Updated Recommendations for
Federal Energy Regulatory Commission

Small Generator Interconnection Procedures Screens

Prepared by

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Solar America Board for Codes and Standards

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Executive Summary

Public demand for customer-owned distributed generation, especially grid-tied photovoltaic (PV) systems, has encouraged federal and state legislation calling for practical procedures for interconnection of non-utility-owned generators to the electric grid. Existing procedures have evolved over the last decade as states and the federal government sought to implement and improve upon early efforts. Early efforts were often unsatisfactory, because high costs, lengthy timelines, bureaucracy, and uncertainty proved to be formidable barriers. Fortunately, much has been learned during the last decade and "best practices" have begun to emerge.

The Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP) apply only to facilities subject to the jurisdiction of FERC, but may serve as a model for state-level interconnection procedures. FERC SGIP was developed and published in 2005 through the efforts of utilities, regulators, industry representatives, consumer and environmental advocates, and other interested parties. According to paragraph 4 of FERC Order 2006, the National Association of Regulatory Utility Commissioners (NARUC) was a key contributor to the FERC SGIP. Regulators anticipated the need to update the small generator rules in FERC's Final Rule, which stated that "beginning two years from the issuance of this order, [we will] consider and recommend consensus proposals for changes in the Commission's rules for small generator interconnections" (FERC Docket RM02-12-000, 2005). There has not been a substantial review yet and the present study is intended to assist with such a review.

To obtain input, we asked 154 subject matter experts (SMEs), composed primarily of the Institute of Electrical and Electronics Engineers (IEEE) 1547.6 and 1547.7 Working Groups, to complete an online questionnaire concerning the need to update the FERC SGIP fast track screens and the 10 kilowatt (kW) Inverter Process in light of current available experience, data, and best practices. We report the responses of the 37 SMEs who replied to the questionnaire, and we also reviewed and considered recent National Renewable Energy Laboratory (NREL) technical reports. The SMEs' responses about each of the various screens ranged from strong consensus for a need to update some screens to general agreement that other existing screens do not need to be changed. Consensus was defined as support from two-thirds of the respondents.

Summary of Recommendations

Solar America Board for Codes and Standards (Solar ABCs) presents these recommendations with the intent that they will serve as the first step toward the update of the FERC SGIP.

Based on SME consensus, FERC and NARUC should collaborate to update the following FERC SGIP screens. FERC and NARUC will need to develop the technical details for each update.

> Screen 2.2.1.7: The limit placed on the size of the aggregate generation on a single phase shared secondary should be updated to be in terms of a percentage of the transformer nameplate power rating.
>
> Screen 2.2.1.9: The stability requirement should be rewritten for clarity.
>
> Screen 2.2.1.3: Area networks should be covered in addition to spot networks. In addition, limits on maximum load should be revised upward in keeping with recent rules enacted in Connecticut and by Consolidated Edison in New York and with the guidelines defined in the IEEE 1547.6, which went to ballot in mid-June 2010.

For the following screens, the SMEs did not reach consensus, but many respondents made strong arguments for updates. These arguments are worth considering, because these screens have the potential to have the greatest impact on the reduction of barriers to high penetrations of PV. The U.S. Department of Energy (DOE) and/or the national laboratories should conduct technical studies of the issues covered in these two screens.

Screen 2.2.1.2: Further investigation and research is needed to determine whether to increase (and by how much) the current 15% limit on generating capacity related to circuit peak load (or whether to change the limit to relate to the circuit minimum load). Researchers should also consider separate treatment of inverter-based generation.

10 kW Inverter Process Size Limit: Further dialogue, and perhaps some research, is needed to determine whether to increase (and by how much) the limit from 10 kW for the simplified inverter interconnection process.

There was not a consensus for updating any of the remaining fast track screens reviewed by the SMEs. Therefore we make no recommendation for change to those screens. In addition, we recommend ensuring that utilities follow the same procedures imposed on other generators. The passage of the investment tax credit (ITC) has profoundly changed the utility role in the distributed generation market in general, and the PV market in particular. Therefore, FERC and NARUC should consider developing an enforceable non-discrimination policy or rule to ensure uniform application of the technical requirements to all distributed generation systems, including utility-owned distributed generation systems.

Author Biographies

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Michael T. Sheehan, P.E., is an Interstate Renewable Energy Council (IREC) representative working on state-level rulemaking and workshops. He is vice president of utility development for an energy efficiency company that sells electronic voltage regulators for both domestic and international utilities. He also has extensive electric utility industry experience, particularly in interconnections, distribution reliability, T&D planning, efficiency, and optimization measures. Sheehan has worked for three utilities (IOUs in the Midwest, Southeast, and Pacific Northwest) and was a member of the Institute of Electrical and Electronics Engineers (IEEE) 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. He developed the System Operator training program and designed the qualifications test and certification procedures. He is a registered professional engineer in the state of Washington and a graduate of the Illinois Institute of Technology.

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Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

For more information, visit the Solar ABCs Web site:

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Introduction

The experience gained over the last decade confirms that distributed generation (DG) is far more likely to be deployed if developers and utility customers can readily discern the costs of interconnection and the length of time required for the interconnection approval process. Although regulators have a challenging task in formulating interconnection procedures, the benefits of implementing procedures that function effectively are substantial.

Solar America Board for Codes and Standards (Solar ABCs) identifies major gaps, barriers to deployment, or other issues in current codes and standards. These issues are prioritized to develop a strategy for the Solar ABCs' annual work plan. The first Solar ABCs paper on the topic of this report was published in 2008, and titled *Comparison of the Four Leading Small Generator Procedures* (Keyes & Fox, 2008). The report reviewed the four sets of interconnection procedures that regulators often consider when developing state and local procedures.

The report at hand is the second phase in the Solar ABCs strategic plan to examine the Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP), and focuses on the FERC SGIP fast track technical screens. Section 2.2.1 of the FERC SGIP contains several screens used to fast track interconnection (FERC, 2005), and some of those screens may be unnecessarily restrictive. Revising these screens to simplify interconnection and increase the number of systems that pass the fast track screens (and the 10 kilowatt [kW] inverter process) can reduce barriers to PV installations. The Solar ABCs asked the North Carolina Solar Center (NCSC) and the Interstate Renewable Energy Council (IREC) to lead the review and development of suggested updates to the FERC SGIP screens and the 10 kW inverter process after conducting an interactive development process based on a questionnaire sent to small generator interconnection subject matter experts (SMEs).

Background

FERC issued the FERC SGIP procedures as a final rule in 2005 (Order 2006) (FERC, 2005), then clarified and refined the procedures in 2006. FERC developed the SGIP with extensive participation by utilities, regulators, renewable energy advocates, industry, and government experts. Through this process, FERC hoped to minimize the federal-state division and promote consistent, nationwide interconnection rules by adopting many of the best practices interconnection rules recommended by the National Association of Regulatory Utilities Commissioners (NARUC). Incorporated into the final FERC rule was the Small Generator Interconnection Agreement (SGIA). FERC issued the current versions of the SGIP and the SGIA as a final amended rule on August 28, 2006 (see Order 2006-B) (FERC 2006-B, 2005).

In summary, Order 2006 (et seq.) required all public utilities that own, control, or operate facilities under FERC's jurisdiction to file standard interconnection procedures (the SGIP) and a standard interconnection agreement (the SGIA) to interconnect generating facilities up to 20 megawatts (MW). The SGIP applies directly to large DG sources interconnecting to FERC jurisdictional lines or those making FERC jurisdictional sales of electricity. For interconnection of DG smaller than a few megawatts, which constitutes the vast majority of such interconnections, the FERC SGIP rarely applies as a result of current FERC recognition of state public utility commission jurisdictions. Small DG sources are usually interconnected to distribution lines rather than to transmission lines, and FERC's jurisdiction covers utility wholesale transmission lines. Thus FERC has only limited jurisdiction over the lower voltage distribution systems. However, according to FERC Order 2006, FERC may claim jurisdiction over a distribution line when a "non-qualifying facility" generator interconnects to a distribution line covered by a public utility's open access transmission tariff (OATT) to make wholesale sales of electricity (FERC 2006, 2005).

Unless they're very small, most utilities own or operate some FERC-jurisdictional utility lines. They are thus required to file interconnection procedures that follow the FERC SGIP as part of their OATT. Some utilities may seek similar requirements for distribution lines subject to state jurisdiction for the sake of procedural uniformity. However, to date, this rationale has not been strong enough to lead to widespread adoption of the FERC SGIP by states. State utility commissions and their NARUC traditionally defend their jurisdiction against encroachment by FERC and don't feel obligated to start with the FERC SGIP in developing their state interconnection procedures. Some states have essentially adopted the FERC SGIP for reasons of regulatory economy and other policy issues. Additionally, utilities (who are very often active and well-represented participants at state commissions) interested in limiting DG may have opportunities at the state level to seek more restrictive interconnection provisions than the FERC SGIP provides. As a result, although the FERC SGIP may have been intended to serve as a model for state utility commissions, as a practical matter the effect of the FERC SGIP as a model has been limited.

Connecting to the Grid is a monthly electronic newsletter published by IREC. *Connecting to the Grid* editor Laurel Varnado says the FERC SGIP screens have been adopted in a number of state and utility interconnection standards (personal communication, March 12, 2010). According to Varnado, Colorado and Connecticut based their interconnection procedures on the FERC SGIP model, and 14 states use FERC SGIP-based technical screens in their interconnection procedures. Further, the updates suggested in this report are largely based on positive experience with state-originated "best practices."

While the FERC SGIP screens aim to be neutral across different types of generation, the technical attributes of DG and the various types of electric power systems (EPS) have a bearing on interconnection requirements. For example, inverters can incorporate improved safety and faster operational features into their controls than is possible in synchronous generators. This provides for failsafe designs that prevent the inverter from operating unless its protective functions are working correctly. Properly designed and tested inverter-based devices require little (if any) additional external protection equipment for interconnection. The fact that inverters are inherently very "controllable" has contributed to their increased use in utility applications—from a few thousand systems in 2002 to more than 69,000 systems by the end of 2008 (IREC, 2009). Rotating generators (i.e. those powered by engines, wind, or hydropower), which pose more difficult technical questions and may use slower mechanical relays to accomplish interconnection, are treated differently in the codes and standards. They should also receive separate treatment in sections of the FERC SGIP, particularly as the differences in the technical issues and their impacts relating to interconnection are magnified by quickly increasing PV penetrations and advances in inverter technologies.

From a utility interconnection perspective, DG systems are generally classified by the type of generator[1] and the protective equipment that makes up the interface between the system and the grid. The classifications include solid-state or static inverters, induction machines, and synchronous machines (see Appendix I). Nearly all renewable energy systems are grid-tied PV systems that produce grid-quality alternating current (AC) power using an inverter, and typically are treated as similar even though the source of power may be different (solar photovoltaic and fuel cell, for example). High-speed microturbines and some wind turbines also use an inverter for interconnection despite the fact that they generate power through the rotation of a generator. This allows the generator to produce AC current at frequencies higher than the grid, with the power converted to direct current (DC) before being converted to grid compatible AC power by the inverter.

1 The IEEE 1547 technical standard uses the term "interconnected system" rather than "generator."

Overview of FERC SGIP Screens

The FERC SGIP contains the technical procedures that a small generator and utility must follow when connecting the generator to utility lines subject to FERC jurisdiction. The standards include provisions for three levels of interconnection based on generator size:

- The "10 kW Inverter Process" for certified,[2] inverter-based systems no larger than 10 kW[3]
- The "Fast Track Process" for certified systems no larger than 2 MW
- The default "Study Process" for systems no larger than 20 MW, including those that fail to pass the fast track screens (this study process is not included in this review).

The standards are embodied in a single set of ten screens for both the 10 kW Inverter Process and the Fast Track Process. Systems that pass all ten of the screens (some states and models use a subset of the 10 screens in the 10 kW Inverter Process) may interconnect without going through a more in-depth study process, which requires additional time and expense. The goal of these technical screens is to reduce resistance to adding new DG capacity by providing a quick and simple method to determine which DG systems can be safely interconnected with negligible risk of negatively impacting grid function. The FERC SGIP screens (§ 2.2.1) are summarized below:

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff. (Note: This screen is non-technical and is not reviewed in this report.)

2.2.1.2 If the interconnection is to a radial distribution circuit, the interconnection may not facilitate an increase in aggregated generation on the circuit that exceeds 15% of the line section annual peak load. A line section is a portion of an interconnected utility's electric system bounded by automatic sectionalizing devices or the end of a distribution line.

2.2.1.3 The interconnection of inverter-based generation may not facilitate an increase in aggregated inverter-based generation to the load side of spot network protectors that exceeds the smaller of 5% of a spot network's maximum load or 50 kW.

2.2.1.4 The interconnection may 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.

2.2.1.5 The proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 87.5% of the short circuit interrupting capability.

2.2.1.6 The proposed interconnection must use the correct type of interconnection (3-wire to 4-wire) to the primary distribution line given the type of electrical service provided to the interconnecting customer.

2.2.1.7 If the proposed generation is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary including the new generation may not exceed 20 kW.

2.2.1.8 If the proposed generation is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition may not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.

2 Certified refers to the certification requirements explained in Attachments 3 and 4 of the FERC SGIP, which may be found at www.ferc.gov/industries/electric/indus-act/gi/small-gen/procedures.doc

3 Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen/procedures.doc

2.2.1.9 The proposed generation may not exceed 10 MW if interconnected to the transmission side of a substation transformer feeding the circuit in an area where there are known, or posted, transient stability limitations (three or four transmission busses from the point of interconnection, for example).

2.2.1.10 Construction would not be required by the utility. (Note: This screen is non-technical and is not reviewed in this report.)

