COALITION FOR COMMUNITY SOLAR ACCESS
PO Box 65491
Washington, DC 20035
202-888-6252
info@communitysolaraccess.org
communitysolaraccess.org

Solar Parties Supplemental Interconnection Comments

9-13-2019

The Oregon Solar Energy Industries Association (OSEIA) and Coalition for Community Solar Access (CCSA) – hereby referred to as the "Solar Parties" - appreciate the opportunity to comment on the proposals and various concepts that have been raised over the past couple months with regards to interconnecting community solar projects. This is a critical element to the success of any community solar program, particularly in Oregon, as has been raised by the solar industry and other stakeholders and highlighted in depth by the Public Utilities Commission (PUC) Staff (Staff).[1] Indeed, even in adopting the community solar rules under Order 17-232, the PUC had the foresight to anticipate potential interconnection challenges and called out Staff and stakeholders to consider ways for "ensuring nondiscriminatory access and evaluating whether the interconnection process is fair and functional for projects seeking to enter the community solar program".[2] Finally, the community solar program provides a controlled pilot space to test potential advancements in Oregon's interconnection policies being considered under other PUC dockets such as UM 2000 and UM 2005.

The Solar Parties applaud the effort by Staff, utilities, and participating stakeholders in generating potential solutions that enable timely and economically viable project development for community solar with an eye toward a late 2019 program launch. To that end, the Solar Parties provide these additional comments in response to concepts raised in the docket and/or during the related workshops ((7/31/2019 & 8/26/2019). Our interest is in maintaining a focus on leveraging best practices and the most accessible tools for providing near term solutions.

The following input is broken down into three primary sections and related objectives:

- Maintaining support for Staff's Draft Proposal for Community Solar Interconnection[3] and recommending two adjustments for improvement: 1) slightly expanding the "pilot" beyond the community solar program; and 2) instituting a distribution upgrade cost sharing mechanism orchestrated by the utilities while continuing discussion and investigation into a pre-emptive mechanism model.
- Supporting the Joint Utilities CSP Interconnection Proposals[4], and recommending the incorporation of 100% of minimum daytime load to serve as the initial screening test where possible, ahead of a secondary 30% of peak load screening test where minimum daytime load is not available.
- Reiterating support for requiring a utility engineer's stamp on interconnection studies.

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[1] See the February 14 presentation filed by OSEIA-CCSA in UM 1930, found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah154853.pdf; and Staff's Draft Proposal filed June 19, found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah13520.pdf
[2] Order 17-232. Found here: https://apps.puc.state.or.us/orders/2017ords/17-232.pdf
[3] Staff's Draft Proposal for Community Solar Interconnection. June 19, 2019. Found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah13520.pdf
[4] Joint Utilities CSP Interconnection Proposal. August 16, 2019. Found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah163325.pdf

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Support for Staff's Draft Interconnection Proposal & Modifications to Previous Comments

The Solar Parties maintain support for Staff's Draft Interconnection Proposal filed on June 19, 2019, with two minor adjustments to our previous comments. [5] Staff produced relatively straight-forward and thoughtful solutions to minimizing prohibitive interconnection costs and barriers by leveraging Energy Resource Interconnection Service (ERIS) for projects that trigger transmission upgrades and by instituting a cost-sharing mechanism for distribution system upgrades.

- The Solar Parties maintain that slightly expanding the pilot to include non-community solar projects for testing interconnection solutions would be: more fair to those developers that have already made investments in the market; reduce the administrative complexity involved in parsing out who is and isn't eligible to participate in the pilot; support more holistic and efficient upgrades that address the actual needs at different locations; and, could help further reduce the cost impact on individual developers by spreading the burden to more projects. Our initial recommendation was to allow for non-community solar projects (regardless of size) to be able to participate in this pilot so long as they had applied into the queue up to a certain date (for example, maybe September 1, 2019 would be reasonable). Although we maintain our first recommendation, we would also support the revised recommendation submitted by the "QF Trade Associations" that the Staff Proposal be applied to all projects sized 3 MW and smaller, regardless of whether they are participating in the community solar program.[6]
- One of Staff's Draft Proposal recommendations was to have the utility be responsible for facilitating distribution system upgrade cost sharing among developers that benefit from the same upgrade. While our initial comments were supportive of this concept, we recommended going a step further an instituting a "pre-emptive" model that's been tested and is under consideration in New York. [7] Though we maintain that this "pre-emptive" model should continue to be investigated as a potential component of the community solar program and long-term solution in Oregon, in the interest of time, we've adjusted our position to fully supporting Staff's recommendation as a first step toward incorporating cost-sharing policy framework. Similar with Staff's Proposal, the current New York policy provides a useful reference in designing such a program in Oregon. New York currently requires an interconnection applicant to be responsible for 100% of "common-system" upgrade costs, but for subsequent projects to pay a prorated portion of the upgrade costs (based on their capacity size relative to the total capacity of all projects benefiting from the upgrade). In turn, payments are made to the utility who then redistributes it among the developers (developers are subject to an administrative fee for

