RESOURCE
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Business and Contract Guide for Distributed Generation (DG) Interconnection

Developed For
National Rural Electric Cooperative Association

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NRECA
A Touchstone Energy® Cooperative

Business and Contract Guide for Distributed Generation (DG) Interconnection

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Foreword

Distributed generation (DG) offers opportunities as well as challenges for cooperatives. This guide is designed to help cooperatives take advantage of the benefits offered by DG while minimizing possible problems. Business and contractual terms and conditions are the foundation for a successful implementation of DG on a cooperative's distribution system. The guide is intended for use by cooperative staff; it is not designed for distribution to members or potential DG operators or owners. See **Consumer Guidelines for Electric Power Generator Installation and Interconnection** for a ready-to-use consumer guide to cooperative requirements.

Introduction and Approach

The **Business and Contract Guide for DG Interconnection** covers projects that fall into the following categories:

- DG systems up to 10 MW, including small 10 kW inverter systems (e.g., residential photovoltaic (PV) solar systems);
- Installations on radial feeder distribution circuits; and
- Both rotating (i.e., induction and synchronous) and static power conversion technologies.

The guide provides a ready reference on how to deal with customer and third-party generators, from the initial information requirements needed to consider an application to the detailed contract documents used to close the deal. Cooperative staff who may benefit from using this guide include transmission and distribution (T&D) engineers, member services personnel, lawyers, and distribution managers. The following are attachments to the guide:

- A Customer Guide for consumers expressing an interest in DG;
- A Pre-Application Report (PAR) template for providing information to a customer requesting information at a specific point of interconnection (POI) or point of common coupling (PCC). This report may be optional in your state;
- An Application Form (in two parts) that must be completed by consumers seeking permission to interconnect;
- A Short Form Interconnection Contract for non-inverter-based DG units of less than 10 kW for installation in a home, residence, business, or farm;
- A Form Interconnection Contract for DG units that do not qualify for the short form;
- A "10 kW Inverter Process" document, which is a complete set of information forms required from an interconnection customer, from the initial application to the final interconnection agreement for inverter-based systems of less than 10 kW (e.g., residential PV solar). The purpose of this process is to streamline the interconnections of these systems and make the interconnection process easier for the customer; and
- Sample inspection, testing, and commissioning procedures.

How to Use this Guide

The goals of this guide are to enable a cooperative to assess the impacts of DG in a clear, unbiased, and consistent manner, as well as provide a DG applicant with a clear understanding of how the application process works and how the interconnection analysis is conducted. For this reason, the guide was developed using the appropriate business and regulatory information that can help co-ops and DG owners accomplish these goals.

The Introduction provides background information on the current regulatory framework regarding DG interconnection. The Application Process section describes all of the technical, procedural, economic, and legal steps that both the cooperative and DG owner can undertake to facilitate the interconnection process. These encompass impact studies, contractual forms and model contractual language, cooperative and DG owner information requirements, sample fee structures, application processing, and metering and telemetry. The Equipment Certification section describes the kinds of equipment tests that exist that may allow for more rapid interconnection approval. Last, the Responsibilities of the Cooperative section outlines additional concerns pertaining to co-ops and provides a list of resources that can assist them in configuring the interconnection process.

The model documents included in this guide will save each cooperative that deals with DG from "reinventing the wheel." They can help co-ops to encourage DG on their systems when it benefits the whole system—and to recognize when DG may pose a risk. By allowing cooperatives to be responsive to member requests for interconnection, the documents can help to differentiate co-ops in the eyes of both consumers and regulators.

A great deal of work has been completed at both the federal and state levels regarding DG interconnection and the qualification and screening processes. For example, California's Rule 21 has examined this topic exhaustively, resulting in the publication of reams of screening steps and System Impact Study rules. In fact, Rule 21 has been held up, often along with work completed in Texas and New York, as a model for DG interconnection rules. Of course, work by the National Association of Regulatory Utility Commissioners (NARUC) has been presented as a model for state DG rules, and the Federal Energy Regulatory Commission (FERC) has leaned on the NARUC model rules in developing FERC Order 2006 on Small Generator Interconnection Procedures (SGIP).

FERC Order 2006 applies to the interconnection of generators no larger than 20 MW with the approximately 176 public utilities that own, control, or operate interstate transmission facilities. FERC's Interconnection Rule for small generators applies to all interconnections to FERC jurisdictional facilities, subject to a transmission provider's open access transmission tariff at the time an interconnection request is made. A special rule within Order 2006 for expedited interconnection of facilities of 10 kW or less also is included, as well as stipulations for differentiated treatment of projects of 10 MW and less.

Recognizing the impact and broad applicability of FERC Order 2006 (promulgated in August 2005 and last amended in November 2013),[1] this guide uses the underlying themes and strategies from this Order and its amendments to establish its overall approach. The process used to establish the fast track screens drew directly from Order 2006, with some simplification of the decisionmaking. The use of work done by a national foundation for applying technical and technology decisions to DG interconnection provides a rational and defensible resource for this guide. In fact, many state regulatory commissions have adopted the SGIP procedures or some variation thereof. Cooperatives regulated by their state commissions should review any specific state requirements and ensure compliance with them. Those cooperatives that are not regulated are still encouraged to review their state commission procedures for

[1] The latest amendment adds an optional pre-application report that can be requested by a customer, and makes specific changes to the Fast Track and Supplemental Review Processes, along with other more minor changes and clarifications.

interconnections and consider adopting similar standards when it makes sense and is consistent with established co-op policies.

Application Process

The application process is the series of prescribed steps that prospective DG owners/operators take if they want to operate in parallel with the distribution utility. The utility requires such information as location, technical, and design parameters, and operational and maintenance procedures. In this process, simpler is better. It is intended to be clear, concise, and not burdensome for any party; at the same time, the process must protect the safety and stability of the cooperative distribution system.

This application process provides a systematic approach for the engineering review of a DG interconnection study. The application forms themselves are discussed below and are included in an attachment to the guide. These forms include the steps that must be taken to account properly for site-specific concerns and address the technical and procedural requirements of the interconnection standard.