The FERC SGIP screen 2.2.1.2 is of particular interest, because it typically limits the size and number of DG systems that can be interconnected quickly without going through the "Study Process." In other words, it is the screen most likely to be failed as PV systems reach higher penetrations. The technical reasons for the capacity limit are related to minimum daytime load on the line section, not peak load. Specifically, the aggregate DG must never be greater than the load on the line section. However, unlike peak load data, minimum load data is currently not uniformly available to utility planners. The 15% threshold of the peak load is therefore an estimate of 50% of the minimum load on a line section. For most distribution systems, a line section minimum load is in the range of 30% of the peak load. Thus, the 15% limit on aggregate generation capacity would represent only half the minimum load of the line section.

The U.S. Department of Energy's (DOE's) 2008 Renewable Systems Interconnection (RSI) studies attempted to address the 15% line section threshold level defined by Screen 2.2.1.2. These studies modeled some of the impacts of high penetration of grid-tied PV systems. One of the RSI reports on voltage support concludes, "In all the cases studied, PV inverters can positively contribute to the feeder voltage regulation and result in an improved voltage profile. At a high enough penetration, PV inverters may be able to provide feeder voltage support" (Renewable, 2008). However, none of the RSI studies addressed safety issues ("islanding") associated with the 15% line section threshold.

This screen was meant to flag interconnection applications that may impact distribution system operation, safety, or reliability—and thus prevent unintended islanding. In addition, inverter-based and rotating generators should probably receive separate treatment in the 15% screen. We were interested in the responses to the questions about the 15% screen from the California-based SMEs, because California has installed more than half of the grid-tied PV systems in the United States.

Status of Distributed Generation in 2010

In the FERC Order 2006 dated May 12, 2005, FERC stated they "believe that the thresholds used in the screens to be conservative and that there is negligible chance that a proposed interconnection could pass the screens and actually impact the safety and reliability of the Transmission Provider's electric system" (FERC, 2005). The need to update the small generator rules was foreseen in FERC's Final Rule, which stated that "beginning two years from the issuance of this order, [we will] consider and recommend consensus proposals for changes in the Commission's rules for small generator interconnections" (FERC Docket RM02-12-000, 2005). To our knowledge, the present study is the first review or proposal to update the FERC SGIP screens.

Currently, interconnection rules in the United States are based upon submissive contribution of grid-tied PV systems. These standards were, of course, originally developed when there was a very low level of penetration of grid-tied PV systems, and even less documented experience. Now is the time to updated regulatory rules like FERC SGIP based on the decade of experience since these rules were codified. Updated rules based on these experiences may avoid the time delays and expense of unnecessary interconnection system impact studies, prevent regulatory lag, and enforce the replacement of fossil fuel and imported oil—all while maintaing reliability and safety.

The fact that the economics of PV systems are believed to be approaching grid parity (Denholm, Margolis, Ong, & Roberts, 2009) heightens the need for regulatory update.

The solar industry has steadily reduced the costs of PV DG systems during the past 10 years, and prices for conventional forms of electricity are likely to rise—perhaps substantially—in the coming decade. These trends are almost certain to dramatically increase the penetration of grid-tied PV systems, so it is imperative to prepare for this opportunity by developing regulatory procedures that maximize the contribution of PV systems to the electric power system. In addition to reducing prices, inverter and grid technologies are rapidly advancing, which could enable inverter-based DG to provide additional value such as providing voltage and volt-ampere reactive (var) support[4]. These movements need to be considered when updating interconnection standards.

Methodology

The goal of this project was to gather the opinions of SMEs who work in the field of small generator interconnections. We used an internet-based questionnaire for this purpose. We developed the questionnaire, as well as the list of SMEs, with input from energy professionals from across the country who participated in two stakeholder planning meetings before we distributed the questionnaire.

More than 200 people attended the first stakeholder meeting, held October 30, 2009, at the Solar Power International conference in Anaheim, California. At the subsequent stakeholder planning meeting, conducted online via GoToWebinar software on December 2, 2009, we presented more details about the scope of the study and described the voter's pamphlet approach[5] that we used to develop the SME questionnaire. Twenty-six people registered for this second meeting. We sent invitations to these meetings to a comprehensive list of Solar ABCs and IREC contacts. Each meeting began with a presentation by one or both of us addressing the basis for the study and the method for conducting the questionnaire. We used any resulting questions and comments to refine the study procedures and questionnaire itself. For example, when attendees questioned the confidentiality of SME responses, we created a confidentiality policy with an option for SMEs to opt out of publicizing their comments. Reaching out to the stakeholders resulted in five additional requests to participate in the questionnaire.

Previous studies have noted a gap between researchers' practical expertise in survey design and familiarity with the questionnaire's topic (Ramirez, 2002). We are experts in the field, and we avoided this problem by designing the questionnaire ourselves with input from other SMEs. This ensured an in-depth understanding of the topic, which is essential in questionnaires requesting complex or technical information. As a result, the FERC SGIP questionnaire was carefully constructed to elicit insightful ideas and opinions from the respondents. We chose a popular online questionnaire tool (Survey Monkey) to collect the SME responses. Major advantages of the online approach include cost-effectiveness and speed. A limitation is demographic—younger people are more likely to respond to online questionnaires (Ramierez).

To begin the process, we asked the SMEs to examine eight technical FERC SGIP screens. We then questioned them about the need to raise the threshold for the simplified interconnection process for inverter-based systems above the current 10 kW limit. We also provided SMEs several references and links to reports, such as the 15 RSI studies (Kroposki et al., 2008).

Prior to the questions about each screen, the questionnaire provided the SMEs a summary of the screen, arguments for updating the screen, and arguments for leaving

4 Voltage and var support are services that enhance grid stability and reliability. Voltage support is service that may be provided by certain devices to slightly adjust the voltage at that location on the grid to keep it within the required range. Var support is a similar service to adjust the amount of reactive power at that location on the grid. Volt-amperes reactive (var) is a unit used to measure reactive power in an AC electric power system.

5 The voter's pamphlet approach is to present both sides of an issue in an unbiased way, with supporting references when possible.

the screen unchanged (see Appendix III). We asked the following questions about each screen:

- Do you support updating this screen? (Response options were Yes, No, or Can't answer because ___.)
- If you support updating this screen, what change would you recommend? (One to five possible screen updates were presented in multiple choice fashion, including the option to write in a suggestion.)
- Please briefly provide an explanation of your position.

SMEs were required to reply to the first question, but the following two questions were optional. In general, everyone who responded "yes" to question 1 also answered question 2, and the vast majority of SMEs also responded to question 3 for each screen. At the end of the questionnaire, the SMEs were asked about their role and experience with DG interconnection.

The questionnaire was then sent to the following SMEs:

- All Members of IEEE 1547.6 Power System Distribution Secondary Networks Working Group
- All Members of IEEE 1547.7 Distribution Impact Studies Working Group
- Eight additional individuals identified by Solar ABCs (two national labs, two utilities, two consultants, and two PV industry).

The SMEs who responded to the questionnaire were a good balance between utility engineers and consultants (see Figure 2). We specifically avoided extending the invitation to complete the questionnaire to trade groups and special interest entities.

Following the collection of the SME questionnaire responses, we held a third stakeholder meeting to present the results. We focused on the issues upon which the SMEs reached a consensus, because these are the issues likely to be recommended for updating. We considered a consensus to be agreement of at least two-thirds of the SMEs. This meeting was held via GoToWebinar software on April 14, 2010, with 113 people registered. Like the other stakeholder meetings, we began with a presentation that addressed not only the results of the voting on the *Do you support updating this screen?* question on each of the issues, but also a brief discussion on the plan for the report. Based on analysis of the questionnaire results and review of recent studies on PV interconnection, and in consultation with other SMEs, we developed recommendations for updating the existing FERC SGIP screens.

Results and Recommendations

Table 1 lists the SMEs receiving the questionnaire and responding to it:

Table 1: Target SMEs

Target SMEs	Questionnaire Recipients	Number of SMEs Completing Questionnaire
IEEE 1547.7 Working Group Only	91	23
IEEE 1547.6 Working Group Only	35	5
Both IEEE 1547.6 and 1547.7 Working Groups	20	7
Solar ABCs Invites	8	2

When we reviewed the responses, we found that roughly two-thirds or more of the SMEs (considered a consensus for the sake of this report) recommended an update of only three of the FERC SGIP screens. Based on this and input from other studies, we recommend that all three of these screens be strongly considered for updating. We also recommend that a fourth very important screen (Screen 2.2.1.2) be aggressively studied to determine how its penetration limit may be increased so that it does not create an unnecessary barrier to PV development or lead to safety or reliability problems. For similar reasons, we suggest studying the size limit of the 10 kW inverter process to determine the appropriateness of increasing it. A discussion of the SME questionnaire responses about these four screens and the 10 kW inverter process is below. Detailed response results of the entire questionnaire are available in Appendix II.

<u>Screen 2.2.1.7</u>: *The existing screen is: "If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW."*

The vote on this screen was 26 for an update versus 6 against, thus showing the strongest support for change of any screen. The change supported by the majority of the SMEs was to base the screen on a percentage of the transformer nameplate power rating instead of a static system size. The comments in favor of an update include, "I do not clearly understand the technical basis of the FERC 20 kW limit. I personally prefer the limit to be based on service transformer nameplate capacity." SMEs opposed to changing this screen said, "Actually, the aggregate capacity of DG installed on a shared secondary should be limited to 10 kW. Simply because there are two customers on a single secondary does not mean that you can safely double the capacity limit of 10 kW. Although the 65% rule applied to a 15 kV transformer limits the aggregate capacity to 10 kW, applying the rule to larger transformer allows the customer to bypass the capacity rules by installing/requesting a larger transformer. As far as safety, I am leaning slightly towards allowing the 65% transformer capacity rule if each customer is constrained to a maximum of 10 kW. Therefore, I am unable to support the change."

There is also a precedent for changing this screen to a percentage of the service transformer nameplate power capacity basis set by New Mexico. Their small generator interconnection procedures have the following screen: "If the proposed Generating Facility is to be interconnected on a single-phase Shared Secondary, the aggregate Generating Facility capacity on the Shared Secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating." Due to the strong SME support in the questionnaire responses and the New Mexico precedent, we recommend that the FERC SGIP screen on shared secondary be updated to a limit based on service transformer nameplate power capacity.

Screen 2.2.1.9: *The existing screen is: "The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (three or four transmission busses from the point of interconnection, for example)."*

This screen received the second highest number of votes for change—24 voted to change it, nine wanted it to remain the same. Comments ranged from "Utility distribution engineers do not know how to address the screen as it is written now" to "The trouble is, a 10 MW [system] can represent a significant amount of generation depending upon the transmission or sub-transmission to which it is connected. This is particularly true in rural systems. The loss of 10 MW of generation could be significant and result in voltage stability problems. FERC and NERC [North American Electric Reliability Corporation] regulations of stability do not apply [to] voltage levels below 100 kV. Therefore, any change to increase the aggregate capacity above 10 MW should be, at a minimum, tied to system voltage." We believe that this screen is vague and thus frequently misunderstood by SMEs, so it should be changed to address specific safety or reliability concerns.

Screen 2.2.1.3: *The existing screen is: "For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW."*

The networks screen vote results were 21 for updating, 11 against, effectively meeting the two-thirds consensus threshold.

We believe this screen needs two updates. First, FERC SGIP screen 2.2.1.3 should expand its narrow focus on spot networks, which typically serve one large building, to also address area network interconnections[6] (FERC Docket RM02-12-000, 2005) that may supply several city blocks. Second, the limit should be raised in accordance with new rules adopted at the state level. Specifically, the state of Connecticut drafted a rule on networks stating, "Total aggregate generation interconnected to an area network will be limited to 3% of the maximum network transformer connected kVA with the feeder supplying the largest number of network units out of service, or a maximum of 500 kW, whichever is less" (Connecticut, 2010). It should be noted that this Connecticut rule also defines some additional technical criteria, which cannot be overlooked, but does not change the significance of this 3% or 500 kW rule.

Additionally, Consolidated Edison of New York, Inc. (Con Ed), in an effort to reduce barriers to interconnection of customer-owned DG, announced that inverter-based systems sized between 25 kW and 200 kW may follow the expedited application process for interconnection to the utility's distribution network systems as long as the inverter-based system has been certified and tested in accordance with UL 1741 (November 2005 revision) and the utility has approved the project accordingly. While the Con Ed networks in New York represent the majority of the area networks in the United States, they are not necessarily representative of all U.S. area networks.

6 Network system means an AC power distribution system in which customers are served from three-phase, four-wire low-voltage circuits supplied by two or more network transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The network system has more than two high-voltage primary feeders, with each primary feeder typically supplying multiple network transformers, depending on network size and design.

Furthermore, the IEEE 1547.6, "Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks," had gone to ballot at the time of this writing (July 2010). When released, the results of this guideline should also be considered when deciding on a possible update to screen 2.2.1.3.

Screen 2.2.1.2 *The existing screen is: "For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the Small Generating Facility, on the circuit shall not exceed 15% of the line section peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line."*

The votes to update this screen were split—18 in favor, 20 opposed. An SME's comment in favor was, "I believe that the majority of the interconnections of (aggregate) gens sized between 15% to 30% of peak load will cause no additional issues, but there may be a few where genuine concerns should be addressed. The key is to have a simple supplemental review process with secondary screens to quickly address the question." An SME concerned about the change wrote, "I think increasing the limit ultimately would be OK if a study focused on min/max loading ratios, time of day aspects, etc., that demonstrates the 15% number is predominantly too conservative an estimate of daytime low load conditions."

More than half of the interconnected grid-tied PV systems installed in the United States are installed in California. As expected, some of the highest levels of grid-tied PV penetration are also in California. We were interested in responses from California-based SMEs, given their level of experience with a 15% threshold. Of the respondents with California DG interconnection experience, ten support updating the screen and seven do not. Of the ten SMEs supporting an update, nearly two-thirds voted to increase the limit to 30% of line section peak load, which is double the current limit.

