

To: Jason Coughlin, National Renewable Energy Laboratory  
From: Joseph F. Wiedman, Thadeus B. Culley  
Re: Recommendations for Wisconsin Net Metering and Interconnection  
Date: 08/04/2011

### **EXECUTIVE SUMMARY**

This document analyzes Wisconsin's existing net metering policies and interconnection procedures and makes recommendations for policy makers to improve toward best practices. In the 2010 edition of the yearly publication *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*, Wisconsin received a letter grade of "C" for its statewide net metering policies and a letter grade of "D" for its statewide interconnection standards. The recommendations in this paper are aimed at moving Wisconsin toward best practices and increasing the use of distributed generation.

We suggest the following top priority recommendations for near term changes to improve net metering and interconnection policy in Wisconsin:

- **Increase the net metering system cap to at least 500 kW.**
- **Require indefinite rollover of net metering credits at retail rate.**
- **Create safe harbor language to protect net metering customers from additional charges and other fees.**
- **Create consistent interconnection standards for all non-FERC jurisdictional interconnections in the state, including electric cooperatives.**
- **Adopt an expedited interconnection process that utilizes the FERC's technical screens.**
- **Prohibit external disconnect switch requirement for inverter-based generators.**

## INTRODUCTION

Net metering and Interconnection are foundational policies for the promotion of distributed and renewable generation. The Solar Alliance, a solar industry advocacy organization, describes net metering and interconnection as being two of the four pillars of cost-effective solar policy.<sup>1</sup> In addition to available incentives and utility rates and revenue policies, net metering and interconnection make up the fundamental architecture of successful distributed generation policy. Net metering and interconnection, thus, provide the basic framework to support broad distributed generation policy goals. For this reason, *Freeing the Grid* awards points for policies and standards that provide versatility and are not confined to a particular technology or customer class.

This paper is organized to identify the most critical areas for improving these statewide policies in Wisconsin and offers recommendations for each category of best practice. Section I of this paper recommends changes to Wisconsin's current net metering policies and Section II makes specific recommendations to Wisconsin's Commission-approved interconnection procedures.

In each section, we provide three "Primary Recommendations" and four "Secondary Recommendations." We identify Primary Recommendations as those high impact policy changes that could achieve the greatest improvement to existing rules. Secondary Recommendations are offered for situations where a comprehensive overhaul of the policies may be possible and those recommendations are supplemental to the primary ones.

Most recommendations in this paper can be accomplished through either statewide legislation or through a Wisconsin Public Service Commission (Commission) rulemaking. The natural advantage of the legislative approach is that the changes could apply to all in-state electric utilities, including electric cooperatives. Commission action, on the other hand, is limited to the utilities subject to the Commission's jurisdiction and excludes electric cooperatives from the policies. All recommended statutory changes are intended to apply to all utilities, including electric cooperatives. All recommendations for regulatory action take into account the limits on Commission jurisdiction.

### I. Recommendations for Net-Metering Policy in Wisconsin.

Net metering across Wisconsin is fairly uniform, but there are important differences between in-state utilities. One reason for these differences is that there is no statutory requirement to provide uniformity across the state. However, public utilities subject to the Commission's jurisdiction—i.e., privately owned utilities and municipally owned utilities—are required, by order of the Commission, to offer net metering for systems up to 20 kW.<sup>2</sup> Unfortunately, the 1992 Commission order does not establish any other requirements to set the contours of net metering in Wisconsin.<sup>3</sup>

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<sup>1</sup> [http://www.solaralliance.org/downloads/four\\_pillars.pdf](http://www.solaralliance.org/downloads/four_pillars.pdf).

<sup>2</sup> See "Findings of Fact, Conclusion of Law and Order," Wisconsin Public Service Commission Docket No. 05-EP-6 (Sept. 18, 1992). The 1992 Order merely establishes that "the utilities shall reestablish net energy billing in their next rate

The overarching recommendation for net metering and interconnection is for the state to create uniform rules that apply to all in-state utilities, including electric cooperatives beyond the Commission's jurisdiction. Uniform standards create familiarity with practices across the state. This familiarity lowers the transaction costs associated with compliance with state regulations for renewable energy businesses operating in the state allowing them to become more efficient and, thereby, to more effectively develop their business. State legislation is necessary to create minimal net metering and interconnection standards throughout the state.

Without the political opportunity to institute statewide standards, the Commission should act to create consistency for all utilities within its jurisdictional authority. While this falls short of statewide consistency, the regulations would nonetheless increase the opportunities for a majority of Wisconsin residents to participate in net metering.

After reviewing the net metering tariffs of Wisconsin's major utilities as well as many of its municipally run utilities, we have three primary recommendations that are suggested as high priorities and four secondary recommendations that could be included in a more comprehensive overhaul of the net metering rules.

#### **Primary Recommendations:**

- Legislative or regulatory action to increase statewide net metering system cap to at least 500 kW.
- Legislative or regulatory action to provide indefinite rollover of excess generation credits at the retail rate.
- Legislative or regulatory action to protect net metering customers from the imposition of standby charges or other fees faced only by net metering customers.

#### **Secondary Recommendations:**

- Legislative action to require electric cooperatives to adopt minimum net metering standards.
- Legislative or regulatory action to allow third-party ownership of net metered systems.
- Legislative or regulatory action to clarify that customer-generators retain the renewable attributes (RECs) associated with on-site generation.
- Legislative or regulatory action to allow aggregate net metering for farms and businesses under common ownership.

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cases, where it is not offered now, for customer-owned renewable resource generators under 20 kW." Conclusion of Law 4.4 at p. 115.

