unless mutually agreed otherwise Time for witness test following notice of completion: Category 4: 20 days Utility notifies customer of result of witness test: Category 4: 10 days	If needed Engineering Study completed: Category 1: 10 days Category 2: 15 days Category 3: 20 days Distribution System Study completed and results provided to customer: Category 1: 10 days Category 2: 15 days Category 3: 20 days Time for witness test following notice of completion: Category 1: 10 days Category 2: 10 days Category 3: 20 days Utility notifies customer of result of witness test: Category 1: 5 days Category 2: 10 days Category 3: 10 days	

Jurisdiction	Fee Structure	Application Process Standard Process & Timing	Application Fast Track Process & Timing	Type Certification And Testing
				of this paralleling equipment does not automatically qualify the applicant to be interconnected to the distribution system at any point in the distribution system. The public utility may still require an engineering review to determine the compatibility of the distributed generation system with the distribution system capabilities at the selected point of common coupling.

After an application has passed the initial screening and study processes and has been technically specified and its design meets the requirements of the rules, it must be constructed and then pass commissioning and testing steps and then commence initial parallel operation. These steps are collectively the “interconnection process” and are reviewed in Table 7.

Table 7: Commissioning, Testing and Initial Parallel Operation

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
California	Customer responsible for testing Generating and Interconnection Facilities for compliance with the safety and reliability provisions of Rule prior to parallel operation. For non-Certified Equipment, customer must submit testing plan to utility for review and acceptance. Alternatively, the parties may agree to have utility conduct testing at the customer’s expense. Test plan must include the installation test procedures published by the manufacturer of the equipment. Facility testing shall be conducted at a mutually agreeable time, and non-testing party may witness tests.	Utility must authorize the Parallel Operation or Momentary Parallel Operation, in writing, within 5 calendar days of satisfactory compliance with the terms of all applicable agreements. Compliance may include, but not be limited to, provision of any required documentation and completion of required inspections or tests. Customer may not commence Parallel Operation of its Generating Facility with EC’s system without utility’s express written permission to do so. For net metered installations, utility authorization for Parallel Operation should normally be provided no later than 30 business days following utility’s receipt of 1) a completed Net Energy Metering Application including required payments; 2) a completed signed Net Energy Metering Interconnection Agreement; and 3) evidence of the customer’s final inspection clearance from the governmental authority having jurisdiction over the Generating Facility. If 30-day period cannot be met, utility must notify the Applicant and the Commission.
FERC	Commissioning tests of the Customer's installed equipment must be performed pursuant to applicable codes and standards. Utility must be given at least five Business Days written notice of tests, or as otherwise mutually agreed to by Parties, and may be present to witness the commissioning tests. Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection or follow-up production testing by NRTL.	For Certified, inverter-based systems <10 kW: Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary. Utility then notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the utility has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. Utility is obligated to complete witness test within ten Business Days of the receipt of the Certificate of Completion, else witness test is deemed waived.

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
Illinois	After execution of an interconnection agreement, customer must provide estimate of date on which installation is to be completed, which may not be later than the later of 18 months following the date of interconnection agreement or 18 months following the date that system or facility modifications were completed by the utility. Installation must be completed as specified in application and any studies indicating a need to modify the equipment. Customer must inform utility in writing when the installation is complete. If the customer fails to install and inform utility of installation within the applicable 18 months window, customer must reapply for interconnection unless an extension of the deadline is mutually agreed. Commissioning tests must be performed pursuant to applicable codes and standards. Utility must be given 10 business days written notice, or as otherwise mutually agreed to by the parties, of the tests and must be present to complete the interconnection, inspect the equipment for compliance with applicable codes and standards, and witness the commissioning tests. If equipment fails inspection or tests utility must provide written explanation why the generation equipment was not in compliance. Once failure is cured, customer must provide 10 business days' notice, for another inspection.	No reference to initial parallel operation procedures.
IREC	The Customer may operate Generating Facility and interconnect with the Company's electric system once all of the following have occurred: 1 After construction, facility is inspected or otherwise approved by the appropriate local electrical wiring inspector with jurisdiction, and 2 Customer returns the Certificate of Completion to the Company, and 3 Utility has either: a) Witnessed the satisfactory Commissioning. All witnessing and inspections must be conducted by the Company, at its own expense, and returned the Certificate of Completion if used.; or b) If the Company does not schedule an inspection of the Small Generating Facility, the witness test is deemed waived (unless the Parties agree otherwise); or c) Utility waives the right to inspect the Small Generating Facility. Utility has the right to disconnect the Small Generating Facility in the event of improper installation.	No reference to initial parallel operation procedures.