The nearly even split in opinion among all the SMEs contrasts with the more favorable response from the California SMEs. Many of the SMEs who voted against raising the limit cited safe operations (islanding) as the issue. Low limits in the screen tend to burden the PV industry with the cost and time delay of system studies. On the other hand, setting the level higher than necessary increases risk and may lead to grid problems, inviting potential backlash that could damage any progress being made in adopting PV. However, raising the limit is vital for continued rapid growth in PV, so it is prudent to determine the appropriate limit. Many SMEs providing input—as well as authors of recent research reports—believe the safe limit is significantly higher than the current 15% limit in this screen. Therefore, we recommend that DOE or NREL develop a study to address the concerns identified by the SMEs and to determine the procedures and limits that will preserve safety and reliability without hampering PV development. One facet of the solution may be to treat inverter-based generators separately from other generators.

10 kW Inverter Process: *"The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5."*

The votes in favor of updating this screen were 21 votes for and 16 against. While these numbers do not reflect a two-thirds majority threshold, we felt that several SMEs who supported an update made strong arguments in favor of it and the arguments made for keeping the existing screen were weaker. For example, one SME with a strong argument explained his support of an update like this, "I favor the increase to 25 kW because of the precedent (in New York, for example), the lack of issues that have arisen from sizes in this range, and most importantly, because the systems still have to pass the fast-track screens. This should adequately protect against systems being installed without proper scrutiny." It should be noted that more than 75% of the SMEs who support increasing the size limit indicated they would support moving the limit to 25 kW or higher.

Even though 16 SMEs did not support updating the screen, their comments shed light on the fact that more dialogue is necessary before a final decision about updating this screen is made. We believe that many of the SMEs who voted against updating this screen may be convinced of the appropriateness of the update if there is an opportunity for open dialogue among SMEs about this screen. For example, one SME said, "Standards such as [Underwriters Laboratories] UL/IEEE/NEC [National Electrical Code] do not address multiple DR [distributed resources]. Twenty-five kW DR, in aggregate, could very quickly cause problems on distribution secondaries," which suggests that this SME did not consider that to be eligible for the 10 kW Inverter Process a system must pass all 10 fast track screens.

Several states (New York and Connecticut, for example) recently adopted small generator interconnection procedures that have a 25 kW system size limit on the streamlined inverter process. Additionally, IREC's model small generator interconnection procedures, which represent best practices, contain a 25 kW limit to its streamlined inverter process, referred to as the Level I process. These procedures were developed more recently than the FERC SGIP, thus allowing IREC to consider recent industry experience with significantly more distributed PV systems than during the development of the FERC procedures.

Considering the responses of the SMEs and the precedents set by the recent state and model small generator interconnection procedures, we believe there is considerable justification to increase the inverter process system size. Despite the lack of a two-thirds majority for updating the screen, but due to the positive responses from many of the SMEs, a lack of issues with systems this size, and the recent precedents set by state and model small generator interconnection procedures, we believe FERC and NARUC should facilitate additional dialogue on the issue and consider increasing the system size limit for the Inverter Process.

Other Screens

For the remaining screens, no consensus was reached by the SMEs. They were mixed about their support of updating those screens, and many mentioned serious concerns regarding both the current versions and the considered updates of these screens. We believe that the process to address issues and concerns in the remaining screens requires additional interactive discussion that is beyond the scope of this report.

Competitive Fairness

Recommendations related to competitive fairness are presented in the following section.

Summary of Recommendations

The Solar ABCs commissioned this study to analyze and suggest updates to the FERC SGIP screens. The goal was to review the lessons learned in federal and state proceedings since the adoption of the FERC screens in order to determine the feasibility of further simplifying interconnection procedures, and, perhaps, moving the federal screens closer to the converging "best practice" state screens, thereby reducing barriers to installing PV equipment.

Thirty-seven subject matter experts responded to an online questionnaire and provided recommendations concerning the technical FERC SGIP screens and the 10 kW Inverter Process. As a result, we recommend that three screens be updated, and that a fourth screen and the 10 kW Inverter Process be studied or discussed further. We discerned no consensus with respect to the remaining screens.

We recommend the following changes:

Screen 2.2.1.7: The limit placed on the size of the aggregate generation on a single phase shared secondary should be updated to be in terms of a percentage of the transformer nameplate power rating.

Screen 2.2.1.9: The stability requirement should be rewritten for clarity.

Screen 2.2.1.3: Area networks should be covered in addition to spot networks. In addition, limits on maximum load should also be revised upward in keeping with recent rules enacted in Connecticut and by Consolidated Edison in New York and with the guidelines defined in IEEE 1547.6, which went to ballot in mid-June 2010.

Screen 2.2.1.2: Further investigation and research is needed to determine whether to increase (and if so, by how much) the current 15% limit on generating capacity related to circuit peak load (or possibly changing the limit to a percentage of the circuit minimum load). Separate treatment of inverter-based generation should be considered. DOE or NREL should aggressively study these issues.

10 kW inverter process: Further dialogue and investigation is needed to determine whether to increase the limit from 10 kW for the simplified inverter interconnection process (and if so, by how much).

The Solar ABCs recommends that FERC and NARUC collaborate to further determine the potential benefits of updating these FERC SGIP screens. The goals are to remove barriers to increased PV penetration and harmonize state and federal approaches to the screens based on what has been learned over the past decade. The current FERC–NARUC collaborative on demand response provides a suitable template for a joint effort on the FERC SGIP screen update.

Competitive Fairness

Prior to February 2008, utilities were not eligible to receive the 30% investment tax credit (ITC) for PV. When the law was amended to extend the ITC to investor owned utilities (IOUs), it resulted in a dramatic increase in utility solar installations. According to IREC's Larry Sherwood, the installations could increase from 22 MW in 2008 to more than 300 MW projected in 2010 (personal communication, April 22, 2010). IOU access to the ITC has profoundly altered the utility role in the PV market. However, this is not a complete blessing. Allowing access to the ITC by IOUs subjects the marketplace to an increased potential for conflicts of interest—when the utility directly competes with nonutility competitors who need the utility's interconnection, for example. The utility's business interest for promoting its own PV installations presents a clear conflict with its role as aggregator and interpreter of study information, federal and state regulations, and industry guidelines for PV installations. Based on previous situations, it cannot be assumed that utilities will keep the public's best interest in mind. Rather, without clear direction from regulators, utilities might discriminate against competitors to maximize shareholder value.

Anecdotal problem reports are abundant. For example, the authors know of a situation in which a utility installed a 3.7 MW synchronous generator on its system without a transfer trip or three-phase circuit breaker, even though it consistently requires both pieces of equipment for interconnection of customer-owned facilities. The cost savings evident in the discriminatory requirements give the utility a significant advantage. This denies the public the benefit of a real market, and allows the beneficiary of a state-granted monopoly to use its monopoly power for its own gain.

Fair-trade practices require utility-owned PV and non-utility-owned PV providers to follow the same rules, often known as anti-discrimination. Therefore, the Solar ABCs recommends that FERC and NARUC be vigilant in ensuring that utilities follow the same procedures that are imposed on other generators. This might be achieved by jointly developing an enforceable non-discrimination policy or rule to ensure uniform application of the technical requirements of all DG systems, regardless of whether they are utility-owned.

Acronyms

AC	alternating current
Con Ed	Consolidated Edison
DC	direct current
DG	distributed generation
DOE	U.S. Department of Energy
EPS	electric power systems
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
IREC	Interstate Renewable Energy Council
ITC	investment tax credit
IOU	investor owned utilities
kV	kilovolt
kVA	kilovolt-ampere
kW	kilowatt
MW	megawatt
NARUC	National Association of Regulatory Utility Commissioners
NEC	National Electrical Code
NREL	National Renewable Energy Laboratory
NCSC	North Carolina Solar Center
OATT	open access transmission tariff
PV	photovoltaic
RSI	renewable systems interconnection
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
Solar ABCs	Solar America Board for Codes and Standards
SME	subject matter expert
UL	Underwriters Laboratories
var	volt-ampere reactive

Glossary

Distributed generation—electricity generation defined by small-scale electricity generators (typically in the range of 3 kW to 10 MW) located at or near the end user, this method serves as an alternative to traditional electric power generation from large central plants. Each small generator may be interconnected with a local utility company's distribution system or not and it may be owned and operated by a customer, a utility, or a non-utility company.

Grid parity—the condition of the cost of electricity from a non-traditional source (e.g. solar photovoltaics) being equal or less than the cost of electricity provided by the local electric grid from an electric utility

Grid-tied—the state of being connected to the electricity grid, in contrast to being "off–grid" or "standalone" which indicates no connection to the electricity grid

Inverter—an electronic device used to convert direct current (DC) electricity into alternating current (AC) electricity. Such a device is required to allow a solar photovoltaic system, which generates DC electricity, to interconnect to the electricity grid, which uses AC electricity.

Islanding—a situation in which a portion of the electrical grid that contains loads and generation source(s) remains energized even after it is isolated from the rest of the electrical grid. A portion of the distribution system that does not shut down during a general grid outage as a result of local distributed generation resources continuing to power it would be an unintentional island.

Peak load—the maximum electric load (measured in kW or MW) experienced over a given period of time

Screen—a test or criterion used to determine if the given electric generator is eligible for a particular interconnection process

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Appendix I: DG System Types and Characteristics (IREC, 2009)

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

Appendix II: Detailed Results of Questionnaire

Responding SMEs

Of the 154 SMEs who received a request to complete the questionnaire, 37 individuals, or 24%, completed it.

	Number of Individuals to Whom Questionnaire Was Sent	Number of Individuals Who Completed Questionnaire
IEEE 1547.7 Working Group only	91	23
IEEE 1547.6 Working Group only	35	5
Both IEEE P1547.6 and P1547.& Working Group	20	7
DOE/Solar ABC invites	8	2

Figure 1: Responding SMEs by Invitation Class

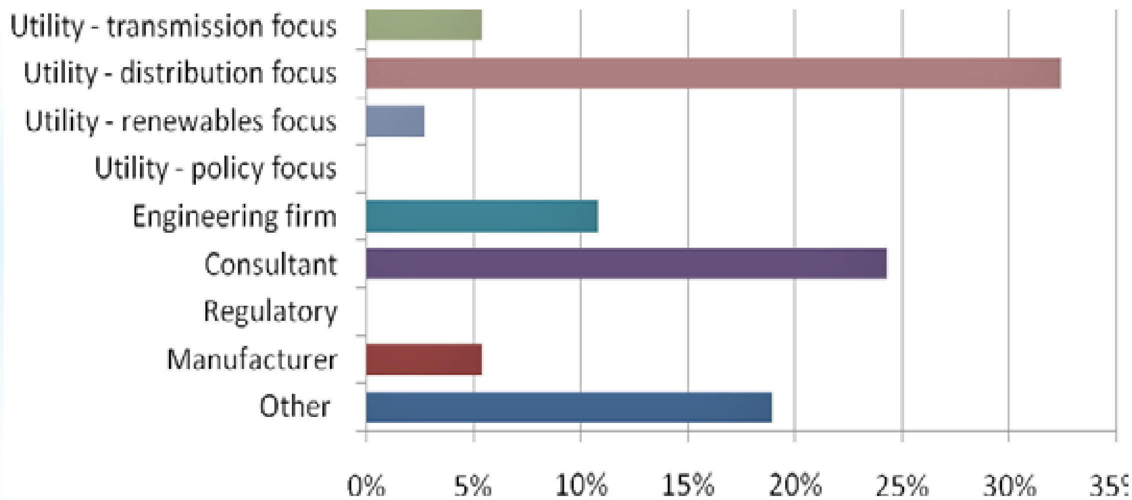

Figure 2: Current Role of SMEs Who Completed the Questionnaire

The categories presented in Figure 2 are the categories used in the questionnaire. The SMEs who answered this question with "Other" include four SMEs from government/ national labs, two from utilities, and one from a renewable energy nonprofit.

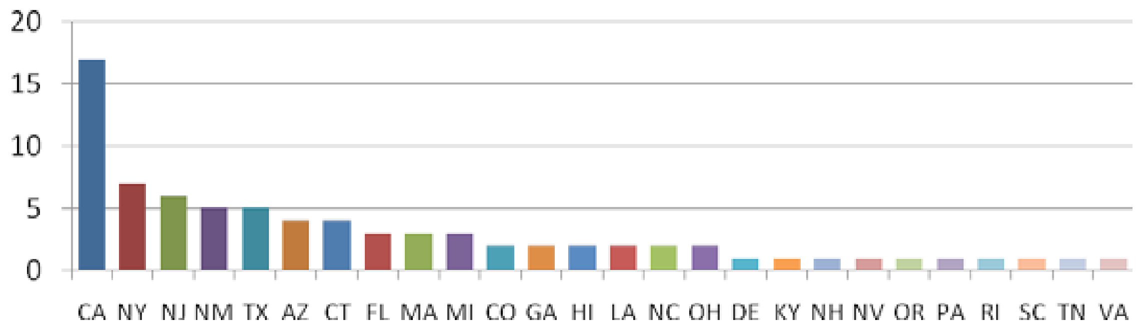

Figure 3: SME Response to: "In Which State or States has the Bulk of Your Recent Renewables Related Interconnection Work Been Focused?"

(31 of 37 Individuals Responded)

Quantitative Results

The first FERC SGIP-related question on the questionnaire was regarding the 10 KW Inverter Process. We sought to determine whether the SMEs agreed that the size limit of this process should be increased. The following are the results of the questions regarding the 10 KW Inverter Process.