3 *Id.*

## A. Primary Recommendations

### 1. Increase net-metering system size cap.

Best practices in net metering avoid imposing statutory or regulatory limits on the size of eligible technologies. Such limits prevent electric customers from correctly sizing a DG system to meet their own demand. The ability to offset retail purchases is one of the primary drivers of distributed generation (DG) and arbitrary size limits tend to limit the types of customers that may participate in a net metering program. Several states take the approach that customer load and demand should determine the system's design parameters, not an arbitrary cap. Colorado, for example, provides that net metering systems may not exceed 120% of the customer-generator's annual electricity consumption nor exceed the capacity of the service entrance.<sup>4</sup> However, for electric cooperatives, the Colorado statute requires net metering up to 10 kW for residential systems and up to 25 kW for non-residential.<sup>5</sup>

The number of states that exceed Wisconsin's current system size cap suggests that it is a top priority for modification. Thirty-six states, Puerto Rico and D.C. have system size caps that exceed Wisconsin's general limit of no more than 20 kW. Nearly half of the states with net metering rules have system size limits in excess of 500 kW.<sup>6</sup> Additionally, nine of the top ten states, in terms of installed capacity<sup>7</sup> of solar photovoltaics (PV), have system size caps over 500 kW. Only Nebraska, Kentucky, Wyoming, Alaska, Oklahoma, and Indiana have net metering system size caps that are equivalent to or lower than those in Wisconsin. For these reasons, we suggest 500 kW as a reasonable system size cap for Wisconsin; a change that will place it in the middle of the distribution of states with net metering.

Of all privately-owned utilities and Class AB municipal utilities in Wisconsin, only Wisconsin Public Service Company (WPS), We Energies and Madison Gas & Electric (Madison) feature system caps in excess of 20 kW. We Energies offers a pilot program for wind facilities up to 100 kW, while Madison and WPS feature a 100 kW in the traditional net metering tariff.

#### Recommendation:

- The state Legislature should act to set a statewide system cap of 500 kW for non-residential systems. A residential system cap of 20 kW would be reasonable considering the ability of residential customers to install 20 kW systems under existing tariffs.
- Alternatively, the Commission should initiate a rulemaking to set a system cap of 500 kW for all utilities within its jurisdiction.

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<sup>4</sup> See 4 CCR § 723-3, Rule 3664(a)(1).

<sup>5</sup> Looking nationwide, system size limits for electric cooperatives are often lower based on the ability of rural grids to handle larger systems and fears of revenue erosion despite strong customer interest in cooperative territories for net metering.

<sup>6</sup> 19 States, Puerto Rico and D.C. have net metering system size caps of over 500 kW.

<sup>7</sup> See *Freeing the Grid* at p. 17. The top ten states in terms of installed PV capacity in 2009 are (in order from first to last): California, New Jersey, Florida, Colorado, Arizona, Hawaii, New York, Massachusetts, Connecticut and North Carolina.

2. *Set statewide policy to require rollover of credits at retail rate.*

To be successful, a net metering program should facilitate rollover of generation credits so that customer-generators receive benefit for excess energy generated during the seasons when renewable output is highest and apply it toward their consumption when output is lowest. This allows customers to potentially achieve zero net energy consumption from the grid. Indefinite rollover provides the best approach to account for variations among different system technologies or locations and customer loads. Customer-generators realize the most financial benefit from net metering in this manner. Additionally, the method of valuing excess generation is critical to supporting customer decisions to invest on net metering systems.

a. *Month to month rollover.*

Rollover of credits from generation in one month to the next month is a best practice and fundamental to the practice of net metering. Ideally, net metering rules allow rollover of generation credits to continue into subsequent months until the customer either terminates service or is able to apply all remaining credits to a retail bill. Some states, however, do not allow indefinite rollover of generation credits and require an annual reconciliation where the remaining credits are purchased by the utility, granted to the utility without compensation to the customer, or simply allowed to expire. While the best practice would be to allow indefinite rollover, a fair annual reconciliation process can promote customer net metering.

Currently, ten states feature indefinite rollover of generation credits at the retail rate. Many other states offer a rollover of generation credits at the full retail rate with an annual reconciliation of excess credits at the utility's avoided cost wholesale rate. Indiana allows indefinite rollover at the retail rate, but grants all remaining credits to the utility when the account is closed.<sup>8</sup> New York's Public Service Commission recently recognized the seasonal variation problem that occurs when customers must cash out credits annually and modified its net metering rules to allow customers to select the date when generation credits would be reconciled.<sup>9</sup> A process that zeroes credits before the load heavy summer months experienced by many customers leaves many of the benefits of net metering unavailable to customers who invest in renewable energy. Therefore, if a state chooses to use some other valuation approach for treatment of any yearly net excess generation, care must be taken to ensure all interests are balanced and customers who invest in renewable energy receive the full value of their investment. New York's legislative response is a solid approach to allow customers to utilize generation credits through the most use-intensive months. There is a range of approaches to rollover that will support development of distributed generation.

The approaches that do not support distributed generation, and are considered worst practices, involve either rollover of credits at avoided costs, annual granting of the credits to the utility without compensation, or no provision for any type of

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<sup>8</sup> 170 IAC 4-4.2-7(3).

<sup>9</sup> See *Order Directing Tariff Revision and Making Other Findings* (May 23, 2011), Case 10-E-0645, before the State of New York Public Service Commission.

rollover. Oklahoma is thought to have the worst practice in this regard. Utilities in Oklahoma are not obligated to purchase excess generation, so it may simply be granted to the utility on a monthly basis.<sup>10</sup>

We recommend that Wisconsin adopt either indefinite rollover of generation credits or an annual reconciliation approach similar to that recently adopted by New York.

*b. Valuing excess generation.*

Most Wisconsin utilities currently allow rollover of excess generation credits from one month to the next at the full retail rate. Valuing excess generation at the applicable retail rate is a best practice. A recent exception to this practice in Wisconsin, however, is the Commission approved tariff for WPS that allows the utility to essentially cease monthly rollover at the applicable retail rate and pay the customer-generator the lower avoided cost for any excess generation.<sup>11</sup> If this were a statewide policy, it would result in a *Freeing the Grid* score of “-2.”

