BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

Re: Study of the Potential for Distributed Energy in Washington State	Docket No. UE-110667

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL

The Washington Utilities and Transportation Commission (UTC or Commission) issued a "Notice of Opportunity to File Written Comments and Notice of Work Session" (Notice) on June 24, 2011, addressing a wide range of topics relating to the greater utilization of distributed energy resources in Washington. The Interstate Renewable Energy Council (IREC) welcomes this investigation into the potential benefits of and barriers to greater adoption of distributed generation (DG). IREC intends to send a representative to the July 25, 2011 work session and greatly appreciates the opportunity to submit these written comments.

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.

INTRODUCTION

The Washington State House of Representatives Technology, Energy and Communications Committee (TEC Committee) hopes to use the Commission's input and expertise to identify both challenges and solutions to Washington's energy equation. The TEC Committee would like, on the one hand, the Commission's "discussion of options to encourage the development of cost-effective distributed energy in areas served by investor-owned utilities" (IOUs).[1] The Notice also speaks to the TEC Committee's concern that the UTC's process consider the "opportunities and challenges facing [IOUs] and their ratepayers in developing distributed energy in this state." IREC appreciates the TEC Committee's and the Commission's concern in creating a balanced solution that minimizes ratepayer impacts while enabling economic growth in the renewable energy sector and establishes long-term grid and rate benefits.

IREC's comments are focused on the near-term fixes that the Washington Legislature and the Commission can implement to measurably advance DG without great costs to IOUs or ratepayers. IREC respectfully suggests that Washington has yet to take advantage of "low-hanging fruit," in terms of best practices in the area of DG policy. IREC encourages the Commission to take this opportunity to address several of these issues, either on its own authority or through written recommendations to the TEC Committee, as Washington can advance its fundamental DG policy toward best practices and open its market to the maturing renewable industries on the West Coast.

IREC suggests that near-term fixes to Washington's DG policy entail modification to net metering and interconnection standards and clarification of the regulatory status of third-party owners of DG. Improvements to these policies will allow market forces to do the heavy lifting to

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1 Notice, p. 1.

unlock opportunities for DG in Washington. The Commission can accomplish this by modifying regulatory restrictions on system size for net metering facilities, reducing the transaction costs of interconnecting through increased uniformity of procedures and elimination of unnecessary requirements on applicants, and by clarifying that financing arrangements for behind-the-meter customer systems will not render a third-party owner a public utility. IREC appreciates that there could be legislative fixes for all of these issues, but suggests the Commission may choose to act under its authority to achieve some of these gains more expeditiously.

IREC's comments also address several emerging policy ideas scoped in the Notice. IREC believes, in particular, that energy storage holds the potential to enable greater integration of variable resources, such as solar and wind, onto the grid. It is important from the outset to identify the policy considerations and remove barriers to allow energy storage solutions to develop in the marketplace. IREC also addresses the issues surrounding the ability of the Commission to set an avoided cost for a market segment in light of a recent ruling from the Federal Energy Regulatory Commission (FERC). IREC does not address all of the issues presented in the Notice, as some of the requests exceed IREC's ability to produce extensive supporting data over such a short period. IREC comments where its experience might assist the Commission in advancing DG policy in Washington.

COMMENTS

A. IREC Supports Regulatory or Statutory Changes that Clarify Third-Party Ownership of DG, Streamline the Interconnection Process and Maximize Availability of Net Metering to Washington Customers

IREC suggests that there are several important changes to Washington DG policy that could be accomplished by legislative action or a regulatory proceeding at the Commission.

Question #4 under Section "A" of the Notice asks if there are "changes in state statutes or rules that would encourage technology-neutral development of distributed energy generally" and if "current interconnection standards need to be changed to accommodate more distributed energy or to accommodate different distributed energy technologies."[2] IREC suggests that either statutory or regulatory changes could improve interconnection and net metering and, most importantly in IREC's view, a simple regulatory clarification could rapidly expand the Washington DG market by explicitly allowing third-party owners of DG to operate in Washington, as they are allowed to do in Oregon, California, Nevada, Utah, Arizona, Colorado, New Mexico, Texas[3] and much of the Northeast. IREC offers the specific following recommendations to advance Washington DG policies in these areas.

1. Third-Party Ownership

IREC suggests that the Commission can act on its own to clarify that a third-party owned system is not an electrical company, subject to the UTC's regulatory oversight. Alternatively, the legislature could expressly exempt third-party owners from electrical company status and UTC regulation.

