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July 24, 2019

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket UM 1930 – In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Community Solar Program Implementation.

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic copy of the Joint Utilities' Comments on Staff's Draft Proposal for Community Solar Interconnection.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of: PUBLIC UTILITY COMMISSION OF OREGON, Community Solar Program Implementation.	**UM 1930**

JOINT UTILITIES' COMMENTS

ON

STAFF'S DRAFT PROPOSAL FOR COMMUNITY SOLAR INTERCONNECTION

July 24, 2019

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I. Introduction

In accordance with Staff's June 27, 2019, email to parties in Docket UM 1930, Idaho Power Company (Idaho Power), PacifiCorp d/b/a Pacific Power (PacifiCorp), and Portland General Electric Company (PGE) (together, the Joint Utilities) submit these comments in response to Staff's Draft Proposal for Community Solar Interconnection filed on June 19, 2019 (Staff Memo).[1] The Joint Utilities appreciate the opportunity to file these comments and the ongoing efforts of Staff, the Public Utility Commission of Oregon (Commission), and stakeholders to develop and implement Oregon's community solar program (CSP). The Joint Utilities have worked diligently with Staff and stakeholders for the past three years to develop a viable CSP that will provide broader customer access to community-based solar generation. The Joint Utilities remain committed to implementing the CSP and look forward to continued efforts to finalize program design and implementation.

The Joint Utilities share Staff's goal of implementing a fair and functional interconnection process for CSP projects—and indeed for all qualifying facilities (QFs) that wish to connect to utility systems. Toward that end, the Joint Utilities support Staff's proposal to allow CSP QFs to share interconnection upgrade costs with each other and continue to support the Commission's efforts to ensure interconnection customers have access to system information that will allow them to make the most economical siting decisions.

However, the Joint Utilities strongly oppose Staff's proposal to facilitate CSP QF interconnections by shifting costs to utility customers. This extreme proposal would—on an

[1] *In the Matter of the Public Utility Commission of Oregon, Community Solar Program Implementation*, Docket UM 1930, Staff's Draft Proposal for Community Solar Interconnection (June 19, 2019) (hereinafter, "UM 1930 Staff Memo").

expedited basis in an emergency rulemaking—reverse the Commission's long-standing interconnection rules and policies, and signal an abrupt departure from its steadfast commitment to ensuring that QFs bear the costs they impose and that utility customers remain indifferent to QF development, as mandated by the Public Utility Regulatory Policies Act of 1978 (PURPA).

As an initial matter, Staff's proposed solutions for CSP QF interconnection are premised upon the incorrect assumption that interconnection costs and timelines inhibit the interconnection of all CSP QFs to any of the Joint Utilities. While the Joint Utilities recognize that some CSP QFs may experience challenges in identifying locations that will not result in daunting interconnection costs, ***interconnection typically is economically feasible for most projects that make careful siting decisions***.

For instance, both Idaho Power and PacifiCorp have completed or are in the final stages of the interconnection process for CSP QFs in their respective service territories. And PGE has conducted a Tier 2 interconnection review for a small CSP project with minimal interconnection costs and has responded to pre-application requests from several larger CSP QFs that at this early stage, based on the proposed siting, do not appear to require significant investment by the developers to interconnect. Interconnection requirements can vary dramatically depending on siting, load, and existing generation, and the Joint Utilities are committed to continuing to work with Staff and stakeholders to ensure that all interconnection customers have access to the information required to make informed and cost-effective siting and design decisions. However, when interconnection of a CSP QF, or any other QF, requires upgrades, the upgrade costs must be borne by the QF that causes them.

Staff proposes the following specific solutions to facilitate the interconnection of CSP QFs:

1. Allow CSP QFs to interconnect using energy resource interconnection service (ERIS) instead of network resource interconnection service (NRIS), which is applicable to other QFs and includes a deliverability analysis;

2. Allocate all transmission system upgrade (i.e., network upgrade) costs to all the utilities' transmission customers pursuant to the Federal Energy Regulatory Commission (FERC) policy reflected in the Open Access Transmission Tariff (OATT) for non-QF merchant generators;

3. Implement a cost-sharing mechanism so that distribution upgrade costs may be shared among CSP QFs; and

4. Require utilities to file a plan to address the perceived backlog of interconnection studies and to file a summary of outstanding studies and the forecasted timelines to process them.[2]

Staff proposes to adopt these measures on an emergency basis for CSP QFs and then to monitor the effects to inform policy for QFs generally in Docket UM 2000.[3]

Staff's ERIS and cost-allocation proposals are inconsistent with the CSP statute, which requires that the CSP "[m]inimize the shifting of costs from the program to ratepayers."[4] By requiring retail customers to pay for interconnection network upgrade costs caused by CSP QFs, Staff's proposal could shift substantial program costs—contrary to the legislature's explicit direction to the Commission to minimize cost-shifting.

Staff's first two proposals are also contrary to PURPA because they would facilitate CSP QF interconnection simply by shifting costs that have traditionally and properly been borne by developers to the very utility customers that PURPA requires be held indifferent to the costs of QF development. Specifically, network upgrade costs allocated to all transmission customers, pursuant to FERC's methodology for non-QFs, fall primarily on the

[2] UM 1930 Staff Memo at 12-15.
[3] UM 1930 Staff Memo at 13-14.
[4] ORS 757.386(2)(b)(B).

utility's retail customers because each utility's merchant function is the primary customer of its transmission function. If a QF were to receive ERIS instead of NRIS, the interconnection process would not identify any of the network upgrades required to make the QF's output eligible for delivery to load using firm transmission—which FERC requires for QF generation.[5] Instead, these additional network upgrades would be identified during the transmission-service study process. Importantly, because the utility typically arranges and pays for transmission service on its own system to deliver QF output to load, the cost of the upgrades would be borne by utility customers—unless the avoided cost rates were adjusted. By shifting costs from the interconnection process (where QFs pay) to the transmission service process (where utility customers pay), Staff's proposal to allow QFs to obtain ERIS would undermine PURPA's customer indifference mandate and force customers to bear the costs of QFs' inefficient siting decisions.

Staff's proposals are particularly problematic because the network upgrade costs that would be allocated to the utility's retail customers are potentially very high. A CSP QF that is 3 MW or smaller may nevertheless trigger ***millions of dollars***[6] in costs for upgrades that would not have otherwise been required absent the QF's inefficient siting decision.[7] By removing the incentive to efficiently site a project, Staff's proposal potentially shifts costs to customers that would not necessarily be incurred if the CSP QF sited its project in a place that would not require costly network upgrades.