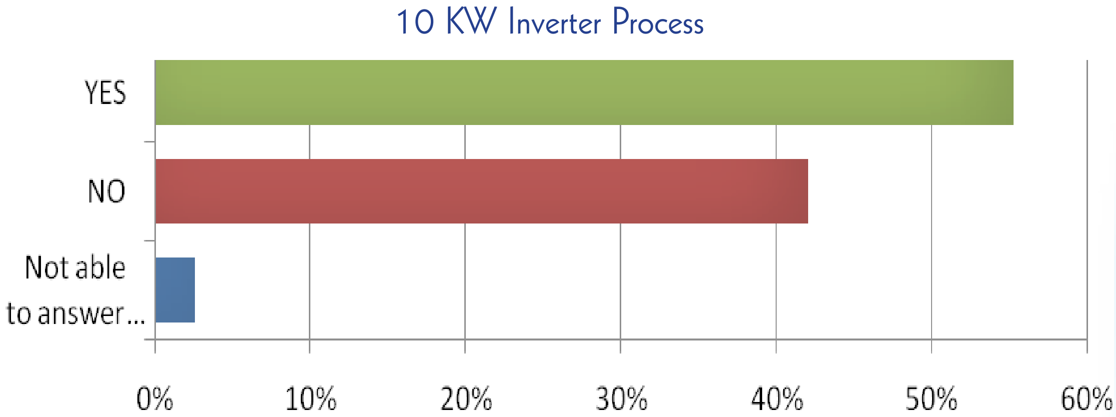

Figure 4: SME Response to: "Do You Support Updating the Size Limit for the Simplified Process for Small Inverter-Based Systems, Currently Known as the '10 kW Inverter Process'?"

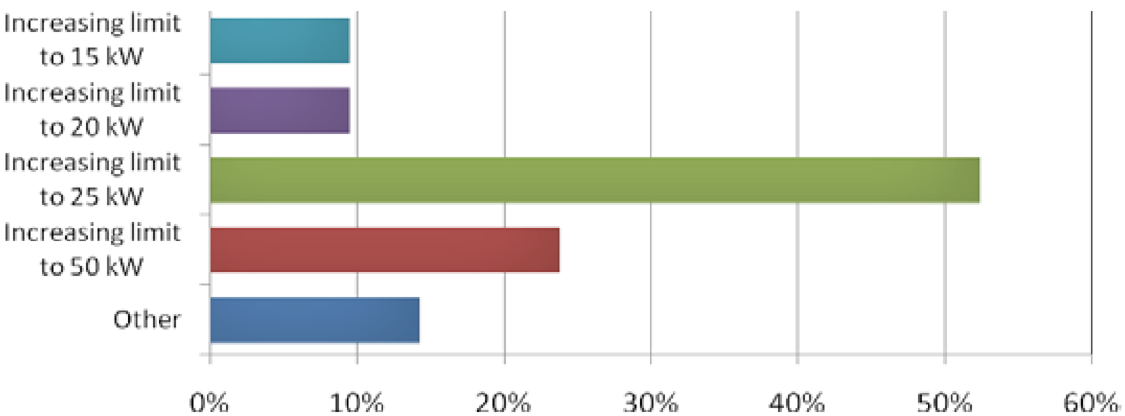

Figure 5: SME Response to: "If You Support Updating this Size Limit, What Change Would you Recommend?"

The updates suggested by SMEs who chose the "Other" option included "10 kW single phase and/or 30 kW total three phase." The SME explanations of their positions included comments such as:

> "I favor the increase to 25 kW because of the precedent (in NY for example), the lack of issues that have arisen from sizes in this range, and most importantly, because the systems still have to pass the fast-track screens. This should adequately protect against systems being installed without proper scrutiny."
>
> "This modest increase is warranted because the industry has acquired substantial experience since the original 10kW threshold was established. A 25kW level will likely find greater acceptance in the small commercial sector."
>
> "The total or aggregate impact of multiple installations at high penetration levels on certain feeders may have unforeseen negative consequences for reliability."

Some SMEs who voted that they would not support an increase in this size limit provided reasons, such as the third comment above, that are addressed by the fast track screens.

Screen 2: Aggregate Generating Capacity Versus Line Section Peak Load (15% Limit)

The first FERC SGIP screen addressed in the questionnaire was screen #2, which addresses aggregate generating capacity versus line section peak load. The existing screen sets a limit of 15% of the line section peak load for the aggregated generation on a radial distribution circuit. The following is a summary of the results of the three questions in the questionnaire regarding this screen, and one additional question that we asked only about this screen regarding the wording of the screen.

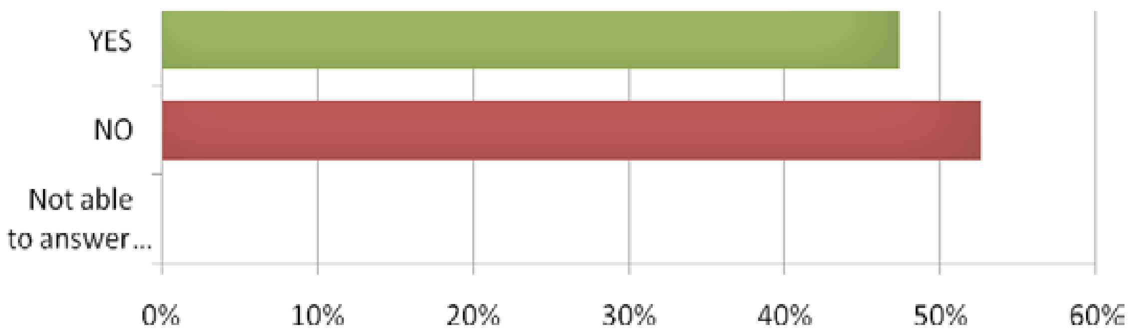

Figure 6: SME Response to: "Do You Support Updating Screen #2?"

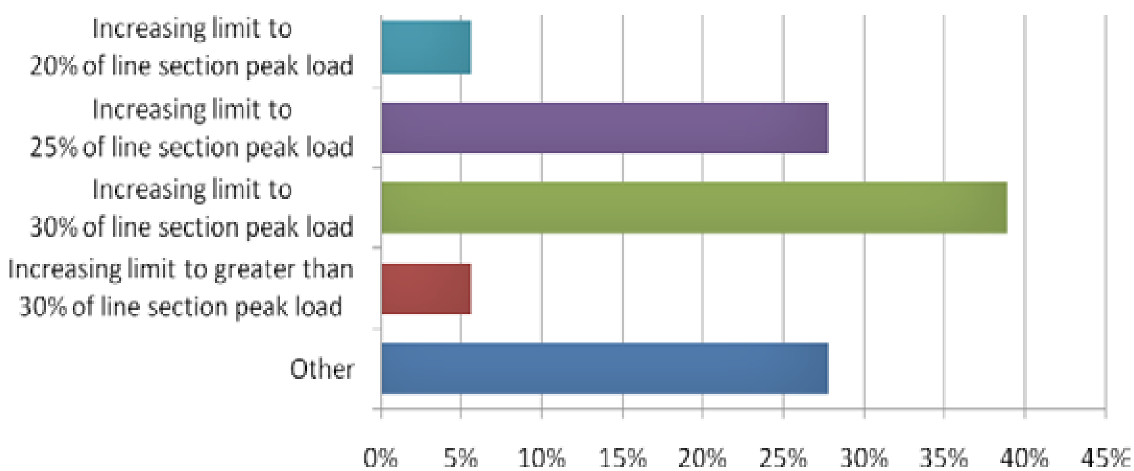

Figure 7: SMEs Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #2)"

In addition to the possible updates provided as answer choices, several SMEs wrote in other suggested updates. These suggestions ranged from "It should be based on the time duration of section peak load" to "Base on minimum load." Some examples of SME explanations of their position on this issue are shown below.

> "15% is a reasonable limit for a screening test. It is clear that penetration levels higher than this can be accommodated, DEPENDING on the characteristics of the circuit, other loads, diversity of generators, etc. The distributed voltage control incorporated into the inverters (see previous question) would also be a factor in changing this limit."

> "The 15% criteria is an intentionally conservative criteria. Not enough is known to make a blanket statement on acceptable limits vs. peak load; more study is needed. If a less conservative criteria is desired, I would prefer a criteria based on minimum load."

“In practice, peak solar output does not coincide with the circuit peak load. Peak solar project output typically occurs from mid-morning to mid-afternoon in the summer, while the circuit peak demand occurs as early as 14:00 hours and as late as 22:00 hours. Due in large part to this non-coincidence, actual solar generation impact on the host distribution circuit is generally less than the solar generator capacity alone would suggest. Therefore, increasing the limit to greater than 30% of line section peak load is possible without complications. [CSI Final 07-08 Impact Report]”

“None of the arguments for increasing the 15% screen addresses the issues of possible voltage rise, operation reliability and flexibility, protection issues etc. At this point we do not have enough experience and knowledge of generation connected to the distribution system to determine if the 15% can be increased. In two-three years, we may [have] gained additional information to allow us to evaluate this screen one more time.”

“We track minimum as well as maximum load and it is at minimum load that generation becomes a problem, not at maximum load, some circuits 15% is too high, others it could be 35%, but in all cases there could be a single standard based on minimum load.”

We asked the SMEs one additional question, about the wording of the comparison made in the screen. We asked if they believed the relevant comparison was correct as stated in the current screen, “aggregate generation on the circuit vs. line section peak load,” or if they felt the following was a more correct way to state the comparison, “line section generation vs. line section peak load.” Based on the responses, no change is recommended. The results are shown in the figure below.

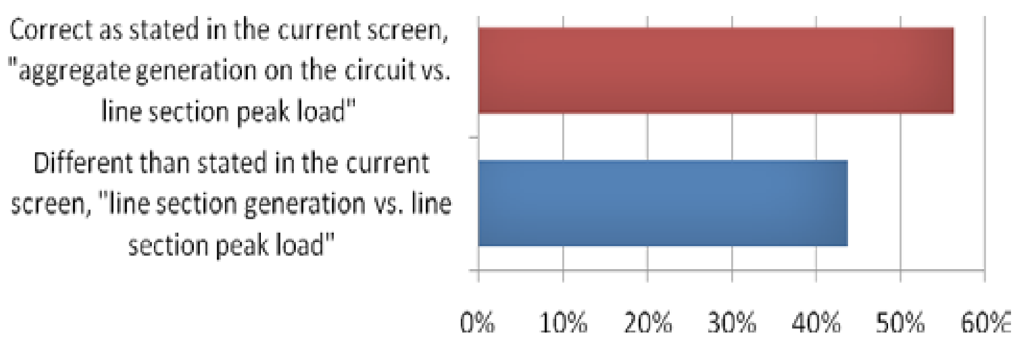

Figure 8: SME Response to Proper Wording of the Comparison Made in Screen #2

Screen 3: Network Protectors (Shall Not Exceed the Smaller of 5% of a Spot Network's Maximum Load or 50 kW)

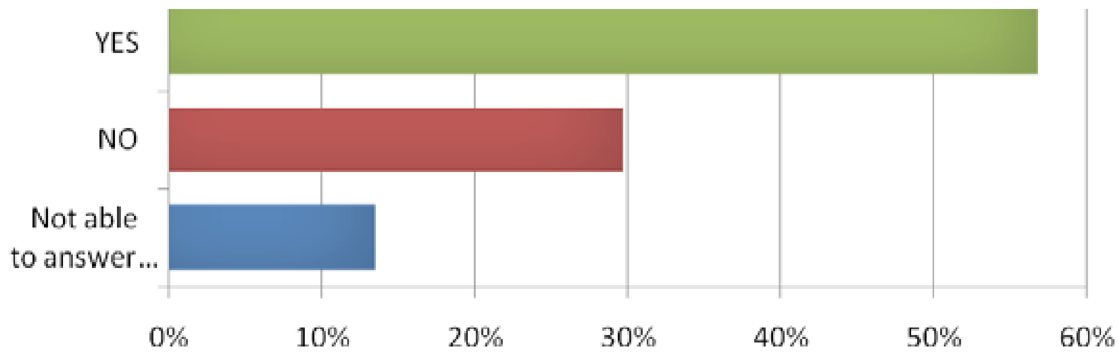

Figure 9: SME Response to: "Do you Support Updating Screen #3?"

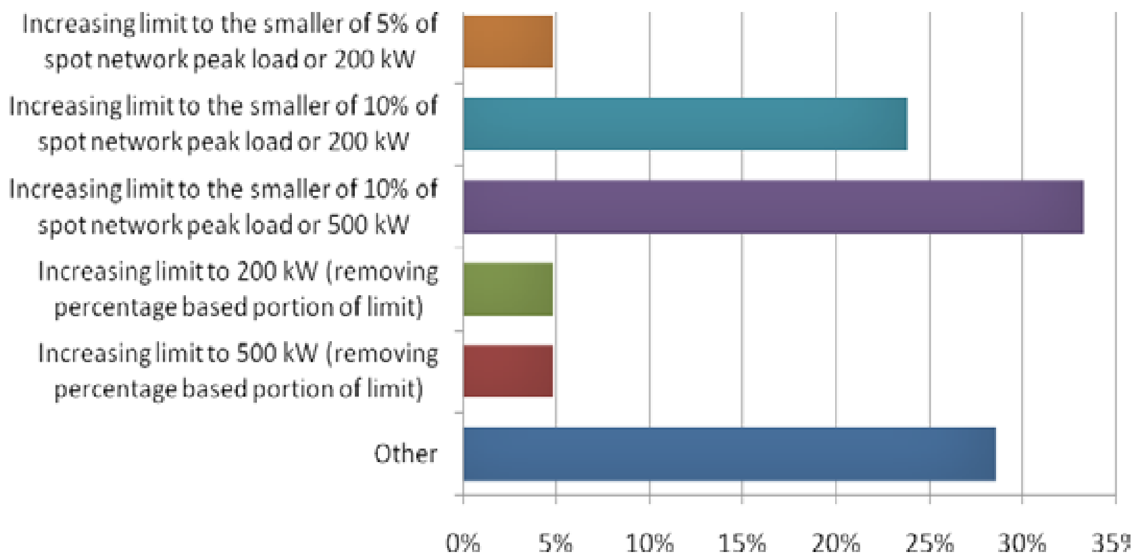

Figure 10: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #3)"

More than 25% of the SMEs who responded that they would support updating screen #3 did not select one of the possible updates included in the second question about this screen. The most common suggestion was to tie the size limit to the minimum load instead of the peak load. Other responses included, "Wait for IEEE P1547.6 to become a published guide" and "[Set the] limits by category."