Seventeen states explicitly provide that third parties may own customer-sited generation, and these are the leading states for solar energy deployment.[4] Third party owners are able to use the available 30% federal tax credit and accelerated depreciation, unavailable to many customers, making solar energy much more attractive in states that allow this form of ownership.

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2 Notice, p. 2.

3 Texas recently passed legislation allowing third-party ownership unanimously in both houses of the legislature. The act goes into effect September 1, 2011.

4 *See* Database of State Incentives for Renewables & Efficiency (DSIRE), Map of "3rd-Party Solar PPA Policies." Available at: http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.ppt.

Government facilities, schools and non-profits are particularly disadvantaged without the allowance of third party ownership because they do not pay federal taxes and otherwise have no ability to use the federal tax credit and depreciation. Third party owners can use the available tax benefits, and competition forces them to pass on these benefits to their customers in the form of lower costs than their customers could achieve on their own.

IREC identifies state policy that allows third-party ownership of DG, and allows those systems to participate in net metering, as a best practice. The annual publication *Freeing the Grid*,[5] to which IREC participates in evaluating state interconnection and net metering policy compared to best practices, awards a bonus point to state procedures that allow a third-party owned system to net meter. Nine of the top ten states in the 2010 edition of *Freeing the Grid* have provisions in their net metering rules allowing this practice. Indeed, even Washington scores a point because the definition of customer-generator does not preclude third-party ownership.[6] The broader question, however, is whether the Commission interprets state law to prohibit or allow this practice.

The issue of whether a third-party may own and operate a customer-sited generation facility in Washington turns on the Commissions interpretation of its authority under Washington law. IREC's experience in other state proceedings has taught that the operative question is whether a third-party entity meets the state's statutory or regulatory definition of a public utility. There are many commonalities among state definitions of "utility" or "public utility," and the issue in many states boils down to whether a third-party owner offers service to the

5 *See Freeing the Grid, 2010 edition.* Available at: www.freeingthegrid.org.

6 RCW 80-10-020(2) defines a "customer-generator" as a "user of a net metering system." *Freeing the Grid* and IREC generally treat statutes that require the customer to "own and operate" a net metering system to preclude third-party owned systems from participating in net metering.

indiscriminate public or dedicates the facility to public use. Utility Commissions in Arizona, New Mexico, and Nevada, among others, have considered this question and determined that these arrangements do not constitute public utilities under those state's laws.[7]

Washington law is not clear on whether third-party ownership is permitted. The UTC has jurisdiction over an "electrical company," which is defined as a person "owning, operating any electric plant for hire."[8] "Electric plant" is broadly defined to include "all real estate, fixtures and personal property operated, owned, used or to be used for or in connection with or to facilitate the generation, transmission, distribution, sale or furnishing for electricity light, heat, or power for hire."[9] While the phrase "for hire" appears broad enough to encompass a third-party owner owning and operating a behind-the-meter facility to sell the output to a single customer, Washington Courts have held that such a literal interpretation is flawed because that statutory section is intended to apply only to public service companies.[10] IREC does not believe the Commission has addressed the issue of whether a third-party owner is captured in the definition of "electrical company" and whether its activities constitute a dedication to public use and trigger public service company status.

The potential regulation of third-party owners of DG is also a problem in the context of Washington's community solar provisions in its incentive program. The community solar rules

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7 *See, e.g.,* Decision No. 71795, Docket E-20690A-09-0346 Arizona Corporations Commission (7/12/10) (allowing third-party ownership model for government and non-profit customers); *Declaratory Order, 09-00217-UT,* New Mexico Public Regulation Commission (12/17/10); *Order,* Docket 07-06024, Nevada Public Utilities Commission (11/26/08).

8 Washington Revised Code § 80.04.10.

9 *Id.*

10 *Inland Empire Rural Electrification, Inc. v. Dept. of Pub. Serv. of Wash.*, 199 Wash. 527 (Wash. 1939); *West Valley Land Co. v. Nob Hill Water Assn.*, 107 Wash. 2d 359 (Wash. 1986).

require customer-owned community solar facilities to be sited on local government property, but do not specify whether the customer-owners can sell electricity to the host.[11] IREC suggests that if only sales by the customer-owner to the utility are permitted, there is no incentive for the host to participate. Community solar projects offer an opportunity to provide low cost, on-site electricity for a local government host, such as a school. In the present budget constrained environment, providing this option to local government entities has even wider public benefit than just the promotion of DG. Allowing the community solar facility to sell to the host, most importantly, adheres to the core principle of DG, which is to place generation close to load where it can be used with minimal line losses or environmental impact. Resolution of the uncertainty surrounding third-party owners could have far-reaching benefit.