[5] OSEIA-CCSA Comments. 7/24/2019. Found here: https://edocs.puc.state.or.us/efdocs/HAC/um1930hac95746.pdf

[6] Comments of NIPPC, The Coalition, and CREA on Proposals for Community Solar Interconnection. Filed August 22, 2019. Found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah163816.pdf

[7] Memo on Distribution System Upgrade Cost Sharing. Filed August 16, 2019. Found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah10249.pdf

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this service).[8] Notably, if there are software needs to support the utility's role as a facilitator in Oregon, the costs for that software and other infrastructure can and should be captured as "start-up" costs for the program.

<u>Support for the Utilities Joint Interconnection Proposals & Recommended Modifications for Improvement</u>

The Solar Parties appreciate the effort by the Joint Utilities to provide an alternative solution to Staff's Proposal with regards to avoiding prohibitive interconnection costs and time-consuming queue backlogs. We are supportive of Proposals #2 and #3 relating to reduced metering costs for small projects and an enhanced pre-application process for non-for-profit projects, respectively. We are also supportive of the framework outlined under Proposal #1, however we recommend modifications to the screening thresholds to better align with technical best practices and program policy objectives.

Specifically, the Solar Parties recommend the following screening parameters and process for determining eligibility for leveraging the utilities Proposed unique interconnection queue and process:

1. Use 100% of minimum daytime load as the initial threshold for determining a project's eligibility. This data should be posted publicly (along with peak-load feeder data) where available, and each subsequent analysis that determines minimum daytime load (e.g., pre-application reports, studies, etc.) should result in the information being used and posted publicly.
2. In any rare case where the minimum daytime load is not or will not be made available, the utility can resort to a threshold level of 30% of peak load.
3. In the case where a community solar applicant fails to meet the thresholds outlined above, that applicant's project should still be reviewed in a timely fashion consistent with the state's interconnection policy for small generators.
4. Projects that have moved through the standard interconnection queue (outside of this community solar queue channel) but are interested in participating in the program should still be able to do so using their existing standard interconnection studies or agreement.

Our recommended modifications would maintain the utility emphasis on right-sizing and locating projects to avoid unwanted energy backflow and transmission service, however it leverages a federal (FERC) basis and national best practices. Notably, these recommendations maintain the Utilities Joint Proposal "caveat" that network upgrades (though not transmission specifically) could still be incurred by the interconnection applicant.[9] Further justification for this approach is outlined below under three subsections: technical justification for using 100% of

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[8] New York. Standardized Interconnection Requirements (issued Feb. 2017). Appendix E. http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/October%20SIR%20Appendix%20A%20-%20Final%2010-3-18.pdf

[9] See Joint Utilities Interconnection Proposal. Pg. 3. Found here: https://edocs.puc.state.or.us/efdocs/HAH/um1930hah163325.pdf

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minimum daytime load; technical justification for using 30% of peak load; and policy justification for adopting both of these screening steps.

Technical Justification for using 100% of Minimum Daytime Load as the First Screen

The idea of using a ratio of generation to load, as the utilities have proposed, to help screen whether a proposed distributed generation project has the potential to cause system impacts is well established. The basic idea behind "penetration" screens is that the risks of "unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts are negligible if the combined DG generation on a line section is always less than the minimum load."[10] The utilities in Oregon are proposing to use a penetration screen for essentially the same purpose; to determine whether a project is likely to cause energy to back feed beyond the circuit and onto the transmission system. However, the utilities proposal assumes overly conservative peak or minimum load ratios instead of using 100% of minimum daytime load.