[5] *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38 (2013) (noting that FERC had "specifically held that . . . the purchasing utility cannot curtail the QF's energy as if the QF were taking non-firm transmission service on the purchasing utility's system"); *see also PacifiCorp*, 151 FERC ¶ 61,170 at P 27 (2015) (FERC "precedent requires electric utilities to deliver a QF's power on a firm basis").
[6] *See infra* Section IV.A.3.d (providing examples of significant upgrade costs required by small generators).
[7] Because CSP projects may be located anywhere in a utility's Oregon service territory and may not be near the project's subscribers, the interconnection studies must assess the full output of the project, which can be up to 3 MW, flowing onto the utility's system.

Staff relies on FERC's non-QF interconnection policies to support its proposals, but this reliance is misplaced. As FERC has explicitly recognized, QFs are not eligible to interconnect under those interconnection policies (embodied primarily in FERC's Order Nos. 2003 and 2006).[8] This exclusion makes sense because of the vastly different statutory, jurisdictional, and policy frameworks that apply to QF arrangements versus non-QF arrangements.[9] In addition, FERC's reasoning for reimbursing interconnecting generators for the cost of network upgrades does not apply in the PURPA context where the entity requesting interconnection service (the QF) is different from the entity requesting transmission service (the utility).

In particular, FERC's decision to allow interconnection customers to choose either ERIS or NRIS was explicitly premised upon the assumption that the same generator would be both the interconnection customer and transmission customer, and would therefore pay for any upgrade costs necessary for firm transmission service—regardless of whether they were assessed in the interconnection or transmission service context.[10] Similarly, FERC envisioned that its cost allocation policy would insulate existing third-party transmission customers from costs caused by new generator interconnections because any new upgrades

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[8] *See, e.g.*, Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006-A, 113 FERC ¶ 61,195 at P 102 (hereinafter Order No. 2006-A) ("NARUC is correct that a QF selling at retail ***is not eligible*** to interconnect under either Order No. 2003 or Order No. 2006. Under the Public Utility Regulatory Policies Act of 1978, such interconnections are governed by state law." (emphasis added) (internal citations omitted)).

[9] For example, utilities are obligated to purchase QF output, 18 C.F.R. § 292.303(1), and FERC's regulations provide that, "[e]ach qualifying facility shall be obligated to pay any interconnections costs which the State regulatory authority. . . may assess against the qualifying facility." 18 C.F.R. § 292.306(a).

[10] More specifically, in the wholesale market context that FERC's policies envision, the entity paying for interconnection and the entity paying for transmission service are either the same, or the two entities are economically linked—as with a seller and purchaser. Therefore, the costs of necessary upgrades will be accounted for between the linked entities in the economics of the purchase and sale of the interconnecting generator's output, and the purchaser of that output can choose whether to buy it in light of those costs. But in contrast, under PURPA, the utility must purchase QF output at a specified price and obtain transmission service to deliver it to load, and therefore upgrades not already accounted for in the avoided cost price must be assigned to the QF as interconnection costs to prevent the utility from paying more than its avoided cost for the QF output.

would be accompanied by a corresponding increase in usage of the system when that same entity secured transmission service. Under PURPA, however, the QF does not bring any new load to the system that would share the costs of the existing system, thereby reducing costs for existing customers. Thus, if QFs do not bear the costs of their siting decisions, it is the utilities' existing transmission customers (mostly their retail customers) that must do so.

Staff also suggests that imposing interconnection costs on utility customers would stimulate the utilities to adopt "creative" solutions, but this theory has no basis. In the absence of any clearly identified suggestions that ensure utility customers remain protected, the possibility of hypothetical solutions should not be relied upon to justify shifting costs.

Although Staff's proposal here is focused on the interconnection process, the Joint Utilities contend that QFs should bear the cost of all network upgrades required to allow a utility to deliver QF output to load on a firm basis (which is required by FERC) regardless of the type of interconnection service provided. Therefore, the Joint Utilities' characterization of cost shifting that will occur under Staff's proposal should not be understood generally as a concession by the Joint Utilities that costly network upgrades identified in the transmission-service context are costs that should be borne by utility customers.

For all these reasons, the Joint Utilities oppose Staff's proposals to change the interconnection service requirements and cost allocation policies for CSP QFs on an emergency basis—and potentially for all QFs in the future.

The Joint Utilities generally support Staff's third proposal—to allow CSP QFs to share distribution upgrade costs—because this proposal appears to properly maintain cost responsibility with the QFs and not shift costs. However, the Joint Utilities recognize that additional discussions will be required to understand how this proposal would work in practice and to ensure that it would not violate the rights of other interconnection customers. Finally, the Joint Utilities are unclear about the scope of Staff's proposed reporting requirements but look forward to clarifying the proposal and discussing what additional information the utilities can provide to increase transparency.

In sum, the Joint Utilities are committed to continuing to work with the Commission, Staff, and all parties to adopt solutions that encourage CSP project development and interconnection while protecting utility customers.

II. <u>Staff has not correctly identified the barriers to interconnection and has overestimated the degree of difficulty CSP QFs are likely to face.</u>

Seeking to identify the barriers to interconnection, Staff provides a summary of statistics regarding PacifiCorp's interconnection process and costs[11] and posits that "Interconnection may be prohibitive for projects in PGE and [Idaho Power] service territory, as well."[12] Staff concludes, based on the PacifiCorp data and anecdotal evidence from developers, that interconnection costs and timelines are the primary barriers to QF interconnection, and Staff's proposed solutions are designed to address these perceived barriers. However, Staff's problem statement—and thus proposed solutions—are premised upon a misunderstanding of the nature and extent of the problem.

A. Factors beyond the utilities' control can significantly impact the timing and results of the interconnection process.

Portions of Staff's Memo, and numerous written and oral comments from developers in this docket and in the generic PURPA dockets, suggest that the interconnection difficulties

[11] Staff acknowledges that its analysis is "purely illustrative" and "limited." UM 1930 Staff Memo at 7. Given the time constraints associated with responding to Staff's recommendation, the Joint Utilities have neither verified the accuracy of Staff's analysis nor assessed whether Staff's comparison of PacifiCorp interconnection data to generic data compiled by the National Renewable Energy Laboratories is reasonable. The fact that the Joint Utilities have not disputed Staff's factual representations and analysis in these Comments does not constitute a concession as to the accuracy or reasonableness of Staff's methodology, calculations, or conclusions.

[12] UM 1930 Staff Memo at 6-7.

QFs experience are the result of the utilities' bad faith and this Commission's policies. However, interconnection customers themselves impact the process in several ways, and the study requirements and process to which the utilities must adhere to protect the reliability of their systems can also contribute to the issues Staff identified.

