BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

Docket UE-112133

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL ON THE UTILITIES AND TRANSPORTATION COMMISSION'S PROPOSED RULEMAKING ON GENERATOR INTERCONNECTION PROCEDURES

Pursuant to a Preproposal Statement of Inquiry, noticed by the Office of the Code Reviser on December 21, 2011, IREC respectfully submits these preliminary comments on the Washington Utilities and Transportation Commission's ("Commission") consideration of revisions to generator interconnection procedures. IREC appreciates the Commission's recognition that reform of the state's existing interconnection policies may be necessary to account for changes in technology and the emergence of national best practices that exceed those at use in the state. IREC appreciates the opportunity to put forth specific proposals for structural and substantive reforms. IREC looks forward to working with stakeholders through workshops in the spring of 2012 in pursuit of greater utilization of DG resources within the state.

IREC is a non-profit organization that has worked for nearly three decades to accelerate the sustainable utilization of renewable energy resources through the development of programs and policies that reduce barriers to renewable energy deployment. IREC has participated in workshops, proceedings and rulemakings before over thirty state public utility commissions during the past three years, addressing topics that directly impact the development of renewable energy resources, including net metering rules, interconnection standards and the permissibility of third-party ownership of renewable generation under state law.

I. Overview of Interconnection Reform and Incorporation of Best Practices.

The Commission's Preproposal Statement of Inquiry sets out three clear guiding principles for this proceeding. The Preproposal suggests that any reformed interconnection procedures should:

- **Lower costs for interconnection,**
- **Accelerate the development of distributed generation systems, and**
- **Avoid unduly shifting costs between ratepayers or classes.**

IREC suggests that these principles can be reduced even more plainly to just three words: money, time and fairness. In IREC's extensive experience participating in state interconnection proceedings and evaluating and promoting best practices in the area of interconnection, these three words are at the core of every recognized best practice. The time and money required to safely interconnect a generator should be fairly proportionate to the size and complexity of the interconnection request. This benefits generators, utilities, and ultimately ratepayers by delivering more DG and, thereby, more of the system and environmental benefits of DG.

Overly burdensome interconnection requirements, on the other hand, discourage customers from investing in distributed generation without providing any real benefit in terms of increased safety or reliability. A best practice in interconnection is, thus, one that fairly balances safety and reliability concerns and delivers the maximum amount of time and cost savings to encourage greater utilization of distributed generation ("DG").

In July 2011, IREC submitted comments to the Commission suggesting particular reforms to interconnection procedures.[1] IREC suggested several limited modifications in those comments: prohibition of external disconnect switch and additional insurance requirements for certain generators and adoption of objective technical review screens. At this time, IREC respectfully submits ten initial proposals, which include the earlier suggested modifications, for Commission consideration during this proceeding.

II. IREC's Ten Proposals for Interconnection Reform

IREC's comments provide a high-level outline of the following ten best practices that address this issue of proportional treatment of generator interconnections; best practices that IREC suggests could significantly improve the climate for DG in Washington:

1. Implement a four-tiered approach to interconnection review:
   - Tier 1: 25 kW inverter-based process;
   - Tier 2: expedited "fast track" review for generators 2 MW or less;
   - Tier 3: expedited path for non-exporting systems of 10 MW or less; and
   - Tier 4: detailed study for all other generators of 20 MW or less;
2. Establish objective Tier 1 and 2 technical screening criteria (a generator that passes these screens must be offered an interconnection agreement);
3. Create supplemental technical review screens to provide a process for potentially quick review of a generator that fails one or more of the initial technical review screens;
4. Establish fixed engineering fees and interconnection charges based on Tiers;
5. Prohibit additional insurance requirements for all generators under 1 MW;
6. Prohibit external disconnect switches for small, inverter-based systems;
7. Create standard form agreements and applications, including online interconnection applications;
8. Create a low-cost and expedient dispute resolution process;
9. Give potential applicants access to available capacity on sections of distribution grid; and
10. Create an informal, collaborative group to address ongoing issues.

These best practices support DG growth by providing an expedited path to interconnection for generators up to 2MW by creating transparent, objective rules of the road. Ultimately, these proposed best practices are all aimed at realizing the guiding principles of this proceeding: lowering the costs, accelerating the path to interconnection for distributed generation, and providing fairness to all parties, including ratepayers.