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
MADRI	Witness Test means the utility's interconnection installation evaluation required by IEEE 1547 Section 5.3 and the utility's witnessing of the commissioning test required by IEEE 1547 Section 5.4. For interconnection equipment that has not been Certified, the Witness Test shall also include the witnessing by the EDC of the on-site design tests as required by IEEE 1547 Section 5.1 and witnessing by the EDC of production tests required by IEEE 1547 Section 5.2. All tests witnessed by the EDC are to be performed in accordance with IEEE 1547.1 Upon providing reasonable notice within ten (10) Business Days after receipt of the Certificate of Completion, the utility may conduct a Witness Test at a mutually convenient time, which must be passed. If the utility does not conduct the Witness Test within 10 Business Days or within the time otherwise mutually agreed to by the Parties, the Witness Test is deemed waived. Unless the utility determines and demonstrates that the Small Generator Facility cannot be interconnected safely and reliably, utility must sign application approval line on the Interconnection Request form subject to 1. The Small Generator Facility being approved by local or municipal electric code officials with jurisdiction over the interconnection; and 2. A Certificate of Completion being returned to the utility; and 3. Successful completion of the Witness Test, if conducted by the utility.	Once the facility has been authorized to commence parallel operation, Customer must abide by all written rules and procedures developed by the utility which pertain to parallel operation.

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
Maryland	The EDC shall have the option of performing a witness test after construction of the small generator facility is completed. The applicant shall provide the EDC at least 20 days notice of the planned commissioning test for the small generator facility. If the EDC elects to perform a witness test, it shall contact the applicant to schedule the witness test at a mutually agreeable time within 10 business days of the scheduled commissioning test. If the EDC does not perform the witness test within 10 business days of the commissioning test, the witness test is deemed waived unless the parties mutually agree to extend the date for scheduling the witness test. If the witness test is not acceptable to the EDC, the applicant shall be granted a period of 30 calendar days to address and resolve any deficiencies. The time period for addressing and resolving any deficiencies may be extended upon the mutual agreement of the EDC and the applicant. If the applicant fails to address and resolve the deficiencies to the satisfaction of the EDC, the interconnection request shall be deemed withdrawn. If a witness test is not performed by the EDC or an entity approved by the EDC, the applicant must still satisfy the interconnection test specifications and requirements set forth in IEEE Standard 1547 Section 5. The applicant shall, if requested by the EDC, provide a copy of all documentation in its possession regarding testing conducted pursuant to IEEE Standard 1547.1.	The Interconnection Customer may operate the Small Generator Facility and interconnect with the EDC's Electric Distribution System once all of the following have occurred: a) Electrical Inspection**:** Upon completing construction, the Interconnection Customer will cause the Small Generator Facility to be inspected by the local electrical wiring inspector with jurisdiction who shall establish that the Small generator Facility meets the requirements of the National Electrical Code. b) Certificate of Completion: The Interconnection Customer shall provide the EDC with a completed copy of the Certificate of Completion, including evidence of the electrical inspection performed by the local authority having jurisdiction. The evidence of completion of the electrical inspection may be provided on inspection forms used by local inspecting authorities. The Interconnection request shall not be finally approved until the EDC's representative signs the Certificate of Completion. c) EDC has either waived the right to a Witness Test in the Interconnection Request, or completed its Witness Test as per the following: i) Within ten (10) business days of the estimated commissioning date, the EDC may, upon reasonable notice and at a mutually convenient time, conduct a Witness Test of the Small Generator Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes If the EDC does not perform the Witness Test within the 10 day period or such other time as is mutually agreed to by the parties, the Witness Test is deemed waived.