When screening approaches were first developed, utilities across the country were mostly tracking only peak and not minimum load. For many years the vast majority of state interconnection procedures, and the Federal Energy Regulatory Commission's (FERC) Small Generator Interconnection Procedures (SGIP), used the so-called "15% of peak load" screen as a way to evaluate whether distributed generation projects required further study before they could be interconnected. While most procedures started with this very conservative peak load ratio and it may have made sense in the early 2000s, the experience gained from substantially more DG being deployed coupled with improved utility data collection capabilities has driven recognition that minimum load is a more prudent benchmark.[11]

Minimum load is the appropriate measurement to use because it directly addresses the concept that if there is always more load than generation on a circuit then the project will not cause energy to back feed beyond the substation.[12] Further, since this is a program focused on community solar, it's worth emphasizing that "daytime" minimum load should be used. To state the obvious, the sun only shines during the daytime, and therefore photovoltaic solar systems without onsite energy storage, only generate power during the daytime. However, it is often the

[10] Michael Coddington, et. al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratory, at 2 (2012) https://www.nrel.gov/docs/fy12osti/54063.pdf.

[11] *See* Federal Energy Regulatory Commission, 14 FERC ¶ 61,159, Order 792, at 81 (Nov. 22, 2013); Michael Coddington, et. al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratory, at 7 (2012) https://www.nrel.gov/docs/fy12osti/54063.pdf; Robert J. Broderick and Abraham Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies*, Sandia National Laboratories, 2012, https://ieeexplore.ieee.org/document/6317712.

[12] Notably, exceeding minimum load does not necessarily mean that there will be system issues or the need for upgrades, but it is a reasonable basis for further evaluation of a project. Studies have shown that penetrations up to and even exceeding 100% of minimum load can be safely accommodated, *see* K. Burman, J.Keller, and B. Kroposki (National Renewable Energy Laboratory); P. Lilienthal, R. Slaughter, and J. Glassmire (Homer Energy, LLC), *Renewable Power Options for Electrical Generation on Kaua'i: Economics and Performance,* NREL/TP-7A40-52076, p. 34 (November 2011), *available at* www1.eere.energy.gov/office_eere/pdfs/52076.pdf*;* J. Bank, B. Mather, J. Keller, M. Coddington, National Renewable Energy Laboratory, *High Penetration Photovoltaic Case Study Report*, January 2013. http://www.nrel.gov/docs/fy13osti/54742.pdf

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Washington, DC 20035
202-888-6252
info@communitysolaraccess.org
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case that the absolute minimum load on a circuit occurs at night.[13] It is for this reason that FERC and other states cited in this section are using a 100% of minimum load screen are looking at the "daytime" minimum load when evaluating a solar system.[14] Using daytime minimum load safely screens for solar systems while allowing for more systems to be installed.

The majority of states that have undergone a comprehensive update to their interconnection procedures since 2011, have chosen to update their screening approaches to now use a 100% of minimum daytime load screen for inverter-based solar PV projects as part of either the Fast Track or Supplemental Review process. This approach was first adopted by California[15] and was subsequently adopted by FERC in SGIP, and has been adopted by at least the following states: Massachusetts, Ohio, Illinois, Iowa, Minnesota, New York, and Arizona.[16]

When FERC considered this issue in 2013, it found that:

- Using a 100% of minimum daytime load screen was "sufficiently conservative" to be used as a basic screening approach where the utility would have the opportunity to evaluate whether additional power quality, voltage, safety or reliability issues would arise (as is the case here).[17]
- When presented with the arguments that 100% of minimum load was not sufficiently conservative, FERC found that so long as it is not being used with other screens that it is appropriate to use 100% of minimum load and expressly rejected using 33 or 67% of minimum load.[18]
- It found that it was appropriate to begin using a minimum load screen, instead of a default peak load screen, even where minimum load data may not have been available universally. Rather, it adopted a screen (first developed in California) that requires utilities to use minimum load if they have it, and if they do not, to try to calculate or estimate or otherwise determine it from a power flow model. Only if a utility is not

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[13] "The fact that PV generation has a strictly daytime pattern is significant considering that voltage impacts tend to be greater during periods of highest instantaneous PV deployment. By the time PV systems are producing a substantial amount of power, loads are well above their nightly lows on most feeders. Therefore, it makes sense to consider minimum daytime load as a technical screening criterion." Robert J. Broderick and Abraham Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies*, Sandia National Laboratories, 2012, https://ieeexplore.ieee.org/document/6317712.