[1] *See* Comments of the Interstate Renewable Energy Council, filed July 8, 2011, Docket No. UE-110667: Re: Study of the Potential for Distributed Energy in Washington State ("IREC's July 2011 Comments").

III. Possible Starting Points

IREC's Model Interconnection Procedures ("IREC Model") incorporate most of these best practice proposals.[2] Accordingly, IREC suggests that the IREC Model could be a good starting point for the Commission. IREC notes, however, that several of the above suggestions are best practices have just recently evolved—since IREC last revised its model interconnection rules—and offers these suggestions with references to the states that are currently employing or developing these practices.

Alternatively, IREC notes that there may be several advantages to adopting the interconnection procedures of a neighboring state as a starting place instead. One advantage of adopting a neighboring state is that there are multi-jurisdictional utilities operating in Washington that have institutional experience with these other procedures. Another advantage is that Washington businesses, such as solar installers, are also active in neighboring markets and will already have a level of familiarity with those procedures.

If the Commission wishes to take this approach, IREC suggests that Oregon's small generator interconnection rules[3] would provide a suitable template for fashioning a final rule. Oregon's interconnection procedures score a solid "B" letter grade in the 2011 edition of *Freeing the Grid,* a publication to which IREC is a contributing author.[4] Indeed, only six states have a total interconnection score better than Oregon. The Oregon rules embody many of the best practices listed above and could provide a great deal of administrative convenience to the Commission and stakeholders as a starting point.

Finally, the Commission could begin with its existing rules, but the changes suggested here to align Washington's rules with other states would be extensive. IREC suggests that it would be easier to start with its rules or Oregon's rather than modifying the existing rules.

IV. IREC's Specific Proposals for Interconnection Reform

The following proposals are suggested as a way to frame the top priorities in addressing interconnection reform in Washington with the underlying goal of creating a robust DG market.

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2 *See* IREC's 2009 Model Interconnection Procedures, available at: http://www.irecusa.org/irec-programs/publications-reports/.

3 *See* O.A.R. 860-082-0005, *et seq.*. IREC focuses on Oregon's small generator interconnection rules, even though Oregon features three separate interconnection standards: one for net metering interconnections, one for small generators up to 10 MW, and another for generators over 20 MW. IREC discourages the Commission from taking this approach and instead suggests the small generator interconnection rules as an integrated starting point for procedures that apply to all jurisdictional interconnections.

4 *See Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*, 2011 edition. Available at: www.newenergychoices.org/uploads/FreeingTheGrid2011.pdf.

<u>IREC Proposal No. 1:</u> Implement a four-tiered approach to interconnection review.

IREC recognizes multiple review levels as a best practice because it allows for expedited review of smaller generators that pose less likelihood of adverse system impacts while providing a more exhaustive review process for larger generators where grid impacts are more likely. The basic architecture of this approach attempts to channel generator interconnection requests, based on system size and provides objective technical screens that further sort generators based on likely impacts. The technical screens, specifically, are discussed as a part of IREC Proposal No. 2, but are an integral part of the multi-level review structure because they provide an expedited path for smaller generators (either through the 25 kW inverter-based simplified process or through the fast track for generators up to and including 2 MW) that is not dependent on utility discretion and, therefore, not subject to undue delay. Best practices impose no more cumbersome requirements than necessary to ensure safety and reliability for the utility and its customers. IREC emphasizes this one aspect of interconnection policy because it lays the basic groundwork required for Washington to create a differentiated review system that removes barriers for low-impact DG systems.

Currently in Washington, interconnection proceeds along one of two tracks and lacks complete uniformity. There is one set of standards for generators 300 kW or less that is standardized across utilities and another non-standardized process for generators larger than 300 kW and less than 20 MW. Creating one consistent set of interconnection standards that apply to all jurisdictional utilities is a best practice. Inconsistency among utility procedures can create confusion for installers and developers who operate throughout the state. Inconsistencies stand in the way of efficient navigation of utility procedures, which affects the ultimate costs of interconnection, and may increase the risk of installer error.

For these reasons, the basic structure of interconnection review in Washington is inconsistent with best practices and with the procedures of a majority of states. Accordingly, IREC suggests that the 300 kW is an arbitrary divide that does not reflect operational realities or match any other state's practice.