IREC suggests at least three ways the Commission could act now to help resolve this uncertainty and allow this mode of ownership to accelerate DG growth in Washington. First, the Commission could, similar to New Mexico, launch an investigation into the practice and issue a declaratory order to disclaim its jurisdiction over third-party owners. Second, the Commission could recommend that the TEC Committee draft legislation to expressly exempt third-party owners from "electrical company" or public service company status. Texas recently passed legislation that accomplishes this end.[12] Lastly, the Commission could institute a rulemaking to clarify that it will not exert jurisdiction over third-party owners who operate within certain factual scenarios that do not implicate the public interest. IREC hopes that the Commission will consider these solutions as consistent with the goals of the notice. Allowing third-party

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11 *See* RCW 82.16.110. "Community solar project means… a solar energy system owned by local individuals, households, nonprofit organizations, or *nonutility businesses* that is placed on the property owned by a cooperating local governmental entity that is not in the light and power business or in the gas distribution business." [emphasis added].

12 *See* SB 981 (Texas 2011), effective 9/1/11.

ownership will unlock potential DG growth without requiring additional expenditures from the Legislature or harming the state's ratepayers.

2. Interconnection

IREC suggests that there are meaningful structural opportunities for the interconnection process in Washington to improve. First, the Legislature could act to provide uniformity throughout the utilities in the state, so that developers and installers familiar with interconnecting to the IOUs distribution systems are not hindered by inconsistent procedures in a municipality or within an electric cooperative. Consistent statewide procedures would breed familiarity and increased efficiency, reducing administrative delays and lowering the transaction costs of interconnecting a facility. The Commission could act to reform the approved interconnection procedures of the IOUs and remove unnecessary cost barriers to DG adoption. Washington is unique in that it allows utilities discretion to draft their own interconnection standards for systems over 300 kW, with limitations.[13] IREC suggests that a uniform, state-wide standard for all interconnections subject to Commission jurisdiction would benefit the DG market, for the reasons stated above.

Specific reforms to the interconnection process, itself, could benefit the DG market by allowing more generators to interconnect to the grid more quickly and without unwarranted costs. IREC suggests that the Commission could lower the costs to install DG by prohibiting requirements for external disconnect switches for inverter-based systems and the requirement that customers carry additional insurance to cover liability associated with the DG facility. IREC suggests that the Commission could adopt or improve upon FERC's Fast Track technical screens to increase the potential for higher penetration of DG without risking adverse impacts on the

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13 *See* WAC 480-108-001

grid. Additionally, the Commission could reduce the interconnection time and cost barriers for small DG systems by taking a similar approach to New York, which recently increased its Simplified Interconnection process to generators with capacity of 25 kW or less.[14]

a. External Disconnect Switch

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.[15] All UL 1741 certified inverters meet IEEE standards and, therefore, have automatic shut-off capabilities integrated into their systems.[16] Because of these standards, in the event the grid goes down, all modern inverters stop power flow to the grid automatically.[17] 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.[18] IREC's Michael T. Sheehan authored a comprehensive review of this issue, "Utility

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14 *See* New York Standard Interconnection Requirements, effective on 12/20/10. Available at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY02R&re=1&ee=1.

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

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

17 *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. Available at http://www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Guide.pdf.

18 Coddington, M.H., R.M. Margolis, and J. Aabakken (2008) *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External*

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."[19] Mr. Sheehan will be participating in the July 25 work session on IREC's behalf.

The costs of an EDS are not insignificant. In a 2008 Florida Public Service Commission proceeding on Interconnection and Net Metering of Customer-Owned Renewable Generation, Florida's investor-owned utilities estimated the cost for them to install external disconnect switches to be as high as $1,200 per switch.[20] As a result, an EDS may represent a 6% increase in the cost of installing a $20,000 small PV generator and as PV panel costs come down in price, the cost of an EDS is likely to represent an even larger percentage of the overall cost of installing distributed generation. The Maine Public Utilities Commission reached this conclusion in a report to that state's Legislature, noting that "the cost of the switches relative to the cost of the generation systems will increase over time making the cost of disconnect switches even more likely to discourage further adoption of small generation."[21]

IREC notes that 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. IREC notes that

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Disconnect Switch. National Renewable Energy Laboratory. Technical Report: NREL/TP-581-42675. Available at: www.nrel.gov/docs/fy08osti/42675.pdf.