Wisconsin policy currently features a degree of flexibility in the method of compensating customers for excess generation that can be retained. Several privately-owned utilities,<sup>12</sup> and many municipal utilities, condition monthly rollover with the following language:

“If, in any month, the customer’s utility bill has a credit balance of \$25 or less, the amount shall be credited to subsequent bills until a debit balance is reestablished. If the credit balance is more than \$25, the customer may be reimbursed by check upon request. Monthly credits shall be computed by taking the net excess kilowatt-hours produced times the sum of the applicable energy charge plus monthly power cost adjustment clause (PCAC) factor.”<sup>13</sup>

Even though this does not constitute traditional “indefinite rollover,” and payments for generation credits in excess of \$25 may be made at the end of every month, it best fits the *Freeing the Grid* criteria of “monthly rollover at retail rate for one year, annual payment at retail rate.”<sup>14</sup> We suggest that a better approach, and one that will create more market confidence, is to clearly define the structure of compensation by defining how rollover must be treated both month to month and on a yearly basis. In this respect, Wisconsin should move away from the diverse approaches to how net excess generation is credited or compensated to customer-generators.

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<sup>10</sup> See O.A.C. § 165:40-9-3.

<sup>11</sup> See *Order Amending Final Decision and Order Denying Request for Rehearing*, 6690-UR-120, 2011 Wisc. PUC LEXIS 134 (March 11, 2011).

<sup>12</sup> *E.g.*, Superior Water, Light & Power Co. (Superior WL&P), North Central Power Co., Dahlberg Light & Power Company.

<sup>13</sup> For example, see Superior WL&P’s tariff, Sheet No. 171.

<sup>14</sup> *Freeing the Grid* at p. 25.

### Recommendation:

- The state Legislature should act to clarify that all net metering customers will be allowed to rollover monthly excess generation on a month to month basis and receive indefinite rollover of generation credits at the retail rate.
  - Alternatively, the Commission should act to implement these provisions in all utilities subject to its jurisdiction.
3. *Include “safe harbor” language to protect customer-generators from additional charges.*

Taking their cue from customers who install traditional combined heat and power systems, many utilities claim that the utility is required to “standby” to meet the increase in customer load should the net-metered system fail (i.e. procure generation to meet the resulting increase in customer demand). As a result, they argue that utilities should be allowed to impose a “standby charge” on net-metered customers that covers the cost of having this extra generation standing by to meet the increased customer demand. Standby charges are not appropriate in the case of intermittent generation for several reasons. First, traditional CHP and intermittent renewable generation have different operating characteristics that undermine the need for standby charges. Moreover, traditional standby charges developed for CHP are not based on the utility’s cost of serving intermittent generation. Accordingly, net metering policies that embed the protection of customer-generators from these types of charges are considered to be a best practice. Finally, from an equity viewpoint, it makes little sense to charge customers additional fees for investing in renewable energy resources that fulfill state renewable energy goals. For these reasons, *Freeing the Grid* awards “3” points for safe harbor provisions in net metering rules that protect net metering customers from “standby” charges or any other service fee that only applies to net metering customers.

Twenty-two states feature safe harbor provisions to ensure that net metering customers are treated no differently than other customers of the same rate class with respect to the utility charges and fees they face. Approximately eight states have net metering policies that either allow charges to be assessed to net metering customer or leave it to the utility’s discretion to do so. For example, New Mexico and North Carolina permit standby charges for certain net metering customers. In North Carolina, generators over 20 kW (residential) and 100 kW (non-residential) face standby charges. In New Mexico, utilities may impose access fees on net metering customers—included in the statutory term “interconnected customers”—where the utility can make a showing in a general rate case that the costs of a net metering facility to the utility’s system outweigh the benefits of that system to the grid. Michigan allows standby charges, but only for systems over 150 kW.<sup>15</sup>

Illinois law provides a solid example of a statutory safe harbor for net metering customers:

An electricity provider shall provide to net metering customers electric service at non-discriminatory rates that are identical, with respect to rate

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<sup>15</sup> See Public Act 295 (2008) § 175.

structure, retail rate components, and any monthly charges, to the rates that the customer would be charged if not a net metering customer. An electricity provider shall not charge net metering customers any fee or charge or require additional equipment, insurance, or any other requirements not specifically authorized by interconnection standards authorized by the Commission, unless the fee, charge, or other requirement would apply to other similarly situated customers who are not net metering customers.<sup>16</sup>

Similarly, Indiana statute provides that net metering “[b]ill charges, credits, rates, and adjustments shall be in accordance with the investor-owned electric utility's tariff and administrative rules that would apply if the net metering customer did not participate in net metering.”<sup>17</sup>

Wisconsin net metering tariffs do not presently contain safe harbor provisions. Clarifying that net-metering customers will be protected from additional charges can create more regulatory certainty for residential and non-residential customers considering investing in distributed generation. We, therefore, recommend that Wisconsin net metering policy prohibit any additional charges on net metering customers that they would not otherwise face. We recommend the use of the Illinois statutory provision as appropriate model language for a net metering safe harbor provision because it explicitly prohibits additional charges.

Recommendation:

- The state Legislature should act to adopt language similar or consistent with the quoted language above from 220 ILCS 5/16-107.5(e).
- Alternatively, the Commission should adopt the quoted language as part of a rulemaking that applies to all utilities within its jurisdiction.

**B. Secondary Recommendations**

*1. Require cooperatives to adopt minimum net-metering policy.*

The Commission does not have jurisdiction over electric cooperatives, so an act of the legislature is required to require that all Wisconsin electric cooperatives offer net metering to customers. As discussed above, consistency of policy will give fair opportunities for all members of electric cooperatives the option to net meter. In our experience, electric cooperatives are very sensitive to the needs of their members. Accordingly, sustained interest in developing a solid net metering program at a cooperative can be instrumental in building support for changing policies.