Both IREC's Model and Oregon's interconnection procedures feature the best practice of four interconnection review paths. The emerging consensus is to assign applicants into one of four levels based on breakpoints: inverter-based systems of 10 kW or less (or in some states, 25 kW), systems of 2 MW or less pursuing a fast track or expedited technical review screen process, non-exporting systems of 10 MW or less, and any other systems of 20 MW or less using a detailed study process for systems that do not qualify for Tiers 1-3.[5] The basic structure of the IREC Model and Oregon procedures only differ on the size allowed for Tier 4. For IREC, systems up to 20 MW that do not otherwise qualify for Tiers 1-3, will interconnect under the Tier 4 detailed study process. In Oregon, the maximum size generator that can interconnect under Tier 4 is 10 MW or less. These approaches are similar to perhaps the most commonly used multi-level tier review in the United States, the Federal Energy Regulatory Commission's ("FERC") Small Generator Interconnection Procedures ("SGIP"), although the SGIP uses 3 review levels

[5] Oregon's small generator procedures only cover interconnections up to 10 MW. IREC's Model covers generator interconnections up to 20 MW.

and a 10 kW inverter-based simplified process.[6] Many states, similarly, incorporate three or four interconnection review "tracks" into their interconnection procedures, including Colorado, Connecticut, Florida, Indiana, Michigan, Oregon, New Jersey, New Mexico, New York, North Carolina, Ohio, Utah, and Virginia.[7]

> <u>Rationale for IREC Proposal No. 1:</u> Interconnection standards should be less stringent for small, simple systems and more stringent only as system sizes increase or as system design or impact require.

<u>IREC Proposal No. 2:</u> Establish objective technical screening criteria to evaluate generator interconnections under 2 MW.

Fast Track technical review screens are used to assess the ability of a generator to be interconnected to a utility's system without the need for a more detailed, and therefore more costly and time-intensive, study of potential impacts. Fast Track screens evaluate the basic characteristics of a proposed interconnection that will indicate potential impacts, such as the line configuration of the distribution grid at the point of interconnection, the total amount of generator capacity proposed on the distribution line section in relation to the loading on that line section, and the generator's contribution to fault current, among other relevant considerations. A generator that satisfies the Fast Track screens should be assumed to pose such a limited potential for adverse system impacts that a detailed interconnection study is not necessary.

Washington does not currently feature objective technical review standards designed for expedited review consistent with best practices. WAC 480-108-020 makes reference to technical standards, but these minimal requirements do not provide assurance that a generator can interconnect safely at any given point on the distribution system. Moreover, the existing process leaves too much discretion to utilities to constitute a true objective technical screening process. For example, WAC 480-108-035(2) provides utilities discretion to determine whether an interconnection is "feasible" without further study.

In contrast, SGIP and IREC Model technical review screens require a utility to execute an interconnection agreement within a specified period for any generator that qualifies for expedited review and passes all the screens. Because technical review screens provide the generator a path to interconnection that does not depend on utility discretion, they are fairly conservative standards that err on the side of caution. These procedures have been thoroughly vetted by industry, utilities and national codes and standards boards. IREC recommends the Commission start with the template of the technical screens utilized in Oregon's interconnection procedures, or alternatively the screens used in either the IREC Model or the FERC's SGIP.

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6 Many states have used the SGIP as a model for their interconnection procedures (for example CO, OR, IL, UT, and VA). All public utilities subject to the Federal Power Act that have wholesale generator interconnections utilize a version of the SGIP in their Open Access Transmission Tariffs ("OATT").

7 A summary of each state's interconnection procedures is available at the Database of State Incentives for Renewables & Efficiency (DSIRE): http://www.dsireusa.org.

Rationale for IREC Proposal No. 2: Technical screens help provide an objective means of expedited interconnection review that significantly reduce the time and money of a full interconnection study.

IREC Proposal No. 3: Establish supplemental technical review screens or procedures for generators that fail one of more of the fast track technical review screens.

One of the most significant fast track technical screens, in terms of a generators impact on a line section, is the screen that restricts the aggregate generation on a line section to 15% of the peak loading of that section. In states with high penetration of DG, like Hawaii, New Jersey, and California, this "peak load" screen is a common cause of screen failure.[8] These states have all begun to consider an alternate approach that will create a "back up" or supplemental review screen for generators that fail the 15% peak load screen.