19 *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.

20 *Comments of Investor-Owned Utilities*, Docket No. 070674-EI, p. 7, ¶ 20 (Jan. 25, 2008). Available at: http://www.psc.state.fl.us/library/filings/08/00653-08/00653-08.pdf.

21 Maine Public Utilities Commission Inquiry into Interconnection Standards for Small Renewable Energy Facilities, Request for Comment on Report on Statewide Small Generator Interconnection Standards, p. 9, Docket No. 2008-186 (Dec. 5, 2008).

the North Carolina Utilities Commission found "good cause to approve a change in the NC Standard whereby an [external disconnect switch or "EDS"] will no longer be required for certified inverter-based generators up to 10 kW, and the decision whether to require an EDS for other generators will be left to the individual utility's discretion."[22] New Jersey's interconnection standard also takes the position that there is no need for the switch and it should therefore never be required at a customer's expense.[23] Pacific Gas & Electric ("PG&E") (the nation's largest utility, with by far the largest number of interconnected solar systems – approximately half of the country's total installed solar photovoltaic capacity) and the Sacramento Municipal Utility District ("SMUD") (with among the longest experience with significant utility solar deployment in the United States) have voluntarily dispensed with the requirement for an external disconnect switch on inverter-based systems with a self-contained meter.[24] The utilities took this action to help reduce the costs of solar systems and increase the number of installed systems. Similarly, Progress Energy Carolinas, Inc. ("PEC") has taken the position that "[f]or installations less than 10 kW, PEC now feels that installation of an external isolation switch is generally not necessary, since PEC's normal work rules address the possibility of customer-owned generation whether or not they have applied with PEC for interconnection."[25]

The significant cost of an EDS might be justified if there were a corresponding safety benefit. However, as noted above, modern standards for inverters, utility line worker training,

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22 *See* Order Approving Revised Interconnection Standard, North Carolina Utilities Commission Docket No. E-100, Sub 101 at pp. 15-18 (June 9, 2008).

23 *See* N.J.A.C. 14:4-9.

24 Summary of SMUD Press Release available at: http://irecusa.org/2007/04/californias-smud-scraps-requirement-for-disconnect-switch/.
PG&E policy change referenced at:
http://www.pge.com/b2b/newgenerator/acdisconnectswitches/

25 *See* Order Approving Revised Interconnection Standard, North Carolina Utilities Commission Docket No. E-100, Sub 101 at pp. 16 (June 9, 2008).

and the absence of any documented safety issues on more than 154,000 gird-connected PV installations in the U.S.[26] provide adequate assurance that prohibiting an external disconnect switch will not compromise the safety of utility workers during a grid outage. Based on the analysis above, best practices regarding the external disconnect switch is to prohibit a utility from requiring one for inverter-based systems.[27] The Commission could act through a rulemaking to eliminate this requirement, or could recommend that the TEC Committee draft legislation to prohibit this requirement.

b. Additional Liability Insurance

UTC rules already recognize the burden of additional insurance requirements for customers engaged in net metering.[28] IREC suggests 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. In particular, given the potential for community solar projects to not be net-metered, this provision in the interconnection rules may force community solar projects to carry additional insurance that is not required of similarly-sized net-metered facilities.

Requirements that customer-generators procure insurance above what they would normally carry are often based on cost allocation arguments – if something goes wrong with a customer's generation facility and it damages the electrical grid, ratepayers should not have to bear the cost of that damage. Such an argument has intuitive appeal on fairness grounds. However, to IREC's knowledge, with more than 100,000 grid-connected PV systems in the

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26 Sherwood, Larry, *U.S. Solar Market Trends 2010*, p. 8 (June 2011). Available at: http://irecusa.org/wp-content/uploads/2011/06/IREC-Solar-Market-Trends-Report-June-2011-web.pdf.

27 See IREC IC Model, Sec. j(5).

28 WAC 480-108-040(9).

United States,[29] there has never been a documented case of a PV system causing personal injury to utility line workers or property damage for a utility.

