UM 1930: Draft proposal for Community Solar Interconnection

Purpose

This report outlines Staff's understanding of the most significant barriers for community solar projects seeking to interconnect with utilities, and proposes a process to address these issues within the timeframe required for a successful community solar program (CSP) launch. Further, this report outlines the next steps to move Staff's proposed solution forward with stakeholders.

Background

Concerns about CSP interconnection

On June 29, 2017, the Public Utility Commission of Oregon (Commission or OPUC) adopted administrative rules for the CSP.[1] The administrative rules require CSP projects to interconnect with the utility in accordance with the State's existing small generator interconnection procedures (SGIP).[2] In the order, the Commission also asked Staff and stakeholders,

> to consider during development of the program implementation manual the potential role of the program administrator ensuring non-discriminatory access and evaluating whether the interconnection process is fair and functional for projects seeking to enter the community solar program.[3]

At the July 26, 2018 Project Details Subgroup meeting, stakeholders raised concerns that interconnection costs may prevent the successful launch of the CSP.[4] Further, Subgroup participants sought clarity about the need for CSP projects to interconnect as Qualifying Facilities (QF) under the Federal Public Utility Regulatory Policies Act (PURPA), because interconnecting as a QF could further increase interconnection costs.[5] Staff committed to work

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[1] *See* OAR Ch. 860, Div. 88; *In the Matter of Rules Regarding Community Solar Projects* (AR 603); Order No. 17-232.

[2] The SGIP are outlined in Oregon Administrative Rules Chapter 860, Division 82.The SGIP are implemented by utilities and, therefore, influenced by utility decisions and practices, as well.

[3] Order No. 17-232, p. 10.

[4] Order No.17-458 approved Staff's request to develop topical, stakeholder-led subgroups to identify and scope Community Solar Program implementation actions that can be taken by Staff and stakeholders concurrently with the issuance of a Request for Proposals (RFP) for a Community Solar third-party Program Administrator. The Project Details Subgroup scope included: interconnection, the role of existing projects, any carve-outs for smaller projects, the flow of needed pre-certification items from projects, deposits and associated process, PPA requirements, QF project requirements, and the CSP project queue.

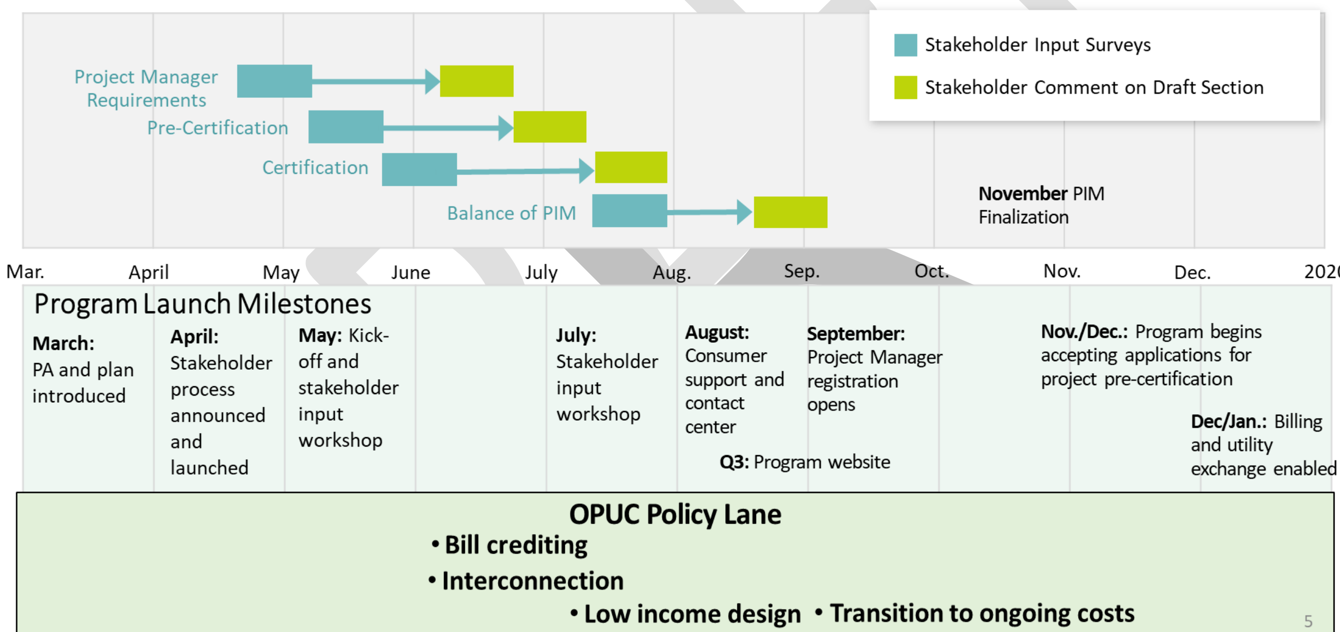
[5] Oregon's investor owned utilities require QF interconnections as Network Resource Interconnection Status (NRIS), as described later in this report. Generators requesting NRIS have a higher level of interconnection requirements than generators interconnecting with

with the Department of Justice (DOJ) to evaluate these concerns and provide clarity about the QF requirement.

On February 5, 2019, Staff shared DOJ's finding that Commission rules require CSP projects to interconnect as QFs (See Attachment A). In its subsequent February 14, 2019 CSP implementation status update, Staff recognized the need to identify near-term opportunities to reduce interconnection barriers for CSP projects within the legal and procedural framework of a QF interconnection.

On May 10, 2019, Staff and the PA Team (consisting of the CSP Program Administrator, Energy Solutions, the Low Income Facilitator, Community Energy Project, and Energy Trust of Oregon) released a plan to develop the program implementation manual (PIM), address outstanding policy issues, create a software platform to facilitate billing and data exchange functions, and begin accepting project pre-certification applications by the end of 2019 (See Figure 1).

Figure 1: Oregon Community Solar Implementation Plan



Additional interconnection proceedings

On February 14, 2019, the Commission opened the UM 2000 Broad Investigation into PURPA and UM 2001 Investigation into Interim PURPA Action. Among other issues related to implementation of PURPA, Docket Nos. UM 2000 and 2001will examine interim actions to relieve interconnection pain points and longer-term actions to address the systemic barriers to small generator interconnection. Table 1 summarized the scope of both investigations.