First, many of the interconnection timing and cost issues experienced by QFs are the direct result of the number of interconnection requests received by the utilities, which has increased dramatically over the last few years. Currently, PacifiCorp's generator interconnection queue includes 308 active queued requests proposing roughly 39,400 MW of generation, and PGE has received 181 small generator interconnection requests for a total of 605 MW of generation since 2017.

The sheer volume of requests can significantly lengthen the process for all customers in the queue because the utilities must process each interconnection request in serial order, with each interconnection study starting with the baseline assumption that the following are in-service: (1) generators already directly interconnected to the system; (2) generators interconnected to affected systems that may have an impact on the request; (3) generators with a pending higher-queued interconnection request, including all of their associated network upgrade requirements; and (4) generators that no longer have a queue position but have an executed interconnection agreement.[13] This means that the utilities must conduct restudies for lower-queued projects whenever a higher-queued project drops out. In addition, the volume of capacity seeking to interconnect can also increase the cost because each study assumes all higher-queued projects are interconnected, which can exacerbate already

[13] *See, e.g.*, *Pro Forma* OATT, Sections 6.2 and 7.3, available at: https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/LGIP-procedures.pdf; *see also* PacifiCorp Business Practice #73 at 1-2 (describing PacifiCorp's serial queue processing method), available at: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP73.pdf.

congested utility systems. Thus, the study requirements, together with the volume of interconnection requests, can contribute to the timeline and cost for interconnection.

Second, as the Northwest & Intermountain Power Producers Coalition (NIPPC) has conceded, PacifiCorp's interconnection queue is overwhelmed because higher-queued projects are "squatting" in the queue without moving forward with their development.[14] Importantly, under current OATT processes, there are no disincentives for customers remaining in the queue even if their projects are unlikely to reach commercial operation.[15] When interconnection customers choose to remain in the queue in hopes that their interconnections will become more economical in the future, all the customers behind them in the queue are affected because the "squatting" customers' projects must be included in every lower-queued customer's studies as if they were built and in operation.

Third, the interconnection process can also be delayed—and interconnection costs increased—by a lack of advanced planning and due diligence by the interconnection customer, prior to requesting interconnection. As NIPPC has pointed out, "PacifiCorp's interconnection queue process is not overwhelmed because developers have insufficient information or data to make informed decisions."[16] On the contrary, QF developers have granular information available to them through the utilities' affordable pre-application processes. However, many QFs do not take advantage of the pre-application process to

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[14] NIPPC Comments on PacifiCorp's Draft Business Practice #73 at 1-2 (May 17, 2019), available at: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP73_NIPPC_Comments_0517192.pdf.

[15] *See, e.g.*, *Pro Forma* Large Generator Interconnection Procedures (LGIP) at Section 3.7, available at: https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/LGIP-procedures.pdf ("Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider."); *Pro Forma* Large Generator Interconnection Agreement (LGIA) Article 5.16, available at: https://www.ferc.gov/industries/electric/indus-act/gi/LGIA.pdf (setting out interconnection customer's right to suspend work on interconnection facilities and/or network upgrades at any time).

[16] NIPPC Comments on PacifiCorp's Draft Business Practice #73 at 1 (May 17, 2019), available at: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP73_NIPPC_Comments_0517192.pdf.

carefully vet their proposed locations, and they instead enter the queue only to discover that interconnection is prohibitively expensive at their chosen location.

In addition, many QFs enter the queue before fully considering their own facility configuration and equipment, which frequently results in the need to conduct restudies once the QF has planned more carefully and revised its facility as a result. The Joint Utilities are hopeful that the data-transparency efforts in Docket UM 2001 will help QFs make more informed siting decisions. Yet, in the end, the QFs will need to take advantage of that information to select locations that enable them to avoid high interconnection costs.

In sum, any effort to address perceived interconnection difficulties should consider the underlying causes of interconnection costs and timelines that are beyond the utilities' control. While comprehensive queue reform is outside the scope of this docket, it is important to understand all the factors affecting interconnection when considering how best to accommodate CSP QFs and ensure a fair and functional process for all QFs.

B. Interconnection typically is economical for projects that make careful siting decisions.

While Staff recognizes that it lacks data regarding Idaho Power and PGE's interconnection queues, Staff nevertheless appears to assume that the three utilities are similarly situated with respect to interconnection issues. The data provided below demonstrate that this is not the case. Given the important distinctions between the utilities' service territories and queues, Staff's decision to recommend a dramatic departure from precedent as a one-size-fits-all solution is surprising and misguided. In the past, the

Commission has differed in its PURPA implementation for the utilities based on their specific circumstances,[17] and such an approach may also be appropriate here.

1. Idaho Power

Idaho Power does not have a significant backlog of interconnection requests in its queue. Since January 2010, Idaho Power has received 243 generator interconnection applications seeking to interconnect more than 7,462 MW of generation.[18] Of these applications, 74 are for projects located in Oregon, and 11 of those 74 have been constructed and are online—totaling 50 MW of wind and 49.5 MW of solar. An additional five solar QFs totaling 27 MW are currently in construction and anticipated to be online in 2019.

Most projects take between six and 18 months to process through the interconnection queue, depending on how much time the project developer takes to submit the required data and return the appropriate agreements. The project with the oldest queue position active today applied on April 23, 2018, and is seeking to interconnect 870 MW.

Interconnection costs are highly dependent on location and various other factors, like voltage, and can be very high for even small generators. The minimum estimated interconnection cost for a typical QF project is approximately $275,000, which consists of a standard four-pole interconnection, protection, and metering package plus contingencies. Idaho Power's estimated interconnection costs have ranged from this minimum up to more than $27,600,000 for small generator interconnections, and up to more than $71,300,000 for large generators. Idaho Power currently has a 3-MW CSP QF interconnection request in the

[17] *See, e.g.*, *In the Matter of the Public Utility Commission of Oregon Investigation into Determination of Resource Sufficiency*, Docket UM 1396, Order No. 11-505 at 4 (Dec. 13, 2011) (declining to adopt a renewable avoided cost option for Idaho Power because it is not yet subject to the renewable portfolio standard); *In the Matter of the Public Utility Commission of Oregon Staff Investigation Into Qualifying Facility Contracting and Pricing*, Docket UM 1610, Order No. 16-174 at 22 (May 13, 2016) (authorizing PacifiCorp to use the PDDRR method for calculating non-standard avoided costs and stating "[w]e will continue to allow PGE, PacifiCorp, and Idaho Power to use different methodologies to negotiate and calculate non-standard avoided cost prices.").
[18] Idaho Power's record peak load for its entire system is approximately 3,400 MW.

facility study stage with approximately $58,000 of currently identified network upgrades in addition to the minimum $275,000 for four-pole interconnection, protection and metering package.[19]

Idaho Power's generation in Oregon (more than 220 MW) far exceeds the system load of approximately 95 MW.[20] For this reason and because Idaho Power has already interconnected a significant amount of generation in its Oregon jurisdiction, the system is at or near capacity in many locations for much of the time. This does not mean that it is impossible to interconnect without large upgrade costs, but it does mean that each application must go through the study process to determine on a case-by-case basis its impact on the system and necessary upgrade costs.