This suggests that it is very unlikely that insurance requirements provide any benefit to ratepayers, but they clearly constitute an extra cost to customers seeking to invest in DG. 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.[30]

c. Adopt FERC Fast Track Technical Screens

A key aspect of a DG facility's ability to interconnect quickly and at a low cost is the presence of an expedited path to generation that uses well-understood, objective screening criteria. The FERC technical screens used in its Fast Track review process (generators of 2 MW or less) are perhaps the most recognizable and widest used example of such objective criteria. An application that passes the Fast Track technical screens will not have an adverse impact on the interconnected system. Because a generator that passes the technical screens is approved for interconnection, those screens are relatively conservative and have been heavily vetted.[31] A process that utilizes the FERC screens provides an additional path to interconnection for

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29 See Sherwood, Larry (2010) *U.S. Solar Market Trends 2009*. Interstate Renewable Energy Council. Figure 4 (annual PV installations through 2009 in excess of 100,000). Available at: http://irecusa.org/wp-content/uploads/2010/07/IREC-Solar-Market-Trends-Report-2010_7-27-10_web1.pdf.

30 Appendix C, *Freeing the Grid*, pp. 106-07 (scores of 0.5 or 1 for insurance).

31 FERC's Order No. 2006, which adopted the SGIP, was the culmination of a four year rulemaking process that specifically identified and addressed the need for expedited procedures for smaller generators that would necessarily have limited grid impacts. *See generally* Order No. 2006, *Standardization of Small Generator Interconnection Agreements and Procedures* 111 FERC ¶ 61,220 (May 12, 2005), *order on reh'g*, Order 2006-A, 113 FERC ¶ 61,195 (Nov. 22, 2005), Order 2006-B, 116 FERC ¶ 61,046 (July 20, 2006); *Pacific Gas & Electric Co.*, Docket No. ER05-1319-000, 113 FERC ¶ 61,021, P.38 (October 11, 2005).

generators with limited grid impacts, such as DG, and encourages greater penetration of those resources by removing a significant time and cost barrier to interconnection.

The current interconnection process in Washington does not utilize FERC's technical screens and does not accomplish the underlying purpose of expedited interconnection. A generator interconnecting in Washington can meet all of the technical standards in WAC 480-108-220 and still face interconnection studies, at the utility's discretion. IREC suggests that the Commission should consider adopting FERC's technical screens to enable small DG facilities with limited or no grid impacts to interconnect on an expedited basis and without the risk that utility discretion will stall the process. IREC's Model Interconnection Procedures, *2009 edition*, generally follow the FERC screens, but also identify certain screens that can safely be excluded for Level 1 interconnections (up to 25 kW).[32] IREC suggests that this approach could provide a suitable template for reform in Washington.

i. 50% of Minimum Load Screen

The Commission may also consider alternative approaches to particular FERC screens that are developing in other jurisdictions. Several states have modified one or more of the FERC technical screens to be more permissive to enable greater utilization of expedited procedures. An emerging issue in several states is modification of the screen that limits the aggregated generation on a distribution circuit to "15% of the line section annual peak load as most recently measured at the substation." (SGIP § 2.2.1.2). Several utilities in California are currently exploring the use of a screen based on 50% of minimum load during the hours from 10 a.m. to

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[32] *See IREC Model Interconnection Procedures*, 2009 edition, p. 6, Section E: Level 1 Screening Criteria and Process for Inverter-Based Generating Facilities Not Greater than 25 kW. available at: http://irecusa.org/wp-content/uploads/2010/01/IREC-Interconnection-Procedures-2010final.pdf.

3 p.m. as a back up screen to potentially allow generators that don't meet the 15% screen to continue to use the Fast Track.[33]

ii. Public Access to Distribution System Data

IREC suggests that a helpful compliment to the FERC technical standards is the practice of requiring utilities to make publicly available on an interactive website the available capacity of distribution facilities at the circuit level. Detailed maps with distribution circuit information can assist developers and customers in identifying suitable points of interconnection, where a generator is likely to pass the FERC technical screens and avoid a costly study process. This approach is currently being implemented in California where all of the IOUs have made this type of information publicly available on map-based websites.