A Pre-Application Report (PAR) is included in the recent amendment to the SGIP that allows customers to request readily available information, for a fee, on a specific point of interconnection (POI) or point of common coupling (PCC) in advance of the official application. A key phrase in the preceding statement is “readily available information.” The intent of the PAR is to allow potential applicants to determine which locations on the utility system may most readily accommodate a proposed DG interconnection without the utility having to complete additional studies or analysis. In this manner, the potential applicant theoretically can more efficiently determine the best POI for which to make an application. Benefits to the cooperative are realized through a defined process (with some provision for cost collection) designed to provide potential applicants with information rather than cooperative staff fielding a multitude of informal questions from potential applicants who are “fishing” for information. Cooperatives deciding to offer potential applicants the opportunity to request a PAR, can find a PAR request form and template, which are included as attachments to this guide.

In some cases, a cooperative may reject the proposed DG project interconnection for demonstrable reliability or safety issues. In these cases, however, the co-op should work closely with the applicant to try to resolve these issues.

The application process actually focuses on the details of the interconnection request, as shown in Figure 1. Note in Figure 1 that the eligibility threshold for consideration of the Fast Track interconnection process is 2 MW. The 2013 amended SGIP extends eligibility for inverter-based systems to apply the screens for the Fast Track Process. Instead of 2 MW for all systems, as in the previous version of the SGIP, it includes a table based on line voltage and location from the utility substation, ranging from 500 kW to 5 MW for inverter-based systems. This is shown in Table 1.

Table 1. SGIP Fast Track Eligibility for Inverter-Based Systems

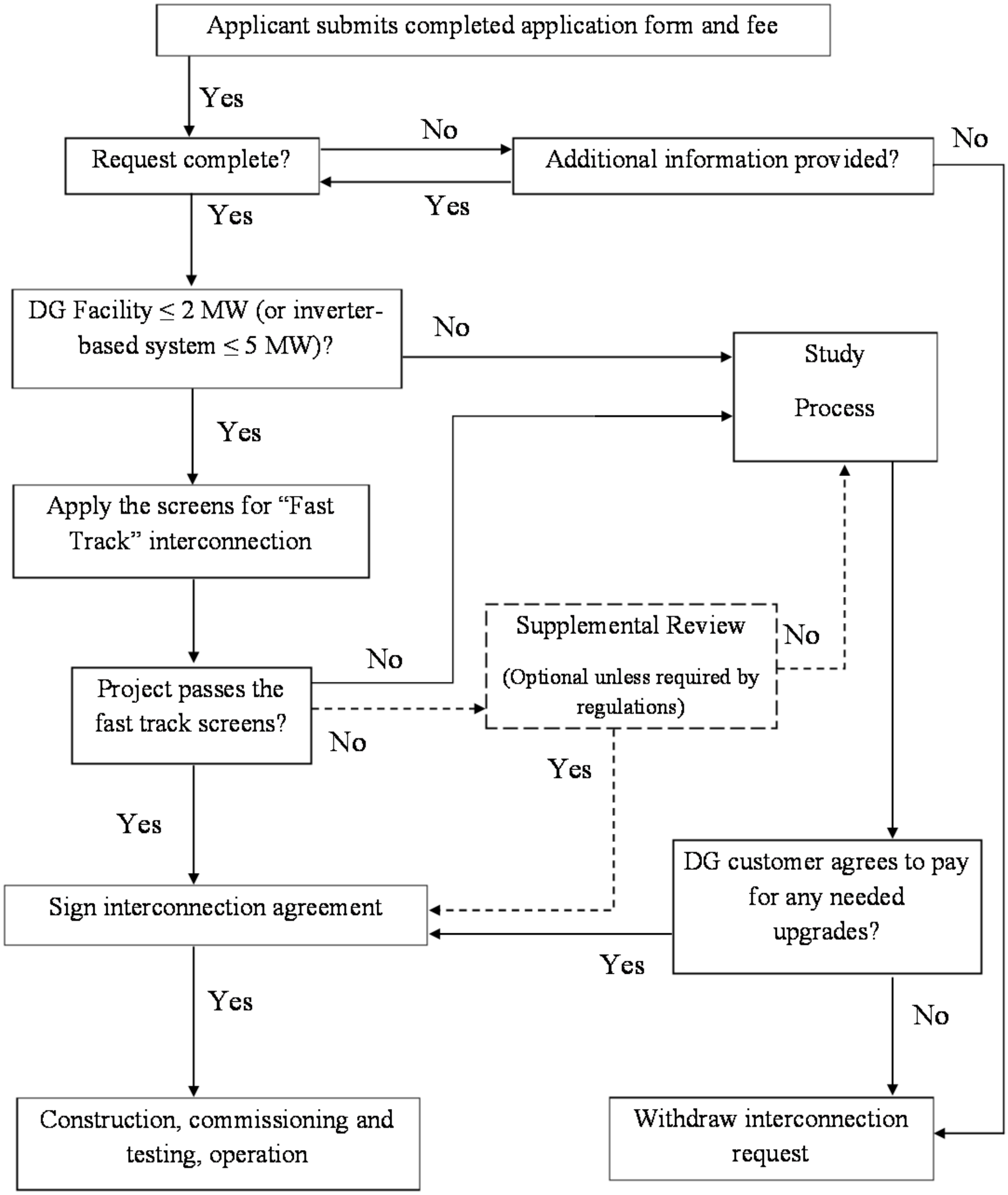
Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	**Fast Track Eligibility Regardless of Location**	**Fast Track Eligibility on a Mainline[2] and ≤ 2.5 Electrical Circuit Miles from Substation**
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 5 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

Induction and synchronous machines thresholds are still at 2 MW in the amended SGIP, regardless of voltage or location. The guide recommends that the cooperative consider extending the Fast Track Process to larger inverter-based systems, consistent with the amended SGIP; however, it is extremely unlikely that an inverter-based system larger than 2 MW would ultimately be able to pass the Fast Track Process screens shown later in this document; it would still require going through the Study Process.

If a project fails the fast track screens, the amended SGIP now includes a defined Supplemental Review Process before an interconnection request goes to the Study Process (refer to Figure 3). This review process is required only if a cooperative is regulated by FERC or if its state commission and the state's requirements include such a process; however, as with many other items associated with the interconnection process, it is worthwhile to consider including the Supplemental Review Process regardless, as long as it makes sense to the co-op and is consistent with its other policies.