The SMEs provided a range of explanations for their positions both for and against updating this screen. Here are some representative comments:

> "I think there is ample evidence from the work in NJ and NY that the limits can be changed, but there are nuances between the different networks (spot, area, secondary) which should be defined, and possibly have different limits for each type."

> "New York is a unique circumstance having very dense load demand. It is prudent to keep this limit until substantially more experience is gained in other geographic areas. Notwithstanding this comment, any EPS operator is free to set their own limits much as Con Ed does."

Screen 4: Short Circuit Contribution (Shall Not Contribute More Than 10% to the Distribution Circuit's Maximum Fault)

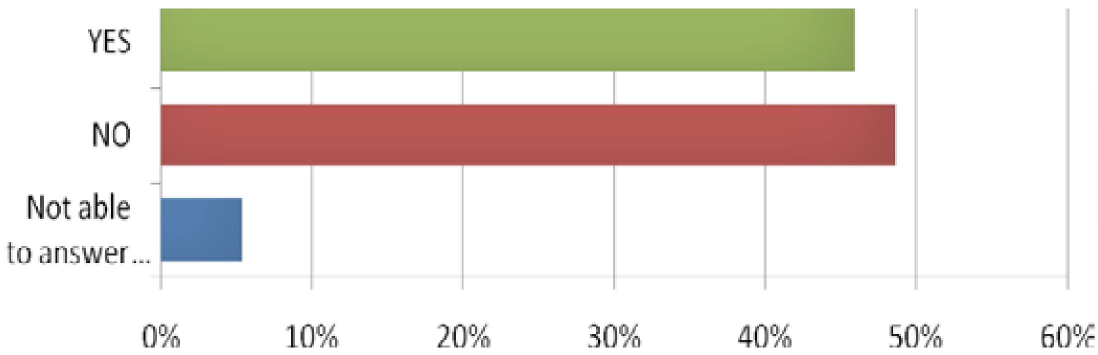

Figure 11: SME Response to: "Do You Support Updating Screen #4?"

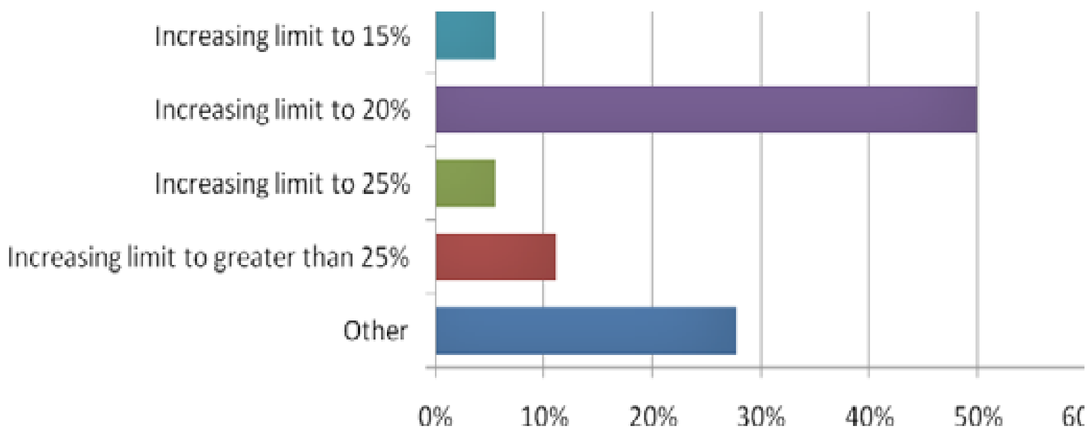

Figure 12: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #4)"

Of the SMEs who support updating this screen, more than one quarter of them chose to write in a suggested screen update. Most of the write-in comments suggested associating a time duration to the current limit in one way or another.

The SMEs' explanations of their positions are represented by this selection of responses:

> "The industry standard of using 2x rated current for the short-circuit value overstates the sustained (momentary) fault current capability of the PV inverter. The actual fault current is closer to 1-1.2 pu after a few cycles and up to the point where a voltage or frequency element is tripped. If the 2x I-nominal will continue to be used, increasing the limit to 20 % should have no consequential impact on the grid."

> "The argument made for changing the screen is that meeting this screen is not a problem for inverter-based units. So why not leave it in?"

> "Again, since this is only a screen, it would require that there be additional studies done if a project exceeds the screen. I am more comfortable with leaving this in place, as the ultimate result of high DG penetration is still an open question, and since system reliability is a very high measure for utilities, we would not want to see future problems in this regard that would require short circuit duty upgrades to both utility and customer switchgear and breakers because we were not staying on top of this issue."

> "Inverter-based devices cannot supply fault current for more than a fraction of a cycle. The problem is not the fault current magnitude, but the location of the current

source. New protection methods must be developed so that inverter-based sources can be rapidly interrupted in the event of high impedance, low current faults on distribution circuits."

"Fault current contribution from DG can be significant depending upon location and characteristics of the distribution feeder to which it is connected. A worst case scenario, which happens to be common place for DG locations, is when DG is located at the extreme ends of long, distribution feeders. Coordination becomes difficult: Protective switchgear settings set to DG fault current levels will be insensitive to traditional distribution/load faults. In this case up-line switchgear will operate in zone 2 (or 3) thus causing a more wide-spread outage. Therefore, depending upon DG technology, location, and distribution feeder characteristics, an impact study may be required. Any "streamlining" process rules MUST be constrained to inverter-based DG ONLY!"

Screen 5: Interrupting Capability of Existing Devices
(Shall Not Cause Equipment on the System to Exceed 87.5% of the
Short Circuit Interrupting Capability)

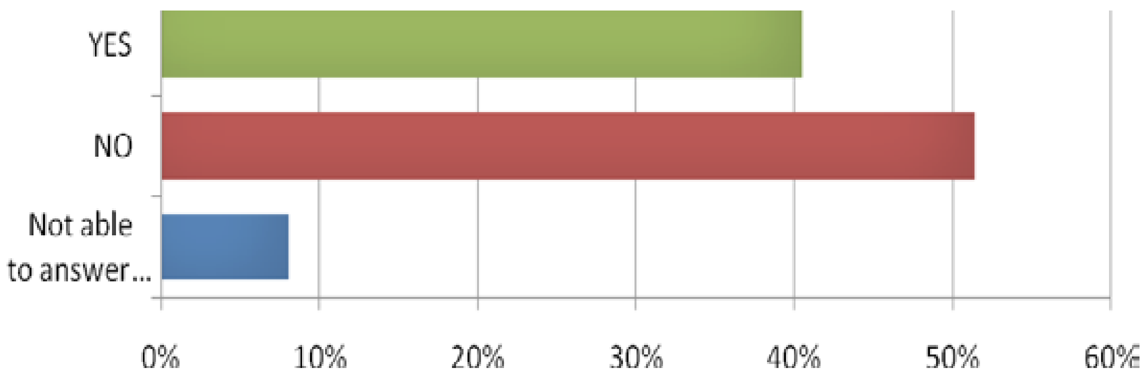

Figure 13: SME Response to: "Do You Support Updating Screen #5?"

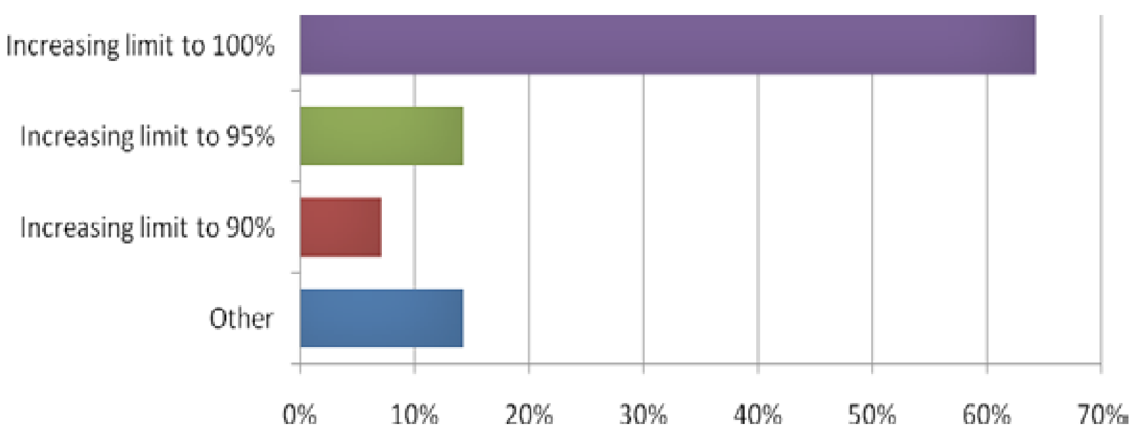

Figure 14: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #5)"

The "Other" options included reducing the limit to 85% as well as increasing the limit to 100% in the first 2-3 cycles following the fault. Clearly, the majority of SMEs who support updating this screen support increasing the limit to 100%.

The following are some representative responses when the SMEs were asked to explain their position on this screen:

"Although the arguments for updating this screen may be valid for inverter-based technology, this screen is utilized for all type of generation projects including non-inverter-based technology"

"The margin in this screening limit is reasonable."

"For inverter-based systems, this should not be a problem unless the system is already very close to the limit. Because fault current is increasing on distribution systems for other reasons rather than the addition of DG on that circuit (increasing substation transformer size, upgrading transmission system, etc.) we need to be very conservative when evaluating the addition of new DG on distributions that are pushing the limit of fault current already."

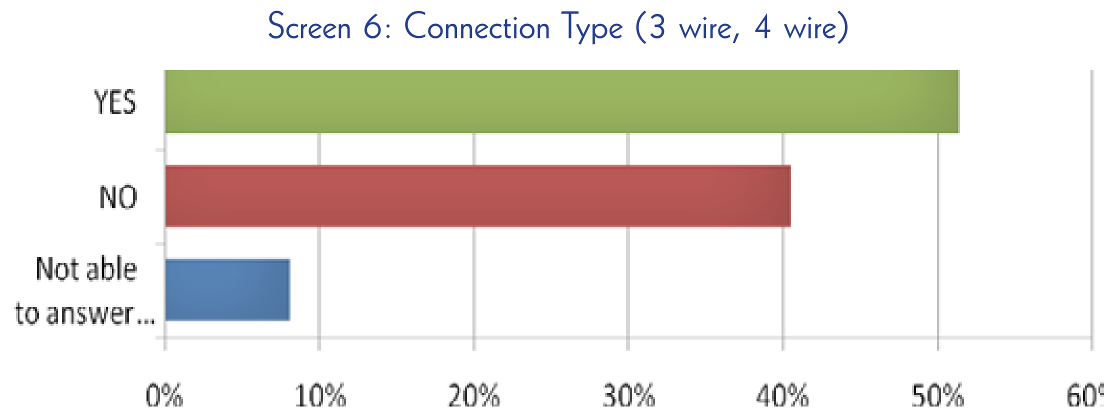

Figure 15: SME Response to: "Do You Support Updating Screen #6?"

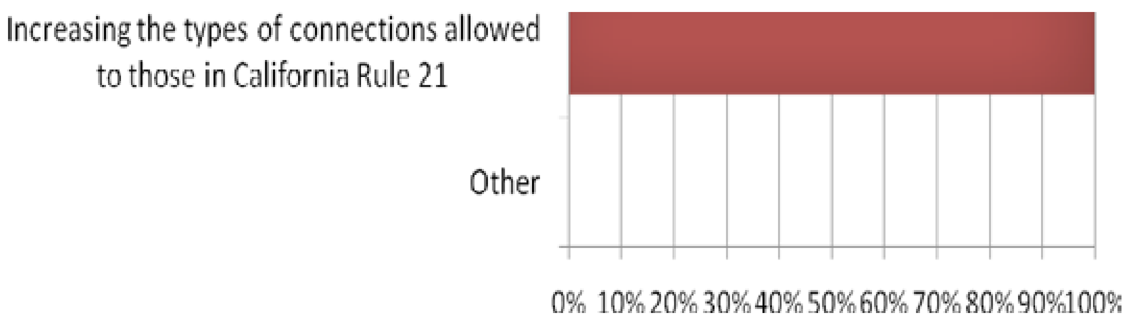

Figure 16: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #6)"

Fewer SMEs responded to the request to provide an explanation of their position on this screen than for the other screens. Those who did respond provided a variety of reasons for either supporting or not supporting an update. Some of the comments were:

"Having participated in the development of the Rule 21 table, I believe it was vetted thoroughly. I don't see any reason [it] couldn't be applied elsewhere."

"Again, this is a screen. The rule 21 language expects the utility to determine circuit peak load to validate the last type of connection, and this is not a screen issue, it's a study issue."

"This appears to provide sufficient protection and allows additional interconnections."

"The California rule requires a study of all of the possible topologies. On transmission, that is simple, not so on distribution."

Screen 7: Single-Phase Shared Secondary System Size Limit (Capacity on the Shared Secondary Shall Not Exceed 20 kW)

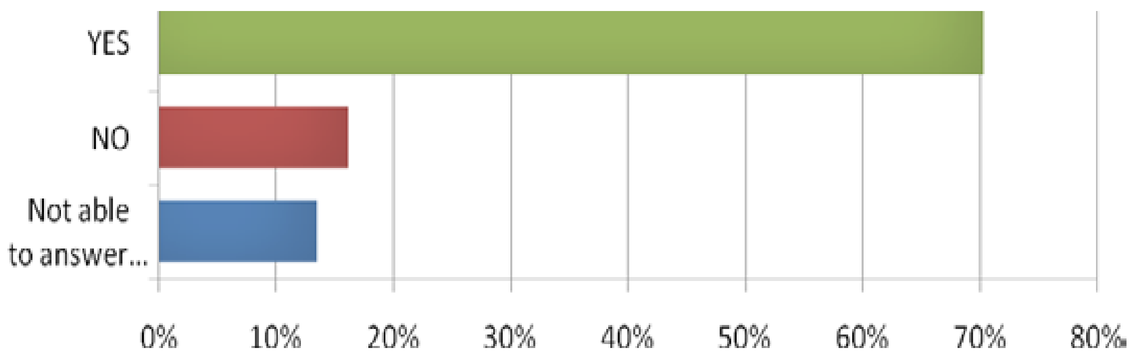

Figure 17: SME Response to: "Do You Support Updating Screen #7?"