Energy Resource Interconnection Service (ERIS). The higher level of requirements can lead to additional interconnection costs.

Table 1: UM 2000 and UM 2001 Investigation Scope

Docket	UM 2000	UM 2001
Scope	Staff's May 28, 2019 UM 2000 Draft White Paper proposed that the Commission organize the investigation around four categories of issues: avoided costs, contracts, interconnection, and planning. Proposed interconnection issues include: • How interconnection costs are allocated between small generators and the utility (e.g., should transmission providers share the costs of transmission system upgrades), as well as between different small generators in the queue (e.g., cluster studies). • Whether the manner in which utilities process generator applications in serial order, based on queue number, should be modified. • The timeliness of utility interconnection studies and process. • The ability to use third-parties to perform interconnection studies and system upgrades.	Develop an interim method to update avoided costs and create more transparent interconnection information, including: • Publicly posting interconnection queue and studies • Publicly posting distribution system information (e.g., feeder and substation loading and capacity) • Publicly posting interconnection milestones (e.g., utility timelines to meet • Forming an interconnection data workgroup to advise Staff on specific interconnection data to be shared.
Timeline	The Commission has not adopted a timeline for addressing interconnection issues scoped within UM 2000. Staff's draft whitepaper proposes an investigation or rulemaking to address	All actions within the UM 2001 scope will be implemented by January 2020

On March 21, 2019, the Commission opened UM 2005 Investigation into Distribution System Planning (DSP). Staff's goal for DSP is to ensure that utility distribution-level investments and operational decisions maximize system efficiency and value for utility customers. This includes consideration for how utilities plan for additional distributed energy resources and what system investments utilities should make to ensure the efficient integration of distributed energy resources, among other customer options. On June 14, 2019, Staff released an updated schedule for UM 2005 in which Commission guidance for utilities to file initial plans will be provided in June 2020. Following Commission guidance, the utilities will have sufficient time to develop and file plans for Commission and stakeholder input. While DSP is expected to ensure that utilities are planning for and investing in the efficient interconnection of resources like CSP, Staff does not anticipate DSP will directly address or drive these investments until the end of 2020, at the earliest.

The need to address CSP interconnections
Based on Staff's understanding that CSP Project Managers (PMs) require certainty about interconnection costs and process prior to applying for pre-certification, Staff finds that a fair and functional process should be in place before the end of 2019. The remainder of this report will assess whether additional efforts are required to ensure fair and functional process by summarizing the following:

- Staff's findings that interconnection under the existing SGIP may not be functional due to delays in processing applications and prohibitive costs for generators;
- Staff's current understanding of the key drivers of interconnection costs for small generators; and
- Staff's proposal to address these key drivers in a manner that will be functional within the CSP launch timeline.

Overview of interconnection process for CSP

The CSP administrative rules require projects to interconnect with utilities under the process provided in Oregon Administrative Rules (OAR) Chapter 860, Division 82 Small Generator Interconnection Rules. These rules (aka Small Generator Interconnection Procedures or "SGIP") were adopted in 2009 and govern state-jurisdictional interconnections for generators 10 MW and under.[6]

The SGIP outlines the process for utilities to identify the equipment and other upgrades required to safely interconnect a generator to the transmission or distribution network. Interconnection review is performed through various studies that vary in cost and intensity dependent upon the generator's expected impact on the system.

The SGIP contemplates two types of upgrades[7]:

- **Interconnection facilities:** facilities and equipment required by a public utility to accommodate the interconnection of a small generator facility to the public utility's transmission or distribution system and used exclusively for that interconnection. Interconnection facilities do not include system upgrades; and
- **System upgrades:** addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility.

  Staff believes that, functionally, there are two distinct types of system upgrades:

    - **Distribution upgrades:** located at or past the POI, needed to safely and reliably accommodate the generation on the local network i.e. does the equipment on the local system have the physical capacity to handle the presence of this additional generation?

[6] State jurisdictional interconnections include interconnections for retail transactions such as net metering and for PURPA sales when a Qualifying Facility generator sells its entire output to the interconnecting utility. The Federal Regulatory Commission (FERC) also has interconnection procedures developed for interconnections subject to FERC jurisdiction.
[7] *See* OAR 860-082-0015.

- **Transmission upgrades:** located at and past the POI, needed to sink the generation to load i.e. does the system have the physical capacity and does the utility have the contractual rights to deliver this generation to local area load or the next closest area with load?

The review process has four tiers that determine the process to identify necessary upgrades:

- Tier 1 is for very small systems (<25 kW);
- Tier 2 is for generators under 2 MW that connect to distribution system and pass screens designed to identify generators that should require minimal upgrades to safely interconnect;
- Tier 3 is for generators under 10MW that do not export energy beyond the point of interconnection; and
- Tier 4 is the default tier for generators under 10 MW that do not satisfy the eligibility or the requirements of Tiers 1-3.

CSP generators must be a least 25 kW and export power beyond the point of interconnection. Therefore, CSP generators must proceed as Tier 2 or 4 as described above. Prior to making an interconnection request, generators can request pre-application information, including relevant existing studies and other materials that may be used to understand the feasibility of interconnecting a small generator facility at a particular point on the public utility's transmission or distribution system. These studies do not necessarily identify what may be prohibitively expensive interconnection facilities or system transmission upgrades (distribution and/or transmission) needed for a particular generator' interconnection.[8]

Tier 2 review is similar to FERC's Fast Track process. For eligible generators, the transmission provider (the utility) holds an optional scoping meeting with the generator, then determines whether the generator meets the screening criteria set forth in the SGIP. If the generator passes the screens, it can proceed with execution of the interconnection agreement. If the generator fails the screens, the interconnection application can be reviewed under Tier 3 or 4, depending on whether it exports power beyond the point of interconnection.