[2] For the purposes of this table, a mainline is the three-phase backbone of a circuit. Typically it will constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil, and 795 kcmil.

Figure 1. The Application Process



Fast Track Screening Process

The Fast Track Screening Process is available for customers with DG projects of up to 2 MW, or up to 5 MW for inverter-based systems (see Figure 2) if the equipment meets the codes and standards listed in Appendix A and the equipment certification process of Appendix B, both taken from the SGIP. Specific screens to be met include the following:[3]

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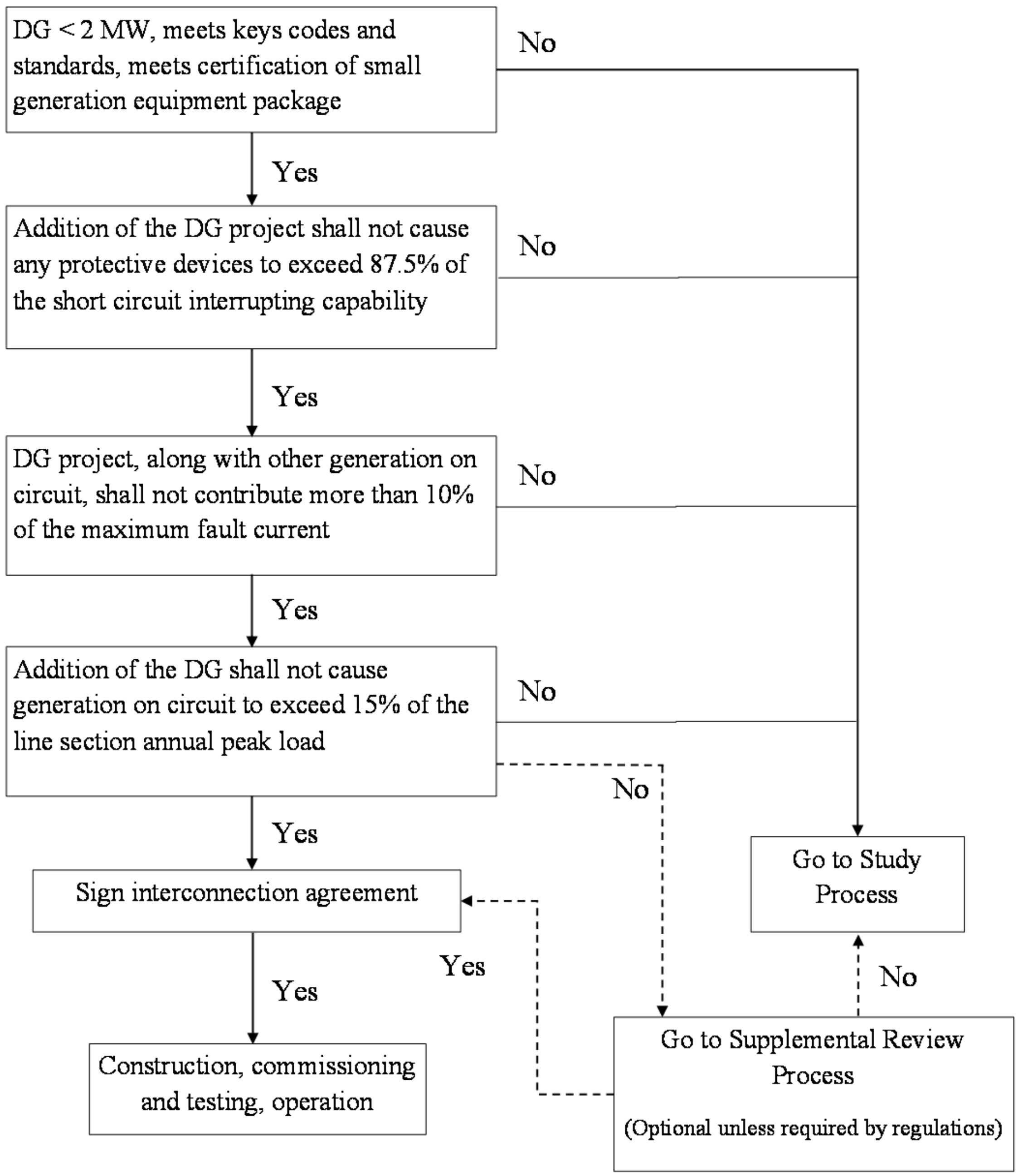
[3] See the NRECA TechSurveillance article *DG Interconnections: Rules of Thumb for When System Impact Studies Are Required* for more information and additional screens to consider.

Figure 2. Fast Track Screening Process



15% of line section annual peak load – For interconnection of a proposed small generating facility to a radial distribution circuit, the aggregated generation, including the proposed small generating facility, on that circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of the utility electric distribution system connected to a customer, bounded by automatic sectionalizing devices or the end of the distribution line.

Limit of 10% contribution to maximum fault current – The proposed small generating facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high-voltage (primary) level nearest the proposed point of change of ownership.

