NET METERING AND INTERCONNECTION PROCEDURES INCORPORATING BEST PRACTICES

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ABSTRACT

State utility commissions and utilities themselves are actively developing and revising their procedures for the interconnection and net metering of distributed generation. However, the procedures most often used by regulators and utilities as models have not been updated in the past three years, in which time most of the distributed solar facilities in the United States have been installed. In that period, the Interstate Renewable Energy Council (IREC) has been a participant in more than thirty state utility commission rulemakings regarding interconnection and net metering of distributed generation. With the knowledge gained from this experience, IREC has updated its model procedures to incorporate current best practices. This paper presents the most significant changes made to IREC's model interconnection and net metering procedures.

1. INTRODUCTION

The federal Energy Policy Act of 2005 (EPAct 2005) required state utility commissions and large utilities not subject to commission regulation to consider the adoption of interconnection and net metering procedures. This accelerated the pace at which states addressed these procedures, but did little to standardize procedures from one jurisdiction to the next. To this day, procedures vary substantially from one state to the next and there are pockets in which no procedures have been developed at all.

While the deadlines provided in EPAct 2005 for regulators to consider adopting procedures were reached in August of 2008, activity in this area is unabated. State legislation, public pressure and a growing awareness of the need for functional procedures regularly spur regulators to develop or revise rules. In that process, regulators typically use their existing rules, the federal procedures or procedures adopted in another state as the starting point. Unfortunately, the starting point that is chosen is often short of best practices. While IREC and other rulemaking participants help guide regulators towards best practices, the final rules typically limit the potential for solar energy and other distributed generation unnecessarily.

IREC developed its model procedures prior to the passage of EPAct 2005, and updated them in 2006, with the recognition that they could facilitate the adoption of solid net metering and interconnection procedures at the state and local levels. IREC has utilized its model interconnection and net metering procedures in over thirty state utility commission rulemakings, and many of IREC's key provisions have been widely adopted. However, with the experience gained in those rulemakings, IREC has identified several improvements that would more fully facilitate the deployment of solar energy facilities and other distributed generation. These improvements were recently incorporated into IREC's models. This paper covers the changes made to IREC's model procedures and the rationale for those changes.

Improvements to the IREC interconnection model include: clarification that third party ownership is allowed, a higher cut-off for Level One applicants, on-line application processes, improved dispute resolution, an alternative provision for the utility external disconnect switch for facilities under 25 kilowatts (kW), applicability beyond 10 megawatts (MW) and provisions regarding network interconnections. Improvements to IREC's net metering model include: modified facility and program size limitations, clarification that third-party ownership is allowed, perpetual rollover of excess generation credits, and an allowance for meter aggregation.

This paper does not attempt to explain every provision in the IREC models. The IREC models are available at www.irecusa.org and now include introductions and footnotes regarding key provisions. As well, IREC participates in the development of grading criteria for state procedures and a guide explaining those criteria. Published by the Network for New Energy Choices, that annually-updated guide is called *Freeing the Grid* and is available at www.newenergychoices.org. Finally, funding by the U.S. Department of Energy's Solar America Board for Codes and Standards (Solar ABCs) allowed two of the authors of this paper to publish a review of the leading interconnection procedures in 2008. That Solar ABCs paper is available at www.solarabcs.org/interconnection.

2. INTERCONNECTION PROCEDURES

2.1 Background

Section 1254 of EPAct 2005 required state utility commissions and utilities not subject to utility commission jurisdiction with more than 500 million kWh of annual retail sales to consider adopting interconnection procedures. According to EPAct 2005, the adopted procedures should "promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies."

At the time EPAct 2005 was adopted, in August of 2005, there were four prominent models. First, the National Association of Regulatory Utility Commissioners (NARUC) had developed a model in 2003, which was the model indirectly referenced in EPAct 2005. Second, California had adopted its Rule 21, which had been the rule for the majority of U.S. small generator interconnections because of California's leading role in promoting distributed generation. Third, in May of 2005, the Federal Energy Regulatory Agency (FERC) issued Order 2006, establishing the Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA). And finally, IREC had developed its model interconnection procedures.