Tier 4 is similar to the study process for large generator interconnections (>20 MW). The study process begins with a scoping meeting between the generator and transmission provider, followed by three studies (Feasibility, System Impact, and Facilities) to evaluate the potential adverse impacts of the generator on the transmission and/or distribution network, whether upgrades are required to safely interconnect the generator, and the estimated cost of required upgrades. Studies include technical analyses such as power flow analysis, sort-circuit analysis, and grounding review. The transmission provider and generator may agree to waive any of the studies.[9]

While the state's SGIP does not specifically identify the service under the SGIP as Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS), the Oregon utilities require small generators that are QFs to interconnect with NRIS. Whether a

[8] See OAR 860-082-0020.
[9] OAR 860-082-0060(4).

generator is interconnecting with ERIS or NRIS determines the studies the utility performs to determine whether it can safely and reliably interconnect the generator.

- **Network resource:** The utility is responsible to treat the generator like its own network resources and deliver the generator output on a firm, uninterruptible basis to network load. In addition to identifying the distribution upgrades required to safely and reliably integrate the additional generation on the local system, the interconnection studies account for the ability to deliver the power to network load during the most severe conditions. If local generation exceeds local load under the severe study conditions, the study will identify needed transmission upgrades determine what is required to export the generation to the next closest load.
- **Energy resource**: The utility is responsible to deliver the generator output on the existing firm or non-firm system capacity on an “as available” basis – for the most part, the utility will only consider the ability for the generator to “plug into” the system. If transmission upgrades are required to deliver the generation to load, those are assessed and secured outside of the interconnection process when the generator makes a transmission service request e.g., securing point-to-point transmission.

Once the small generator receives results from all of the necessary studies and agrees to pay for the necessary interconnection facilities and system upgrades, it can execute an interconnection agreement with the utility. After the agreement, the transmission provider will perform the required upgrades and the generator will complete construction of the facility in compliance with utility requirements.

Ensuring a fair and functional process

To determine whether the SGIP provides a fair and functional process for CSP, Staff reviewed the concerns raised by stakeholders, including prospective CSP generators, in UM 1930 and in UM 2000. Further, Staff analyzed publicly available interconnection queues and interconnection studies. Finally, Staff met multiple times with Idaho Power Company (IPC), PacifiCorp (PAC), and Portland General Electric (PGE) to further understand the challenges facing generators subject to the SGIP.

Staff notes that PAC posts its small generator interconnection queue and associated interconnection studies publicly. PGE and IPC do not post this information, but have been asked to do so in 2019 under UM 2001. Therefore, the queue and cost data Staff has been able to analyze relates to CSP projects seeking to interconnect with PAC. Staff recognizes the need to further examine interconnection issues with PGE and IPC to the extent that PAC issues are not universal to utilities subject to the SGIP.

Based on available information, Staff’s analysis includes the following findings:

1. CSP interconnection within PACs service area is highly unlikely in at least several locations:

   Analysis of the PAC interconnection queue indicates that PAC has received 74 interconnection requests from small solar generators (≤10 MW) located in Oregon 2016-present. Of these generators applying for interconnection after 2015:

   - Zero have reached commercial operation.

- Three have executed an interconnection agreement (one has since terminated).
- None of the three projects that executed an interconnection agreement since 2015 were QFs.
- 45 have withdrawn or been removed for lack of progress.

Staff understands from input within UM 1930, UM 2000, and additional activities that the lack of small generators interconnecting with PacifiCorp is primarily driven by interconnection costs. Referring back to the 74 generators mentioned previously, nineteen (26 percent) proceeded with interconnection studies (presumably after an initial scoping meeting with the utility indicated that interconnection studies would likely produce prohibitive upgrade costs). Of those nineteen, Staff's basic analysis of the studies showed that the total of all upgrade costs to be borne by the generators fell within a range from $274,000 to $42,199,000 ($40 million were transmission upgrades), with a median of $2,150,000 per study. This includes costs for all upgrades required past the point of interconnection on the distribution and transmission system. To provide context to these upgrade costs, a National Renewable Energy Laboratories 2018 assessment of interconnection cost estimates required of generators between 100 kW and 20 MW in the West found that upgrade costs per study ranged from $23,000 to $19.7 million, with a median of $306,000.[10] This context is purely illustrative and limited by the widely variable nature of interconnection upgrades. The cost and type of upgrades (distribution or transmission) estimated for a generator are specific to the generator's location, project design, the makeup of other generators in the area or in queue, and additional characteristics of the generator and utility system.

Further, PAC has not posted an interconnection study for an Oregon interconnection request received after May 29, 2018, because the amount of generation considered in-service in an interconnection study (i.e., the aggregate of existing generation, higher-queued proposed generation, and generators with executed agreements) its Balancing Authority Area (BAA) has reached levels that exceed load in that BAA. Under this condition, new interconnection requests have produced a non-viable interconnection study result. PAC has proposed a new Interconnection Business Practice (Business Practice No. 73) to help interconnection applicants understand whether changing the project design might resolve the non-viable determination.[11] The business practice does not resolve constraints in the underlying study environment and system. PAC has not indicated an effective date for the business practice or whether it plans to revise it in response to comments.

2. Interconnection may be prohibitive for projects in PGE and IPC service territory, as well.

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[10] National Renewable Energy Laboratory, *Review of Interconnection Practices and Costs in the Western States, 2018, p.12*. https://www.nrel.gov/docs/fy18osti/71232.pdf

[11] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP73.pdf

While the same level of public data is not yet available within PGE and IPC's interconnection queue, anecdotal UM 2000 stakeholder input suggests that interconnection costs and timelines may not be functional for a successful CSP launch. See Attachment B for an excerpt from the UM 2000 summary of concerns raised at the April 5, 2019 workshop. In addition, PGE and IPC have been subject to disputes and complaints related to interconnection costs and timelines for small generators.

3. The CSP launch timeline requires a near-term, temporary solution that is specific to CSP projects:

Staff finds that, while efforts are underway to address these and other small generator interconnection issues holistically under UM 2000, the timeline is to be determined and will not be functional for projects to have the interconnection process certainty required to apply for CSP pre-certification at the end of 2019..

Based on these findings, Staff assessed the primary drivers of interconnection costs, identified a near-term solution to address the most significant cost drivers for CSP projects in a functional timeframe, and developed a process to move the solution forward.