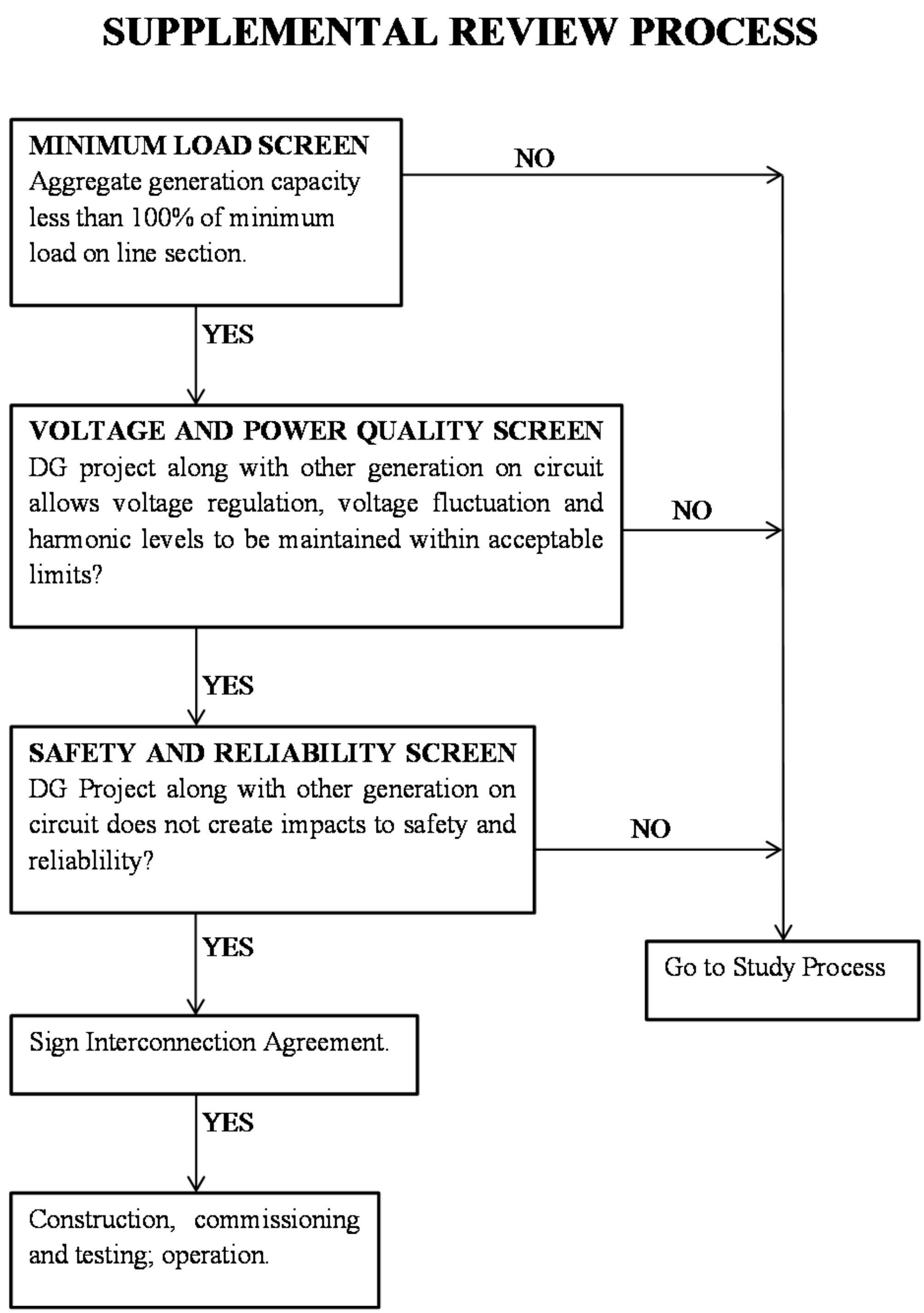
The DG project shall not cause any protective device to exceed 87.5% of the short circuit interrupting capability – The proposed small generating facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability, which includes, but is not limited to, substation breakers, fuse cutouts, and line reclosers. This also applies to the interconnection proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Supplemental Review Process

The Supplemental Review Process can be offered by the cooperative as an option to an applicant whose request has failed the Fast Track Screening Process, rather than moving to the Study Process. (Note that this process is only required if the co-op is regulated by FERC or if its state commission and its state specifies this as a requirement.) The applicant must agree to submit a good faith estimate deposit before the cooperative can perform the review. The intent of the Supplemental Review Process is to allow for a less rigorous process to save time and money for the applicant and determine any adverse system impacts and mitigation measures.

The Supplemental Review Process is most applicable when an application fails the Fast Track Screening Process only marginally. In practice, however, the Study Process time, effort, and cost should be consistent with the DG characteristics and its specific POI or PCC location; realistically, it may not save time or lower costs to use the Supplemental Review Process. In fact, if an application does not pass this process, it will be required to go through the Study Process anyway, which may end up costing the applicant more time and money in the end. Figure 3 presents specific steps in the Supplemental Review Process. An application must pass all three screens; otherwise, it moves to the Study Process.

Figure 3. Supplemental Review Process



Minimum Load Screen – The proposed small generating facility, in aggregation with other generation on the line section, shall not exceed 100% of the minimum line section load. For PV systems with no energy storage, the daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems) shall be used, whereas, the absolute minimum load shall be used with all other generation types. Minimum load data should represent actual data from the past 12 months or be calculated or estimated from existing data or a power flow model. If minimum load data are not available or cannot be calculated, estimated, or determined, this screen cannot be applied.

Voltage and Power Quality Screen – In aggregate with existing generation on the line section (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits, as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453 or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

Safety and Reliability Screen – The location of the proposed small generating facility and the aggregate generation capacity on the line section must not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process.

The Study Process

The Study Process shall be used when the DG project:

(1) Is larger than 2 MW but no larger than 20 MW;
(2) Is not certified; or
(3) Did not pass the Fast Track Process; or
(4) Did not pass the Supplemental Review Process if the cooperative offered this and the applicant accepted it.

When conducting an interconnection study, the cooperative should seek to do the following:

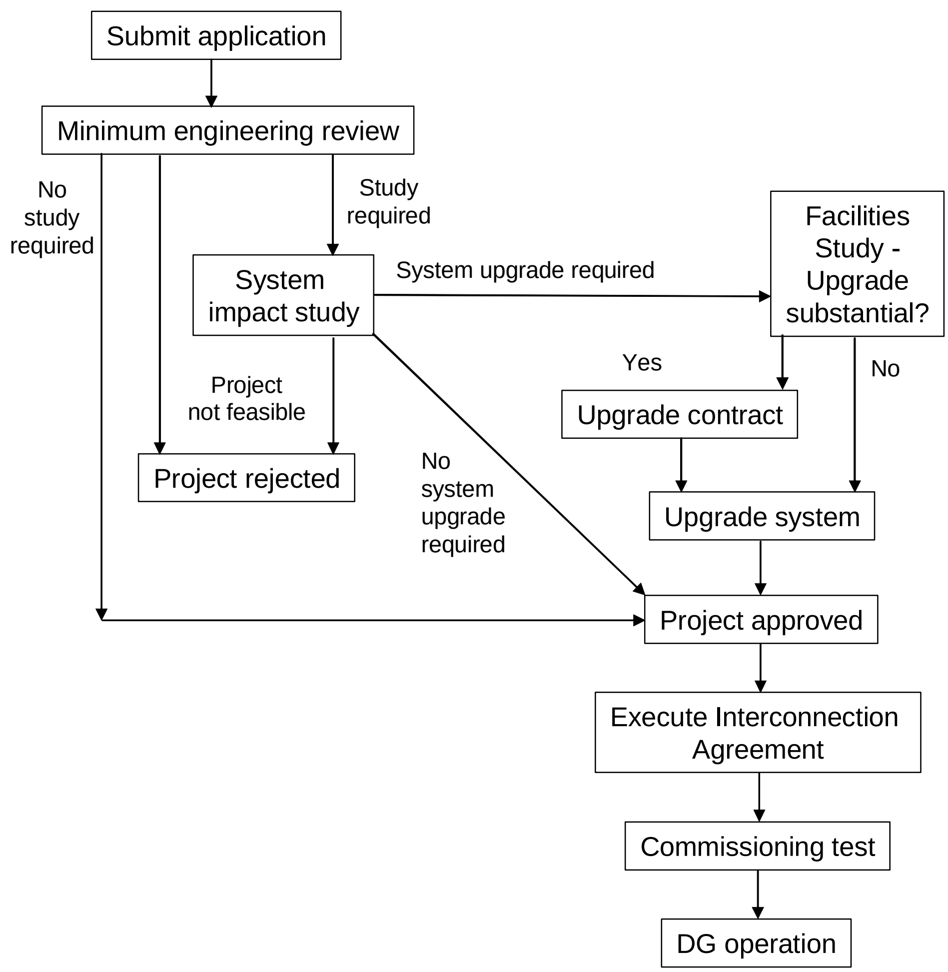
- Base study scope on the characteristics of the DG at the proposed location;
- Consider system and operational costs incurred and benefits realized as a result of the DG interconnection;
- Provide a cost estimate to the DG applicant before initiation of any studies if the co-op plans to charge any study costs to the applicant—fees *and charges for these studies are discussed below*;
- Make written reports and study results available to the DG applicant; and
- Use its best efforts to meet the application processing schedule or notify the DG applicant in writing why it cannot meet the schedule, and provide estimated dates for application processing and interconnection.

The Study Process (see Figure 4) consists of the Minimum Engineering Review, the System Impact Study, and the Facilities Study. At an initial meeting, the parties shall determine whether a Minimum Engineering Review is needed or proceed directly to a System Impact Study, a System Upgrade Study (referred to by FERC as a Facilities Study), or an interconnection agreement. Cooperatives can reference IEEE Standard 1547.7 *IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection* for guidance on completing any necessary studies.

Minimum Engineering Review

The Minimum Engineering Review, also known as the Feasibility Study in FERC Order 2006, is a preliminary technical assessment designed to identify at a high level any adverse system impacts that would result from interconnection of the DG project. Examples of such negative impacts would include exceeding the short circuit capability rating of any breakers, violations of thermal overload or voltage limits, and a review of grounding requirements and electric system protection.

Figure 4. The Study Process



System Impact and Facilities Studies

Beyond the Minimum Engineering Review or Feasibility Study, the Study Process includes a System Impact Study and a Facilities Study. A System Impact Study is designed to identify and detail the electric system impacts that would result if the proposed DG project were interconnected without project modifications or electric system modifications, focusing and expanding in detail on the adverse system impacts identified in the Feasibility Study. A System Impact Study shall evaluate the impact of the proposed interconnection on the safety and reliability of the electric system.

In instances in which the Feasibility Study or any preliminary review shows potential for distribution system adverse impacts, the area electric power system (EPS) shall send the interconnection customer a distribution System Impact Study Agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if one is required. Once the customer agrees to pay the cost of the study, the process continues.

Once the required System Impact Study is complete, a Facilities Study Agreement shall be sent to the customer if needed—including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the Facilities Study. (Note that in some cases, the System Impact Study and Facilities Study are combined into one.) The design for any required interconnection facilities and/or upgrades shall be performed under the Facilities Study Agreement. Upon completion of the Facilities Study, and with the agreement of the interconnection customer to pay for interconnection facilities and upgrades identified in the Facilities Study, the area EPS shall provide the customer an executable interconnection agreement within five business days. The contract forms are summarized in the following section.

Contract Forms

Specific contract forms are included as attachments to this guide.

Information Requirements and Study Fees

The cooperative engineer needs information from the DG owner/developer to be able to make an informed decision regarding the impact of the proposed project on the distribution system. The cooperative also has a responsibility to make certain information readily available to the DG applicant. The recent amendment to the SGIP in late 2013 includes a PAR that can be formally requested by an interconnection customer for a non-refundable fee of $300. The PAR completed by the utility needs to include only readily available information for a single POI or PCC; however, the actual cost for a cooperative to prepare the PAR will likely be more than $300. A co-op should consider the actual cost of preparing the PAR and then determine the appropriate fee to be charged. A template for preparing the PAR is included as an attachment to this guide, which may minimize the time required by a cooperative to complete it.

The cooperative's engineering department or responsible employee has the responsibility of evaluating the impact of a DG interconnection on the distribution system. This evaluation tends to drive the assessment of a study fee. As an example, the Texas rules require no System Impact Study and no associated application fee when all of the following conditions for the proposed DG are met:

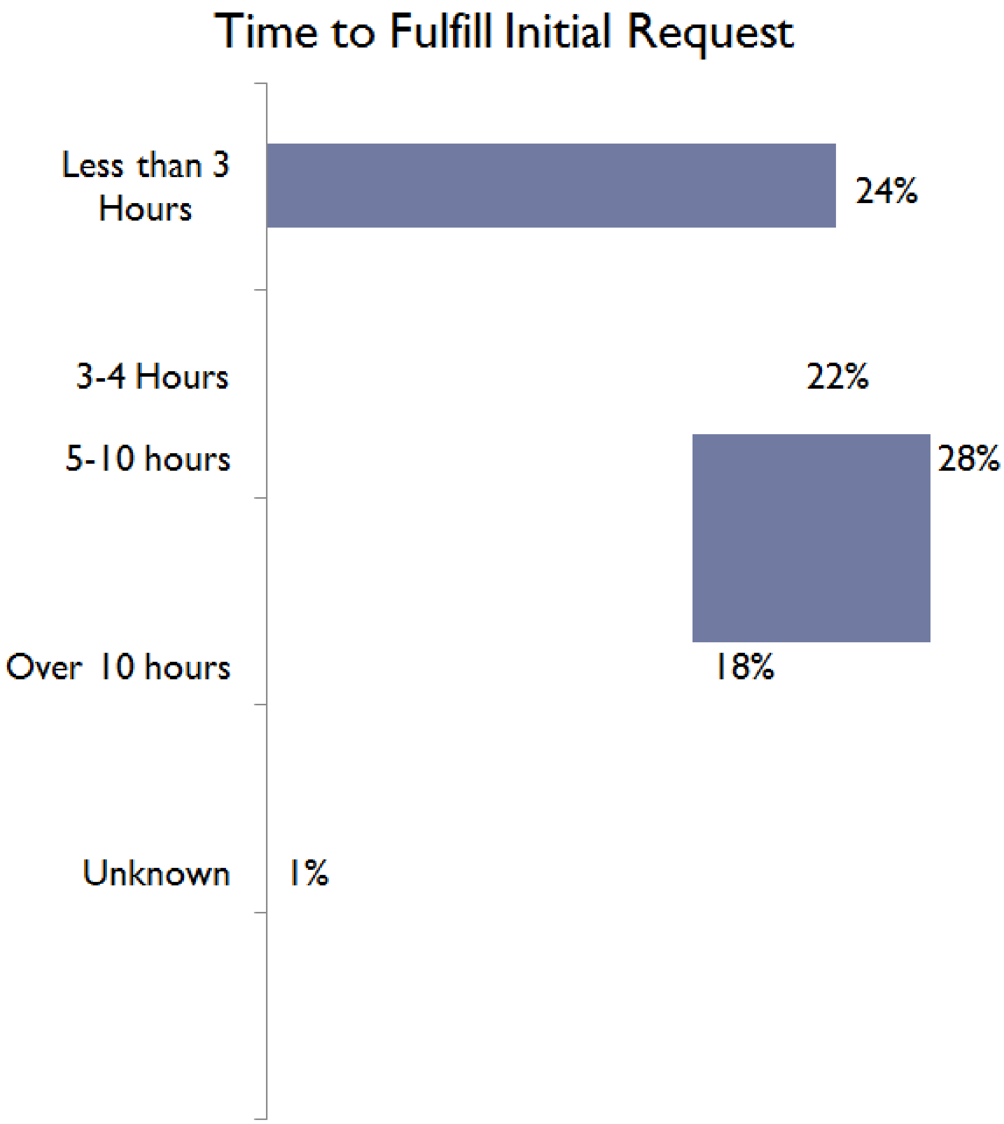
- Equipment is "pre-certified";
- Capacity is 500 kW or less;
- Equipment is designed to export no more than 15% of the total load on feeder (based on the most recent peak load demand); and
- Equipment will contribute no more than 25% of the maximum potential short circuit current of the feeder.

Note that these items are similar to the fast track screens included in the SGIP. Certification of equipment is discussed further below and in Appendix B of this guide. Many cooperative distribution systems are much smaller than those of the Texas utilities for which the above rules were originally developed; accordingly, the 500-kW guideline may be too liberal for the typical cooperative system. Additionally, in some cases, the DG unit may not be at a strong point on the feeder; in such cases, the 15% guideline might be applied at a point on the feeder (i.e., a line section) rather than on its total load.

Over time, application fees included in state interconnection standards have become much simpler to apply and much lower in cost; this of course helps to promote DG interconnections. It is typical for very small interconnections, particularly those pre-certified and involving net metering, to have no application fee or a very small one. For example, the New York standards, last revised in February 2014, do not allow an application fee for systems of 50 kW or less and only allow for a $350 application fee for systems up to 2 MW (this fee is refunded to net-metered customers). However, it is advisable that even for these types of interconnections, some nominal fee be assessed to limit the numbers of applications from customers who are not serious about interconnection.

An NRECA survey conducted in June 2014 indicated the time needed to fulfill an initial interconnection request (see Figure 5).

Figure 5. Time to Fulfill Initial Request



The submission requirements shown in Table 2 are representative of those currently proposed or in force in Texas, New York, and California.

Table 2. Representative Submission Requirements in Texas, New York, and California

DG Size	Operating Characteristics	Application
5 kW or less	Isolated	Not Required
>5 kW to 30 kW	Isolated	Part 1

DG Size	Operating Characteristics	Application
Up to 3 kW	Parallel operation, either power export or no power export	Part 1
>3 kW to 30 kW	No power export, parallel operation	Parts 1 & 2
>3 kW to 30 kW	Power export	Parts 1 & 2
>30 kW to 100 kW	Isolated	Parts 1 & 2
>30 kW to 100 kW	No power export, parallel operation	Parts 1 & 2
>30 kW to 100 kW	Power export	Parts 1 & 2
>100 kW to 1 MW	No power export, parallel operation	Parts 1 & 2
>100 kW to 1 MW	Power export	Parts 1 & 2
>1 MW to 3 MW	Power export	Parts 1 & 2

Application fees are designed to at least partially cover the costs of application processing and System Impact Studies. In many cases, though, cooperatives will separate the application fee and study fee for larger (>100 kW) interconnections and pass on the actual cost of the studies to the interconnecting customer. For these larger-sized interconnections, the actual cost to perform studies can be much higher than for typical application fees. Cooperatives should set fee levels for their systems that they believe are appropriate, given the costs to conduct the studies and local political pressures. It should be noted that these provisions do not preclude a cooperative from performing a study; they simply regulate when the co-op can charge a fee for its cost. Whether or not a study fee is billable to the applicant, a cooperative may reject an application for demonstrable reliability or safety issues but should work to resolve those issues to the mutual satisfaction of the utility and applicant.