As IREC discussed in its earlier comments to the Commission in the spring of 2011, an emerging best practice is to now allow generators that fail the 15% peak load screen to proceed on the expedited path if they pass an alternate screen based on 50% of daytime minimum load, usually tracked between the hours of 10 a.m. and 3 p.m.[9] This screen accounts for the fact that a large portion of DG uses solar photovoltaic ("PV") generating technology, and that the relevant period to account for impacts would be when the system is most likely producing or exporting excess generation. Accordingly, as long as the generating capacity does not exceed a certain percentage of the minimum load on that line section, there is little to no risk of adverse system impacts. In other words, if generation never exceeds minimum load, any injection of electricity will likely be consumed on that line section and not contribute any negative system impacts. For this reason, it would be reasonable to utilize a 100% of minimum load screen, but only where the examined circuit is limited to solar PV generation. IREC is aware that utilities in New Jersey are beginning to use the 100% of minimum load screen in those circumstances.

It may be the case that the data necessary to calculate minimum loading is not always available for a particular line section, but with the deployment of advanced metering infrastructure ("AMI"), this data should be more and more readily available moving forward.

Rationale for IREC Proposal No. 3: Supplemental technical review screens, such as the 50% of minimum load screen, may support greater use of expedited procedures while maintaining grid safety and reliability.

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8 For example, Southern California Edison's Wholesale Distribution Access Tariff queue spreadsheet, page marked "Fast-Track Evaluation" shows failure of the peak load screen as one of the most prevalent causes of fast track failure for wholesale interconnections to its distribution system. Available at: http://www.sce.com/nrc/aboutsce/regulatory/openaccess/wdat/wdat_queue.xls.

9 *See* IREC's July 2011 Comments at p. 14.

<u>IREC Proposal No. 4:</u> Provide certainty in interconnection charges and engineering fees.

Interconnection application fees along with other fees can create challenges, especially if these fees are unknown at the onset of project development. Reasonable fee levels have been established in the FERC procedures as a result of extensive negotiations with a wide range of stakeholders. As an example of these modest fees, the SGIP requires a $100 non-refundable application fee for its Level 1 10 kW Inverter Process and $500 application fee for its Level 2 Fast Track process. Many states waive application fees for smaller systems altogether. In the two leading states for solar energy installations, most systems face no fee at all. California's Rule 21 waives interconnection fees for net metering facilities and exempts up to $5,000 in interconnection expenses for other distributed generation under 1 MW.[10] New Jersey, similarly, waives interconnection fees for generators of 10 kW of less (Level 1 interconnections).[11]

In addition to capping interconnection charges and engineering fees for all customers, some states waive interconnection costs for certain small generators. Wisconsin's interconnection procedures, while leaving much to be desired in other categories, feature an exemption of fees for Tier 1 (20 kW or less) interconnection customers.[12] Additionally, Massachusetts, Nevada, New York, Minnesota and Kentucky provide waiver from interconnection charges for small or net metered generators.[13]

In addition to waiving fees for very small generator interconnections, some states have adopted fee structures oriented toward keeping costs low for smaller systems. For example, Massachusetts limits application costs for expedited and standard applications, basing the fees on a $3/kW rate with a minimum fee of $300 and an application cap at $2500.[14] In Maine, the application fee for generators up to 2 MW under the Fast Track review is $50 plus $1 for each kW of nameplate generating capacity.[15] Under Maine's Study Process, all applications are capped at $100 plus $2/kW of nameplate capacity.[16] Accordingly, there are several approaches available that help to lower the initial costs for small generators, including waiver of application fees for the smallest categories.

For generators that cannot pass Fast Track screens or are not eligible for the Fast Track process, the study process may expose the interconnection customer to open-ended financial commitment. Where an interconnection standard requires engineering review for certain systems,

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10 *See* California Rule 21.C.1.d.

11 *See* New Jersey Administrative Code § 14:8-5.7(a).

12 *See* Wisconsin Statutes PSC § 119.08

13 *See, e.g., Freeing the Grid* at pp. 88-89; Massachusetts Model Interconnection Tariff § 3.5 (Level 1 fees waived); Kentucky PSC Order No. 2008-00169 (Level 1 Fees waived); Minnesotta Public Utilities Commission Order (9/28/04), Attachment 1 at p. 10 (Docket No. E-999/CI-01-1023); New York Standard Interconnection Requirements at p.2 (no application fee for system 25 kW or less); Nevada Rule 15.D.1.b (fees waived for net metering systems).