Assessment of interconnection barriers for CSP projects

Staff understands that a broad range of interconnection issues have been raised; however, Staff has identified the following most significant drivers of interconnection costs for small solar generators in Oregon:

<u>Assignment of costs to small generators:</u> Under the current SGIP, generators are required to assume the cost of all "system upgrades," in order to execute an interconnection agreement. There is no mechanism for sharing costs with the transmission provider (the utility) or other generators that may benefit from the upgrades.

Further, for purposes of Oregon's SGIP, the upgrades allocated to the generator include transmission system upgrades. Under FERC's LGIP and SGIP, however, the costs of interconnection-related transmission system upgrades are allocated to the transmission provider rather than the interconnecting generator because they are presumed to benefit all users of the transmission system. This presumption does not exist for Oregon jurisdictional interconnections under Oregon's SGIP.

In its order adopting the SGIP, the Commission specifically noted that its cost allocation rule differed from FERC's, but concluded the proposed Oregon Administrative Rules:

> include language that is meant to strictly limit a public utility's ability to require one small generator facility to pay for the cost of system upgrades that primarily benefit the utility or other small generator facilities, or that the public utility planned to make regardless of the he small generator interconnection.[12]

[12] Order No. 09-196, pp. 4-5.

However, the Commission's intention to strictly limit a public utility's ability to require generators to pay for upgrades to the system upgrades is not necessarily evident in the language of the cost allocation rule adopted by the Commission. Instead, OAR 860-082-0035 simply requires the interconnection applicant to "pay the reasonable costs of" interconnection facilities and system upgrades.

Further, the utilities' small generator interconnection agreements (SGIA) do not include any reference to cost allocation of system upgrades that may benefit the transmission provider. With respect to system upgrades that may benefit other generators, the SGIA states that the generator paying for the upgrade may receive compensation from future interconnecting generators, but under "separate rules promulgated by the Commission or by terms of a tariff filed and approved by the Commission."

Network Resource Interconnection Service Requirement: Requiring generators to bear costs of all system upgrades may be particularly burdensome under the utilities' practice to require that QFs interconnect with Network Resource Interconnection Service (NRIS). Although the SGIP do not specifically require or even contemplate that QFs interconnect with NRIS, IPC, PAC, and PGE require that they do so regardless of size and interconnection point (distribution versus transmission). For NRIS, the Transmission Provider studies the Transmission System at Peak Load, under a variety of stressed conditions, with all designated network resources operating at full capacity, to determine whether, with the Generator Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with the Transmission Provider's reliability criteria and procedures.[13] The utilities explain that they require QFs interconnect with NRIS because the utility's market function is responsible for making that transmission service request on behalf of QFs. If QFs do not interconnect with NRIS and pay for the upgrades necessary for NRIS, the utility would be responsible for any upgrades needed for transmission service to deliver the QF's output to load.

Under FERC's SGIP, a generator under 20 MW interconnects with a service like Energy Resource Interconnection Service (ERIS). For ERIS, an interconnecting generator is responsible for system upgrades required to "plug into" the system and flow the output of its facility onto the Transmission Provider's transmission system in a safe and reliable manner.[14]

Notably, NRIS is not available to small generators under FERC's SGIP. If a small generator would like to request NRIS, it must proceed under FERC's Large Generator Interconnection Procedures.

If a higher queued generator in a relevant area requires system upgrades, the lower queued small generator must bear the cost of those upgrades if the higher queued generator has stalled. Due to this issue of assigning upgrade costs in serial queue order, utilities can require

[13] Standardization of Generator Interconnection Agreements and Procedures, 104 FERC 61,103 (2003 WL 21725988).
[14] Id. 61, 136.

a very small generator to bear hundreds of millions of dollars in costs to construct a transmission line needed to serve a generator that has not, and may not ever, come online.

Through the CSP and UM 2000 discussions, the utilities explain that they require QFs to obtain NRIS to ensure firm, non-interruptible delivery of the QFs' generation to network load, and so that costs of upgrades necessary to enable firm delivery are paid for by the generator during the interconnection process. The utilities explain that if QFs are allowed to interconnect with ERIS, the utility's merchant function may have to pay for necessary system upgrades as a condition of obtaining transmission service from the utility's transmission function. Although network upgrades are likely to benefit the utility and other transmission customers, the utilities claim that requiring utilities to bear the cost of transmission system upgrades to transmit QF output violates the customer indifference standard of PURPA.

The utilities' decision to require that QFs obtain NRIS is a unilateral one that is not dictated by Div. 82. Div. 82 does not define the interconnection service offered to small generators. Notably, the service is not similar to NRIS and nowhere does Div. 82 require deliverability to load as a condition of interconnection.

<u>Allocation of costs among generators:</u> As alluded to in the previous section, costs are assigned in serial order based on queue position. In other words, the project that first triggers an upgrade bears the full cost of the upgrade that may benefit subsequent generators and there is no mechanism currently used to allocate costs among generators applying to interconnect in a similar area. And, a lower queued generator is required to bear the upgrade costs of higher queued generators in order to come online first. This leaves small generators with otherwise minimal impact to the system bearing the cost of higher queued generators, including large generators that are stalled due prohibitive upgrade costs. It also creates queue bottlenecks and aggravates interconnection backlogs.

The utilities' SGIA does not include a mechanism for cost sharing between the interconnecting generator and any generators that may subsequently use the system upgrades. However, the language makes clear that cost sharing among generators would be pursuant to "separate rules promulgated by he Commission or by terms of a tariff filed and approved by the Commission[,]" and "[s]uch compensation will only be available to the extent provided for in the separate rules or tariff."[15] These separate rules or tariff have not yet been adopted.

<u>Lack of information/control over costs:</u> The issues listed above are exacerbated by generators' lack of control over upgrade costs. Currently, there is not enough comprehensive and transparent information to help site and design projects to avoid prohibitively expensive system upgrades in the first place.

Further, it is difficult to verify the conclusions of the studies performed by the utility. This includes both the methodologies to identify the required upgrades and to estimate the costs assigned to those upgrades. While generators can raise formal and informal disputes about specific studies to the Commission, this is not an efficient mechanism to ensure appropriate

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[15] Interconnection Agreement for Small Generating Facility, Art. 4.4.

upgrades and costs are identified for all generators. And, this process can exacerbate congestion in the interconnection queue. Staff does not have the resources to adequately verify these study methodologies and outcomes, either.