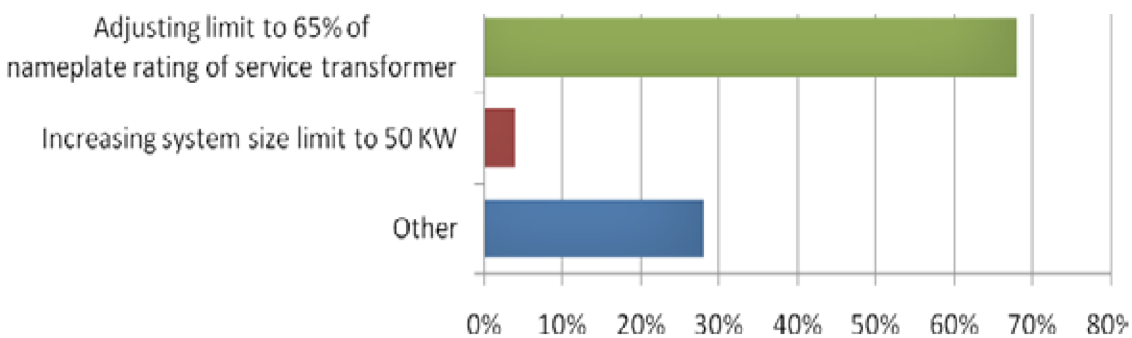

Figure 18: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #7)"

More than 25% of SMEs who support updating this screen preferred an update other than the two options included as answer choices. The suggestions included: "should not allow more than 50% of transformer nameplate" and "Adjusting limit to 85% of service transformer nameplate."

The explanation of their positions included comments such as:

> "The % of nameplate criteria is better because the 20 kVA value assumes a particular range of transformer sizes. Exactly what percentage should be used (65% or other) could be worth further discussion."
>
> "There is a wide diversity in the number of customers connected to a single transformer. Neither a kVA, nor a percentage screen is correct."
>
> "Service transformer size can be changed to allow larger DR."

"65% may be fine, recognizing that typical sizes found in the field are often 25 kW units. Most residential installations are from 3-8 kW in size, so the 65% factor will start to limit the number of installations on these systems faster than the 20 kW size does now."

Screen 8: Single-Phase Shared Secondary (20% Imbalance Limit)

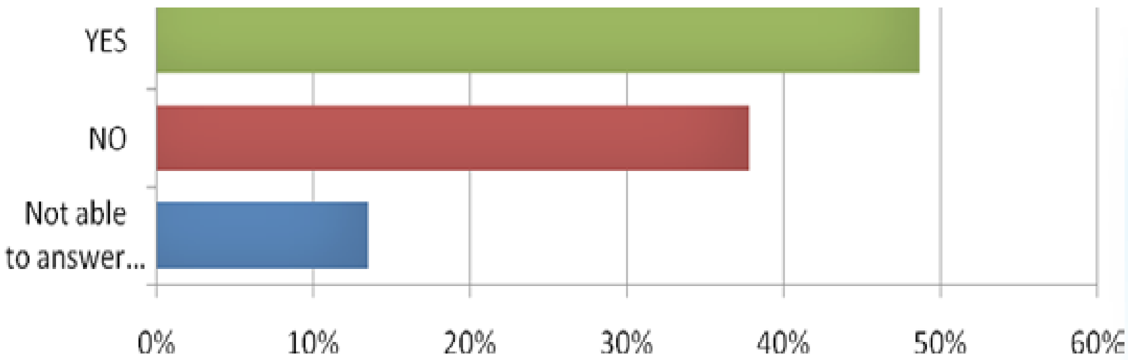

Figure 19: SME Response to: "Do You Support Updating Screen #8?"

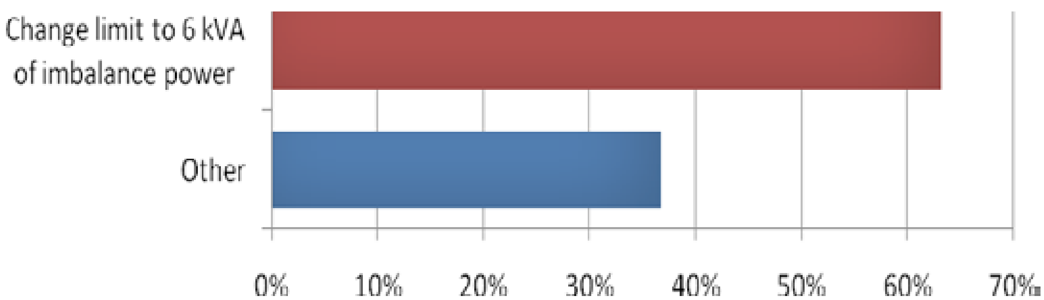

Figure 20: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #8)"

More than one-third of the SMEs supporting an update to this screen preferred something other than the offered "change limit to 6 kVA of imbalance power" option. The other updates, or comments, that were received included: "use percentage (similar to NM rule)" and "10 to 20 percent of transformer rating."

The SME comments explaining their position on this issue included:

> "6 kVA of a 10 kVA transformer is too high of a limit. Even for a 15 kVA transformer, 6 kVA represents 40 % imbalance. Imbalance issue goes beyond neutral return current. Voltage imbalance will also occur and can be a significant problem particularly if utility regulating equipment is 3-phase and not single-phase based."

> "The amount of imbalance should depend on the size of the service transformer."

> "If the transformer is dedicated to the use of the DER then it has to be rated, if it has not been tested and its rating certified as a generated step-up transformer. Standard distribution transformer kVA rating is based on the secondary voltage taking into consideration the voltage drop through the transformer. When used as a generator step-up transformer its secondary can be overexcited."

Screen 9: Size Limit in an Area Where There are Known Stability Limitations

(Shall not Exceed 10 MW)

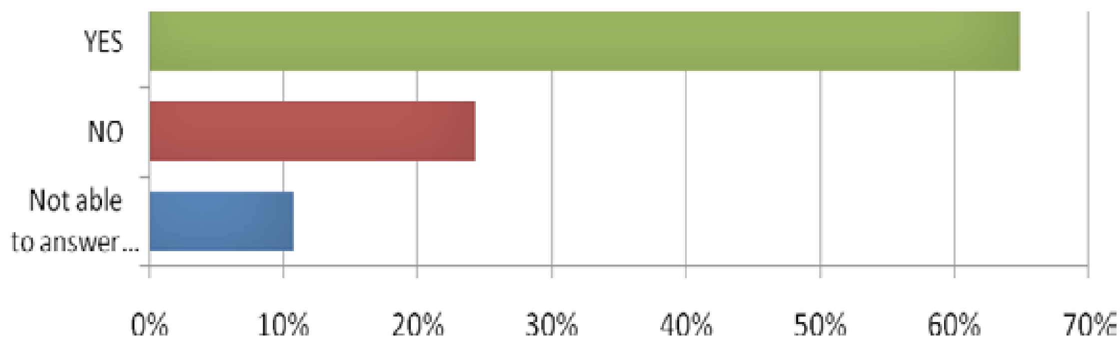

Figure 21: SME Response to: "Do You Support Updating Screen #9?"

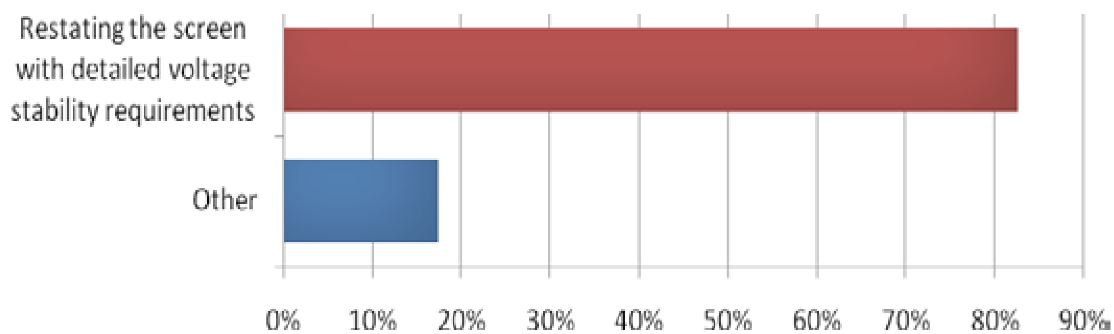

Figure 22: SME Response to: "If You Support Updating this Size Limit, What Change Would You Recommend? (Screen #9)"

The SMEs who supported an update to this screen and chose the "Other" option to the second question wrote responses that mostly indicated restating the screen with both voltage and power stability requirements. One SME suggested the screen be removed entirely.

The SMEs provided the following comments on their positions on this screen:

> "I agree with the arguments stated, it needs to be tied to something more concrete."
>
> "Utility distribution engineers do not know how to address the screen as it is written now."
>
> "As written, the rules are not clear. Transient instability is a study result, not a chronic condition."
>
> "Low frequency stability concerns will definitely be impacted by high penetrations of inverter-based DE. In some RTOs, high penetrations of DE may actually be operated as a Power System Stabilizer to dampen oscillation. This is well within the capability of existing inverters."

Comparison of Utility Versus Non-Utility SME Respondents

There were significant differences in the responses of SMEs who identified themselves as currently having a role with a utility and those who identified themselves as having a non-utility affiliation. The figure below compares the support of utility vs. non-utility SME respondents for updating the limits of the 10 kW Inverter Process and each of the eight FERC SGIP screens they were asked about. The issue with the largest difference is the 10 kW Inverter Process.

There is also a significant difference on several other issues. Perhaps most noteworthy are screens #2 and #3 dealing with capacity limits. The non-utility SMEs were more supportive of updating these screens as well as the 10 kW Inverter Process.

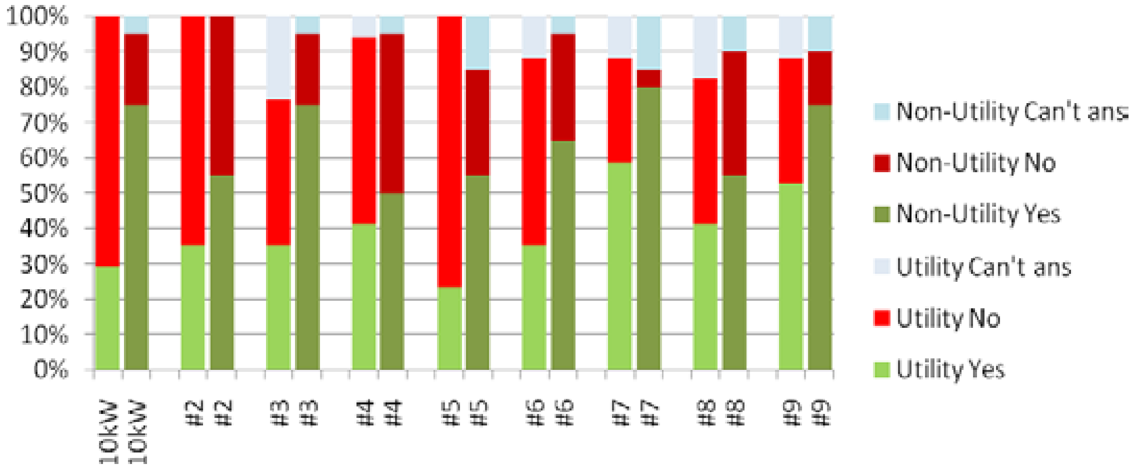

Figure 23: Breakdown of support for Screen Update by Utility SMEs and Non-Utility SMEs

Surprisingly, only two of the 17 (11.8%) utility SMEs indicated recent DG interconnection experience in California, yet 14 of the 20 (70%) non-utility SMEs indicated recent California experience.

More than half of the interconnected inverter-based DG systems installed in the United States are installed in California, so—not surprisingly—many areas with the highest levels of PV grid penetration are in that state. We were interested in the support of SME respondents with DG interconnection experience in California on the issue of updating the 15% line section limit (Screen #2) compared to the support of the complete pool of SME respondents. Of the 17 respondents who indicated California DG interconnection experience, 10 said they would support updating Screen #2 (59%) and only seven (41%) did not support updating this screen. Of those supporting updating Screen #2, nearly two-thirds supported increasing the limit to 30% of line section peak load.

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1. Questionnaire Overview

Goals of this Questionnaire
The purpose of this questionnaire is to collect expert opinions on the FERC Small Generator Interconnection Procedures (SGIP) screens. IREC will use this feedback to develop a report for the DOE Solar America Board for Codes and Standards (Solar ABCs), recommending updates to the FERC SGIP screens or establishing a new set of model screens. The SGIP screens haven't been substantially revised since original passage of the SGIP in FERC ORDER 2006 on May 12, 2005. Since that time, the U.S. has installed over 1,200 MW of grid-tied solar. We believe that the solar industry has gained enough experience and knowledge to warrant a reexamination of the SGIP screens. **We greatly appreciate your time and expertise in this project. If you have questions please feel free to call:**

- **Tommy Cleveland: (919) 515-9432**
- **Michael Sheehan: (206) 232-2493**

Overview of the Questionnaire
Throughout the questionnaire you will find both multiple-choice and open-ended questions. <u>We request that you answer all questions marked with an asterisk; the questionnaire requires an answer to these questions before you can advance to the next page</u>.