Recommendation:

- The state Legislature should act to require electric cooperatives to adopt net metering policies. As tied to the primary recommendation of increasing system size limits, the statutory requirement of net metering should reflect as closely

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<sup>16</sup> 220 ILCS 5/16-107.5(e).

<sup>17</sup> 170 IAC 4-4.2-7(1).

## 2. *Allow third-party ownership of net-metered systems.*

Under third-party ownership models, instead of buying a renewable energy system outright, a customer signs a long-term contract with a third-party who installs and owns a renewable energy system on the customer's premises. This model has proven successful for many reasons. First, the host does not have to put up initial capital to purchase the system. Additionally, third-party owners are often able to better utilize available tax credits and incentives. This is particularly the case where the utility customer is a tax-exempt non-profit or a governmental subdivision. Finally, under some third-party ownership models, the host customer only pays the third-party owner for the amount of renewable energy actually produced by the system. This gives the third-party owner a strong incentive to keep the system operating at peak output levels. This outcome not only insures the host customer only pays for what they receive, but also helps insure that ratepayer incentives for renewable energy result in maximum renewable energy production. Given the widespread adoption of this approach,<sup>18</sup> third-party ownership of renewable energy systems has become an important driver of a sustainable renewable energy market.

Net metering rules should be sufficiently broad to allow third-party owned systems to participate in net metering, if they are otherwise allowed. For example, an unnecessary restriction to the definition of a customer-generator may require that the person "own and operate" the system. Other states have adopted more permissive language that defines a customer-generator as the "user" of a net metering system or the "owner or operator." Delaware, for example, recently expanded its definition of customer-generator to explicitly include leased and third-party owned systems.<sup>19</sup>

Most Wisconsin utilities have net metering tariffs that require the customer to "own" the net metering system. However, the municipal utilities and several of the smaller privately-owned utilities simply refer to the "customer's generating facilities," which may be sufficiently flexible to allow third-party ownership as "ownership" is not specified as a prerequisite. We suggest that the net metering rules, or any future statute, clarify that a customer need not own the on-site system to net meter.

### Recommendation:

- The state Legislature should enact legislation to define "net metering customer" or "customer-generator" as a user of a net metering facility, without respect to ownership of the facility. The Legislature should also consider exempting third-party owned net metering systems from public utility status and from the jurisdiction of the Commission.

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<sup>18</sup> DSIRE features a summary map titled "3<sup>rd</sup>-Party Solar PPA Policies" that shows the third-party model is allowed in some form in over 20 states. Consideration of whether a third-party system may net meter is a separate consideration from whether a third-party may legally operate in a state. Map available at: <http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1>.

<sup>19</sup> Delaware PSC Order No. 7984 § 8.1.1.

- The Commission should promulgate rules applicable to all jurisdictional utilities to clarify that a net metering facility does not need to be owned by the net metering customer. The Commission could also consider a declaratory order to disclaim jurisdiction over the third-party owners of net-metered systems.

3. *Clarify REC ownership in favor of customer-generators.*

Renewable energy credits (RECs) provide another potential stream of revenue for owners of systems that generate electricity with renewable resources. Customers often retire RECs to support their green energy claims. In many areas of the United States, RECs are a valuable commodity that can be sold in voluntary “green power” markets or are used by utilities to fulfill a utility’s RPS requirements. Utilities should not be permitted to seize RECs from system owners as a condition for net metering or interconnection and any transfer of RECs should be voluntary. Indeed, FERC ruled that PURPA contracts do not automatically convey RECs, as the renewable attributes are distinguishable from the energy and capacity normally compensated through a PURPA contract.<sup>20</sup> Because RECs and net metering are state law programs, however, it is important for state law to definitively establish whether the customer or the utility owns RECs associated with net metered generation.

Because a customer-generator’s right to the renewable attributes associated with on-site generation can directly impact the willingness of a customer to invest in renewable energy, a best practice in net metering rules is for rules to provide the explicit acknowledgement that the customer-generator retains the rights to the associated RECs. Wisconsin law does not explicitly address REC ownership for net metering customers. A statutory or regulatory right to RECs associated with on-site generation is a “bankable” revenue stream that can assist in financing customer-owned systems.

Recommendation:

- The state Legislature should enact legislation to clarify that RECs associated with on-site generation are the property of the net metering customer. Alternatively, if RECs are to be granted to the utility, the customer should be appropriately compensated for the market value of all RECs transferred to the utility.
- The Commission should promulgate rules applicable to all jurisdictional utilities that clarify that net metering customers retain ownership of all renewable attributes of generation associated with the net metering customer. Alternatively, if RECs are to be granted to the utility, the customer should be appropriately compensated for the market value of all RECs.

4. *Implement aggregate net metering.*

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<sup>20</sup> See *American Ref-Fuel Company*, 107 F.E.R.C. ¶ 61,016 (2004); see also Holt, Ed and Bird, Lori, “Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges,” NREL/TP 620-37388 (January 2005).

Aggregated Net Metering is a practice where multiple customer accounts/meters are aggregated for purposes of “netting” the usage of those accounts against the generation credit from a single generator. Aggregated net metering primarily benefits farms and properties that may have multiple meters such as municipalities, schools, universities or business parks. Some states allow aggregate metering that combines accounts for net metering across one or multiple property boundaries.

Wisconsin utilities’ tariffs do not address meter aggregation in this form. The only “aggregation” discussed in utility tariffs is the aggregation of generation for the purposes of customer system size limits, not the aggregation of loads for netting against a generator or generators. Wisconsin could expand its net metering program and assist the state’s many farmers by allowing aggregation of the multiple meters on a single farm against a single generating facility. Increasing net metering system size and allowing aggregation could work in tandem to encourage more farms to utilize biogas, biomass or anaerobic-digester facilities to serve on-site load.