Finally, there is no realistic ability for generators to hire third-parties to conduct studies or build necessary facilities in place of the utility.

<u>Delay in conducting interconnection studies</u>: In addition to drivers of prohibitive costs, utility delays in conducting studies are not functional for the CSP timeline. PacifiCorp has not posted the results of a completed interconnection study since May 2018. There are currently thirty-four requests for interconnection in its queue that have not been studied (or at least there is no posted study). PacifiCorp explains it stopped interconnection studies to work on how to address unsolvable generation/load imbalances stemming from interconnection requests. On June 3, 2019, PacifiCorp implemented Business Practice 73 "<u>Study Models and Assumptions When Modeled Generation Exceeds Study Area Load"</u> addressing what occurs when PacifiCorp determines an interconnection request is infeasible because of an unsolvable generation/load imbalance. When PacifiCorp recommences conducting and posting studies, it will have to tackle at least 34 pending requests for interconnection in Oregon.
These issues are secondary to the risk that CSP projects will not be able to execute an interconnection agreement due to cost and PAC's halt in processing studies.

Addressing the barriers
To develop a proposal to address barriers for CSP projects, Staff identified a range of potential solutions and used the following criteria to identify the most fair and functional solutions for CSP projects:

- Feasibility: Can the solution be implemented before the end of 2019?
  - Could implementation be quick and relatively direct?
  - Does it align with existing practices or guidance?
  - Could it conflict with FERC or other jurisdictional requirements?
- Impact: What impact will the proposed solution have on reducing interconnection costs?
  - Will it incentivize participation in CSP by directly relieving major barriers?
  - Will the solution minimize cost-shifting to ratepayers by ensuring that costs socialized to all ratepayers provide system benefits?[16]

[16] ORS 757.386(2)(b) directs the Commission to adopt CSP rules that, at a minimum incentivize consumers to participate and minimize the shifting of costs to non-participants.

Figure 2: Staff considerations to address key small generator interconnection cost drivers

Cost Driver	Potential Solution	Staff's Considerations for CSP
Assignment of transmission system costs to small generators	Remove utility NRIS requirement i.e., treat generator as ERIS	• Quick policy change, simple concept • Aligns SGIP better with state LGIP and FERC policies about responsibility for transmission upgrades • Network upgrade costs will be borne by ratepayers • Allows utilities to use creative solutions and find efficiencies for firm delivery (e.g. consider re-dispatch of network resources in deliverability studies)
Assignment of distribution system costs to small generators	Implement cost sharing between generator and utility	• May enable utilities to find creative solutions and efficiencies • Utilities' share of costs will be borne by ratepayers, but it's unclear if they provide system benefits in return. • Does not encourage efficient siting of distributed generators • Long-term consideration for ability to integrate DERs is in the scope of UM 2005
Allocation of costs among generators	Cost sharing between generators Allow leap frogging based on readiness	• Does not shift upgrade costs to ratepayers • Cost sharing between generators requires coordination and a calculation methodology (this admin may be funded by ratepayers) • Modifying serial queue policies, imposed by FERC, would require legal analysis and analysis of projects in queue
Lack of information/ control over costs	Provide additional data for generators prior to studies Allow third-party to perform studies and system upgrades Conduct an audit of utility study and cost estimation methodologies Independent study review/ dispute process for individual generators	• Uncertain ratepayer impact of utility resources required to provide additional data/transparency, fund independent analysis • Interim steps underway through UM 2001 • Long-term transparency within the scope of UM 2005 • Uncertain ability of CSP projects at varying levels of sophistication to contract third-party studies and upgrades • Independent analysis of utility study methodologies not possible before end of 2019 • Independent review of individual CSP project study results could be ready sooner, but does not provide as much certainty of dispute resolution before end of 2019

Proposed Solution

While Staff believes all proposed solutions should be considered by the Commission, the most direct mechanisms to address interconnection costs for CSP projects is to consider how upgrade costs are allocated to CSP generators and whether it's reasonable for all ratepayers to cover a portion of the costs that provide system benefits. Further, Staff finds that the range of proposed solutions for CSP projects have compelling policy considerations for all small generators in Oregon. Therefore, Staff proposes that CSP provide a discrete, capacity limited environment to test the various solutions for broad, long-term consideration under UM 2000. This pilot-based approach provides the opportunity to test the actual ratepayer impacts of modifying the assignment of upgrades costs—where discussion of customer indifference has been theoretical to date—and the opportunity to test the extent to which these utilities are empowered to find creative solutions and efficiencies in identifying interconnection upgrades.

To facilitate this solution, Staff proposes the following:

Addressing cost barriers: Adopt a new rule within the SGIP specifying the cost allocation for CSP project interconnections.