IREC's model followed the basic format of the SGIP/SGIA while clarifying, simplifying and improving many of its provisions. Modifications to the model were made as late as November of 2006. The IREC model borrowed from the NARUC model, California's Rule 21 and the model developed by the Mid-Atlantic Demand Resource Initiative (MADRI), and added provisions of its own.

Since 2005, there have been very limited revisions of the leading models. The SGIP/SGIA was slightly revised in FERC Orders 2006-A and 2006-B, but is unchanged since late 2006. The NARUC and MADRI models are unchanged. California's Rule 21 has been regularly updated, but with few substantive changes. IREC's model was only modestly updated in 2006. Significantly, many states have adopted procedures in the past three years and have included provisions that improved on the existing models.

Starting in early 2009, IREC began the revision of its model procedures to incorporate the best practices developed at the state level. In the past year, IREC has participated in interconnection rulemakings in Florida, North Carolina, Illinois, New York, Virginia, South Dakota, Michigan, Kentucky, Colorado, Utah, California and New Mexico. While each state includes some flawed elements in its procedures, each has added provisions that have led to an evolution of what defines best practices. IREC's 2009 revisions to its model procedures incorporate these practices, as described below.

2.2 Changes to IREC's Interconnection Procedures

2.2.1 Third Party Ownership

Since the passage of the various model interconnection procedures, third party ownership of solar facilities has emerged as the most economically efficient method of ownership in many cases. Third party owners have federal tax liabilities and can utilize the available 30% investment tax credit and accelerated depreciation, while the owners of property on which facilities are sited often cannot. For example, facilities sited on churches, schools, government buildings and other property owned by entities that do not pay taxes or do not owe taxes would not have access to these tax advantages without third party ownership. Additionally, many facility owners are intimidated by the thought of being in the power generation business. Distributed generation is not seen as core business for most utility customers and the risks are perceived as to high.

Under third party ownership, an outside party owns the facility and sells electricity to the property owner. Data available through the California Public Utilities Commission indicates that roughly half of the installed capacity in that state is owned by third parties. Based on this fact, it appears that a prohibition of third party ownership in a state could cut the potential for solar energy facilities in half.

In several states, the utility commission has considered whether the act of selling electricity makes the third party owner a public utility under state law. This would mean that the third party owner would be subject to utility commission regulation and might violate the exclusive franchise afforded to the host customer's existing utility. In practice, no entity will consider third party ownership if there is the potential for commission regulation and the possibility that the entity will not be allowed to operate. Appropriately, the states that have considered third party ownership have generally found that it is allowed and need not be heavily regulated. Substantial installations owned by third parties are already in place in California, New Jersey and Colorado, with several others following suit. In the past year, Nevada, Oregon and Florida have explicitly addressed the issue and found to varying degrees that third party ownership is allowed.

The prior IREC model and other models did not fully anticipate the emergence of third party ownership. While the prior IREC model did not prohibit the practice, the issue was not directly addressed. A key provision that has the potential to subvert third party ownership arises in some state procedures in the definition of a customer-generator or a generating facility. Where a customer-generator is defined as the owner of a generating facility, or a generating facility is defined as being owned by the customer-generator, third party ownership is precluded. The IREC model previously addressed this indirectly by defining the facility as equipment "used" by the customer-generator.

In its revised model, IREC explicitly states in the definition of customer-generator that third party ownership is allowed. As stated previously, preclusion of this form of ownership could cut the potential for solar energy in a state in half, making it critical that the issue be squarely addressed.

2.2.2 Level One Cut-off

Following the lead of the SGIP/SGIA, IREC's previous model included simplified procedures for inverter-based facilities up to ten kW, which covers almost all residential solar installations. IREC categorized these as Level One applicants. The rationale for simplified procedures for these applicants is that there is very little potential for disruption of grid safety and reliability from such systems as they are required to comply with UL1741 and IEEE 1547. Some factors that utilities should consider for non-inverter based systems or for larger systems are not necessary to consider for the typical residential or small commercial solar installation. The simplified process for Level One applicants addressed this reality.