2. PGE

PGE does not have a backlog in its queue, and its interconnection process is currently streamlined without significant delays. Generally, projects that make careful siting decisions should be able to interconnect to PGE without triggering expensive network upgrades.

Since April 2015, PGE has received a total of 225 small generator interconnection requests—the majority of which occurred in 2017 (91 requests) and 2018 (80 requests). Of those 225 requests, 170 resulted in at least one study, while 55 withdrew prior to commencing any study. PGE has 12 small-generator projects that are fully interconnected and generating, and an additional 56 projects have completed the interconnection study process and signed interconnection agreements. Currently, PGE has just 16 active requests in the study process.

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[19] Idaho Power's initial capacity tier for the CSP is approximately 3.3 MW (2.5 percent of the electric company's 2016 system peak). OAR 860-088-0060.

[20] 2018 normalized Oregon average system load at the customer level was 95 MW. As of July 10, 2019, Idaho Power has 120 MW of Oregon PURPA generation currently online, plus 101 MW of non-PURPA wind and 22 MW of non-PURPA geothermal generation. Idaho Power has approximately 19,000 total Oregon customers.

In other words, of the small generator interconnection requests PGE has received since 2017, 30 percent have completed the process and signed interconnection agreements, 24 percent withdrew prior to completing any studies, 38 percent withdrew after completing at least one study, and the remaining 7 percent are currently proceeding through the study process.

For new small-generator interconnection applications it receives, PGE estimates the interconnection process will take approximately nine to 12 months if the applicant is responsive to PGE's requests and meets all applicable deadlines. PGE therefore expects that projects currently in the small generator interconnection queue should be able to complete the interconnection study process within 12 months, barring any need to restudy a project due to changes in the queue.

The estimated interconnection costs from PGE's small generator interconnection studies conducted to date have ranged from $25,000 to $4,068,000, and none of PGE's small generator interconnection studies have yet required upgrades to the transmission system (i.e., the upgrades required thus far have all been distribution upgrades, rather than network upgrades).

Finally, PGE has recently responded to pre-application requests from several CSP QFs, and although the projects are in the very early stages of the process, the pre-application process results appear favorable and suggest the CSP QFs may be able to interconnect with reasonably economical upgrades.[21] These figures demonstrate that PGE's interconnection process is currently working well, despite having been slowed somewhat in the past due to the influx of requests.

[21] It is important to note that projects 3 MW and larger may include a requirement for real-time SCADA communications that can introduce additional interconnection costs.

3. PacifiCorp

PacifiCorp is differently situated from Idaho Power and PGE because of its already overburdened queue and an unprecedented influx of interconnection requests. PacifiCorp has received at least 25,000 MW of requests in the past two years alone, bringing the total amount of generation in its interconnection queue to approximately 39,400 MW—all for a system whose peak load across its entire six-state footprint is only approximately 12,600 MW. This influx of interconnection requests presents a modeling, studying, and overall queue-administration challenge. To be clear, however, the congestion in PacifiCorp's interconnection queue is driven by neither the requirement that QFs receive NRIS nor the requirement that QFs pay for all the costs incurred because of their siting decisions. Therefore, the adoption of Staff's cost allocation and ERIS proposals would not necessarily facilitate more timely interconnections, but it would make it far more likely that when a CSP QF interconnects, customers will pay more. To address the root causes of PacifiCorp's overburdened queue, it has already begun a stakeholder process to explore broad reform solutions to alleviate the backlog in the queue and enable efficient administration.[22]

However, given its unique circumstances, PacifiCorp is investigating whether the broader, but still limited, curtailment authority provided to utilities with respect to purchases of "as-available" power under PURPA might be employed in the CSP. In particular, unlike QFs selling pursuant to long-term, fixed-rate power purchase agreements that can only be curtailed under system emergency conditions,[23] FERC has made clear that a utility can also

[22] As described in its OASIS site (https://www.oasis.oati.com/ppw/index.html), PacifiCorp has initiated a stakeholder process to solicit feedback on how to implement broad-based interconnection queue reform to address the backlog of projects awaiting interconnection.

[23] *See, e.g.*, *Idaho Wind Partners 1, LLC*, 140 FERC ¶ 61,219 at P 40 (2012), *on reh'g*, 143 FERC ¶ 61,248 at P 16 (2013) (finding that a utility cannot curtail QF power under the light loading curtailment provision of FERC's PURPA regulations where the utility is purchasing from that QF under a power purchase agreement

curtail "as-available" PURPA purchases—which is the type of purchase envisioned by the CSP regulations[24]—under certain light load scenarios.[25] The ability to potentially curtail CSP QFs under light load scenarios raises the possibility that PacifiCorp could provide interconnection on less robust terms, such as allowing an ERIS interconnection, and use its ability to curtail the as-available QF to potentially obviate the need for network upgrades and, thus, ensure customer indifference is still maintained when its merchant function arranges for transmission service. PacifiCorp is not yet ready to conclude that this approach is operationally or legally viable, but raises it here to ensure transparency and to emphasize the ongoing commitment to exploring all solutions.[26]

III. Legal Background

Before discussing Staff's proposals, which touch on a number of complex, interrelated legal issues, the Joint Utilities offer the following legal background regarding PURPA implementation, interconnection costs, NRIS and ERIS, Oregon's QF interconnection requirements, and FERC's interconnection policies.

A. State Jurisdiction over PURPA Implementation and Interconnection Costs

State public utility commissions are obligated to implement PURPA in a way that ensures customer indifference.[27] As Congress made clear when adopting PURPA, utility

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with long-term, fixed avoided-cost rates); *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 37 (2013) (explaining the system emergency exception).

[24] *See* OAR 860-088-0140(1)(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 [sic] Act (PURPA) and ORS 758.505, et. seq.").

[25] 18 C.F.R. § 292.304(f)(1).

[26] In any event, PacifiCorp does not contend that this approach would necessarily work for the other utilities, or that it would work for all CSP QF interconnections.