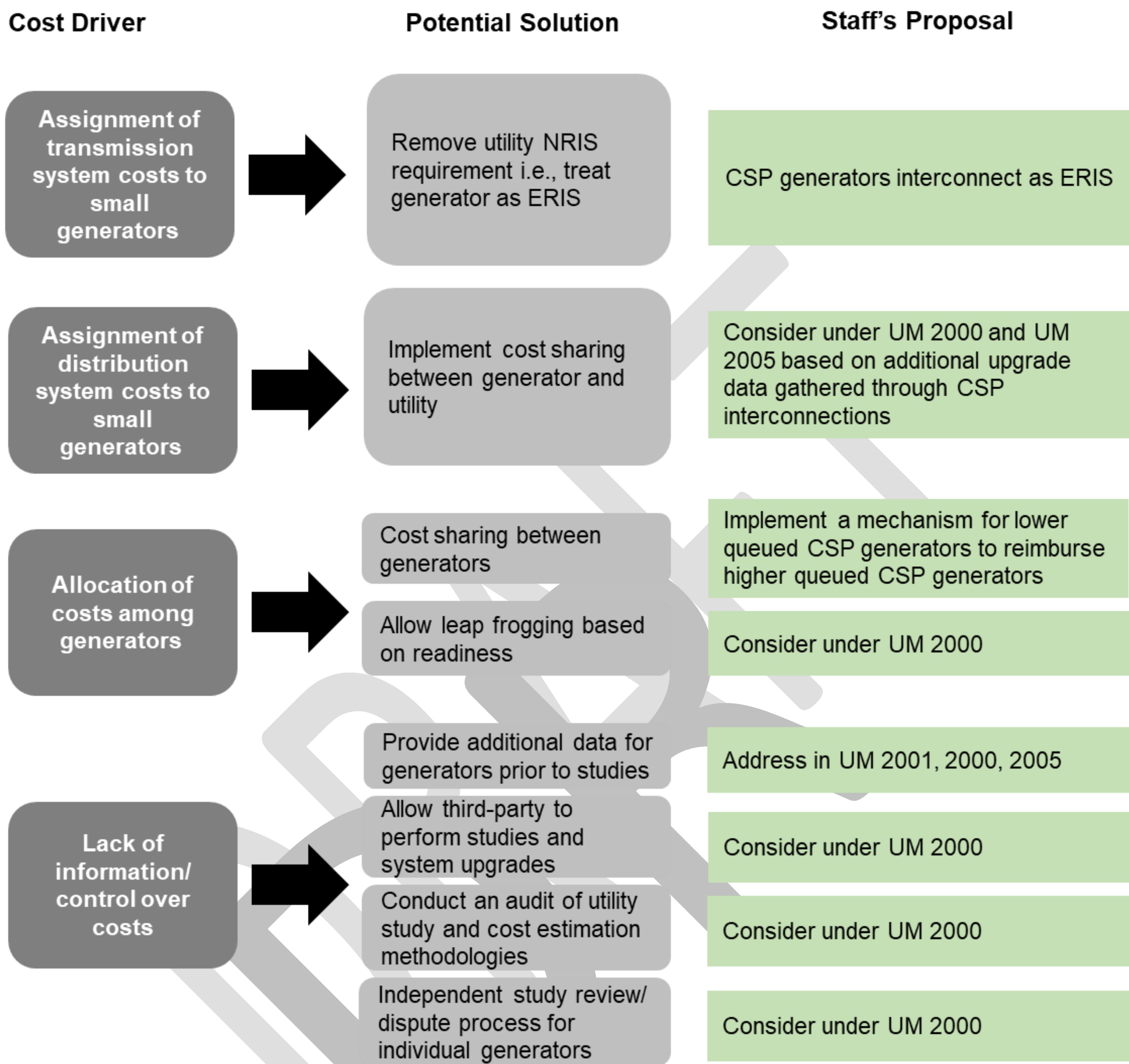
- <u>Transmission upgrades:</u> The generator will interconnect as an energy resource. To the extent there are necessary upgrades to the utility's transmission system (at and past the point of interconnection) as part of the utility's procurement of transmission service, the costs will be allocated subject to the utilities' Open Access Transmission Tariffs.
- <u>Distribution upgrades:</u> The utility will implement a cost-sharing mechanism for distribution system upgrade costs (at and past the point of interconnection) between CSP projects. The first CSP project triggering an eligible upgrade would initially bear 100% of the cost of the upgrade, less the upgrade allowance. Subsequent CSP projects benefiting from that upgrade to the distribution system will reimburse the first CSP project commensurate with the project's utilization of the available capacity created by the upgrade.
- The CSP-specific SGIP rule (CSP rule) described above is intended as a time-and-capacity-limited pilot. Unless the Commission chooses to extend the rule, the utility will accept interconnection applications under the CSP rule for 18 months following the rule's adoption or until the aggregate capacity (MWac) of generators with an executed CSP interconnection agreement that have received pre-certification equals the utility's capacity tier (2.5 percent of 2016 system peak load), whichever comes first.
    - Generators seeking to interconnect under the new CSP rule will execute an interconnection agreement with the utility that is contingent upon the project receiving pre-certification in the CSP.
    - If the generator does not receive CSP pre-certification, it can withdraw from the interconnection queue or execute an interconnection agreement with the utility subject to the existing SGIP. The generator will be responsible for the cost of additional studies and upgrades required to interconnect under the existing SGIP.

    - If a CSP generator has executed an interconnection agreement under the CSP rule, but has not received CSP pre-certification before the aggregate capacity of CSP generators with an executed CSP interconnection agreement that have received pre-certification equals the utility's capacity tier, the generator may choose to retain its interconnection agreement under the CSP rule for 18 months to allow for pre-certified projects to withdraw from the CSP pre-certification queue. Or, the generator can execute a new interconnection agreement with the utility under the existing SGIP, subject to the same requirements to bear the cost of additional studies and upgrades required to interconnect under the existing SGIP.

- Staff will work with the utilities to closely track the type and amount of upgrade costs borne by ratepayers and the impact on the firm delivery of the QFs' generation to network load to inform UM 2000 and UM 2005.

Addressing timing barriers: With respect to delays performing interconnection studies, Staff proposes the Commission require all utilities to file a plan to address the backlog of studies with the Commission. This is particularly acute barrier for PacifiCorp, but Staff finds that it will benefit CSP generators across utilities. Staff proposes that each utility file a summary of outstanding interconnection studies and forecasted timeline to process the studies with the Commission, by September 1, 2019.

Figure 3: Summary of Staff's initial proposal



Next steps

Staff proposes a path forward that balances the urgency of the CSP launch timeline with the need to refine this proposal with stakeholders. First, Staff will hold a stakeholder workshop on July 17 2019 in the OPUC Hearing Room in Salem. The purpose of the workshop is to receive feedback on the proposed emergency rulemaking and outline remaining issues to be addressed. Workshop topics will include:

- Has Staff identified the appropriate barriers for CSP generator interconnections?
- Will Staff's proposal be fair and functional? Do stakeholders suggest any modifications, additions, or alternative solutions to address the interconnection barriers?