Now that more than 50,000 solar facilities have been interconnected to the U.S. electric grid, utilities have substantial experience with interconnections. The simplified rules for inverter-based systems up to 10 kW have helped streamline the processing of applications, as the vast majority of applicants seek to install these smaller systems. At the same time, utilities and regulators have begun to recognize that slightly larger systems are equally safe and can be processed under the simplified procedures. Most recently, the New York Public Service Commission revised its procedures to extend its first level to 25 kW. Following this logic, IREC has adjusted its Level One cut-off to 25 kW.

2.2.3 On-line Applications

The IREC model and other models provided application procedures with timelines that begin with receipt of the application by the utility. While use of electronic mail was certainly widespread in 2005, the prevalent models did not provide for electronic delivery of applications. This meant that days would pass before an application was received and an applicant could not be sure of utility receipt unless the applicant delivered the application in person or paid for delivery with a return receipt. By allowing for electronic delivery, the delay associated with using the postal system and delivery costs can be eliminated.

The New York Public Service Commission adopted rules for on-line applications for smaller facilities in its 2009 revisions, and other states have similar procedures. IREC adopted the procedures similar to New York's for all applicants. In an electronic age, there is no reason for an applicant to create a hard copy of an electronic file to send to a utility that, in all likelihood, will digitize the hard copy or transcribe the information into an electronic file. In particular, sending hard copies of wiring diagrams that are then scanned by a utility entails reduced image clarity that is completely avoidable through electronic delivery.

Along similar lines, the IREC model now requires utilities to provide their interconnection procedures and applications on-line, including an application that can be electronically completed. For many utilities, the procedures are established by the state utility commission, and a simple link to the commission's rules will suffice, along with an application process.

In practice, installers assist customers with the application process in most cases. Customers are unlikely to notice the difference that on-line applications will make, but installers will realize reduced costs and approval times. In turn, a competitive marketplace can be expected to pass these savings on to customers.

2.2.4 Improved Dispute Resolution

Dispute resolution is a vexing problem for distributed generation. The issues in dispute are often minor, such as whether a new meter or fuse is required. Whether a facility has failed a screen and requires further study can also be a point of contention. In general, the utility makes such decisions and the customer must chose whether to accept the decision, abandon the project, or pursue dispute resolution. In practice, the available dispute resolution procedures are often cumbersome and time consuming, leaving customers with only the choices of acceptance or abandonment.

Existing dispute resolution procedures are often adapted from standard contract language or from utility commission complaint procedures. Contracts frequently allow for arbitration or mediation that is often non-binding, allowing either party to insist that disputes be resolved in court. Even with binding arbitration, the process can be expensive and time consuming, and it entails uncertainty. Where commission procedures are used, the parties are forced into a process typically used for utility bill disputes with informal or formal adjudication in front of an administrative law judge, often with a delay of a month or more from the time of notice of a dispute.

IREC previously addressed dispute resolution by suggesting the concept of a technical master who could be appointed by the utility commission. This would allow customers the certainty that disputes would be quickly addressed at a reasonable cost. This process has not been widely adopted, primarily due to concern that an unknown arbiter would be given the discretion to override a utility decision concerning safety and reliability. To address this, IREC has modified its procedures to clarify that the technical master's determination may be appealed to the state utility commission, with the costs of the prevailing party at appeal covered by the non-prevailing party. IREC anticipates that this procedure will result in very few appeals, while addressing the concern that grid safety and reliability might otherwise be compromised.

2.2.5 Utility External Disconnect Provisions

New Jersey's interconnection procedures have long prohibited utilities from requiring an external disconnect switch for facilities that meet the requirements for Levels 1 and 2, covering systems up to two megawatts (MW). IREC took these provisions a step further, stating that a utility may not require a customer-generator to install a disconnect switch if the generating facility meets applicable standards, referencing Standard No. 1547 of the Institute for Electronics and Electrical Engineering (IEEE) and Underwriters Laboratories (UL) Standard No. 1741. In practice, no state has extended the rule beyond what New Jersey implemented, though several states have recognized that a disconnect switch is unnecessary for smaller, inverter-based systems. As this compromise is sufficient to address the vast majority of interconnections, IREC has now added a footnote explaining that the compromise is not a substantial step back from what IREC recommends.