[27] 16 U.S.C. § 824a-3 (rate for QF purchases may not exceed "the cost to the electric utility of the electric energy which, ***but for*** the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." (emphasis added)); *S. Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269 at p. 62,080 (1995) ("The intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.").

customers are not required to subsidize QF development by paying more to purchase from QFs than they otherwise would have absent the QF purchases.[28] Consistent with that charge, the Commission has "on a number of occasions, reaffirmed [its] intention to encourage the economically efficient development of QFs, while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power."[29]

B. Interconnection Costs Under PURPA

Under FERC's PURPA regulations—which have been in place since the 1980s and which were left unchanged by FERC's landmark interconnection orders—QFs are obligated to pay interconnection costs,[30] with the only reimbursement mechanism envisioned being one from the ***QF*** to the ***utility***.[31]

FERC's regulations define "interconnection costs" broadly:

> [T]he reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities ***necessary to permit interconnected operations with a qualifying***

[28] *See* Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 97-98 ("The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.").

[29] *Portland Gen. Elec. Co. v. Pac. Nw. Solar, LLC*, Docket UM 1894, Order No. 18-025 at 4 (Jan. 25, 2018) (internal quotation marks and citations omitted).

[30] 18 C.F.R. § 292.306(a) ("(a) Obligation to pay. Each qualifying facility shall be obligated to pay any interconnections costs which the State regulatory authority . . . may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics."); *see also Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38, n.73 (2013) (stating that PURPA requires a utility to make transmission arrangements for the QF power, but that "[t]his is not to suggest that the QF is exempt from paying interconnection costs, which may include transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations." (internal citations omitted)).

[31] *See* 18 C.F.R. § 292.306(b) (providing that the state has the authority to decide whether there should be a reimbursement mechanism for interconnection costs); *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, 12,230 (1980) (hereinafter Order No. 69) (responding to comments seeking clarification on "the manner in which electric utilities would be reimbursed" by explaining that it is best left to the states to decide whether a QF should pay for its interconnection in an upfront lump sum or amortized over some period of time).

> ***facility***, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.[32]

This definition includes a wide range of costs—of varying types—that would not be incurred but for the QF. When it adopted the definition of "interconnection costs" in Order No. 69, FERC clarified, "These costs may include, but are not limited to, operating and maintenance expenses, ***the costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection***, and reasonable insurance expenses."[33] Thus, FERC has explicitly authorized state commissions to require QFs to pay the costs of system upgrades required by QF interconnections.

C. Types of Interconnection Service

There are two types of interconnection service available to interconnecting generators: ERIS and NRIS.[34]

ERIS is a basic interconnection service, which makes an interconnecting generator eligible to deliver the generating facility's output using the existing firm or non-firm capacity of the transmission system on an ***as available*** basis.[35] An ERIS interconnection study identifies only those facilities—including any network upgrades—necessary to physically

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[32] 18 C.F.R. § 292.101(7) (emphasis added).
[33] Order No. 69 at 12,219 (emphasis added).
[34] ERIS and NRIS are a product of FERC's Order Nos. 2003 and 2006 proceedings in which FERC standardized the interconnection procedures and agreements for large and small generators. *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003) (hereinafter Order No. 2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 (2004) (hereinafter Order No. 2003-A), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2005) (hereinafter Order No. 2003-B), *order on reh'g*, 111 FERC ¶ 61,401 (2005) (hereinafter Order No. 2003-C); *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 111 FERC ¶ 61,220 (2005) (hereinafter Order No. 2006), *order on reh'g*, Order No. 2006-A.
[35] *Pro Forma* LGIP at 3 (definition of "Energy Resource Interconnection Service"); Order No. 2003 at P 753.

interconnect the generating resource to the system. Crucially, ERIS does not identify upgrades that may be required to ensure the deliverability of the generator's output.

NRIS is a more comprehensive interconnection service option with the principal purpose of making an interconnecting generator eligible to deliver its output to load on a firm basis.[36] Consistent with this level of interconnection service, an NRIS study includes a deliverability analysis that identifies the facilities—including any network upgrades—necessary to allow the aggregate of generation in the area where the interconnecting generator sited its project to be delivered to the aggregate of load during peak conditions.[37] As FERC has explained, NRIS "ensures that the Generating Facility, as well as other generating facilities in the same electrical area, can be operated simultaneously at peak load and that any output produced above peak load requirements can be transmitted to other electrical areas within the Transmission Provider's Transmission System."[38] "Thus, [NRIS] ensures that the output of the Generating Facility will not be 'bottled up' during peak load conditions."[39]

D. Oregon QF Interconnection Requirements

Oregon's PURPA rules echo FERC's regulations, providing that:

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[36] *Pro Forma* LGIP at 8 (definition of "Network Resource Interconnection Service"); Order No. 2003 at PP 754-56.

[37] *See, e.g.*, Order No. 2003-A at P 531 ("The purpose of Network Resource Interconnection Service is to provide for only those Network Upgrades needed to allow the aggregate of generation in the Generating Facility's local area to be delivered to the aggregate of load on the Transmission Provider's Transmission System, consistent with the Transmission Provider's reliability criteria and procedures." (emphasis in original)); *see also Pro Forma* LGIP Section 3.2.2.2 ("The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures.").

[38] Order No. 2003-A at P 531.

[39] Order No. 2003-A at P 531.

> Interconnection costs are the responsibility of the owner or operator of the qualifying facility. Interconnection costs that may reasonably be incurred by the public utility will be assessed against a qualifying facility on a nondiscriminatory basis with respect to other customers with similar load or other cost-related characteristics.[40]

This Commission has adopted small generator interconnection rules for QFs 10 MW or less, codified in OAR Chapter 860 Division 82, and standard large generator interconnection procedures for QFs greater than 20 MW, attached to Order No. 10-132.[41] Each is discussed in turn.

1. <u>Oregon Small Generator Interconnection Rules</u>

Ten years ago, the Commission adopted interconnection rules for QFs and other small generators with a nameplate capacity of 10 MW or less.[42] According to Staff's comments in that rulemaking docket, the rules were developed "with input from a diverse group of stakeholders that not only included the public utilities but also distributed generation developers, small generator owners and operators, representatives from the Commission Safety and Reliability division and technical and process experts in the field of small generator interconnection."[43] The rules were based on the Mid-Atlantic Distributed Resources Initiative (MADRI)[44] model small generator interconnection procedures, which in turn were based on FERC's Order No. 2006 small generator interconnection procedures

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[40] OAR 860-029-0060(1).

[41] *See In re Public Utility Commission of Oregon Investigation into Interconnection of PURPA Qualifying Facilities with Nameplate Capacity Larger than 20 Megawatts*, Docket UM 1401, Order No. 10-132, App'x A (Apr. 7, 2010).