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
Massachusetts	Utility has the right to witness the commissioning testing as defined in IEEE Standard 1547-2003 at the completion of construction and to receive a copy of all test data. Facility must be equipped with equipment required to perform test. Prior to final approval by the Company or anytime thereafter, the Company reserves the right to test the generator relaying and control related to the protection of the utility's system. Following receipt of Certificate of Completion, utility may conduct Witness Test. Customer has no right to operate in parallel until a Witness Test has been performed or has been previously waived on the Application Form. Utility must complete this Witness Test within 10 business days of the receipt of the Certificate of Completion, else deemed waived. After successful wiring inspection and/or Witness Test, utility must notify Customer in writing that interconnection is authorized. If the Witness Test is not satisfactory, the Company has the right to disconnect the Facility, and will provide information to the Interconnecting Customer describing clearly what is required for approval. If Customer does not complete construction within 12 months after receiving approval, Customer to reapply for interconnection.	Momentary Paralleling- Protective relays to isolate the Facility for faults in the Company EPS are not required if the paralleling operation is automatic and takes place for less than one-half of a second. An Interrupting Device with a half-second timer (30 cycles) is required as a fail-safe mechanism. Parallel operation of the Facility with the utility system shall be prevented when the utility's line is dead or out of phase with the Facility. Control scheme for automatic paralleling must be accepted by the Company prior to the Facility being allowed to interconnect with the Company EPS.
Minnesota	If not Type-Certified (type tested), must be equipped with protective hardware and/or software designed to prevent the Generation from being connected to a de-energized utility system. Generation may not close into a de-energized utility system and must have protective equipment to prevent this from occurring. Customer is responsible for final design and installation of protective measures required by utility. Utility will review and approve the design, the types of relays specified, and the installation. Mutually agreed upon exceptions may at times be necessary and desirable. It is strongly recommended that the Customer obtain utility's written approval prior to ordering protective equipment for parallel operation. Customer will own protective measures installed at their facility. Rule specifies sequencing of all commissioning tests which must be completed prior to moving on to the next section of tests. Utility has the right to witness all field testing and to review all records prior to allowing normal operation Notice to utility, with sufficient lead time	No special provisions regarding initial parallel operation

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
	to allow utility personnel to witness any or all of the testing. (Rule delineates specific tests to be performed). For smaller systems utility may have a set of standard interconnection tests that will be required. On larger and more complex systems Customer and utility will get together to develop the required testing procedure which must be based on written test procedures If not Type-Certified, system must be certified as ready to operate by a Professional Electrical Engineer registered in the State of Minnesota, prior to commercial use.	

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
New York	Verification testing will be performed in accordance with the written test procedure provided in STEP 5 and any site-specific requirements identified by the utility in STEP 6. The final testing will be conducted at a mutually agreeable time, and the utility shall be given the opportunity to witness the tests. The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in STEP 9. In addition, the applicant must have complied with and must continue to comply with the contractual and technical requirements. All interface equipment must include a verification test procedure (except for single phase inverters and inverter systems rated 15 kW and below) as part of the documentation presented to the utility. Except for the case of small single-phase inverters as discussed later, the verification test must establish that the protection settings meet the SIR requirements. The verification testing may be site-specific and is conducted periodically to assure continued acceptable performance is changed, the verification test must be performed. A qualified individual must perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory-trained and certified technicians, and licensed electricians with experience in testing protective equipment. The utility reserves the right to witness verification testing or require written certification that the testing was successfully performed. Verification testing must be performed at least once every four years. All verification tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal must be clearly and permanently marked. The generator-owner shall maintain verification test reports for inspection by the utility. Single-phase inverters and inverter systems rated 15 kW and below shall be verified upon initial parallel operation and once per year as follows: the owner or his agent shall operate the load break disconnect switch and verify the power producing facility automatically disconnects and does not reconnect for five minutes after the switch is closed. The owner shall maintain a log of these operations for inspection by the connecting utility. Any system that depends upon a battery for trip power shall be checked and logged once per month for proper voltage. Once every four (4) years the battery must be either replaced or a discharge test performed.	Single-phase inverter-based systems rated 15 kW or less will be allowed to interconnect to the utility system prior to the verification test for a period not to exceed two hours, for the sole purpose of assuring proper operation of the installed equipment. The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in STEP 9. In addition, the applicant must have complied with and must continue to comply with the contractual and technical requirements.