3. Net Metering

IREC suggests that Washington net metering policy can facilitate expansion of DG by increasing the eligible system cap and program participation limits. Net metering rules should encourage customers to adopt DG that is appropriate to their size and demand, including larger customers with high on-site usage. The current net metering limit of 100 kW restricts the use of net metering by larger and energy intensive customers who could reduce demand on the grid by offsetting their usage with on-site generation. IREC considers the elimination of size limits to be a best practice, so long as the system is designed not to exceed on-site load, but encourages the

33 Pacific Gas & Electric and Southern California Edison have indicated that they will utilize this approach for processing FERC jurisdictional interconnections to distribution lines. However, minimum load data may not be available on every line section and the IOUs will only utilize the screen where they have the ability to gather that data.

Commission to advise the TEC Committee to increase the net metering system size limit to at least 2 MW. Fifteen states currently have net metering system limits of 2 MW or higher.[34]

IREC suggests that Washington's current net metering program cap of 0.25% of utility peak demand (at 1996 levels) should be expanded beyond the modest adjustment to 0.5% scheduled to occur in 2014. Over twenty states feature program caps of 5% of utility peak demand or greater, a best practice in the area of program caps.[35]

IREC recognizes that adopting the best practice in this regard would represent a drastic change from current practice for the Commission, utilities, Public Utility Districts (PUDs) and local regulators and recommends a measured approach. First, IREC recommends that utility peak demand should be determined at current levels, not 1996 levels, as some counties in Washington have grown over the past 15 years, while others have constricted. Applying a program cap based on historic levels could create uneven application of the rule and not reflect growing load centers that could potentially absorb more net metered DG. Second, regulators, including the Commission and local regulators, should be given the discretion to set the program cap higher. This approach has been successful in Utah, where the Public Service Commission has the statutory authority to increase, but not eliminate its 0.1% program cap.[36] The Utah Commission promptly increased the cap to 20% of 2007 peak demand for Rocky Mountain Power, its only regulated electric utility, and Electric Cooperatives retain the discretion to raise the cap beyond 0.1%.[37]

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34 *See* http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1 .

35 *Id.*

36 Utah Code § 54-15-103(3)(a).

37 *See* "Report and Order Directing Tariff Modifications," Docket No. 08-035-78 (2/12/09).

While IREC supports raising the 0.5% program cap and applying it to current peak demand levels, it suggests that a practical alternative may be to retain the 0.5% cap so long as the legislature provides regulators discretion to raise the cap as they see fit. This measured approach would provide stakeholders opportunities to address the pros and cons of increasing the cap when such changes are actually proposed. With that change, we would then suggest that the UTC raise the cap for IOUs.

As the Commission is probably aware, Puget Sound Energy is quickly approaching the existing cap. Halting the most successful program in the state because an arbitrary cap has been hit would be unfortunate. If at all possible, a regulatory solution to address this looming roadblock would be helpful, such as allowing PSE to adopt the 0.5% cap now instead of waiting until 2014.

B. Other Cross-Cutting Issues

1. Energy Storage Issues

Energy storage is not an entirely new concept, but technological advances are bringing the mass-market potential within reach. IREC observes that at this early stage in industry development, it is difficult to assess which storage options will be the most effective. Policy surrounding energy storage devices is also somewhat complicated as energy storage can be viewed as analogous to generation when those devices export power under a sale contract, but may also provide transmission or ancillary services. IREC encourages the Commission to follow the ongoing proceedings at the FERC considering how energy storage will impact FERC-jurisdictional and state-jurisdictional practices.[38]

IREC does not recommend any particular storage technology, but does see the corollary value of distributed storage to providing grid benefits while minimizing line losses by being located close to load centers. IREC notes that much of the same regulatory uncertainty facing third-party DG owners might also be relevant in the context of the energy storage discussion. A third-party owner of storage might face the same possibility as a third-party owner of DG, that they are operating an "electrical plant" for hire. It is important for the Commission and the TEC Committee to remove barriers to these creative market solutions.

IREC also suggests that energy storage could become a more attractive option for DG owners or operators, and thus create greater opportunities for grid integration of variable resources, if the Commission directed utilities to credit production from the generator prior to storage. It is IREC's understanding that the state production credit is currently based on net production, after losses in storage. For example, if a 5 kW generator with a 10 kWh battery backup produces 5000 kWh per year but has losses through the battery system of 1000 kWh, then the production incentive payment is only based on 4000 kWh. Since a customer could install battery backup without a solar array and pay the utility for the electricity that is ultimately lost in storage, it seems that the full solar array annual production should be credited. This would remove the current disincentive for customers to invest in storage facilities. Customers should enjoy the benefits of the production of their DG system without a penalty for installing a storage device. Storage devices could ultimately provide the solution to managing variable

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38 *See Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies*, F.E.R.C. Docket No. AD10-13-000.

resources on the distribution grid and should be encouraged by removing barriers, such as the production crediting issue, to use of storage in tandem with DG.