New York recently passed legislation to allow aggregate net metering for agricultural customers, but it also allows generation credits to apply to off-site loads, so long as there is common ownership of the accounts.<sup>21</sup> As part of a broader modification of Wisconsin’s net metering policy—i.e., in conjunction with raised system size caps—aggregate net metering could provide a substantial boost to in-state renewable generation.

#### Recommendation:

- The state Legislature should enact legislation to allow commercial and agricultural customers to use aggregate net metering to offset usage from multiple meters under common ownership from on-site generation.
- The Commission should promulgate regulations to allow commercial and agricultural customers to use aggregate net metering to offset usage from multiple meters under common ownership from on-site generation.

## **II. Recommendations for Interconnection Standards in Wisconsin.**

### **Primary Recommendations:**

- Legislative action to require consistency in interconnection standards throughout the state.
- Legislative or regulatory action to adopt the FERC’s technical screens as part of an expedited interconnection process
- Legislative or regulatory action to prohibit external-disconnect-switch requirements for inverter-based generators.

### **Secondary Recommendations:**

- Legislative or regulatory action to prohibit additional insurance requirements.
- Legislative or regulatory action to reduce interconnection process timelines to at least the FERC standards.

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<sup>21</sup> See New York Assembly Bill 6270 (2011).

- Legislative or regulatory action to remove system size limit.
- Legislative or regulatory action to institute informal process for interconnection disputes.

## **A. Primary Recommendations**

### *1. Statewide consistency in interconnection standards.*

Consistency in statewide interconnection procedures promotes efficiency and decreases the opportunities for mistakes by installers and utilities. For example, a solar installer operating out of Milwaukee may extend its business throughout the state and encounter varying forms and procedures for interconnecting a system. Lack of familiarity with differing procedures can create unnecessary delays that are more related to administrative design than any engineering or technical aspect of the interconnection.

Aside from the increasing the efficiency and familiarity of installers, consistent standards ensure that all Wisconsin ratepayers have equal footing to install on-site generation. If there are differing obligations on customers in different service territories, the economics of customer generation will needlessly vary across the state, disadvantaging citizens that aspire to install a generating system merely based on which utility service territory they reside in. For example, because an external disconnect switch can cost \$100s to \$1000s, if one utility regularly requires an external disconnect switch and another regularly waives the requirement, there will be regional disadvantages to installing on-site generation that have little to do with the safety of the proposed interconnection, the generating potential of the site, or operational capacity of the utility's system.

Seven states, the District of Columbia and Puerto Rico have interconnection standards that apply to all utilities within territorial boundaries, earning a "+1" on the *Freeing the Grid* grading scale.<sup>22</sup> Six more states, including Wisconsin, earn a "+0.5" for applying standards to all utilities within the state regulatory agency's jurisdiction. Wisconsin's interconnection rules are not mandatory for electric cooperatives.

### **Recommendation:**

- Extend existing interconnection procedures to electric cooperatives through legislative action. While the Commission does not have authority over electric cooperatives, the legislature could require electric cooperatives to adopt the standard interconnection procedures approved by the Commission. Incorporating by reference the standard interconnection rules approved by the Commission for other in-state utilities will grant the Commission the ongoing ability to ensure statewide consistency in interconnection procedures.

### *2. Adopt FERC technical screens and a standard expedited review process.*

All interconnections share some fundamental characteristics. These relate to, among other things, the size of the generator relative to the section of the grid to which it connects,

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<sup>22</sup> See *Freeing the Grid*, Appendix A, pp. 106-07 (Interconnection Grades).

and the ratings of the protective equipment installed. These factors determine how complex the interconnection process needs to be.

The majority of states that have adopted state-level interconnection standards have designed the interconnection process using, as their base, the FERC's *pro forma* Small Generator Interconnection Procedures (SGIP). As part of this process, these states adopted the SGIP's Fast Track technical screens.

Using FERC's technical screens as the heart of state-level interconnection standards is important for several reasons. FERC's screens were adopted after years of review and are designed to streamline interconnection review on only those DG systems that require additional review. In this sense, technical screens save time and monetary resources for both utilities and developers. Moreover, technical screens give developers reasonable assurance that a proposed project that meets the technical screens will likely be approved without significant delay or modifications to the project. This outcome avoids additional expenses due to delay or dispute over proposed distribution upgrades that are not necessary for grid safety and reliability. For these reasons, adoption of FERC technical screens forms the heart of any solid interconnection standard.

Leading states have also begun to provide additional information on the distribution system as a means to ease the interconnection process and conserve utility review resources. For example, California utilities are required to publish detailed distribution system data that discloses the available capacity of distribution circuits.<sup>23</sup> This information, paired with the objective screening criteria in FERC's technical screens<sup>24</sup> gives developers a good indication of suitable spots to interconnect that are likely to pass technical screens and, thus, achieve more economic interconnection.

Wisconsin interconnection procedures currently leave too much discretion for utilities to require more cumbersome study, even where a generator may pass FERC screens and pose no threat to the utility's system. PSC 119.20, "General Design Requirements," provides some basic technical parameters that all DG systems must meet, as well as some additional requirements—such as telemetry—for larger systems, but it leaves the utility discretion to determine if "an engineering review is needed."<sup>25</sup> The minimal requirements outlined in PSC 119 do not provide the "go" or "no go" clarity of the FERC's technical screens. As a result, a generator that would meet the FERC technical screens, and, therefore, pose no issues for the grid may still be subject to more

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<sup>23</sup> See PG&E's distribution system map, made available at:  
[http://www.pge.com/b2b/energysupply/wholesaleelectricssuppliersolicitation/RA\\_M/index.shtml](http://www.pge.com/b2b/energysupply/wholesaleelectricssuppliersolicitation/RA_M/index.shtml)

<sup>24</sup> This distribution system information is primarily provided for the benefit of wholesale programs, in which generators are interconnecting pursuant to the utilities FERC-jurisdictional distribution access tariffs that use the SGIP technical screens and not California's Rule 21, which does not strictly adhere to those screens.