Two comprehensive analyses of the utility external disconnect switch were undertaken in 2008 and concluded that small inverter-based systems do not need to have disconnect switches. The purpose of the switches is to disconnect generators from the electric grid when the grid is down, assuring that electricity will not flow to the grid when line workers are repairing the lines. Inverters certified under UL 1741 provide this function already, and several other methods of disconnection are available, so the study authors concluded that the disconnect switches are unnecessary, at least for smaller inverter-based systems and possibly for larger systems. For further information, see the studies by the National Renewable Energy Laboratory (NREL) and the Solar ABCs cited at the end of this paper.

Florida, North Carolina and New Hampshire set the cut-off for requirement of the disconnect switch at 10 kW, while Oregon set it at 30 amps (7.2 kW for 240 volt service). Delaware and New York set the cut-off at 25 kW. California and Nevada use a 1 kW cutoff, but allow utilities to set the limit higher, which has been done by both Pacific Gas & Electric (PG&E) and the Sacramento Municipal Utility District (SMUD). Given the experience of these states and utilities and the conclusions of the NREL and Solar ABCs studies, there is little justification to require a disconnect switch on an inverter-based system under 25 kW.

IREC continues to believe that a disconnect switch is not necessary, but has softened its stance in two respects. First, the model now includes a provision that the utility may install a disconnect switch at its own expense. IREC expects that few utilities will elect this option, recognizing that the switches are not needed, but this addresses the utility concern that in some instances it may want to have a disconnect switch and should not be precluded from installing it at the utility's expense. The second softening is to add a footnote explaining the trend toward dropping the requirement for small inverter-based systems and acknowledging that a 25 kW cut-off will cover more than 95% of all installations.

2.2.6 Applicability Beyond 10 MW

The IREC model was previously capped at 10 MW, in conformance with the prevailing standard for interconnection established by IEEE 1547. In part, this cap was also set on the assumption that facilities larger than 10 MW would be subject to federal jurisdiction rather than state jurisdiction. In practice, states often have jurisdiction over interconnection of "qualifying facilities" up to 80 MW under the Public Utility Regulatory Policy Act (PURPA).

With state interconnection procedures only covering systems up to 10 MW, applicants seeking to interconnect larger systems under state jurisdiction have to negotiate the terms with the utility. Establishing a place in state interconnection procedures for these larger systems could substantially reduce the costs for review of these systems. Undoubtedly, the utility will study the proposed interconnection closely, but there is no need to develop a unique study process or agreement for each applicant. These items can be standardized. As revised, the IREC model now covers all state-jurisdictional interconnections regardless of system size, defining the study process and a standardized agreement. Both California and North Carolina have embraced this approach in their interconnection procedures.

2.2.7 Network Interconnections

Most electric service is provided by radial distribution circuits, but many urban cores are served by area networks with higher reliability. Spot networks provide similar service for individual customers or groups of customers. The heightened reliability inherent in networks adds complexity and a concern that interconnected generation might jeopardize reliability. Many utilities take the conservative approach of not allowing generation on networks, and many state procedures provide utilities with broad discretion regarding network interconnections.

IREC's procedures had allowed network interconnections under its fast track provisions up to the lower of 10% of the network's minimum load or 500 kW. While IREC consulted with various engineers to determine that this level would assure grid safety and reliability, no published reports addressed the appropriate levels and there was little practical utility experience. Without sufficient support, network provisions that facilitated interconnections were not widely incorporated into state procedures.

On the suggestion of Consolidated Edison (ConEd) that the New York procedures include allowance for inverter-based facilities up to 200 kW to connect to area networks, New York's interconnection procedures were revised in early 2009 to include this new benchmark. ConEd operates the most extensive area network system in the country, covering much of New York City. Fast track procedures for area networks in New York should be applicable elsewhere and IREC is modifying its procedures to include similar provisions.