The questionnaire begins with some background on the SGIP screens for your reference. The next page focuses on the "10 kW Inverter Process" and whether it is appropriate to apply these procedures to systems larger than 10kW. The following eight pages of questions reference SGIP screens #2 through #9. Each of these pages starts with the existing language of the screen, a summary of the precedent for the current version of the screen, and a summary of arguments for updating the screen. Below this brief guide to each screen there will be these three questions:

1. Do you support updating this screen? Yes, No, or Can't Answer *(This question requires an answer)
2. If you support updating this screen, what change would you recommend?
3. Please briefly provide an explanation of your position.

The questionnaire concludes with a page of background questions to collect some relevant demographic data, which will help us understand the perspective of each respondent.

Thank You
To thank you for taking the time to share your expertise with us we will send everyone who completes the questionnaire a summary of the voting results.
Respondents will also receive a copy of the final report when it is published.

Stay Involved
This questionnaire is not your only chance to provide input. You are also invited to participate in future stakeholder meetings for this study, about which you will receive email announcements. You may also visit www.solarabcs.com or email Tommy_Cleveland@ncsu.edu for information.

Final Outcome
The final outcome of this study of the Solar ABCs will be a paper suggesting updates to the FERC SGIP screens based on the input received in this questionnaire.

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2. Confidentiality Policy and Options

Confidentiality Policy
Unless the respondent chooses to opt-out of confidentiality, the data collected from each respondent will not be released in full or in part. The responses you provide in the questionnaire will be aggregated for the purposes of producing the report. Only the report authors will have access to the questionnaire responses.
Please contact Tommy_Cleveland@ncsu.edu (919) 515-9432 with any questions regarding this policy.

*** 1. Please consider opting-out of the confidentiality policy. This will allow the authors to include more information in the final report, which we believe will improve the quality of the final Solar ABCs report.**

Please select the level of confidentiality you desire.

◯ Keep my responses fully confidential. I understand the confidentially policy stated above.

◯ I would like to partially opt-out of the confidentiality policy: The authors may anonymously quote from my responses (quotes may be used, but the only identification of the source revealed will be a State or region of the country).

◯ I would like to fully opt-out of the confidentiality policy: The authors may share and quote any of my responses.

3. Overview of FERC SGIP Screens

Overview of the FERC Small Generator Interconnection Procedures
The Federal Energy Regulatory Commission (FERC) "small generator" interconnection standards for distributed energy resources up to 20 megawatts (MW) in capacity include a Small Generator Interconnection Procedures (SGIP) document and a Small Generator Interconnection Agreement (SGIA). The FERC's standards apply only to facilities subject to the jurisdiction of the commission; these facilities mostly include those that interconnect at the transmission level. The FERC's standards generally do not apply to distribution-level interconnection, which is regulated by state public utilities commissions. However, the FERC has noted that its interconnection standards for small generators should serve as a useful model for state-level standards.

FERC's Small Generator Interconnection Procedures (SGIP) contains a series of technical screens for the Fast-Track interconnection process of generation facilities up to 2 Megawatts (MW). Systems that pass the screens qualify for the Fast-Track interconnection process (SGIP Section 2), allowing them to avoid lengthy/expensive interconnection studies (SGIP Section 3). Inverter-based generators 10 kW or smaller that pass the screens qualify for a simplified interconnection process known as the "10 kW Inverter Process". Projects that fail the screens should be able to interconnect after the needed studies are complete and any needed upgrades identified by those studies are in place.

These screens generally apply to a range of systems, including inverter-based facilities such as solar energy systems. There is recent evidence to suggest that some of the existing screens may be more stringent than needed for inverter-based generators. Inverters are inherently very "controllable" and their use in utility applications has risen from a few thousand systems as of 2002 to over 69,000 systems by the end of 2008. Because inverters are power electronic devices, it is possible to incorporate safety and operational features into their controls, such as providing fail-safe designs that prevent the inverter from operating unless its protective functions are working properly. Inverter-based and rotating generators are treated differently in the codes and standards, so that properly designed and tested inverter-based devices require little (if any) additional external protection equipment.

The current screens may be found in section 2.2.1 of the Small Generators Interconnection Procedures (SGIP). Here is a summarized list for your convenience:(Link to access full SGIP document)

1. Tariff jurisdiction: This is non-technical and not addressed in this questionnaire.
2. Aggregate generating capacity vs. line section peak load (max 15%)
3. Network protectors (shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW)
4. Short circuit contribution (shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage primary level)
5. Interrupting capability of existing devices (shall not cause equipment on the system to exceed 87.5 % of the short circuit interrupting capability)
6. Connection type (3 wire, 4 wire)
7. Single-phase shared secondary system size limit (capacity on the shared secondary shall not exceed 20 kW)
8. Single-phase shared secondary (20% imbalance limit)
9. Size limit in an area where there are known stability limitations (shall not exceed 10 MW)
10. Construction would not be required by the utility: This is non-technical

4. 10 kW Inverter Process Size Limit (10 kW)

Present FERC SGIP "10 kW Inverter Process" Size Limit (SGIP Attachment 5): The title of Attachment 5 is "Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW."

SGIP Attachment 5, paragraph 4.0, first sentence: "The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process..."

In summary, the "10 kW Inverter Process" offers a simplified interconnection application, within the SGIP Section 2 "Fast Track" screens.

Argument for Keeping the SGIP 10 kW Inverter Process Size Limit at 10 kW

The 10 kW inverter-based process came from a stakeholder group in Massachusetts, presumably in 2004 (see footnote 46 of FERC Order 2006). The state had few, if any, interconnections of systems over 10 kW at the time. Looking to national and international experience, that group still found it reasonable to have a 10 kW cut-off for simplified procedures. Experience since 2005 has shown the 10 kW limit on the very simplified process to be safe.

Argument for Updating the SGIP 10 kW Inverter Process Size Limit to 25 kW

The concise argument for including certified, inverter-based systems up to 25 kW in the simplified interconnection process (currently known as the "10 kW Inverter Process") is that the dramatic rise in the number of inverter-based systems world-wide has not revealed interconnection complications in the 10 kW to 25 kW range, or foreseeable problems in that range.

In New York all systems up to 25 kW are governed by a simplified process.

Additionally, increasing the limit to 25 kW not only simplifies the interconnection process for many small systems, but also illustrates the importance of relying on national technical standards. It is possible to state in a single sentence of a document that systems must meet the requirements established by UL, IEEE, and the National Electric Code (NEC). Several states now use a one- or two-page interconnection agreement for very small DG systems, especially for net metered systems.

The Interstate Renewable Energy Council (IREC) recommends moving the limit to 25 kW by including this limit in its widely-used Model Interconnection Rule..

IREC Model Rule

> "Level 1 Screening Criteria and Process for Inverter-Based Generating Facilities Not Greater than 25 kW:"

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*** 1. Do you support updating the size limit for the simplified process for small inverter-based systems, currently known as the "10 kW Inverter Process"?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this size limit, what change would you recommend?

- ☐ Increasing limit to 15 kW
- ☐ Increasing limit to 20 kW
- ☐ Increasing limit to 25 kW
- ☐ Increasing limit to 50 kW
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

5. Screen #2: Aggregate generating capacity vs. line section peak load (max 1...

Present FERC SGIP Screen 2.2.1.2 "For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the Small Generating Facility, on the circuit shall not exceed 15% of the line section peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. "

Argument for Keeping the FERC SGIP Screen 2.2.1.2 at 15% of the line section peak load

The intent of this screen is to assure that generation on a line section will not exceed load at any time, but utilities typically track peak loads and not minimum loads. Fifteen percent of peak load was established in the FERC SGIP procedures as a conservative estimate of minimum load. This limit has not provided any known problems. Existing state rules and utilities have commonly accepted the FERC SGIP screen 2.2.1.2, for example California Rule 21:

California Rule 21 provides some discussion on this issue:

1. Low penetration of Generating Facility installations will have a minimal impact on the operation and load restoration efforts of Electrical Company's (EC) Distribution System.
2. The operating requirements for a high penetration of Generating Facilities may be different since the impact on EC's Distribution System will no longer be minimal, therefore requiring additional study or controls.

Argument for Increasing the FERC SGIP Screen 2.2.1.2 generating capacity versus line section peak load limit

Below are excerpts from two recent sources suggesting higher PV penetration levels are possible without complications.

The Executive Summary of the Renewable Systems Interconnection Study: Utility Models, Analysis, and Simulation Tools, SANDIA REPORT: SAND2008-0945 Printed February 2008

> "As penetration levels rise on individual feeders into the 30% range, concerns emerge regarding the dynamic performance of distributed generation (DG). A need will develop for dynamic analysis tools used to study generator oscillations, damping, and anti-islanding controls for large numbers of generators. Existing tools must be upgraded, advanced system models for PV and other distributed generators must be developed, and these must be improved to accommodate a wider range of users."

Interconnecting PV on New York City's Secondary Network November 2009 Distribution System, NREL/TP-7A2-46902 K. Anderson, M. Coddington, K. Burman, S. Hayter, B. Kroposki, and A. Watson

> "PV penetration levels of 20% to 30% are generally considered to be the maximum level allowable in radial distribution systems before changes to the system are necessary."

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Additional Issue: Clarity Needed in Existing Screen

The FERC procedures call for aggregate generation on the circuit to not exceed 15% of line section peak load, when the relevant comparison would seem to be line section generation vs. line section peak load. FERC Order 2006 has no discussion on this point.
Please see question 4 below to provide input on this issue.

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to 20% of line section peak load
- ☐ Increasing limit to 25% of line section peak load
- ☐ Increasing limit to 30% of line section peak load
- ☐ Increasing limit to greater than 30% of line section peak load
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

4. Regarding the section on the page above entitled "Clarity Needed in Existing Screen", I believe that the relevant comparison is

- ◯ Correct as stated in the current screen, (*aggregate generation on the circuit* vs. line section peak load)
- ◯ Different than stated in the current screen, (*line section generation* vs. line section peak load)

6. Screen #3: Network protectors (Max is the smaller of 5% of a spot network's...

Present FERC SGIP Screen 2.2.1.3 "For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW. "

Argument for Keeping the FERC SGIP Screen 2.2.1.3 at 5% of spot network or 50 kW

The existing screen has been adopted by many states. In Pennsylvania the screen states "(f): for interconnection of a proposed small generator facility to the load side of spot network protectors, the proposed small generator facility shall utilize an inverter-based equipment package. The customer interconnection equipment proposed for the small generator facility must be certified, and when aggregated with other generation, may not exceed 5% of the spot network's maximum load."

There are a couple of terms that need to be defined:

1. Spot Network means a Secondary Network system consisting of two or more network units at a single site. The low-voltage network side terminals of these network units are connected together with bus or cable.
2. Network System means an AC power Distribution System in which Customers are served from three-phase, four-wire low-voltage circuits supplied by two or more Network Transformers whose low-voltage terminals are connected to the low-voltage circuits through network protectors. The Network system has more than two high-voltage primary feeders, with each primary feeder typically supplying multiple Network Transformers, depending on network size and design.

Argument for Changing the FERC SGIP Screen 2.2.1.3 limit of 10% or 200 kW whichever is less

There is a new study ("Limit on Generation Size on Area Networks", Prepared by Mr. David Smith PE, consultant) on the limit on generation size on area networks. The study states:

> "The maximum amount of inverter based generation to be allowed on an area network can be expressed as either a percentage of the minimum load, or as a percentage of the installed transformer capacity. Considering three-phase faults on the primary feeder and at the substation, it should be expressed in terms of the installed network transformer capacity. Considering protector operation (sitting open cycling, and pumping) during unfaulted conditions, it is perhaps better to define the generation in terms of minimum load on the area network. From the standpoint of defining for a given area network the allowed amount of inverter based generation, it would be easier to administer if the criteria were expressed in percent of installed network transformer capacity. The regulations in the State of NJ place an upper limit on the amount of inverter based generation that can be placed on the area network, said limit being 10 percent of the annual minimum load, or 500 kW, whichever is less. This 10 percent level is consistent with the findings of this study for area networks, where it is concluded that inverter based generation in the range of 3% to 4% of the installed network transformer capacity is acceptable."

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In addition, Consolidated Edison of New York, Inc. (Con Edison), in an effort to reduce barriers to interconnection of customer-owned DG, has announced that while it will still perform a detailed, site-specific study when it receives a request for interconnection to its distribution network systems (secondary and spot networks), inverter-based solar generators up to 200 kW may interconnect to the company's distribution network system without such a study.

* 1. Do you support updating this screen?

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to the smaller of 5% of spot network peak load or 200 kW
- ☐ Increasing limit to the smaller of 10% of spot network peak load or 200 kW
- ☐ Increasing limit to the smaller of 10% of spot network peak load or 500 kW.
- ☐ Increasing limit to 200 kW (removing percentage based portion of limit)
- ☐ Increasing limit to 500 kW (removing percentage based portion of limit)
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

7. Screen #4: Short circuit contribution (10% limit)

Present FERC SGIP Screen 2.2.1.4 "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 of the high voltage (primary) level nearest the proposed point of change of ownership."

Argument for Keeping the FERC Screen 2.2.1.4 at 10%

The FERC SGIP screen have two screens linked to fault current: First (2.2.1.4), the aggregate distributed generation on a distribution circuit is not permitted to contribute more than 10% of the available fault current at the primary voltage point closest to the point of coupling with the generator. Second (2.2.1.5), a distributed generation interconnection is not permitted to result in available fault current exceeding 87.5% of the interrupting capability of a distribution protective device.

Existing state rules and utilities have commonly accepted FERC SGIP screen 2.2.1.4.

Argument for Changing the FERC Screen 2.2.1.4 to 20%

The fault current contribution from induction motors is usually much larger than that of current controlled inverter-DG. It is common practice to ignore the fault current contribution of induction motor loads, particularly small, distributed motor loads, in distribution overcurrent conditions.

The fault current from DG is much smaller than that of the motor loads. Thus, there is ample precedent for considering current-controlled inverter-based DG as an insignificant short circuit current condition.