2. Pricing Issues

IREC notes that significant developments have occurred in the past year regarding how a state may set the compensation level for renewable generators selling directly to a utility under the Public Utility Regulatory Policies Act of 1978 (PURPA).[39] PURPA provides a limited exemption for qualifying facilities (QFs) from FERC's exclusive jurisdiction over wholesale sales under Section 201 of the Federal Power Act.[40] Under PURPA's must-buy obligations, the utility must purchase a QFs as-available output, but not in excess of the utilities incremental cost of electricity, i.e. the cost avoided by not producing the next unit of generation.[41] State regulatory bodies are charged with implementing PURPA and must determine the avoided cost of generation and are preempted from setting a rate in excess of avoided cost.[42] Until 2010, FERC repeatedly rebuffed state efforts to pay generators with specific characteristics (i.e., renewable or CHP) a rate higher than the utility incremental cost of energy from all resource types.[43]

FERC clarified in 2010 that its earlier precedents do not prevent states from setting separate avoided costs for generators that meet a specific state procurement requirement.[44] This FERC order, at a minimum, allows states with Renewable Portfolio Requirements—as separate, mandatory procurement obligations—to set an avoided cost that reflects the next unit of

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39 16 U.S.C. § 2601, *et seq.*

40 *See* 16 U.S.C. § 824(b)(1).

41 *See American Paper Institute v. American Elec. Power,* 461 U.S. 402 (1983).

42 *Id.*; *see also Southern California Edison Co.*, 70 F.E.R.C. ¶ 61,215 (1995).

43 *Southern California Edison Co.*, 70 F.E.R.C. ¶ 61,215 (1995); *MidWest Power Systems, Inc.*, 78 F.E.R.C. ¶ 61,067 (1997).

44 *See Cal. Pub. Util. Comm'n*, Order Denying Reh'g, 134 F.E.R.C. ¶ 61,044 (Jan. 20, 2011).

"renewable" generation, rather than from all available resources. Because only renewable generation is available to meet a renewable procurement requirement, the avoided cost of meeting that requirement justifies a different avoided cost than has typically been used.

The implications of this order have not been fully tested, but the clear impact is that an identifiable procurement segment may have its own avoided cost determination. For example, a state with a solar carve out in its RPS might have three avoided costs: its existing avoided cost based on a combined-cycle natural gas facility or some other proxy for the price of conventional generation, (2) the avoided cost of the least-cost renewable technology and (3) an avoided cost of solar. In the context of Washington's renewable mandate, the RPS currently features a double credit for eligible DG, up to 5 MW.[45] Similar to a minimum procurement requirement, Washington's double counting bonus for DG could provide a basis to set an avoided cost for DG at double the cost of the least-cost renewable alternative, i.e., utility-scale wind generation.

IREC notes that the determination of avoided cost can be accomplished through administrative means or by locating a market price for a specific procurement segment through competitive bidding.[46] Administrative determinations of avoided cost can be costly and highly contentious, whereas an avoided cost derived from a market mechanism may result in a more accurate reflection of the price necessary to support development of renewable DG. Current FERC policy allows state's more flexibility to support renewable programs by determining these multi-tiered avoided costs by resource or segment type.

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[45] RCW 19.285.040(2)(b).

[46] *See, e.g., Cogen Lyondell, Inc.*, 95 FERC ¶ 61,243, 61,838 (2001); Southern California Edison Co., 70 FERC ¶ 61,215 (1995), *reconsideration denied,* 71 FERC ¶ 61,269, 62,080 (1995); *Cf. Jersey Central Power & Light Co.*, 73 FERC ¶ 61,092 (1995).

CONCLUSION

IREC appreciates the opportunity to submit these comments and respectfully suggests that the most immediate benefits to DG in Washington can come from adjustments to existing policy. IREC urges the Commission to consider the permissibility of third-party ownership as a top priority to achieve the goals of increased DG with minimal ratepayer impact. IREC supports a Commission action to declare that third-party owned systems are legal in Washington and are not "electrical company" subject to regulation. IREC also urges the Commission to recommend to the TEC Committee to conform its interconnection and net metering policies to best practices discussed in these comments.

Respectfully Submitted on July 8, 2011.

/s/

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