As of this writing in mid-March, IREC has not finalized its network provisions. In part, this is because IREC is waiting for a report on network interconnections being finalized by the NREL. It is expected that IREC's procedures will be reflective of the New York procedures.

3. NET METERING PROCEDURES

3.1 Background

Section 1251 of EPAct 2005 required state utility commissions and larger utilities not subject to state jurisdiction to consider net metering, but provided only a paragraph to describe what net metering is. Net metering was simply defined as: "service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."

The EPAct 2005 definition of net metering left many details to be developed at the state level, and the result was a wide variety of state procedures. On significant points such as facility size, program size and rollover of excess generation from one month to the next, there has been broad variation. Important elements of net metering are explained in detail in *Freeing the Grid*, the annual publication prepared by the Network for New Energy Choices and previously cited.

To assist utility commissions in their efforts to adopt and improve net metering, IREC developed model procedures in 2003, with some revisions made as late as November of 2006. In most respects, these procedures remain best practices. However, with the evolution of the solar industry, IREC recognized the need to update its model with the changes noted below.

3.2 Changes to IREC's Net Metering Procedures

3.2.1 Facility Size Limitation

In 2006, IREC settled on a size limitation for net metered facilities of two MW. At the time, many states either did not allow net metering or capped their programs at 100 kW. Two MW seemed ambitious, but IREC reasoned that the logic of net metering applies equally to larger systems.

As of early 2009, IREC's ambitious cap has been matched or superseded by fourteen states. For a current listing of all state facility size limitations, see the U.S. map at www.dsireusa.org. Ten states have coalesced on a two MW cap (OR, UT, CO, FL, NY, MA, CT, NJ, DE & MD), while Rhode Island uses a 3.5 MW cap and Pennsylvania adopted a five MW cap. As well, Arizona, New Mexico and Ohio have uncapped the facility size for their net metering programs, though only Arizona allows rollover of excess kilowatt-hours from one month to the next rather than paying utility avoided cost rates for excess generation.

The two obvious limits for net metering programs are the service entrance capacity and the customer's annual electricity consumption. The service entrance capacity is defined by the standard interconnection equipment installed by the utility, establishing how much electricity can flow to a customer. The same equipment and wires can necessarily accommodate no greater electricity flows in the opposite direction, so the generating facility less the on-site load should never exceed the service entrance capacity. Conservatively, IREC uses this limitation to set the maximum facility size at the customer's service entrance capacity.

The facility size is also constrained by the customer's annual electricity consumption. Under IREC's model, the customer is never paid for excess generation; that excess simply rolls over to future months. There is no incentive to oversize a facility under this process, alleviating a primary utility concern.

Given these limits to net metered facility sizing, IREC sees no need to limit facility size by mandate. IREC's new model establishes the service entrance capacity as the only cap on facility size. However, because the customer could pay the utility to expand the service entrance capacity if desired, in effect, the only facility size cap under the IREC model is based the customer's consumption of electricity.

3.2.2 Program Size Limitation

Many state programs have capped their net metering programs at one percent of a utility's peak load or less, while 18 states have not capped their programs at all. Program size limitations were instituted based on uncertainty regarding whether net metering programs might contribute to higher rates for utility customers generally. IREC saw little likelihood that this might be the case, but conservatively established a five percent cap. Now, IREC has elected to lift this cap altogether.

Numerous studies in the past three years have substantiated a capacity value for net metered solar facilities, supporting the contention that net metering fairly compensates customer-generators without burdening other utility customers. Studies conducted for Austin Energy and Arizona Public Service are two examples, with links provided in the references section here. Most importantly, Dr. Richard Perez and three other leading solar policy experts documented the various approaches to credit photovoltaic installations for their capacity contributions, and demonstrated the effect of location using the examples of Rochester, NY; Portland, OR; and southern Nevada. That report is cited here and and recently repackaged for a January 2009 article in *Public Utilities Fortnightly*.

The PV capacity valuation article displays what intuition would suggest. For utilities that peak during summer months, solar facility generation can shave utility peak loads because both are directly correlated to sunshine. However, solar modules pointed south make only a modest contribution to peak loads because there is little generation during the late afternoon when utilities experience their peaks. To address this, Perez considers modules pointed to the southwest or modules on tracking systems, which can provide a significant amount of their rated capacity by pointing at the westerly sun during utility peaks.