[14] FERC SGIP Screen 2.4.4.1.1

[15] California Public Utilities Commission, Decision 12-09-018, at 24-25 (Sept. 13, 2012); the latest version of California's Interconnection Procedures, as adopted by the utilities, can be found here, the 100% of minimum load screen is found in section G.2.a: https://www.cpuc.ca.gov/Rule21/

[16] Massachusetts at https://www9.nationalgridus.com/non_html/Interconnect_stds_MA.pdf; Ohio at http://codes.ohio.gov/oac/4901%3A1-22; Illinois at https://www.icc.illinois.gov/downloads/public/edocket/384872.pdf; Iowa at https://www.legis.iowa.gov/docs/ACO/chapter/199.45.pdf; Minnesota at https://mn.gov/puc/energy/distributed-energy/interconnection/; New York at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B?OpenDocument; Arizona at https://docket.images.azcc.gov/0000199110.pdf.

[17] Federal Energy Regulatory Commission, 14 FERC ¶ 61,159, Order 792, at 81 (Nov. 22, 2013).

[18] *Id.* at 83-84.

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able to calculate, estimate or otherwise determine minimum load, should it default to using peak load.[19]

Although the direct application of the screening approach is being proposed here for a slightly different reason (i.e. specifically for community solar projects to determine whether they could potentially contribute to the need for transmission system upgrades), the technical reasoning behind the 100% of minimum load screen used by FERC and the other states is consistent. Essentially, most state procedures use a set of technical screens to assess whether a project poses a risk of impacts sufficient enough to warrant further study. Under the Supplemental Review process, as adopted by FERC and many states, if the addition of a project's exported capacity would cause the generation on the line section to exceed 100% of minimum daytime load, then it would proceed to a full study. If the project is below 100% of minimum daytime load, then the utility will evaluate whether there are any additional voltage, power quality, safety and/or reliability issues that warrant further study. This is similar to what is being proposed here by the utilities, where a penetration screen would be applied to determine whether a community solar project could qualify for consideration, it is not being proposed as the sole evaluation.

At this point the utilities in Oregon should have sufficient data available to either know the minimum load or be able to calculate it. They have SCADA available on many circuits, and where SCADA is not available, "minimum daytime load can be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis."[20] Since this is being proposed here to be used only as a basis for further evaluation, it is appropriate to use minimum load that has been calculated even where there might be some change in the minimum load from previous years. Peak load should only be used in the rare case where minimum load cannot truly be determined.

The PUC should take FERC's lead (and that of multiple other states) and require the utilities to use 100% of daytime minimum load as the first default screen for community solar projects.

***Technical* Justification for using 30% of Peak Load as a Secondary Screening Level**

As mentioned previously, peak load should only be used for screening purposes in the rare case where minimum load cannot truly be determined. In other words, peak load can serve as the second-tier screen when minimum load is not or cannot be made available. In which case, it makes sense to use 30% of peak load, rather than the 25% level proposed by the utilities, as the threshold for determining project eligibility. The National Renewable Energy Laboratory

[19] FERC SGIP Screen 2.4.4.1: "Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4."

[20] Michael Coddington, et. al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratory, at 7 (2012) https://www.nrel.gov/docs/fy12osti/54063.pdf.

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determined minimum load is typically about 30% of peak annual load.[21] This is also roughly consistent with solar industry experience and utility assumptions in Oregon based on at least a handful of select projects that have been studied in PGE and Pacific Power interconnection queues.

The Solar Parties could support the utilities development of more accurate summer peak-to-minimum daytime load ratios for determining appropriate (second tier) peak load screening levels based on averages in their respective service territories.

***Policy* Justification for Using 100% of Minimum Daytime Load and 30% of Peak Load Screening Levels**

Making the recommended modifications to the screening levels and process in the utilities proposal has real implications toward meeting program policy objections. Specifically, these minor changes will have a material impact on the number of circuits and amount of capacity that can be leveraged by the full range of project sizes envisioned for the program (i.e., up to 3 MWac).