[42] *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket AR 521, Order No. 09-196 (Jun. 8, 2009). The rules for small generator interconnections in Oregon are found at OAR 860-082-0005 through 860-0882-0085.

[43] Docket AR 521, Staff's Third Set of Comments at 1 (Nov. 9, 2007).

[44] MADRI is a collaborative group of state and federal entities—include various state commissions and FERC—that "seeks to identify and remedy retail and wholesale market barriers to the deployment of distributed generation, demand response, energy efficiency, and energy storage in the Mid-Atlantic region." *About the Mid-Atlantic Distributed Resources Initiative*, https://www.madrionline.org/about/.

(SGIP).[45] Staff stated, "[a]ny difference between what is being proposed in this Rule and the requirements of the FERC rule are meant to address the requirements of the [Commission] statutory authority for regulation of public utilities in Oregon."[46]

As relevant here, OAR 860-082-0035 provides, "[a] public utility must design, procure, construct, install, and own any system upgrades to the public utility's transmission or distribution system necessitated by the interconnection of a small generator facility," and the QF (or interconnecting generator) "must pay the reasonable costs of any system upgrades." Notably, the MADRI model SGIP requires the interconnection customer to pay for "distribution upgrades,"[47] whereas the Oregon SGIP includes similar cost-allocation language but uses the term "system upgrades," thus encompassing *all* interconnection costs caused by QFs—not just costs related to the distribution system.

2. Oregon Large Generator Interconnection Procedures

Around the same time it adopted the SGIP, the Commission ordered Oregon-regulated utilities to adopt Oregon large generator interconnection procedures and agreements (QF-LGIP and QF-LGIA, respectively) that, while largely modeled on FERC's *pro forma* LGIP and LGIA, modified those requirements specifically for PURPA interconnections.[48] In particular, the Oregon QF-LGIP requires the interconnection customer to receive NRIS.[49] In addition, the QF-LGIP states that the interconnection customer, rather

[45] AR 521, Staff's Third Set of Comments at 1 (Nov. 9, 2007).
[46] AR 521, Staff's Third Set of Comments at 1-2 (Nov. 9, 2007).
[47] *MADRI Model Small Generator Interconnection Procedures* at 72 (Nov. 22, 2005), available at: https://www.madrionline.org/wp-content/uploads/2017/02/inter_modelsmallgen-1.pdf ("The EDC shall design, procure, construct, install, and own any Distribution Upgrades. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer."); *see also id.* at 8 (defining "Distribution Upgrades").
[48] Order No. 10-132 at 3.
[49] Order No. 10-132, App'x A at 15 ("Interconnection Customer[]s will be processed for Network Resource Interconnection Service.").

than the utility, is responsible for all costs associated with network upgrades driven by the interconnection unless it can establish quantifiable, system-wide benefits of the upgrades.[50]

E. FERC's Non-QF Interconnection Requirements and Rationale

In 2003, FERC adopted interconnection procedures applicable to non-QF interconnections. Under FERC's process, non-QF interconnection customers can choose either ERIS or NRIS.[51] The transmission provider then conducts studies to identify any necessary improvements, which, under both FERC's *pro forma* SGIA and LGIA, are classified into three categories: (1) interconnection facilities, (2) distribution upgrades, and (3) network upgrades:

1. Interconnection facilities are those necessary improvements that are located on the interconnection customer's side of the point of interconnection between the generating facility and the point of interconnection.[52]

2. Distribution upgrades are necessary improvements to the distribution system located on the transmission provider's side of the point of interconnection.[53]

3. Network upgrades are necessary improvements to the transmission system located on the transmission provider's side of the point of interconnection.[54]

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[50] Order No. 10-132 at 3.
[51] FERC-jurisdictional interconnecting small generators that choose NRIS switch to the large generator interconnection procedures and agreement.
[52] *Pro Forma* LGIP, Section 1 ("Definitions") ("**Interconnection Facilities** shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades." (emphasis in original)).
[53] *Pro Forma* LGIP, Section 1 ("Definitions") ("**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities." (emphasis in original)).
[54] *Pro Forma* LGIP, Section 1 ("Definitions") ("**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." (emphasis in original)).

For all interconnections, FERC requires that the interconnection customer provide the upfront funding for the cost of all three types of improvements.[55] The interconnection customer does not receive reimbursement for the costs of interconnection facilities or distribution upgrades, but the transmission provider must reimburse the interconnection customer for the cost of network upgrades upon the facility reaching commercial operation.[56] Reimbursement must occur on a dollar-for-dollar basis and is typically provided as a transmission credit as the interconnection customer takes transmission service.[57]

Under the OATT, however, despite the upfront funding, FERC did not intend for the cost of network upgrades to be ultimately borne by interconnection customers. Rather, as FERC has explained, the "Order No. 2003 reimbursement policy was designed to work with the transmission rate pricing policies of the *pro forma* OATT to ensure native load and other transmission customers of the transmission provider are protected from subsidizing the cost of the network upgrades built to interconnect a generator to the grid."[58] The link between FERC's interconnection and transmission service pricing is critical because FERC assumes that the same customer receives both services. If that link is broken, the application of FERC's interconnection policies results in the subsidization FERC explicitly sought to prevent.

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[55] *See Pro Forma* LGIA Articles 11.1, 11.2 and 11.3, available at: https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/LGIA-agreement.pdf; *see also Pro Forma* SGIA Article 4, available at: https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

[56] *See Pro Forma* LGIA Article 11.4; *see also Pro Forma* SGIA Article 5.2.

[57] *Pro Forma* LGIA Article 11.4; *see also Pro Forma* SGIA Article 5.2.1; Order No. 2003-B at P 3.

[58] *Interstate Power and Light Co. v. ITC Midwest, LLC*, 144 FERC ¶ 61,052 at P 36 (2013); *see also* Order No. 2003-A at PP 579-90.

IV. Discussion of Staff's Proposed Solutions[59]

A. The Joint Utilities oppose Staff's cost-allocation and ERIS proposals because they would shift costs to customers—contrary to the CSP statute, PURPA's customer-indifference requirement, FERC's PURPA regulations, and FERC's stated interconnection goals.

Staff recommends that the Commission conform to FERC's interconnection policies by allowing QFs to select ERIS and socializing network upgrade costs to all of the utilities' transmission customers.[60] The Joint Utilities oppose Staff's ERIS and cost-allocation proposals because: (1) shifting significant costs to customers violates the CSP statute; (2) it is inappropriate for Oregon to mirror FERC's non-QF interconnection policies given that the reasoning underlying them does not apply in PURPA's must-purchase and customer-indifference construct; (3) Staff's proposals would violate PURPA and shift potentially significant QF-caused costs to utility customers, requiring customers to pay in excess of their avoided cost for QF output; and (4) costs should not be allocated to customers based merely on the supposition that there are "creative" solutions available. Each is discussed in turn.