14 *See* Massachusetts Department of Public Utilities Order No. 09-03-A, Model Interconnection Tariff § 3.5.

15 Maine Public Utilities Commission Rules, 65-407, Chapter 324 § 9.I.

16 *Id.* at § 11.U.

it is important that the parties involved know what the fees are beforehand. The engineering charges are most commonly set at a fixed dollar per hour rate or maximum amount per study. For example, the Maine Public Utilities Commission capped engineering fees at a rate of $100 per hour, noting that the purpose was to provide a degree of certainty and to eliminate disputes about the proper rate.[17] Study fee caps and fixed engineering rates do tend to provide upfront financial uncertainty for interconnection customers. Engineering fees are fixed by the interconnection procedures in 11 states, including Maine, Massachusetts and Oregon.[18] The SGIP does not fix or cap engineering charges.

> Rationale for IREC Proposal No. 4: Fixed interconnection charges that vary by Tier and fixed engineering fees give applicants a clear understanding of the costs they will face. An exemption from interconnection charges and costs for net metered customers promotes greater customer adoption of systems to serve on-site load.

IREC Proposal No. 5: Prohibit any additional insurance for inverter-based generators up to 1 MW and allow only reasonable amounts for all others.

Additional or excessive insurance requirements create a cost barrier that can discourage customers from investing in distributed generation. These additional insurance requirements are often impractical, because the premiums for liability insurance policies are likely to exceed the benefits the customer hopes to attain by installing the generator in the first place. As IREC previously suggested in its July 2011 comments to the Commission, UTC rules already exempt net metering systems from the burden of additional insurance requirements.[19] IREC continues to suggest that "there is no significant justification to continue to allow additional insurance to be required at the IOUs discretion for other generators interconnecting under these rules."[20]

Again, prohibition of additional insurance requirements—at least for some generators—is a best practice because it removes a significant cost that does not have a corresponding benefit. It is important for a customer to self-insure to the degree necessary to protect against on-site risks and liabilities, but this should be no different than a property owner's normal interest in guarding against liabilities resulting from on-site activity. There is no reason for the Commission to regulate and inject its judgment into how customers should manage on-site risks. Instead, the Commission's role is to determine whether there is a need to regulate the risk to the utility through additional insurance requirements, and those risks are quite minimal. As IREC noted previously, "with more than 100,000 grid-connected PV systems in the United States,[21] there has

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17 *See Order Adopting Rule* at p. 17, Maine Public Utilities Commission, Docket 2009-219 (1/4/10)

18 *See* http://www.dsireusa.org.

19 WAC 480-108-040(9).

20 IREC's July 2011 Comments at p. 13.

21 See Sherwood, Larry (June 2011) *U.S. Solar Market Trends 2010* at p. 8. (PV installations in U.S. through 2010 in excess of 154,000). Published by IREC and Available at: http://www.irecusa.org/irec-programs/publications-reports/.

never been a documented case of a PV system causing personal injury to utility line workers or property damage for a utility."

IREC's Model prohibits any additional insurance requirements for any generator 1 MW or less. This best practice is also reflected in procedures in Delaware, Maine, New Jersey, and Utah.[22] Twenty-four states embrace this view and prohibit additional insurance requirements, do not require additional insurance beyond what a customer would typically carry, or do not mandate it automatically for most renewables as part of their interconnection rules.[23]

> <u>Rationale for IREC Proposal No. 5:</u> Prohibiting additional insurance requirements for generators 1 MW or less is a best practice because it removes a significant ongoing cost for generators. Experience has shown that this insurance is not necessary to protect ratepayers because, in the case of distributed solar PV, there are no documented cases of such systems causing personal injury to a utility worker or property damage to a utility.

<u>IREC Proposal No. 6:</u> Prohibit external disconnect switch requirements for small, inverter-based generators.

As a safety redundancy measure, interconnection procedures may require that an interconnecting generating facility install an external disconnect switch ("EDS") that is clearly marked and accessible by utility personnel. In instances of power outage, there is a theoretical possibility that a grid-tied system may continue generating electricity and export it to the grid, putting utility workers at risk of encountering energized lines. If a generating facility is inverter-based and will therefore not export power when the grid is de-energized, then interconnection procedures may waive the requirement or prohibit utilities from requiring external disconnect switches for such generators.