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
Oregon	“Witness Test” means the on-site visual verification of the interconnection installation and commissioning as required in IEEE 1547 Sections 5.3 and 5.4. For interconnection equipment that has not been Lab Tested, the Witness Test may, at the discretion of the EDC, also include a system design and production evaluation according to IEEE 1547 Sections 5.1 and 5.2 as applicable to the specific interconnection system technology employed. The Applicant must provide the EDC at least 20 business days notice of the planned commissioning for the Small Generator Facility. The EDC has the option of conducting a Witness Test at a mutually agreeable time within 10 business days of the scheduled commissioning. If the EDC does not conduct the Witness Test within 10 business days of the scheduled commissioning date, or within the time otherwise mutually agreed upon by the parties, the Witness Test is deemed waived. If the Witness Test is conducted and is not acceptable to the EDC, the Applicant must be allowed a period of 30 calendar days to resolve any deficiencies. The Parties may mutually agree to extend the time period for resolving any deficiencies. If the Applicant fails to resolve the deficiencies to the satisfaction of the EDC within the agreed upon time period, the Application is deemed withdrawn. Non-approval: If the Small Generator Facility is not approved under a Level 2 review, the Applicant may submit a new Application including the difference in the application fee or deposit, for consideration under Level 3 or Level 4 procedures without losing its original Queue Position provided the new Application is submitted within 15 business days of notice that the Application was not approved. Operation: The Applicant must notify the EDC before commencing operation and only operate the Small Generator Facility in accordance with the executed Interconnection Agreement and the executed Power Purchase Agreement.	Parallel Operation and Maintenance Obligations Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of the Interconnection Agreement, the Applicant will abide by all written provisions for operating and maintenance as required by the Rule and detailed by the EDC in Form 4 provided on the Commission’s website.
Texas	Testing of protection systems must 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	No specific requirements

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
	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.	
Washington	Acknowledges that test will be required. Does not specify tests or have explanatory language.	All generating facilities must obtain an electrical permit and pass electrical inspection before they can be connected or operated in parallel with the electrical company's electric system. Generator shall provide to electrical company written certification that the generating facility has been installed and inspected in compliance with the local building and/or electrical codes local laws and regulations. Prior to initial operation, all generators must submit a completed certificate of completion to the electrical company, execute an appropriate interconnection agreement and any other agreement(s) required for the disposition of electric output

Jurisdiction	Commissioning & Testing	Initial Parallel Operation
Wisconsin	"Commissioning test" means the process of documenting and verifying the performance of a DG facility so that it operates in conformity with the design specifications. Customer must give the utility opportunity to witness or verify system testing. Upon receiving notification that an installation is complete, utility has 10 working days, for a Category 1 or 2 DG project, or 20 working days, for a Category 3 or 4 DG project, to complete witness commissioning tests, perform an anti−islanding test or verify the protective equipment settings at its expense or waive its right, in writing, to witness or verify the commissioning tests. Customer must provide the public utility with the results of any required tests. Utility may review the results of the on−site tests and shall notify the applicant within 5 working days, for a Category 1 DG project, or within 10 working days, for a Category 2 to 4 DG project, of its approval or disapproval of the interconnection. If approved, the public utility shall provide a written statement of final acceptance and cost reconciliation. Customer with DG system that passes the commissioning test may sign a standard interconnection agreement and interconnect. If the public utility does not approve the interconnection, the applicant may take corrective action and request the public utility to reexamine its interconnection request. Utility may not charge a commissioning test fee for initial start−up of the DG facility. Utility must provide the acceptable range of settings for the paralleling equipment Category 2, 3, or 4 DG facilities. Customer must program protective equipment settings into paralleling equipment.	A standard interconnection agreement shall be signed by the applicant and public utility before parallel operation commences. The public utility may verify the protective equipment settings prior to allowing the DG facility to interconnect to the distribution system.

Table 8 summarizes the provisions for dispute resolution and insurance and liability requirements for each of the jurisdictions.