For example, under the utilities proposal to use a 25% of peak load test, there would be about 389 circuits and 505 MW-ac of capacity available in Pacific Power territory. Of that, only 14% of circuits and 25% of available capacity could handle a project that is over 2 MW in size. Further, literally only three projects that are 3 MW in size could pass the screening test.[22] Note that these estimates do not account for additional siting, permitting, and other development challenges which likely significantly reduce the actual available circuits and capacity. That said, just bumping the peak load penetration screening test to 30%, as opposed to 25%, more than doubles the number of available circuits and as well as available capacity for projects over 2 MW in size and could potentially enable over a dozen 3 MW projects (again, this is prior to considering additional siting and permitting challenges).

The ability to leverage more sites and larger projects is a major component of project economics. Notably, concerns with project economics have been communicated directly and/or indirectly with PUC Staff and the Program Administrator by both solar industry members as well as non-profits and community-based groups interested in pursuing community solar project development. The economies of scale gained by larger project sizes is necessary to make projects pencil in Oregon's program based on initial estimates regarding the credit rate, low-income requirements, and administrative costs. Aside from these cost and revenue variables, project siting itself is costly and any limitations on the number of potential project sites increases the cost and risk associated with development.

[21] Michael Coddington, et. al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratory, at 2 (2012) https://www.nrel.gov/docs/fy12osti/54063.pdf.
[22] Based on Pacific Power's UM 2000 data, posted August 30, 2019 on OASIS. Note, feeders with "Redacted" or "N/A" information were not included in this estimate.

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202-888-6252
info@communitysolaraccess.org
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With regards to using 100% of minimum daytime load, Q1007 in Pacific Power's queue provides an interesting example demonstrating the value and legitimacy it can hold over the peak load test.[23] Applicant Q1007 submitted an application for an 860-kW project. This sizing neatly (and probably intentionally) aligns with 100% of minimum daytime load for that feeder, per the Study which states that: *"The light load for the Wallowa City feeder, 5W28, at Wallowa substation was estimated at 33% of peak demand. The results of the power flow simulation show that voltages do not exceed ANSI range A on the feeder and transient voltages are within allowable limits for all scenarios considered"* [note - that the summer peak load for this feeder is 2600 kW]. Yet, if the utilities proposal was adopted and minimum daytime load ignored (despite that minimum load data clearly being available for the feeder and demonstrating the project size did not pose a threat to the system), this project would not pass the 25% threshold test (since it's closer to 33%). This would represent an example of a policy coming up short of the public interest.

Responses and Additional Input on Request for Engineering Transparency

The Solar Parties provide the following supplemental input regarding comment and discussion around quality control and enforcement of interconnection studies. The Solar Parties reiterate their interest in establishing a policy that requires utilities to include an engineering stamp on their interconnection studies. In response to concerns around there being more than one engineer involved in such studies, the Solar Parties recommend all engineers include their stamps and/or a lead engineer accepts the responsibility.[24] Although the Solar Parties deem it unnecessary and less justified, we are willing to also provide a (Professional Engineer) PE stamp for line diagrams.[25] The Solar Parties also reiterate the recommendation to allow for soliciting their own engineer to conduct needed studies. The existing interconnection rules already require the utility to provide the necessary technical information, primarily as part of conducting these studies.

Finally, the Solar Parties appreciate the question raised by Staff on whether the PUC should institute a more standardized process and potential third-party reviewer for facilitating industry challenges. While this may be a potential fallback, the Solar Parties are concerned it could perpetuate bottlenecks in the interconnection process. Instead, the PUC could issue an order that stated all interconnection activities must be performed and endorsed by a PE, in turn putting the enforcement obligation on the professional engineers and engineering board rather than PUC.

[23] See System Impact Study for Q1017. Found here: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Q1007SIS.pdf

[24] See OAR 820-025-0015 which says final documents "must bear the seal and signature of the registrant under whose supervision and control they were prepared."

[25] This is in response to a question/comment raised by the utilities during the August 26 workshop.

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info@communitysolaraccess.org
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The Solar Parties appreciate this opportunity to provide input on potential interconnection solutions in support of Oregon's community solar program and we look forward to continued discussion in the coming months.

Respectfully submitted,

/s/ Charlie Coggeshall
Policy Advisor for OSEIA and CCSA
charlie@communitysolaraccess.org