1. Requiring customers to pay network upgrade costs for CSP projects is inconsistent with the CSP statute's mandate to minimize cost shifting.

The CSP statute specifically requires the Commission's CSP implementation to "[m]inimize the shifting of costs from the program to ratepayers who do not own or subscribe to a community solar project."[61] Staff has previously recognized that "there is a high potential" for such impacts through the CSP, highlighting this risk to support the adoption of customer size caps (thereafter adopted by the Commission).[62] In the Commission's guidance to Staff in this docket, the Commission has repeatedly

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[59] Although the Joint Utilities find many of the options Staff raises for further consideration in other dockets to be problematic, these Comments address only the specific resolutions Staff has proposed in Docket UM 1930.
[60] UM 1930 Staff Memo at 13.
[61] ORS 757.386(2)(b).
[62] *In the Matter of Rules Regarding Community Solar Projects*, Docket AR 603, Order No. 17-232 at 4 (June 29, 2017) (describing Staff's comments).

acknowledged the importance of achieving CSP implementation "at the lowest cost possible to non-participants," consistent with the legislature's direction to minimize cost shifting.[63] Thus, Staff's proposals to shift network upgrade costs to customers are inconsistent with the CSP statute and the Commission's articulated goals for the CSP in its implementing orders.

2. FERC's interconnection policies were not intended to apply in the PURPA context and were designed to avoid shifting costs.

When FERC adopted its large and small generator interconnection policies, it specifically did not apply them to QF interconnections with the purchasing utility.[64] Importantly, FERC's interconnection policies are premised upon assumptions that do not hold true under PURPA, and FERC's intended result—to insulate existing customers from costs caused by new interconnection customers—would be completely undermined if FERC's non-QF interconnection policies were applied to PURPA interconnections. Therefore, it would be inappropriate, and contrary to federal law, for the Commission to simply adopt FERC's interconnection policies without adjusting its other PURPA policies (e.g., avoided cost pricing) to hold customers indifferent.

a. FERC's refund policy was intended to prevent existing customers from subsidizing new generation.

Staff's proposal implies that shifting network upgrade costs caused by QFs to existing transmission customers is acceptable because it would be consistent with FERC's *pro forma* LGIP, under which network upgrades necessitated by a generator's interconnection are ultimately rolled into transmission rate base. However, the assumption that FERC asked transmission customers to subsidize new generators is simply incorrect. In fact, FERC's

[63] Docket UM 1930, Order No. 18-088 at 3 (Mar. 19, 2018); Docket UM 1930, Order No. 18-177 at 1, 3 (May 23, 2018).
[64] *See, e.g.*, Order No. 2006-A at P 102 ("[A] QF selling at retail is not eligible to interconnect under either Order No. 2003 or Order No. 2006. Under the Public Utility Regulatory Policies Act of 1978, such interconnections are governed by state law." (internal citations omitted) (citing Order No. 2003 at PP 813-14 and 16 U.S.C. § 2601 *et seq*. (2000))).

policy was intended to *prevent* transmission customers from subsidizing the interconnection of new generation.[65]

Specifically, based on the express assumption that the interconnection customer and transmission service customer are the same party, FERC sought to use transmission service, paid by the interconnection customer, to prevent cost-shifting. However, when the interconnection customer does not arrange and pay for transmission service, as is the case under PURPA, the threat of subsidy arises.

FERC reasoned that the cost of constructing new network upgrades would be offset by the new interconnection customer's usage of the transmission system (i.e., a new transmission reservation), and that the new customer would also assume a share of the costs of the *existing* system—thereby reducing existing customers' rates. In Order No. 2003-A, FERC reasoned that ***as long as the interconnection customer itself subsequently takes new and incremental transmission service***, its pricing policy would not cause subsidization of generators by existing customers because the transmission provider could charge the higher of ***either***: (1) the "rolled-in" rate ***or*** (2) an "incremental rate," which FERC reasoned "ensures that other transmission customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation."[66]

Rolled-in rates include the cost of the network upgrade as a component of the transmission rate base that is then included in all transmission customer rates. FERC reasoned that "in most instances, ***the additional usage of the transmission system by a new***

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[65] *See, e.g.*, Order No. 2003-A at PP 580 (policy intended to "ensure[] that other transmission customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation"), 586 (interconnection policy "does not mean . . . that native load customer must subsidize the cost of the Network Upgrades"), and 580 n.106 (policy intended to "fully insulate existing customers from the costs of any necessary system upgrades").
[66] Order No. 2003-A at P 580.

Interconnection Customer will generally cause the average embedded cost transmission rate to decline for all remaining customers," which would "enable . . . existing transmission customers to benefit from this overall lower average embedded cost rate," even though the rate includes the network upgrades.[67]

Alternatively, in an instance where network upgrades were significant, FERC explained that the transmission provider could charge the costs of those upgrades to the generator that caused them in the form of an *incremental* transmission rate, which effectively assigns the network upgrade costs to the interconnection customer and excludes the network upgrade from the transmission rate base used to set rates for existing customers.[68]

On rehearing, in Order No. 2003-B, FERC affirmed Order No. 2003-A, emphasizing that it "strongly encourages policies that promote efficient investment decisions and protect native load and other Transmission Customers from having to bear the burden of the Interconnection Customer's Network Upgrade costs."[69] FERC then reiterated in Order No. 2003-C that "native load and other [transmission] customers" should be "held harmless" from the costs of an interconnection customer's network upgrades.[70]

Thus, FERC's policies assumed that each new interconnection request brings new *and additional* use of the transmission system that relieves rate pressure on existing customers. Under PURPA, however, the utilities have the obligation to purchase and then to

[67] Order No. 2003-A at P 581 (emphasis added).
[68] Order No. 2003-A at P 581 (incremental rate calculated by "dividing the costs of any necessary network upgrades by the projected transmission usage by the new generator") and n. 107 ("In those instances where a Transmission Provider elects to charge an Interconnection Customer an incremental transmission rate for interconnection-related Network Upgrades because it results in a rate that is higher than the average embedded cost rate, the issue of whether crediting results in native load or other Transmission Customers ultimately bearing the cost of the Network Upgrades becomes somewhat irrelevant. ***This is because the incremental rate approach ensures that the costs associated with those Network Upgrades will not be included in the transmission rates charged to other customers***." (emphasis added)).
[69] Order No. 2003-B at P 33.
[70] *See* Order No. 2003-C at P 27.

deliver the QF output to load and the QF does not bring any new load that would share the costs of the existing system, thereby relieving rate pressure on existing customers. As a result, if QFs do not bear the costs of their siting decisions, the utilities' existing transmission customers (mostly their retail load) would.