A range of information is needed from the DG owner/developer as part of the application. (See Consumer Guidelines for Electric Power Generator Installation and Interconnection.) As shown on the application, Part 1 generally is required for small DG projects; both Parts 1 and 2 are required for larger, grid-connected projects. Part 1 of the application requires the following information:

- Owner/applicant contact information;
- Project design engineer and/or architect, including contact information;
- Electrical contractor (as applicable);
- Location of proposed generation interconnection;

- Type of generator data (e.g., PV, diesel, gas engine, etc.);
- Inverter performance data;
- Transfer switch data (if applicable);
- Estimated load, generator rating, and mode of operation information (e.g., total site load, generator rating, mode of operation, any power for export); and
- Description of proposed installation and operation (general description of the proposed installation, its planned location, and when the applicant plans to operate the generator).

Part 2 of the application requires some additional data and more details of the proposed DG project; its information requirements include the following (only as applicable):

- Synchronous or induction generator data;
- Prime mover information (e.g., type, manufacturer, model number, hp, energy source, etc.);
- Transformer between generator and grid (e.g., manufacturer, type of transformer connections, impedance, reactance, etc.);
- Inverter data (e.g., manufacturer, model, ratings, etc.);
- Power circuit breaker (model, voltage, impacity, interrupting rating, etc.);
- Protective relay data (e.g., manufacturer, model); and
- Additional information:
  - A single line diagram showing the customer's primary switchgear, transformers, and generation facilities;
  - A general operating description (combined heat and power, closed-transition peak shaving, open-transition peak shaving, emergency power, etc.); and
  - Project location (e.g., address, closest co-op pole number, grid coordinates, etc.).

For *new* DG facilities, additional information typically will need to be provided, such as data on flicker-producing loads, project construction and commissioning schedule, site location drawings, etc.

For guidance, the cooperative engineer typically will need to provide the following information to the DG owner/operator:

- Preliminary fault duties;
- Cooperative distribution system feeder one-line diagram;
- Operating guidelines;
- System phasing;
- Phase designations; and
- Method of grounding.

Application Processing Time

The cooperative has full responsibility for the review, approval, or rejection of the DG interconnection application. The approval process is designed to ensure that interconnection of the applicant's DG project will not adversely affect distribution system operations. The approval process needs to occur in a non-discriminatory and timely manner.

As the application process proceeds, certain applications may require minor modifications while being reviewed. The guide recommends that such minor modifications to a pending application shall not require that it be considered incomplete and treated as a new or separate application.

Upon receipt of a completed application, the cooperative should establish a definitive period of time[4] for processing the application and providing one of the following notifications to the DG applicant:

- Approval to interconnect;
- Approval to interconnect with a list of prescribed changes to the DG design;
- Justification and cost estimate for prescribed changes to distribution required to accommodate the DG unit; or
- Application rejection with justification.

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

Normally, the application will be submitted, processed, and an interconnection agreement signed before construction activities begin. However, a DG applicant may choose to begin construction earlier, assuming any risk associated with possible rejection of the application. In any case, DG owners/operators must receive cooperative approval before interconnection.

Metering and Telemetry

Metering in general should track the status (on and off) and kWh output of the DG unit. Cooperatives may want the metering for DG systems greater than 25 kW to include time tagging of kW output as well. Because of the economic impact of larger DG systems (greater than 200 kW), telemetry can be a good idea for monitoring real-time output and other DG functions for large and medium generators that are operated remotely. Telemetry may not be necessary if the DG unit is prevented, via protective relaying, from injecting energy into the cooperative distribution system. Telemetry data should be

[4] The suggested time period for this review is four to six weeks. The Texas interconnection rules allow four to six weeks for the entire interconnection process after receipt of a completed application. New York allows 15 business days for a preliminary review and up to 60 business days for the complete Study Process for systems greater than 50 kW that are not "non-type tested." In its Rule 21 Model Tariff Language, California allows 20 business days from the time the application is complete, but only for systems that do not meet the requirements for the Fast Track Process.

available to the cooperative, and the communication of such data should be compatible with the cooperative's communication methods.

Equipment Certification

An established trend in the field of DG interconnection is the "certification" of equipment. This certification typically is accomplished by an equipment "type test"—a test performed or witnessed once by a qualified independent testing laboratory for a specific protection package or device to determine whether the requirements of the technical interconnection guidelines are met (see Appendix B of this guide). Typically, equipment manufacturers will sponsor the type test.

> **EXCERPTS FROM TEXAS PUBLIC UTILITY COMMISSION REQUIREMENTS FOR CERTIFICATION OF DISTRIBUTED GENERATION EQUIPMENT BY A NATIONALLY RECOGNIZED TESTING LABORATORY**
>
> Distributed generation units (DG packages) that are certified to be in compliance by an approved testing facility or organization shall be installed on a company utility system in accordance with an approved interconnection control and protection scheme without further review of their design by the utility. To ensure that the pre-certified DG package is compatible with the utility's system, the utility shall determine the interconnection and control scheme required and shall review and approve the electrical configuration for each DG installation. DG packages that have not been pre-certified may still be interconnected subject to utility review. In this document, a DG package is defined as including the generating unit, the protection and control system and generator breaker. This document does not preclude on-site testing requirements.
>
> PUCT PROJECT NO. 22318
> FEBRUARY 2001

Although the time required to complete the interconnection application process described above will vary to some extent, projects using previously submitted designs that have been type tested satisfactorily will move through the process more quickly. Applicants submitting type-tested systems, however, are not exempt from providing the cooperative with complete design packages, which are necessary for verification of the electrical characteristics of the generator systems, the interconnecting facilities, and their impact on the cooperative distribution system.

Responsibilities of the Cooperative

While the guide offers sample application and contract forms, cooperative lawyers should review all terms, conditions, and policies to ensure that prudent and proper requirements have been imposed on customer and third-party generators; appropriate liability protection has been incorporated in the final agreement; and that costs are consistent with state and federal law and the cooperative's governing documents. This guide and all attached documents should be reviewed by the cooperative's counsel, management, and engineers to ensure that it is consistent with the matters already listed as well as with the cooperative's business operations and physical system requirements.