Table 8: Dispute Resolution and Insurance Requirements & Liability

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
California	Commission has initial jurisdiction to interpret, add, delete or modify any provision of this Rule or of any agreements and to resolve disputes. Disputes procedure: The dispute must be reduced to writing in a letter to other Party with relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice procedures being invoked. Parties must meet within 45 calendar days of letter. If not resolved within 45 calendar days of letter, on demand of either party, dispute is submitted to Commission for resolution. Pending resolution Parties must proceed diligently with the performance of their respective obligations	Customer must maintain general liability insurance with a combined single limit of not less than: (a) $2,000,000 for each occurrence if >100 kW; (b) $1,000,000 for each occurrence if >20 kW and <100 kW; and (c) $500,000 for each occurrence if <=20 kW. (d) $200,000 for each occurrence if <= 10 kW or less and is connected to residential
FERC	Parties must agree to attempt to resolve all disputes to provisions of rule. In event of dispute, Party must provide written Notice of Dispute describing dispute. If not resolved within two Business Days after receipt of Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute. DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. Parties must agree to conduct all negotiations in good faith and be responsible for one-half of any costs paid to neutral third-parties. If neither Party elects to seek assistance from DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of procedures in rule.	The Parties agree to follow all applicable insurance requirements imposed by the state. All insurance policies must be maintained with insurers authorized to do business in that state. Each party’s liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees is be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0 Indemnification that provides Parties must indemnify, defend, and save the other Party harmless from damages, losses, claims, of injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of other Party's action or inactions on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.
Illinois	Complaints alleging violations of rule must be filed pursuant to 83 Ill. Adm. Code 200.	Does not address insurance or liability issues.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
IREC	For disputes related to the technical application of rules, the PUC may from time to time designate a technical master for the resolution of such disputes. If the [state PUC] has so designated, the parties shall use the technical master to resolve disputes related to interconnection and such resolution shall be binding on the parties. Costs for dispute resolution by the technical master, if any, shall be as directed by the technical master subject to review by the PUC. PUC may designate a U.S. Department of Energy national laboratory; college or university; or an approved FERC RTO with distribution system engineering expertise as the technical master. Should the FERC identify a national technical dispute resolution team, PUC may designate said team as its technical master. IREC rules then provides: Process and legal disputes.	Limitation of Liability Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, is limited to the amount of direct damage actually incurred and does not include any indirect, special, consequential, or punitive damages. Indemnification: Protects each Party from liability incurred to third parties. Liability under this provision is exempt from the general limitations on liability (above). Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations, except in cases of gross negligence or intentional wrongdoing by the indemnified Party. If entitled to indemnification as a result of a claim by a third party, and indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, the claim. If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this Article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery. After receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified person must notify the indemnifying party of such fact. Any failure of or delay in such notification will not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party. Neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
MADRI	Each Party agrees to attempt to resolve all disputes regarding the provisions of these interconnection procedures promptly, equitably and in a good faith manner. For disputes related to the technical application of these rules, the PUC may from time to time designate a technical master for the resolution of such disputes. If the PUC has so designated, the parties shall use the technical master to resolve disputes related to interconnection and such resolution shall be binding on the parties. Costs for dispute resolution by the technical master, if any, shall be as directed by the technical master subject to review by the PUC. The PUC may designate a Department of Energy national laboratory; college or university; or an approved FERC RTO with distribution system engineering expertise as the technical master. Should the FERC identify a national technical dispute resolution team, the PUC may designate said team as its technical master. See PUC dispute resolution or complaint procedures.	Limitation of Liability Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages. Indemnity provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party. 6.3.3 If an indemnified person is entitled to indemnification under this Article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim. 6.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this Article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery. After receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified person must notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party. Neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
Maryland	A party shall attempt to resolve all disputes regarding interconnection as provided in this section promptly, equitably, and in a good faith manner. When a dispute arises, a party may seek immediate resolution through complaint procedures available through the Commission, or an alternative dispute resolution process approved by the Commission, by providing written notice to the Commission and the other party stating the issues in dispute. Dispute resolution shall be conducted in an informal, expeditious manner to reach resolution with minimal costs and delay. When available, dispute resolution may be conducted by phone. When disputes relate to the technical application of this section, the Commission may designate a technical master to resolve the dispute. The Commission may designate a Department of Energy National Laboratory, PJM Interconnection L.L.C., or a college or university with distribution system engineering expertise as the technical master. When the Federal Energy Regulatory Commission identifies a National technical dispute resolution team, the Commission may designate the team as its technical master. Upon Commission designation, the parties shall use the technical master to resolve disputes related to interconnection. Costs for a dispute resolution conducted by the technical master shall be established by the technical master, subject to review by the Commission. Pursuit of dispute resolution may not affect an applicant with regard to consideration of an interconnection request or an applicant's queue position.	Insurance Level 1: Insurance Disclosure The attached terms and conditions contain provisions related to liability, and indemnification and should be carefully considered by the interconnection customer. The interconnection customer is not required to obtain general liability insurance coverage as a precondition for interconnection approval; however, the interconnection customer is advised to consider obtaining appropriate insurance coverage to cover the Interconnection Customer's potential liability under this agreement. Levels 2, 3 & 4: For Small Generator Facilities with a Nameplate Capacity of 1 MW or above, the Interconnection Customer shall carry adequate insurance coverage that shall be acceptable to the EDC; provided, that the maximum comprehensive/general liability coverage that shall be continuously maintained by the Interconnection Customer during the term shall be not less than $2,000,000 for each occurrence, and an aggregate, if any, of at least $4,000,000. The EDC, its officers, employees and agents will be added as an additional insured on this policy. Indemnity This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 6.2. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party. Promptly after receipt by an indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party. If an indemnified Party is entitled to indemnification under this Article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
		If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this Article, the amount owing to the indemnified person shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability

Massachusetts	Dispute Resolution is multi-stage process beginning with negotiation, then mediation, followed by non-binding arbitration and then adjudication. Rule contains extensive procedural requirements for each stage with specific time deadlines. See rule for details.	Customer must maintain, general liability insurance for each occurrence/in the aggregate with a combined single limit of not less than:
		a. $5,000,000/$5,000,000 if facility is >5 MW;
		b. $2,000,000/$5,000,000 if >1 MW <=5 MW;
		c. $1,000,000/$1,000,000if >100 kW and <=1 MW;
		d. $500,000/$500,000if >10 kW and <=100 kW.
		No insurance is required, but is recommended, for Facilities less than or equal to ten (10) kW.
		All required insurance shall be carried by reputable insurers qualified to underwrite insurance in
		MA having a Best Rating of “A-”. In addition, all insurance shall, (a) include Company as an
		additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that Company shall not incur liability to the insurance carrier for payment of premium for such insurance; and (c) provide for thirty (30) calendar days’ written notice to Company prior to cancellation, termination, or material change of coverage.
		If requirement of (a) above prevents Customer from obtaining the insurance required without added cost or due to written refusal by the insurance carrier, then on Customer’s written Notice to Company, the requirements of (a) are be waived.
		Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Customer.
		Customer is responsible for providing the Company with evidence of insurance in compliance with this Interconnection Tariff on an annual basis.
		Prior to the Company commencing work on System Modifications, the Interconnecting Customer shall have its insurer furnish to the Company certificates of insurance evidencing the insurance coverage required above. Customer must notify and send Company a certificate of insurance for any policy written on a "claims-made" basis. The Company may at its discretion require the Interconnecting Customer to maintain tail coverage for three years on all policies written on a "claims-made" basis.
		Self Insurance: If Customer is a company with a self-insurance program established in accordance with commercially acceptable risk management practices, Customer may comply with the following in lieu of the above requirements as reasonably approved by the
		Company:
		a. Customer must provide Company, at least thirty (30) calendar days prior to the Date of Initial Operation, evidence of such program to self-insure to a level of coverage equivalent to that required above.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
		b. If Customer ceases to self-insure to the standards required hereunder, or is unable to provide continuing evidence of Customer's financial ability to self-insure, Customer must promptly obtain the coverage required.
Minnesota	The following is the dispute resolution process for problems that occur with the implementation of interconnection process: 1) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner. 2) In the event dispute that cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, Parties must submit dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the State of Minnesota. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Minnesota Public Utilities Commission, which maintains continuing jurisdiction over the process.	At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under this Agreement, the Interconnection Customer shall maintain, during the term of the Agreement, general liability insurance, from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less then: a) $2,000,000 if >250kW. b) $1,000,000 if between 40kW and 250kW c) $300,000 if <40kW. d) Insurance must include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Customer's ownership and/or operation of the system Policy must include an endorsement to include the utility as an additional insured; (b) contain a severability of interest clause or cross-liability clause and provide that the utility shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to utility prior to cancellation, termination, alteration, or material change. If system is on a residential service and <40kW, then the endorsements not required. Customer must furnish the required insurance certificates and endorsements to Utility prior to the initial operation of the system. Thereafter, Utility has the right to periodically inspect or obtain a copy of the original policy or policies of insurance Evidence of the insurance must state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Utility. If Customer is self-insured with an established record of self-insurance, Customer may comply with the following in lieu of above requirements: Customer must provide, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under above. If Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of its ability to self-insure, Customer must immediately obtain the coverage required. Failure of Customer or Utility to enforce the minimum levels of insurance does not relieve the Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