The article goes on to show PV provides a diminishing capacity contribution as a utility experiences higher penetration of solar facilities. Depending on location, a given penetration level will reduce the utility peak to a level below the utility's early evening peak or even below its non-summer peak. In both Rochester and Nevada, this declining capacity contribution is modest, with roughly 60% of the facility's rated capacity still worthy of credit for its contribution to utility peak loads when solar penetration reached 20% of the utility's total generation. In Portland, Oregon, which is only slightly summer peaking, the decline was more pronounced, with the capacity contribution falling to roughly 20% at just 10% solar penetration.

IREC is persuaded that most areas experience a significant capacity contribution from solar facilities at levels well in excess of five percent of utility annual peak load. IREC considered following the lead of the Utah Public Service Commission, which set the program size limitation for Rocky Mountain Power at twenty percent in 2009. Instead, IREC opted to lift the program size limitation altogether, as 18 states have done. IREC recognized that limitations in interconnection procedures necessitated by grid stability concerns have the practical effect of capping net metering at the programmatic level at some amount under twenty percent.

3.2.3 Third Party Ownership

The discussion of the third party ownership issue for IREC's interconnection procedures applies equally to

IREC's net metering procedures. There is no reason to leave any ambiguity in state net metering procedures about whether third party ownership is allowed. As with its interconnection procedures, IREC modified its net metering model to include in the definitions that a third party may be the owner of a net metered facility.

3.2.4 Perpetual Rollover of Excess Generation

IREC's model previously called for a determination of excess generation at the end of the calendar year, and gave the utility the option of either rolling over the annual excess indefinitely or paying the customer for the excess generation at the utility's avoided cost of generation. Unfortunately, this approach has the potential to force certain customers to size their facilities at much less than the customer's annual consumption.

In most locations, a solar facility will generate the most electricity in the summer months and less in the winter months. If a customer hopes to generate as much electricity as the customer consumes over the course of a year, that customer should overproduce in summer months and roll over the excess generation to the less sunny months. However, this approach is not possible given a calendar year-end settlement.

Ideally, a yearly accounting for solar facilities would commence at the start of summer, allowing summertime excess generation to roll over to the rest of the year. Unfortunately, setting this mid-year date might have just the opposite effect for net metered wind facilities, which tend to produce more in winter months in many areas of the country.

To address this issue, the IREC model now provides for perpetual rollover of excess generation. This approach assures that customers do not have an incentive to oversize their facilities while removing the complication of a year-end accounting. In addition, a footnote is included regarding the rarity of oversized facilities with the suggestion that an alternative approach that would transfer year-end excess generation to a low income or renewable energy program. For this approach, IREC suggests that the customer-generator be permitted to select a start date.

3.2.5 Meter Aggregation

Some utility customers have multiple meters and have questioned whether a single net metered facility can net against consumption measured through multiple meters. For instance, farms often have multiple meters for water pumping equipment spread across a wide area. Without a provision allowing meter aggregation, a farmer would be forced to limit any one generating facility to the annual consumption measured by any one meter. Illogically, a farm with ten meters that each could be offset with five kW facilities could not install a single 50 kW facility.

To address this issue, IREC has followed the example of several states that allow meter aggregation (Oregon, Washington, Pennsylvania, Massachusetts and Vermont).

4. CONCLUSION

The 2009 revisions to IREC's model interconnection and net metering procedures incorporate current best practices, but without a doubt, best practices will change. As new technologies, new financing mechanisms and new policies emerge, there will be a need to revise IREC's procedures again. As ever, IREC will attempt to work with all stakeholders to discern how best practices are evolving.

5. ACKNOWLEDGEMENTS

The authors appreciate the continued contractual support of the Interstate Renewable Energy Council. As well, the authors wish to thank Mr. Michael Sheehan for the technical expertise that he brings to IREC's discussions of best practices for interconnection of distributed generation.

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