- What additional elements are required to implement the proposed solution? For example:
    - How does this solution apply to CSP generators that have executed an interconnection agreement or begun the interconnection study process with electric utilities?
    - Are screens or additional requirements needed to identify eligible generators?
    - Does this require modification of the existing interconnection process? For example:
        - Is a separate tier or queue required to implement Staff's proposal?
        - Would CSP need anything different than the standard pre-application study available to all generators?
    - Which upgrades should be eligible for the cost-sharing mechanism?
        - Should there be a minimum cost for an upgrade to be eligible for the cost-sharing mechanism?
    - How will generators confirm they are CSP projects?
    - How does the emergency rulemaking align with PACs efforts to address its net-generation issue for all generators seeking interconnection?

Stakeholders may provide written comment to UM 1930 in advance of the workshop. Staff requests that Stakeholders file written comments by July10, 2019.

Following the workshop, Staff will consider stakeholder's written and oral feedback and propose that the Commission open the emergency rulemaking at a public meeting in August or September.

Working with the PA and utilities, Staff will facilitate the implementation of the CSP interconnection rule and report back to the Commission on the impact of the tier on both ratepayers and the successful launch of the CSP.

Attachment A

DEPARTMENT OF JUSTICE
INTEROFFICE MEMO

DATE: January 31, 2019

TO: Caroline Moore

FROM: Stephanie S. Andrus

SUBJECT: CSP Projects as QFs

This memorandum addresses whether a Community Solar Program Project (Project) must be a qualifying facility (QF) under PURPA in order to participate in Oregon's Community Solar Program (CSP). Under the Commission's rules, Projects of non-electric companies should be QFs to facilitate the Commission's jurisdiction over sale of the unsubscribed portions of these Projects' generation.

Under the Federal Power Act (FPA), the Federal Energy Regulatory Commission (FERC) has jurisdiction of wholesales of energy for resale in interstate commerce and states have jurisdiction of all other sales, including retail sales of electricity to end use customers.[17] However, FERC has shared with states its authority over wholesale sales under the Public Utility Regulatory Policy Act (PURPA). PURPA requires utilities to purchase energy and capacity offered by qualifying facilities (QFs). The state is authorized to establish the rate for these purchases as well as terms and conditions of the sale.

ORS 757.386 requires the Commission to implement a community solar program that allows an electric company's retail customers to subscribe or own a portion of a solar project located in the electric company's service territory and receive a bill credit for their share of the project output transmitted to the electric company. The Commission has adopted rules to ensure transactions between electric companies and Project Managers and electric companies and participants under ORS 757.386 are subject to Commission's jurisdiction.

First, the Commission's rules require the electric companies to allow participants to virtually net meter and receive bill credits for the participants' proportionate shares of a Project's generation. Net metering is a retail transaction so the Commission is authorized to establish the bill credit rate and other terms of the transactions.

[17] 16 U.S.C. §824.

Second, the Commission's rules allow a Project to sell unsubscribed generation via a PURPA sale, if the Project is not an electric company However, it is likely that not all of a Project's output will be subscribed or owned by a CSP participant, at least not consistently throughout the life of the Project. Accordingly, the Commission has adopted rules addressing the disposition of the "unsubscribed" portion of Project output. OAR 860-088-0140 provides:

> (1) Upon project certification, the project's remaining unsold and unsubscribed generation is eligible for sale subject to the following requirements:
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> (a) Upon request, an electric company must enter into a 20-year power purchase agreement with a pre-certified project to purchase the project's unsold and unsubscribed generation on an "as available" basis subject to the requirements of the Public Utility Regulatory Policy Act (PURPA) and ORS 758.505, et. seq.;
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> (b) If the electric company is the Project Manager, the electric company may seek Commission approval to recover from all ratepayers the "as available" rate for the project's unsold and unsubscribed generation; and
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> (c) Renewable energy certificates associated with generation sold under section (1)(a) of this rule at the "as available" rate will not transfer to the electric company unless otherwise agreed by the Project Manager and electric company.
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> (2) The value of any project generation that is not sold to or subscribed by participants, sold to an electric company under a power purchase agreement, or sold on another basis must be donated to the electric company whose service territory encompasses the project at the "as available" rate and used by the electric company to assist low-income residential customers' participation in the Community Solar Program.

Under subsection (1)(a), the unsubscribed output is sold to the electric company at the electric company's "as available" avoided cost rate. The transaction is a wholesale sale. The Commission's ability to establish the rate for a wholesale is limited to its authority granted under PURPA. Accordingly, the Commission's rule requiring that electric company's purchase unsubscribed output at the Project's request at the as available avoided cost rate is predicated on the assumption the Project will be a QF and eligible to make sales under PURPA.

Subsection (1)(b) addresses the disposition of the unsubscribed output when the Project is an electric company Project. Under subsection (1)(b), the electric company can use the unsubscribed portion to serve its retail customers, but must charge its retail customers the "as available" rate. The transaction at issue is a retail sale and therefore the Commission is authorized to establish the rate for without relying on its authority under PURPA. Accordingly, an electric company does not have to be a QF in order to participate in the CSP.

Subsection (2) provides that unsold and unsubscribed output must be donated to the electric company's low-income residential customers' participation based on the as-available rate. As already noted, the Commission does not have authority over wholesale transactions unless they are PURPA transactions. Accordingly, to effectuate the Commission's rule regarding donation of unsubscribed output at the as-available rate, the Project must be a QF.

Subsections (1)(a) and (1)(b) have permissive language that seems to provide Projects with optionality regarding the disposition of unsubscribed energy. Subsection (1)(a) provides "[u]pon request, an electric company must enter into a 20-year power purchase agreement with a pre-certified project" for the unsubscribed output. Subsection (1)(b) provides that an electric company "may" sell unsubscribed output to its retail customers.
Although OAR 860-088-0140 does not expressly limit Projects to the specified options for the disposition of the unsubscribed output, the rules are appropriately interpreted to exclude any other options.