Jurisdiction	Dispute Resolution	Insurance Requirements & Liability
New York	Each Party must attempt to resolve disputes promptly, equitably and in a good faith manner. If a dispute arises and cannot be resolved within 10 working days after written notice, the parties must agree to submit to mediation by a mutually acceptable mediator, in a mutually convenient location in New York State, in accordance with the then current CPR Institute for Dispute Resolution Mediation Procedure, or to mediation by a mediator provided by the New York Public Service Commission. The parties agree to participate in good faith in the mediation for a period of up to 90 days. If the parties are not successful in resolving their disputes through mediation, then the parties may refer the dispute for resolution to the New York Public Service Commission, which maintains continuing jurisdiction. If dispute > $2,000, the Customer shall either place such disputed amounts into an independent escrow account pending final resolution of the dispute in question, or provide to the Company an appropriate irrevocable standby letter of credit in lieu thereof.	Customer is not required to provide general liability insurance coverage as part of Agreement, the SIR, or any other Company requirement. Due to the risk of incurring damages, the Public Service Commission recommends that every distributed generation customer protect itself with insurance, and requires insurance disclosure as a part of this Agreement. Customer must disclose whether Customer has obtained, or already has in effect under an existing policy, general liability insurance coverage for operation of the Unit and intends to maintain such coverage for the duration of this Agreement (attach Certificate of Insurance or copy of Policy) or has not obtained general liability insurance coverage for operation of the Unit and/or is self-insured. The inability of the Company to require the Customer to provide general liability insurance coverage for operation of the Unit is not a waiver of any rights the Company may have to pursue remedies at law against the Customer to recover damages.
Oregon	Dispute Resolution Except as provided in section (4) of this rule, nothing in this rule restricts the rights of any Party to file a complaint with the Commission under ORS Chapter 756. Pursuit of the dispute resolution process under this subsection does not affect an Applicant with regard to consideration of an Interconnection Request or its queue position. (1) Before filing a complaint with the Commission or using the alternative dispute resolution mechanism set forth in section (4), the EDC, Applicant or Interconnection Customer must first provide the other Party with a written Notice of Dispute (Notice). Such Notice must describe in detail the nature of the dispute and a proposed resolution.	A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees related to or arising from any act or omission in its performance of the provisions of the OSGIR or the resulting Interconnection Agreement. (1) General liability insurance is not required for approval of an interconnection Application, or for the related Interconnection Agreement, for a Small Generator Facility with an Electric Nameplate Capacity of 200 KW or smaller, or for a Net Metering Facility as provided for in ORS 757.300(4)(c). (2) All other Interconnection Customers are required to obtain prudent amounts of general liability insurance in an amount sufficient to protect other Parties from any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of the provisions of the OSGIR or the Interconnection Agreement. Neither Party may seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