<sup>25</sup> PSC 119.04(4).

cumbersome, costly, and time-consuming engineering review to determine the “suitability of the installation.”<sup>26</sup>

We recommend that the Commission or the Legislature act to make the FERC’s technical screens the basis for an expedited review process that provides objective standards for interconnection approval. The FERC technical screens are perhaps the most thoroughly used and vetted aspect of the *pro forma* SGIP found in many state interconnection procedures.

The SGIP standards are already in place for FERC-jurisdictional interconnections within Wisconsin, as these screens are embedded in the existing Open Access Transmission Tariff (OATT) and used throughout the Midwest ISO. Accordingly, adopting these technical screens for use in state jurisdictional interconnections should pose no difficulties for utilities.

#### Recommendation:

- The state Legislature should require all in-state utilities to utilize the FERC’s technical screens as part of statewide interconnection standards to provide an expedited path to interconnection.
- Alternatively, the Commission should act to open a rulemaking to adopt the FERC’s technical screens and create an expedited interconnection process to apply to all jurisdictional utilities.

#### 3. *Prohibit external disconnect switch requirement for inverter-based generators.*

External disconnect switches for systems utilizing modern inverters are unnecessary because all inverters that meet IEEE standards have automatic shut-off capabilities integrated within the systems that shut down interconnected systems automatically in the event of grid failure.<sup>27</sup> It is important to note that not one accident resulting from the islanding of net-metered renewable energy systems has been reported even though over 100,000 grid-tied systems have been installed nationwide. Without a justification for external disconnect switch requirements, rules that allow utilities the discretion to require such a device, or explicitly require one, impose an unnecessary expense on customer-generators. The cost of installing an external disconnect switch can be substantial and presents an unnecessary financial obstacle to customer adoption of on-site generation.

New Jersey and Maine are two states that prohibit external disconnect switches

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<sup>26</sup> PSC 119.02(17).

<sup>27</sup> For a thorough discussion of the recommendation to eliminate the external disconnect switch requirement for small, inverter-based systems, see Sheehan, M., “*Utility External Disconnect Switch Report: Practical, Legal, and Technical Reasons to Eliminate the Requirement*,” published by the Solar America Board for Codes and Standards, available at: <http://www.solarabcs.org/about/publications/reports/ued/index.html>.

where a generator meets the other applicable requirements for interconnection, including compliance with UL 1741 or IEEE 1547. New Jersey’s administrative code provides that a utility “shall not require an applicant whose facility meets the criteria for interconnection approval under the level 1 [10 kW inverter-based system] or level 2 [up to 2 MW] interconnection review procedure . . . to install additional controls or external disconnect switches not included in the interconnection equipment.”<sup>28</sup> Maine prohibits a utility from requiring “additional controls (including but not limited to a utility accessible disconnect switch)” where the generator complies with all of the applicable standards.<sup>29</sup> Other states, including Florida, prohibit external disconnect switches for inverter-based systems 10 kW or less, but otherwise may impose the requirement.<sup>30</sup> Florida is awarded a “0.5” in the *Freeing the Grid* score because removing the expense of an external disconnect switch is important to smaller systems that are unable to absorb the expense with economies of scale.

Wisconsin currently does not feature a best practice in regard to external disconnect switches and it receives a score of “-1” from *Freeing the Grid* in this category. PSC Chapter 119.10(1) requires applicants to include a one-line diagram that includes a “lockable interconnection disconnect switch.” Section 119.20(3) states that “the public utility *may require* that the applicant furnish and install an interconnection disconnect switch that opens, with a visual break, all ungrounded poles of the interconnection circuit.” The 2010 *Freeing the Grid* score of “-1” is justified because the disconnect switch may be required “at the utility’s discretion.”

#### Recommendation:

- The state Legislature should prohibit utilities from requiring external disconnect switches for inverter-based systems that otherwise meet applicable interconnection requirements. At a minimum, a legislative fix should exempt inverter-based systems 10 kW or less from the external disconnect switch requirements.
- The Commission should clarify the circumstances under which a utility may require external disconnect switches. The Commission should either prohibit the requirement for inverter-based systems, or exempt smaller inverter-based systems from the requirement.

### **B. Secondary Recommendations**

#### *1. Prohibit additional insurance requirements.*

Excessive insurance requirements only serve to discourage customers from investing in renewable energy systems and participating in net metering programs. Requiring customer-sited generators—especially those with relatively small DG systems—to obtain and maintain million-dollar insurance policies is impractical, because the high premiums will likely exceed the economic benefits of net metering.

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<sup>28</sup> N.J.A.C. § 14:8-5.8(b).

<sup>29</sup> CMR 65-407-324(12)(E).

<sup>30</sup> Florida Administrative Code § 25-6.065(6)(a).