This guide and the materials attached hereto are only models for convenience of use. They will need to be customized to meet the needs of each cooperative. For example, the contract states that customers will have to maintain adequate insurance as approved by the cooperative. The co-op should decide ahead of time what amount would be adequate:

Is a $100,000 homeowner's policy sufficient, or is more required?[5] A June 2014 NRECA survey indicated the following supplemental insurance coverage requirements.

Table 3. Required Supplemental insurance Coverage

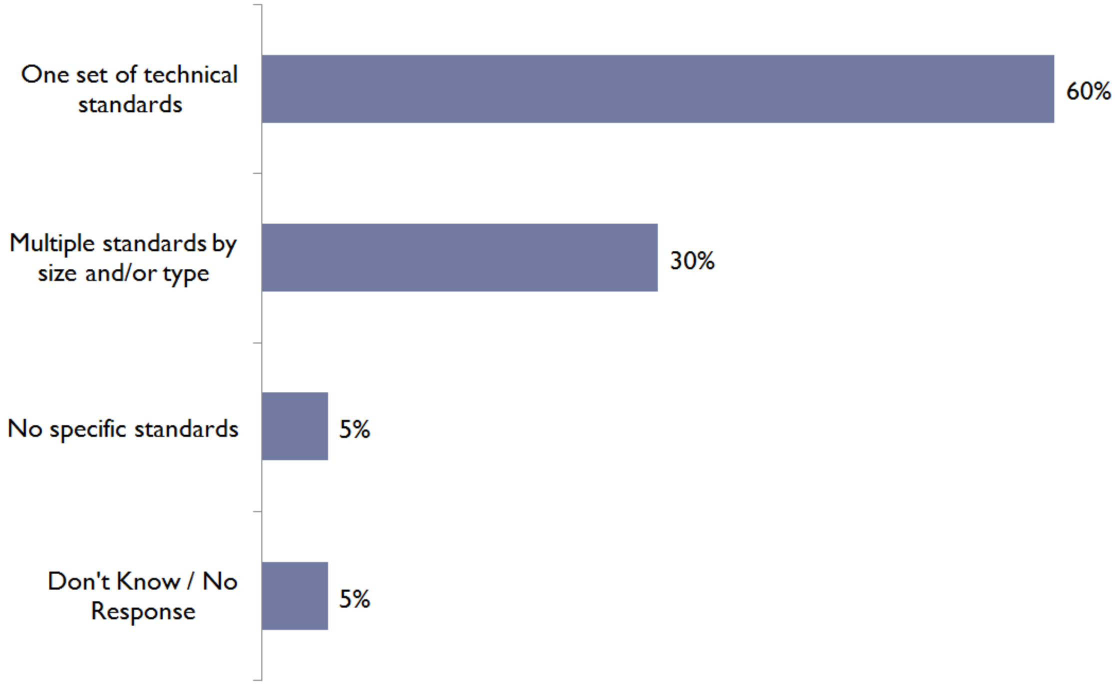
Required Supplemental Insurance Coverage

	$100,000 - $250,000	$250,001 - $500,000	$500,001 - $1,000,000	Over $1,000,000
Residential (n=73)	18%	36%	27%	1%
Commercial (n=61)	5%	18%	53%	10%
Agricultural (n=52)	2%	15%	56%	10%
Institutional (n=52)	4%	14%	56%	10%
Other (n=34)	3%	3%	44%	37%

The contract also states that telemetry is required for all generators greater than 200 kW to monitor connection status, real power output, and reactive power. The cooperative will need to determine if 200 kW is a reasonable threshold for its system. Each cooperative should make many other similar judgments.

[5] Insurance requirements typically are based on the DG size. For example, Colorado establishes $300,000 for 10 kW or less; $1,000,000 for up to 500 kW; and $2,000,000 for up to 2 MW. New York, on the other hand, specifically does not require any insurance coverage.

Figure 6. Percentage of Cooperatives Adopting Technical Standards for Interconnection of Consumer-Owned or Leased Solar PV Systems



This guide and attached materials are not adequate on their own to support interconnection. Each cooperative will also need to do the following:

- Adopt technical requirements for interconnection. To assist in that process, the cooperative could obtain and consult the IEEE Standard 1547.2, **Application Guide for IEEE 1547 Standards for Interconnection of DR with EPS**. Figure 6 provides the percentage of cooperatives that indicated in a June 2014 NRECA survey that they have adopted technical standards for interconnection of consumer-owned or leased solar PV systems.
- Revisit the cooperative's bylaws or other governing documents to determine the requirements for consumers to obtain the cooperative's approval before installing DG.
- For a distribution cooperative, it is important to examine the role of the G&T and the impact of its all-requirements contract, if one exists. From both an engineering and economic perspective, distribution co-ops may want to seek G&T cooperative approval of any power purchase contracts with DG owners/operators.
- Consider what role the cooperative and its G&T (or other wholesale energy supplier) wants DG to play on the system. Pertinent questions a co-op will want to ask include the following:
  - Does the G&T need to approve any power purchase agreement from a DG? (See prior bullet.)
  - What are the cooperative's obligations under its all-requirements contract or other wholesale power agreement? Note that some G&Ts may want to be a party to the interconnection contract and protect their own interests in the arrangement.
  - Will the cooperative or G&T purchase excess power from consumers?

   - Will the cooperative or G&T wheel excess power for the consumers to other purchasers of the energy?
   - Does the cooperative or G&T want to pay for the right to dispatch customer-owned generation or otherwise take advantage of the resource for the benefit of the system?
- Draft any policies, rate structures, or contracts necessary to implement the cooperative's business decisions for dealing with DG. NRECA has published the **Manual for Developing Rates for Distributed Generation** to assist co-ops in that process. This manual is available in the DG interconnection toolkit.

Appendix A
Certification Codes and Standards
(From Amended SGIP)

IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Standard 929-2000, IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Standard C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Standard C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Standard C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Standard C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Standard C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Standard C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Standard 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Standard 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Appendix B

Certification of Small Generator Equipment Packages

(From Amended SGIP)

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such 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 NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 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.

3.0 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 nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the 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.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' 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 to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 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 these small generator interconnection procedures shall be considered certified under these procedures for use in that state.