The as available rate for unsubscribed output is intended to incent Project Managers to obtain subscriptions or sales of as much of the Project as possible. Staff initially proposed a rule providing that a Project could not be certified unless 90 percent of it was subscribed or owned by CSP participants. Eventually, Staff agreed to propose, and stakeholders supported, a rule with a 50 percent subscription/ownership requirement based on the fact the as available rate for the unsubscribed portion was sufficient to incent maximum subscriptions and sales of Project shares. The Commission adopted the Staff proposal and the underlying rationale:

> The proposed rules require that 50 percent of the total capacity of a project be subscribed before the project can receive final certification. With respect to the remaining unsold or unsubscribed portion, the proposed rules allow the project to sell up to 10 percent at the "as available" Public Utility Regulatory Policy Act (PURPA) rate.
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> Staff advocates in its final comments that a minimum subscription of 50 percent achieves a balance between allowing flexibility for developers and ensuring that projects are actually subscribed. Stakeholders counter that limiting the sale of unsold or unsubscribed generation to the "as available" PURPA rate is a sufficient incentive to drive project managers to maximize participation. They further caution that the proposed 10 percent limit adds a significant, unnecessary burden to project financing and development.
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> ***Resolution:*** We adopt the minimum subscription of 50 percent as a reasonable balance of the competing interests and goals underlying this provision. We remove the 10 percent limit on the sale of unsold or unsubscribed generation. Based on the comments that the "as available" PURPA rate is a sufficient incentive to maximize participation in the projects, we find the provision unnecessary.[18]

[18] In the Matter of Rules Regarding Community Solar Projects (AR 603), Order No. 17-232 (2017 WL 2839877, p. 6.).

It may be possible for the Commission to design a CSP in which a Project has the option to either sell unsubscribed generation at wholesale to electric company under PURPA, and subject to jurisdiction of the Commission, or not under PURPA, and subject to FERC's jurisdiction. While the Commission may be able to compel electric companies to enter into non-PURPA PPAs with electric companies,[19] the Commission would not be able to establish the purchase price or other terms of the sale.[20]

However, if the Commission were to amend its rules to allow Projects to sell unsubscribed generation at wholesale subject to FERC jurisdiction, Staff should consider recommending that the Commission amend the rules to maintain the incentive to subscribe as much of the Project as possible. For example, the Commission could amend the rules regarding certification to require a percentage higher than 50% be subscribed before the Project can be certified.

[19] See Entergy Nuclear Vt. Yankee, LLC, Shumlin, 733 F.3d 393, 417 (2d Cir. 2013) ("[S]tates have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction.")

[20] It is not clear whether the length of such a PPA is within the state's authority as part of a resource acquisition requirement or whether the length is exclusively a matter subject to FERC's jurisdiction as a term of a wholesale sale.

Attachment B

Excerpt from UM 2000 April 5 – Workshop Notes

Issues related to interconnection for QFs:

Interconnection

- Utility-Developer Interaction
    - Better communication between developer and utility engineer
    - Studies – ability to: audit, self-perform, challenge, discuss
    - NR eligibility – Audit – Self perform
    - Interconnection – need customer right to self-perform studies, builds with quality vendors
    - Studies – ability to: audit, self-perform, challenge, discuss
    - Study – Inputs develop interconnection, right to have so can validate
    - Third party studies and construction
    - Access to previous studies
    - More transparency access to data
    - Additional transparency
    - Transparency – access to data – study data - regs
    - Analytics – history on how process is working
    - Data on study process – audit/analyze
    - Third party engineering firm allowed to review substance of interconnection report
    - Communication with engineers
    - Requirement that studies receive stamps
    - Timing of requests in relation to purchase contracts
    - Sources of utility cost assumptions
- Overall Process
    - No response obligation for utilities – silence!
    - Network upgrade costs as a means to burden QF interconnection
    - Who pays for network upgrades vs customer indifference education
    - Education on difference between interconnection and transmission
    - Requirement for back and forth on interconnection study report
    - Timing of advance payments, refunds for overpayments
    - Interconnection options fundamental options
    - Remedy if utility is short-staffed
    - Utility Staff for interconnection studies (why delay? Short staffed?)
    - Enough information to verify study results
    - Process – barriers in implementation
- Classification
    - Special QF process – NR resource
    - The requirement that QFs take NRIS
    - #1 NR requirements for QF PPA eligibility is garbage not consistent with variable resource
      $$$
    - Requirement to identify as QF (or not) at beginning of process
    - Inordinately high costs of network upgrades without sufficient technical justification
    - Prompt payments
    - Appropriate cost assignment for upgrades
- Other
    - AR 521 language – third party contractor reschedule

- IOU RFPs use interconnection bid criteria to exclude RFP participation – ratepayers screwed
- Interconnection queue issues deny ratepayers competitive options QFs RFP bidders
- Transmission – utility claim conditional firm isn't long-term firm
- Education
- Real-time communication (SCADA) data
- Data protection cyber/physical security issues

- Oversight
  - No consequences for utility bad behavior
  - Education difference between open access policies and PURPA policies
  - Utilities not making schedule – studies – tariff – builds
  - Conflicts between PPA and interconnection agreements
  - PPA and interconnection agreements interaction
  - Changes to PPA COD due to delays
  - Need more strict requirements for utilities to follow timelines.
  - Enforcement of existing rules
  - Utility penalties on utility for failure to complete interconnection
  - Publication of interconnection study requirements
  - Utilities need to comply with rules
  - Lack of effective dispute resolution
- Queue
  - Lack of movement by PAC in processing the IC queue
  - Keeping queue up to date
  - Education on serial queue order interconnection process requirements for QFs and non-QFs
  - Make load queue public (load vs generation effects) study outcomes
  - Education appropriate use of publicly available interconnection data
- Load Pockets
  - Exist? Load pockets
  - "Load pockets"
  - Queue and load pockets
  - Education on load pockets
  - Customer indifference in constrained areas
  - Responsibility to locate project
- State – federal guidelines
  - Entire QF-specific interconnection study construct is bogus (vs FERC OATT)
  - Comparison of current OATT tariff – policy different from federal mandate
  - What rules/guidelines apply to 10-20 MW projects?
  - Use of "QF interconnection process/rules" artificial barrier to evade PURPA
- Costs
  - No cost sharing
  - Cost allocation responsibility
  - Lack of refunds for network upgrades
  - Cost
  - Lower cost equipment alternatives
  - Cost – What – How much

- Other
    - Informal technical dispute advisory board of industry representatives like OJUA
    - Mini focused issue workshops
    - Option put all options on the table
    - Communication