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	(2) The Party receiving a Notice under this section must refer it to a designated senior representative for resolution on an informal basis as promptly as practicable. In the event the Parties are unable to resolve the dispute within 30 calendar days (or such other period as the Parties may agree upon by mutual agreement), either Party may submit it to the Commission pursuant to ORS Chapter 756 or, if the Parties mutually agree, for alternative dispute resolution as set forth in section (4). Parties may not informally resolve a dispute that requires Commission approval as set forth in OAR 860-082-0005(3). (3) For complaints filed with the Commission under ORS Chapter 756 or under the alternative dispute resolution process described in section (4), the following "Good Utility Practice" standard must be used: (a) "Good Utility Practice" is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. (b) Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region. (4) The EDC, the Interconnection Customer or Applicant may use the following alternative dispute resolution process only if both Parties to the dispute mutually agree in writing and both Parties accept all aspects of the alternative procedures set forth in this	

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	section. Once both Parties agree in writing to use this alternative dispute resolution process, it may only be terminated by mutual written agreement of the Parties. (a) Procedures: Proceedings initiated under this alternate dispute resolution provision are conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within 10 days of the referral of the dispute to arbitration, each Party must choose one arbitrator to sit on a three-member arbitration panel. The two arbitrators so chosen must, within 20 days, select a third arbitrator to chair the arbitration panel. In either case, the arbitrators must be knowledgeable in electric utility matters, including electrical T&D Systems and interconnection equipment and facilities, and must not have any current or past substantial business or financial relationships with any Party to the arbitration (except prior arbitration). The arbitrator(s) must provide each of the Parties an opportunity to be heard and conduct the arbitration in accordance with applicable arbitration rules and Commission regulations. (b) Arbitration Decision: Unless the parties otherwise mutually agree, the arbitrator(s) must render a decision within 90 days of appointment and must notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) are authorized only to interpret and apply the provisions the OSGIR and any Interconnection Agreement (if applicable) entered in to under these rules, and the arbitrators do not have power to modify or change any of the above in any manner. Except as provided in subsections (c) and (d) of this section, the decision of the arbitrator(s) is final and binding on the Parties. (c) The EDC must file, without further comment, the arbitrator's final decision with the Commission	

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	within 5 business days of its issuance. The Commission must approve or reject the final decision within 60 days of its filing, with written findings as to any deficiencies. The Commission's review of the arbitrator's final decision is limited solely to ensure: (A) It does not unfairly or unjustly discriminate against a person who is not a party to the alternative dispute resolution process; (B) It is consistent with the public interest, convenience and necessity, and (C) It does not unfairly or unjustly harm the EDC's ratepayers. Prior to rejecting the final decision, the Commission must notify the Parties of its intended action and provide an opportunity for a response. (d) Either Party may request reconsideration of the Commission's order issued under subsection (c) as provided in ORS 756.561. A Party may appeal a Commission order as provided in ORS 756.610. (e) A Party may not seek judicial review of an arbitrator's final decision except as provided in subsection (d). (5) Costs: Each Party is responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (a) One half the cost of the single arbitrator jointly chosen by the Parties; or (b) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen.	
Texas	Complaints relating to interconnection disputes are handled in an expeditious manner pursuant to Commissions rules relating to Complaints. In instances where informal dispute resolution is sought, complaints shall be presented to the Electric Division, which attempts to informally resolve complaints within 20 business days of the date of	Not addressed.

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	receipt of the complaint. Unresolved complaints are presented to the commission at the next available open meeting.	
Washington	Not addressed.	For certain solar, wind, hydro or fuel cells, no additional insurance will be necessary. For other generating facilities, additional insurance, limitations of liability and indemnification may be required by the electrical company.
Wisconsin		Customer must maintain liability insurance equal to those shown below or prove financial responsibility by another means mutually agreeable to the Customer and Utility. For a DG facility in Category 2 to 4, the utility must be named as an additional insured party in the liability insurance policy: Category 1: $300,000, Category 2: $1,000,000, Category 3: $2,000,000, Category 4: Negotiated. Each party must indemnify, hold harmless and defend the other party, its officers, directors, employees and agents from and against any and all claims, suits, liabilities, damages, costs and expenses resulting from the installation, operation, modification, maintenance or removal of the DG facility. The liability of each party shall be limited to direct actual damages, and all other damages at law or in equity shall be waived.