In IREC's July 2011 Comments (pp. 9-10), IREC proposed that any interconnection reform include a provision that prohibits external disconnect switches for inverter-based systems:

> "IREC suggests that external disconnect switches (EDS) are not necessary for inverter-based systems interconnecting under Washington's technical standards. Washington's technical standards for interconnection require UL 1741 listed inverter based systems under 300 kW to install an external disconnect switch, although the utility may waive the requirement.[24] All UL 1741 certified inverters meet IEEE standards and, therefore, have automatic shut-off capabilities integrated into their systems.[25] Because of these standards, in the event the grid

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22 *See Freeing the Grid* at pp. 88-89. (This is indicated by a score of 0.5 or 1).

23 *Id.* (scores of 0.5 or 1 for insurance).

24 *See* WAC 480-108-020(2)(a) and (b).

25 *See* Institute of Electrical and Electronics Engineers (IEEE). (2003) *1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.*

goes down, all modern inverters stop power flow to the grid automatically.[26] Solar energy systems using a UL 1741 certified inverter automatically disable the generating unit and stop the flow of electricity back to the grid. A 2008 report by the National Renewable Energy Laboratory (NREL) assessing the need for external disconnect switches concludes that the switch is made redundant and unnecessary by UL and IEEE standards and the extensive safety training utility workers receive.[27] IREC's Michael T. Sheehan authored a comprehensive review of this issue, "Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement," and similarly concluded that for 'properly designed and installed Code-compliant PV systems, the UEDS provides little, if any, additional safety, beyond what is already present.'[28]"

IREC suggests that the best answer to the question of whether an EDS should be required is whether the utilities in Washington, in actual practice, are utilizing the EDS for safety purposes. Going to the location of a generator and manually disconnecting it, tagging the location, and later returning to reconnect the facility is a labor-intensive prospect. In California, the investor-owned utilities ultimately dropped the EDS requirement for small, inverter-based generators when it examined the efficacy of the requirement and found that the devices were not being used. The Commission may consider data requests to jurisdictional utilities to discover whether those utilities have, to date, ever used the EDS and to what frequency if so. If utilities are not using the function of the EDS, then there should be no reason to continue to require it in cases where the measure is redundant.

IREC does not repeat here the entirety of its July 8 2011 comments, but suggests that the Commission may consider incorporating the comments submitted in UE-110667 by reference. At the most basic level, the proposal to remove the EDS requirement—at least for certain generators—is consistent with the guiding principles of this proceeding and best practices because it removes a significant cost that does not increase the margin of safety for utility line workers.

IREC noted in its July 2011 comments, a growing number of regulators and utilities agree that external disconnect switches are unnecessary for small inverter-based systems and present a barrier to new technology that can make compliance unduly burdensome and expensive.[29] IREC suggests that, at a minimum, prohibiting EDS requirements for Tier 1 systems will remove a significant up front cost from smaller systems that have less opportunity to absorb the cost through economies of scale. This approach is consistent with best practices among the

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26 *See* Haynes, Rusty and Whitaker, Church (2007) *Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues.* Fifth ed. IREC and North Carolina Solar Center.

27 Coddington, M.H., R.M. Margolis, and J. Aabakken (2008) *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. National Renewable Energy Laboratory. Technical Report: NREL/TP-581-42675. Available at: www.nrel.gov/docs/fy08osti/42675.pdf.

28 *See* Sheehan, Michael T., P.E., "*Utility External Disconnect Switch: Practical, Legal, and Technical Reasons to Eliminate the Requirement,* published by Solar America Board for Codes and Standards. Available at: http://www.solarabcs.org/about/publications/reports/ued/index.html.

29 IREC's July 2011 Comments at pp. 10-11.

states. At least eleven other states prohibit external disconnect switches for certain generators.[30] For example, Maine prohibits the requirement of an external disconnect switch for generators which meet its certification requirements and North Carolina prohibits disconnect switch requirements for certified inverter-based generators up to 10 kW.[31] In California, utilities have voluntarily dispensed with disconnect switch requirements for inverter-based systems less than 11 kVA that are installed in locations with self-contained meter sockets.

Rationale for IREC Proposal No. 6: External disconnect switches can represent a needless expense discouraging customer adoption of DG. This requirement does little to increase safety where generators already utilize a modern inverter.

IREC Proposal No. 7: Create standard form application and agreement for all review levels.