Just as Maine and New Jersey prohibit utilities from requiring additional equipment like external disconnect switches, the provisions in those states also prohibit utilities from requiring additional insurance. Other states require the customer-generator to carry the amount of general liability insurance that the customer would normally carry. Some states, including Wisconsin, have scaled insurance requirements based on systems size. *Freeing the Grid* recognizes the best practice in this area to prohibit additional insurance and to not require the customer to add the utility as an “additional insured” on the policy. Following the same logic as additional requirements on small generators, *Freeing the Grid* grading generally looks favorably on procedures that exempt small systems from these requirements. For example, North Carolina receives a “0.5” because its rules prohibit residential customers—who typically install smaller systems—from carrying more liability insurance than required by a homeowner’s policy.<sup>31</sup>

The Wisconsin Interconnection Procedures require insurance scaled to the generator’s size. Table 119.045-1 in Wisconsin’s procedures show insurance requirements that escalate according to category: **1** (\$300,000); **2** (\$1,000,000); **3** (\$2,000,000); **4** (negotiated). Category 2-4 must name the public utility an additional “insured” in the liability policy. These requirements exceed what is thought to be necessary according to best practices, but are only slightly more restrictive than states like Michigan and Colorado which score a 0.5. Additionally, the negotiated level for Category 4 leaves an open question to the upward bound of requirements, accounting for the “-2” in the 2010 *Freeing the Grid*. Adjusted to account for similarities in insurance levels to other states receiving a 0.5, and the fact that “additional insured” is only required for Categories 2-4, we decided to increase the score on review to a “0.”

Recommendation:

- The state Legislature should enact a statute that prohibits additional insurance for interconnection customers. At a minimum, the statute should exempt systems up to the residential net metering system size limit. If the system size limit recommendation is adopted, this would be systems of 20 kW or less.
- Alternatively, the Commission should issue a rulemaking to exempt small generators from additional insurance requirements for all utilities subject to its jurisdiction.

2. *Improve interconnection timelines to at least match FERC standards.*

The FERC standards establish a timeline for each step of the application process, for each type of generator. There is room for improvement in this area, and some states have elected to trim the amount of time allowed for the different steps. The time that it takes to process an interconnection request can directly affect the economics of a project.

Eighteen states and the District of Columbia either utilize the FERC’s timelines or have expedited timelines to process applications and proceed with each step of the study

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<sup>31</sup> See North Carolina Utilities Commission Docket, No. E-100, Sub 101, Order on 6/9/08.

process.<sup>32</sup> The FERC screens are heavily vetted and fairly conservative, meaning that they are reliable from an operational and safety perspective.

The Wisconsin Interconnection Procedure timelines are generally longer than those timelines found in the FERC SGIP. While not all study processes are similarly designed and a particular application may not engage in all steps, the *Freeing the Grid* analysis of timelines focuses on the individual components of the study to determine if it exceeds its FERC equivalent. Determining whether procedures exceed FERC timelines, therefore, requires a judgment call.

The Wisconsin procedures are shorter than those in the SGIP for smaller systems, but exceed SGIP timelines for studies of Category 4 generators. Given that the Wisconsin procedures also lack an expedited process for smaller generators—where the SGIP allows generators up to 2 MW to apply for expedited interconnection review—the fact that timelines for smaller category generators are shorter is discounted. A side-by-side comparison is attached to this paper in Appendix A.

The greatest area for improvement for the Wisconsin procedures, then, is to shorten the timelines for category 4 interconnections. Taken together with the recommendation here to adopt the FERC’s technical screens as part of an expedited review process, interconnection review times in Wisconsin would move significantly toward best practices.

#### Recommendation:

- The state Legislature should enact a statute that sets timelines in accordance with the FERC timelines for the study process that applies to all in-state utilities.
- The Commission should promulgate rules for all jurisdictional utilities to provide timelines for the study process (engineering review and distribution system study) that are equivalent to or superior to the timelines in the FERC SGIP study process.

### 3. *Make Applicable to all State Jurisdictional Interconnections*

States generally have jurisdiction over the interconnection of generators that are not engaged in a FERC jurisdictional wholesale sale. FERC jurisdiction over interconnection is based on its jurisdiction under the Federal Power Act to regulate wholesale sales in interstate commerce.<sup>33</sup> The Federal Power Act does not extend to retail sales<sup>34</sup> and states have jurisdiction over the interconnections of qualifying facilities (QFs) where the generator sells all of its output to the interconnected utility and does not engage in sales to

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<sup>32</sup> See *Freeing the Grid*, Appendix A, pp. 106-07 (Interconnection Grades).

<sup>33</sup> See 16 U.S.C. § 824(b)(1).

<sup>34</sup> See 16 U.S.C. § 824(b)(1) (“The provisions of this subchapter . . . shall not apply to any other sale of electric energy.”).

a third-party.<sup>35</sup> Importantly, states may exercise jurisdiction over the interconnections of all such QFs.

Limits on the applicability of interconnection procedures can create jurisdictional confusion. Many states, including Wisconsin, limit the applicability of state interconnection procedures to interconnections to distribution systems. Other states limit the applicability based on system size, leaving systems over the threshold size relegated to federal interconnection standards. The best practice in this area is to alleviate the potential gaps in jurisdiction and set an applicability for interconnection standards that encompasses all state jurisdictional interconnections.

Currently, Wisconsin's procedures apply to generators up to 15 MW that interconnect to the utility's distribution system. We recommend that this size restriction be removed or increased to at least 20 MW, to match the FERC SGIP standard and to avoid any gap in state jurisdiction over interconnections that are otherwise not FERC-jurisdictional. Additionally, the state has jurisdiction over the interconnection of QFs to transmission level voltage, so long as the QF sells all of its output to the interconnected utility.

#### Recommendation:

- The state Legislature should enact a statute to establish interconnection procedures for all interconnections within the state of 20 MW or less that are not FERC-jurisdictional. Alternatively, the statute could remove any system size limit and apply to all QFs (80 MW or less). The statute should apply to any state-jurisdictional interconnection, regardless of whether it is interconnecting at the transmission or distribution level.
- The Commission should modify the system size limit to 20 MW or impose no cap at all, consistent with the approach suggested for the legislature. The rules should not be limited solely to distribution level interconnections.

#### 4. *Develop informal process for interconnection disputes.*

Inevitably, some requests for interconnection will result in disputes. The best standards provide a low-cost means of expert resolution, e.g., through a telephone call to a technical master employed by the state public utility commission. Other options are more administratively burdensome and more expensive. 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.