DG Power Quality, Protection and Reliability Case Studies Report August 2003, NREL/SR-560-34635

As a conclusion, under both three-phase and single-phase fault, the inverter-based current controlled DG has little impact on fault contribution and fuse-saving strategy. The GE NREL 2003 study states:

> "Figure 32 shows the fault, grid and motor (transformer high side) currents. It can be observed that the motor phase current has a phase jump at the beginning of the fault, signifying that the motor momentarily feeds power into the grid. There is an initial drop in the current magnitude because of the drop in the voltage magnitude. However, it can be observed in Figure 33 that the per-cycle I2t increases as the fault proceeds because of the increased motor slip, caused by the sag in the motor terminal voltage. Once the fault is cleared, the terminal voltage increases leading to an inrush into the induction machine. Figure 34 shows the motor torque and speed response to the fault. It is clearly seen that the fault current contribution from motor is larger than inverter-DG."
>
> Based results on Figure 34 on this GE NREL Study I would remove the requirement for inverter based system between 87.5 and 100% of their short circuit interrupting capability."

Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources, NREL/TP-550-46698

The conclusions of the paper suggest that fault current contributions from inverter-based DG may occur for short enough time periods to be ignored: The conclusions state:

> "The current industry's practice regarding fault current level assessment for setting protective relays has been to apply a "rule of thumb" of 2 times rated continuous current for

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DER. This seems to be the standard practice at low levels of DER penetration. Tests of 2 grid tied inverter systems at NREL suggest that the fault current is typically higher, but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles). This time period is typically within the subtransient reactance values for synchronous generators and trip times for circuit breakers, and therefore can possibly be ignored. What effect this may have on the protective relays at higher levels of DER penetration is not well understood and warrants continued research in this area."

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to 15%
- ☐ Increasing limit to 20%
- ☐ Increasing limit to 25%
- ☐ Increasing limit to greater than 25%
- ☐ Other (please specify)

3. Please briefly provide your an explanation of your position.

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8. Screen #5: Interrupting Capability of Existing Devices (not to exceed 87.5%...

Present FERC SGIP Screen 2.2.1.5 "The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability."

Argument for Keeping the FERC Screen 2.2.1.5 at 87.5%

The FERC SGIP screen have two screens linked to fault current: First (2.2.1.4), the aggregate distributed generation on a distribution circuit is not permitted to contribute more than 10% of the available fault current at the primary voltage point closest to the point of coupling with the generator. Second (2.2.1.5), a distributed generation interconnection is not permitting to result in available fault current exceeding 87.5% of the interrupting capability of a distribution protective device.

Existing state rules and utilities have commonly accepted FERC SGIP screen 2.2.1.5.

Argument for Changing the FERC Screen 2.2.1.5 to 100%

The fault current from DG is much smaller than that of the motor loads. Thus, there is ample precedent for considering current-controlled inverter-based DG as an insignificant short circuit current condition.

DG Power Quality, Protection and Reliability Case Studies Report August 2003, NREL/SR-560-34635

As a conclusion, under both three-phase and single-phase fault, the inverter-based current controlled DG has little impact on fault contribution and fuse-saving strategy. The GE NREL 2003 study states:

> "Figure 32 shows the fault, grid and motor (transformer high side) currents. It can be observed that the motor phase current has a phase jump at the beginning of the fault, signifying that the motor momentarily feeds power into the grid. There is an initial drop in the current magnitude because of the drop in the voltage magnitude. However, it can be observed in Figure 33 that the per-cycle I2t increases as the fault proceeds because of the increased motor slip, caused by the sag in the motor terminal voltage. Once the fault is cleared, the terminal voltage increases leading to an inrush into the induction machine. Figure 34 shows the motor torque and speed response to the fault. It is clearly seen that the fault current contribution from motor is larger than inverter-DG."
>
> Based results on Figure 34 on this GE NREL Study I would remove the requirement for inverter based system between 87.5 and 100% of their short circuit interrupting capability".

Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources, NREL/TP-550-46698

The conclusions of the paper suggest that fault current contributions from inverter-based DG may occur for short enough time periods to be ignored: The conclusions state:

> "The current industry's practice regarding fault current level assessment for setting protective relays has been to apply a "rule of thumb" of 2 times rated continuous current for DER. This seems to be the standard practice at low levels of DER penetration. Tests of 2

grid tied inverter systems at NREL suggest that the fault current is typically higher, but for much shorter time periods (2-4 times rated current for 0.06 – 0.25 cycles). This time period is typically within the subtransient reactance values for synchronous generators and trip times for circuit breakers, and therefore can possibly be ignored. What effect this may have on the protective relays at higher levels of DER penetration is not well understood and warrants continued research in this area."

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing limit to 100%
- ☐ Increasing limit to 95%
- ☐ Increasing limit to 90%
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

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9. Screen #6: Connection type (3 wire, 4 wire)

Present FERC SGIP Screen 2.2.1.6 "Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function."

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

---

Argument for Keeping the FERC Screen 2.2.1.6 at present types of interconnection

Existing model rules, state rules, and utilities have commonly accepted the FERC SGIP screen 2.2.1.6, for example IREC Model Rule.

IREC Model Rule

> "If the proposed generator is interconnected to the Electric Power System (EPS) as shown in the table below:
>
> | Primary-Distribution Line Type | Type of Interconnection to Primary-Distribution Line | Result/Criteria |
> |---|---|---|
> | Three-phase, 3-wire | 3-phase or single phase, phase-to-phase | Pass screen |
> | Three-phase, four wire | Effectively-grounded 3 phase or Single-phase, line-to-neutral | Pass screen |
>
> "

Argument for Changing the FERC Screen 2.2.1.6 to additional types of interconnections

California Rule 21 allows more possible line configurations than the FERC SGIP screen. California Rule 21 allows mixed 3-wire and 4-wire configurations with the limitation of DG capacity shall be less than or equal to 10% of the line section's peak load.

California Rule 21 "Line Configuration" Screen Significance

> "If the Electric Company's primary distribution system is 3-wire, or the DG interconnection transformer is single-phase (line-to-neutral), then there is no concern about over-voltages to the utility, or to other customers' equipment caused by the loss of a system's neutral grounding while anti-islanding protection is in operation. The utility identifies the primary-distribution line configuration. Based on the proposed interconnection type, the utility determines from the table below if the DG passes the screen.

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Primary-Distribution Line Type	Type of Interconnection to Primary-Distribution Line	Result/Criteria
Three-phase, 3-wire	Any	Pass screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass screen
Three-phase, 4-wire (For any line that has such a section or mixed 3-wire and 4-wire)	All others	To pass, aggregate DG capacity shall be less than or equal to 10% of the line section's peak load.

"

Additionally, THE NEW MEXICO INTERCONNECTION MANUAL uses the same rules as CA Rule 21 regarding connection type.

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Increasing the types of connections allowed to those in California Rule 21 (as in table above)
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

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10. Screen #7: Single-phase shared secondary system size limit (20 kW)

Present FERC SGIP Screen 2.2.1.7 "If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW."

Argument for Keeping the FERC Screen 2.2.1.7 at present 20 kW level

Shared secondary - 20 kVA maximum: To allow customers on a shared single-phase secondary to have equal access to the capacity of the shared utility distribution transformer, a limit is placed on individual customer's Generating Facility capacity. This limit allows for some diversity of loads and generation at each of the customer's electrical service in a shared secondary without overloading the serving distribution transformer. Existing state rules and utilities have commonly accepted the FERC SGIP screen 2.2.1.7 approach, for example California Rule 21.

<u>California Rule 21</u>

> "For single-phase Generators connected to a shared single-phase secondary system, the maximum Net Nameplate Rating of the Generating Facilities shall be 20 kVA. Generators connected to a center-tapped neutral 240-volt service must be installed such that no more than 6 kVA of imbalanced power is applied to the two "legs" of the 240-volt service. For Dedicated Distribution Transformer services, the maximum Net Nameplate Rating of a single-phase Generating Facility shall be the transformer nameplate rating."

Argument for Changing the FERC Screen 2.2.1.7 to 65% nameplate rating of service transformer

Instead of the system size limit approach used in the existing SGIP screen, New Mexico uses the percentage of the nameplate rating of the service transformer as the screen metric. This approach may better capture imbalance concerns on a shared secondary.

<u>THE NEW MEXICO INTERCONNECTION MANUAL</u>

> "If the proposed Generating Facility is to be interconnected on a single-phase Shared Secondary, the aggregate Generating Facility capacity on the Shared Secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating."

FERC-SGIP screens - Solar ABCs study

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Adjusting limit to 65% of nameplate rating of service transformer
- ☐ Increasing system size limit to 50 KW
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

11. Screen #8: Single phase shared secondary (20% imbalance limit)

Present FERC SGIP Screen 2.2.1.8 "If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer."

Argument for Keeping the FERC Screen 2.2.1.8 at present 20% nameplate rating of the service transformer

Existing state rules and utilities have commonly accepted FERC SGIP screen 2.2.1.8, for example:

THE NEW MEXICO INTERCONNECTION MANUAL , (page 10)

> "If the proposed Generating Facility is single-phase and is to be interconnected on a center tap of a 120/240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer."

Argument for Changing the FERC Screen 2.2.1.8 to 6 kVA of imbalance power

Imbalance – maximum of 6 kVA of imbalance between the two sides of a center-tapped 240-volt service. The 6 kVA limit for imbalances on single-phase 240-Volt services is to protect from excessive power imbalances causing overloading of the neutral conductor supplied by the utility. This neutral conductor, which mainly carries an amount of current similar to the difference in current between the two 240-Volt supply conductors is often undersized compared to either of the 240-Volt supply conductors. For instance, if one supply conductor is carrying 35 amps and the other supply conductor is carrying 25 amps, the neutral conductor would carry the difference, or approximately 10 amps. An imbalanced Generating Facility can increase the difference in current between the two supply conductors and thus increase the current carried by the neutral conductor.

California Rule 21 Southern California Edison Revised Cal., PUC Sheet No. 31574-E, Cancelling Revised Cal. PUC Sheet No. 30685-E, Rule 21, GENERATING FACILITY INTERCONNECTIONS

> "Single-Phase Generators: For single-phase Generators connected to a shared single-phase secondary system, the maximum Net Nameplate Rating of the Generating Facilities shall be 20 kVa. Generators connected to a centertapped neutral 240-volt service must be installed such that no more than 6 kVa of imbalanced power is applied to the two "legs" of the 240-volt service. For Dedicated Distribution Transformer services, the maximum Net Nameplate Rating of a single-phase Generating Facility shall be the transformer nameplate rating."

FERC-SGIP screens - Solar ABCs study

*** 1. Do you support updating this screen?**

- YES
- NO
- I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- Change limit to 6 kVA of imbalance power
- Other (please specify)

3. Please briefly provide an explanation of your position.

FERC-SGIP screens - Solar ABCs study

12. Screen #9: Size limit in an area where there are known stability limitation...

Present FERC SGIP Screen 2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

Argument for Keeping the FERC Screen 2.2.1.9 unchanged
Existing model rules and utilities have commonly accepted FERC SGIP screen 2.2.1.9, for example IREC Model Rule.

IREC Model Rule

> "The proposed generator, in aggregate with other generation interconnected to the distribution low-voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission voltage level busses from the Point of Common Coupling (PCC))."

Argument for Changing the FERC Screen 2.2.1.9 to restate the screen with detailing voltage stability requirements if appropriate

There are no known transient stability limits posted. The utilities have transmission path ratings which are voltage stability limits. We believe that this screen should be rewritten for voltage stability.

Abraham Ellis Sandia National Labs

> "I don't think WECC has any "stability areas" posted. However, the rating of all transmission paths and their respective limiting conditions are posted in the WECC path rating catalog. Most of the ratings are based on voltage stability."

Duquesne Light Company Transmission Planning Criteria

> "The PJM RTO established stability limits for preventing electrical separation of a generating unit or a portion of the PJM RTO. PJM recognizes three types of stability:
>
> - Steady State Stability – A gradual slow change to generation that is balanced by load.
> - Transient Stability – The ability of a generating unit or a group of generating units to maintain synchronism following a relatively severe and sudden system disturbance. The first few cycles are the most critical time period.
> - Dynamic Stability – The ability of a generating unit or a group of generating units to damp oscillations caused by relatively minor disturbances through the action of properly tuned control systems.

FERC-SGIP screens - Solar ABCs study

PJM will operate the facilities that are under PJM operational control such that the PJM system will maintain angular and voltage stability following any single facility malfunction or failure. In general, stability is not a limiting constraint on the PJM RTO."

*** 1. Do you support updating this screen?**

- ◯ YES
- ◯ NO
- ◯ I am not able to answer YES or NO because...

2. If you support updating this screen, what change would you recommend?

- ☐ Restating the screen with detailed voltage stability requirements
- ☐ Other (please specify)

3. Please briefly provide an explanation of your position.

FERC-SGIP screens - Solar ABCs study

13. Experience/Background questions

Please answer these background questions about your experience with interconnection and FERC SGIP screens.

*** 1. Which of the following best decribes your current role?**

- Utility - transmission focus
- Utility - distribution focus
- Utility - renewables focus
- Utility - policy focus
- Engineering firm
- Consultant
- Regulatory
- Manufacturer
- Other (please specify)

2. In which state or states has the bulk of your recent renewables related interconnection work been focused?

	#1	#2	#3	#4	#5	#6	#7
State:							

*** 3. Briefly explain your experience (engineering or policy) with the interconnection of PV systems.**

*** 4. Explain your experience with the FERC SGIP screens.**

5. What do you think needs to be done next with the FERC SGIP screens?

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14. Thank you for your time and effort.

You may click the "previous page" button below to revisit any of the questions. If you are satisfied with your answers click "Done."

Thank you again for your time and effort. You will be receiving a summary of the questionnaire results as soon as they are compiled. You will also receive a copy of the final report as soon as it is published.

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