Using standard forms and agreements accomplishes several positive things for the development of a distributed generation market. First, installer and contractor familiarity with uniform standards and forms, across all in-state utility service areas, will lead to greater efficiency and lower transaction costs. Second, the transparency of standard forms and agreements will give the participants in the market confidence that they are getting a fair shake using vetted standards and contract terms. Both the IREC Model and the FERC's SGIP have accompanying standard form agreements and applications that could serve as templates for the Commission.

Rationale for IREC Proposal No. 7: Standardization lowers transaction costs, promotes fairness and creates more market certainty.

IREC Proposal No. 8: Create a low-cost and expedient dispute resolution process.

IREC acknowledges that it is inevitable that some requests for interconnection will result in disputes, no matter how well designed the rules. In that event, best practices suggest that the parties should have a low-cost means of expert resolution available. For example, technical disputes might be resolved via a simple telephone call to a technical master employed by the state public utility commission. Informal dispute resolution is also a far less expensive option than a formal Commission complaint proceeding. Of course, if the standard explicitly states that all disputes will be resolved through or by a utility's discretion, the standard becomes less reliable in the eyes of counter-parties.

Rationale for IREC Proposal No. 8: Expedited, low-cost dispute resolution should be provided for in the rules to give a basic framework for parties to solve

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30 *See* http://www.dsireusa.org.

31 *See* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=ME15R&re=1&ee=1 (Maine); http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC04R&re=1&ee=1 (North Carolina).

problems without involving the extensive resources required in Commission adjudication.

IREC Proposal No. 9: Explore the potential of publication of distribution system information.

Access to distribution level information can assist developers in locating preferred points of interconnection and reduce the time and expense of bringing a project to operation. The information that IREC proposes be made available to developers relates to the available capacity on distribution circuits to accommodate new generation facilities. As IREC explained in its July 2011 comments, this data can be a helpful compliment to the FERC technical standards—particularly the peak load screen. Indeed, if utilities provide access to the available capacity of distribution facilities at the circuit level and an accounting of existing generating capacity, developers and customers could fairly evaluate how much headroom exists on a circuit and gauge the likelihood that a given location is appropriate for a project. Thus, detailed maps with distribution circuit information can assist developers and customers in identifying suitable points of interconnection, and could facilitate a quicker and lower cost interconnection by giving sufficient information to minimize the risk that a project would require costly, detailed study process. This approach is currently being implemented in California where all of the major investor-owned utilities have made this type of information publicly available on map-based websites.[32]

Rationale for IREC Proposal No. 9: Access to utility distribution grid information is emerging as a best practice by encouraging efficient siting based on likelihood of expedited review.

IREC Proposal No. 10: Create a reporting mechanism to promote transparency and enable future efforts to improve interconnection processes.

IREC is aware that even the most thoughtfully developed standards may lead to unexpected issues in practice. IREC suggests, as other stakeholders also suggest, that it may be beneficial to have an informal, ongoing collaborative process between the Commission, utilities and stakeholders to identify problems they are encountering with any reformed standards and identifying solutions that can be adopted without having to engage in further rulemaking. IREC suggest that such an informal group could convene once a year and can continue to communicate through an email listserv so that all members of the group are kept abreast of developing issues.

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[32] *See, e.g.,* San Diego Gas & Electric's Distributed-Generation Map (http://sdge.com/distributed-generation-map); Southern California Edison Company's Preferred Locations Map (http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm); Pacific Gas & Electric Company's Solar PV and RAM Program Map (http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/).

Rationale for IREC Proposal No. 10: An informal, collaborative group could help develop consensus among utilities, the Commission and stakeholders regarding how to address any issues that arise within the new, reformed interconnection procedures. This group could foster a beneficial dialogue between the parties, increase the transparency of the interconnection process and help installers, customers and developers understand the utilities' perspective, and vice versa.

IV. Conclusion

IREC appreciates the opportunity to participate in Commission consideration of improved interconnection rules. Consistent with promoting the expansion and greater utilization of distributed, renewable resources in the state, IREC respectfully submits these comments on best practices in the area of interconnection. IREC emphasizes the importance of a quick, low-cost path for generators that will have limited impacts, and strongly supports Commission adoption of an expedited path, based on objective, technical review screens, for generators up to and including 2 MW. IREC looks forward to participating in workshops and hopes to assist the Commission in improving the conditions for a successful DG market in Washington.

Respectfully Submitted on January 30, 2012.

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