Fourteen states, Puerto Rico and the District of Columbia have a dispute process in place as part of those jurisdictions' interconnection procedures.<sup>36</sup> Massachusetts, for example, offers a process that progresses from "good faith negotiation" (8 days to resolve) to "mediation/non-binding arbitration" and, finally, to a formal adjudication before the

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<sup>35</sup> See *Western Mass. Electric Co.*, 61 F.E.R.C. ¶ 61,182 (1992), *aff'd* *Western Mass. Electric Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1990).

<sup>36</sup> See *Freeing the Grid*, Appendix A, pp. 106-07 (Interconnection Grades).

Commission if the other processes fail.<sup>37</sup> In the second step of the Massachusetts dispute process, parties meet with Department staff and try to reach agreement. If no agreement is reached in that process, the Department provides a list of third-party neutrals from which the parties can mutually select a mediator. If a party request a technical master, both a mediator and a technical master will be selected through a mutually agreeable process. The FERC offers a similar informal dispute resolution process,<sup>38</sup>but Massachusetts dispute process is an exemplar of best practices in quickly and fairly resolving disputes at fair costs to parties involved.

There is no informal dispute resolution process detailed in the WIP. Instead, PSC 119.40 provides that a customer may appeal to the Commission for a formal determination that a utility requirement is excessive or unreasonable in light of the rules. This receives a score of “0” as proceeding through the formal Commission process is more administratively burdensome than procedures that allow for appointment of a technical master or some alternate dispute resolution process. The FERC’s informal dispute resolution service comes at no charge to parties, unless a third-party impartial is required or requested.

Recommendation:

- The state Legislature should enact a statute to establish an informal dispute resolution that gives parties the option to request a technical master to resolve technical disputes. Massachusetts interconnection procedures § 9.0 is a solid template to base such provisions.
- The Commission should promulgate rules to establish a dispute resolution for jurisdictional utilities that is similar to the Massachusetts process.

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<sup>37</sup> See Mass. Dept. of Public Utilities Order 09-03-A § 9.0.

<sup>38</sup> See FERC’s Dispute Resolution Service’s website for more details:  
<http://www.ferc.gov/legal/adr/drs.asp>.

## **Summary of Recommendations**

In this memo, we make the following recommendations for net metering and interconnection:

### **Primary Net Metering Recommendations:**

- Legislative or regulatory action to increase statewide net metering system cap to at least 500 kW.
- Legislative or regulatory action to provide indefinite rollover of excess generation credits at the retail rate.
- Legislative or regulatory action to protect net metering customers from the imposition of standby charges or access fees.

### **Secondary Net Metering Recommendations:**

- Legislative action to require electric cooperatives to adopt minimum net metering standards.
- Legislative or regulatory action to allow third-party ownership of net metered systems.
- Legislative or regulatory action to clarify that customer-generators retain the renewable attributes (RECs) associated with on-site generation.
- Legislative or regulatory action to allow aggregate net metering for farms and businesses under common ownership.

### **Primary Interconnection Recommendations:**

- Legislative action to require consistency in interconnection standards throughout the state.
- Legislative or regulatory action to adopt the FERC's technical screens as part of an expedited interconnection process
- Legislative or regulatory action to prohibit external-disconnect-switch requirements for inverter-based generators.

### **Secondary Interconnection Recommendations:**

- Legislative or regulatory action to prohibit additional insurance requirements.
- Legislative or regulatory action to reduce interconnection process timelines to at least the FERC standards.
- Legislative or regulatory action to remove system size limit.
- Legislative or regulatory action to institute informal process for interconnection disputes.

Any of the above recommendations could be dealt with on a piecemeal basis and would significantly improve the existing standards. If an omnibus bill energy bill or broadly scoped rulemaking were introduced, all of the secondary recommendations could be swept in to adopt the best practices in one action. The authors recommend placing the primary recommendations into high priority of action as the items represent systematic caps that prevent net metering and interconnection from applying more broadly.

**Appendix A** (Comparison of Interconnection Timelines)

<b>SGIP/WIP</b>	<b>FERC SGIP</b>	<b>WI Interconnection Procedures</b>	<b>Difference (+/-)</b>
Notice of Complete App.	10 days	10 days	0
<b>Fast Track Initial Review/</b> <i>(Initial App. Review)</i>	15 days	10 days	-5
<b>Customer Options Meeting/</b> <i>N/A</i>	10 days from determination of FT screen failure	N/A	
<b>Supplemental Review</b>	10 days from receipt of deposit	N/A	
<b>Feasibility Study Agreement</b>	5 days from Scoping Meeting	N/A	
<b>Feasibility Study Report/</b> <i>(Engineering Review results)</i>	30 days from execution and delivery of Agreement	Cat 1- 10 days Cat 2- 15 days Cat 3- 20 days Cat 4- 40 days After receipt of payment and agreement	WI generally longer, considering that smaller systems would likely proceed under SGIP Inverter Process or Fast Track
<b>System Impact Study Agreement</b>	15 days from transmittal of Feasibility Study Report	N/A	
<b>System Impact Report/</b> <i>(Distribution System Study)</i>	30 days From execution and payment of Agreement	Cat 1- 10 days Cat 2- 15 days Cat 3- 20 days Cat 4- 60 days After receipt of payment and agreement	WI Cat 4 significantly longer
<b>Facilities Study Agreement</b>	5 days from completion of System Impact Study	N/A	
<b>Facilities Study Report/</b> <i>(Distribution System Study)</i>	No upgrade- 30 days; Upgrades req.-45 days	Cat 1- 10 days Cat 2- 15 days Cat 3- 20 days Cat 4- 60 days After receipt of payment and agreement	WI Cat 4 significantly longer
<b>Interconnection Agreement must be delivered</b>	5 days from completion of Facilities Study	N/A	