Staff's recommendation to "align" Oregon's QF interconnection policy with FERC's non-QF policy is inappropriate because the critical fact on which FERC's policy was based—that the interconnection customer and transmission customer are the same—is not present under PURPA. Moreover, Staff's proposal would contravene FERC's stated intent in adopting its non-QF policy—to prevent subsidization and hold existing customers harmless.

b. This Commission already considered and rejected FERC's non-QF cost-allocation approach.

When the Commission adopted its small generator interconnection rules and Oregon QF-LGIP, it considered cost allocation for interconnection upgrades and opted not to follow FERC's policies. In adopting the SGIP rules, the Commission took note of FERC's policy of providing transmission credits to reimburse interconnection customers for transmission upgrades.[71] Yet the Commission opted not to follow FERC's approach, explaining,

> Because ***not all small generator facilities under this Commission's jurisdiction will be using a public utility's transmission system***, a process allowing cost sharing of system upgrades using transmission credits is not feasible. . . . The proposed rules, however, 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 small generator interconnection.[72]

[71] Order No. 09-196 at 4 ("Under the Federal Energy Regulatory Commission's rules governing small generator interconnection, there is a process for sharing the cost of system upgrades among small generator facilities using transmission credits.").

[72] Order No. 09-196 at 4-5 (emphasis added). Staff states that the protective language the Commission referenced is not evident. Staff UM 1930 Memo at 9. However, the Commission immediately went on to state, "Under the proposed rules, a public utility may only require a small generator facility to pay for system

Similarly, when the Commission adopted the Oregon QF-LGIA and QF-LGIP, the cost-allocation policy for network upgrades was the primary disputed issue in the docket,[73] with certain parties arguing that QFs should not be required to pay for network upgrades, which could be extremely costly, and asserting that the policy was discriminatory.[74] However, Staff responded in that docket that the claims of discrimination were misinformed and explained the important distinction between wholesale generators and QFs:

> FERC generators include in the sales price of the power they sell, the transmission costs to move the power from the generator to the point of use which include ongoing payments to the interconnected utility for the use of the utility's T&D system. ***PURPA QFs only sell power or capacity without any separate charge for the additional use they put on the interconnected utility's T&D system***.[75]

Thus, in adopting the Oregon QF-LGIP and QF-LGIA, the Commission was fully informed about the distinctions between its cost-allocation policy and FERC's.[76] With this knowledge, the Commission rejected the arguments that Oregon's QF cost-allocation policy should mirror FERC's non-QF policy, explaining that the FERC precedent cited did not relate to PURPA facilities and thus did not address the requirement that utilities pay no more

upgrades that are 'necessitated by the interconnection of a small generator facility' and 'required to mitigate' any adverse system impacts 'caused' by the interconnection. We therefore believe the proposed rules adequately protect small generator facilities." Order No. 09-196 at 5. Thus, the Commission's Order itself indicates the precise language that the Commission deemed adequate to ensure that interconnection customers—such as QFs—bear only the costs they impose that do not primarily benefit the system.

[73] *See* Order No. 10-132 at 2.

[74] *See, e.g.*, Docket UM 1401, Opening Comments of the Industrial Customers of Northwest Utilities at 4-10 (June 8, 2009) (arguing that the QF-LGIA cost-allocation provisions should not be modified for several reasons and providing examples of interconnection costs charged by each utility).

[75] Docket UM 1401, Staff's Reply Comments at 4-6 (Aug. 13, 2009) (emphasis added).

[76] The Joint Utilities also note that FERC has recognized that Oregon has a different cost-allocation methodology for QFs that directly assigns network upgrade costs. In 2012, PacifiCorp made a filing with FERC explaining that a small QF had originally obtained a FERC-jurisdictional interconnection and was therefore receiving a refund of its network upgrade costs. After PacifiCorp learned that the QF was selling all of its output to PacifiCorp, the company and the QF negotiated an Oregon-jurisdictional interconnection agreement that terminated the network upgrade refunds in accordance with Oregon policy. PacifiCorp informed FERC of this change through a filing made in Docket No. ER12-2223-000, and FERC accepted the filing without change.

than their avoided cost rate.[77] The Commission's reasoning remains equally valid today, and the Commission should not deviate from its prior decisions now—particularly in an emergency rulemaking.

3. <u>Staff's ERIS and cost-allocation proposals would violate PURPA by shifting potentially significant costs to customers.</u>

Staff proposes that CSP QFs be allowed to receive ERIS instead of NRIS and that any network upgrades caused by CSP QFs be allocated to all the utility's transmission customers. However, both of Staff's proposals would shift the costs caused by QF interconnection from QFs to utility customers, which would harm customers and violate PURPA's requirement of customer indifference. First, allowing ERIS for QFs would shift the costs of network upgrades from the interconnection service context—where they are paid for by the QF—to the transmission service context—where they are paid for by utility customers. Second, requiring transmission customers to bear the costs of interconnection network upgrades (regardless of whether the QF received ERIS or NRIS) means that utility customers ultimately would bear nearly all of the network upgrade costs. While any cost-shifting violates PURPA, the amount of network upgrade costs shifted under Staff's proposals could be substantial.

a. The utilities appropriately require NRIS for all QFs to adhere to FERC's PURPA requirements and avoid shifting costs.

Requiring NRIS for QF interconnections follows from three separate federal legal requirements: (1) PURPA's customer indifference standard; (2) the requirement that QF power be delivered on firm transmission even where the transmission system is constrained

[77] Order No. 10-132 at 3-4.

and without regard for the type of interconnection;[78] and (3) FERC's prohibition on curtailing QFs absent emergency conditions.[79] NRIS requires a utility's transmission function to study the transmission system under a variety of severely stressed conditions to determine whether, with the new interconnecting generator at full output, the aggregate of generation in the local area can be reliably delivered to the aggregate of system load.[80] This means that network upgrades required for NRIS make the interconnecting generator eligible to qualify for designation as a network resource, i.e., the precise type of transmission service arrangement used to deliver QF power to load.[81] As FERC has described, "the principal purpose of [NRIS] is to allow the Generating Facility to qualify for designation as a Network Resource by a Network Customer."[82] Using NRIS for QFs ensures that the required upgrades are identified and the associated costs are assigned to QFs.

If the QF were allowed to interconnect with ERIS, the interconnection study would not identify—and the QF would not be responsible for—the costs of any deliverability-related interconnection network upgrades associated with the QF's siting choice. Instead, when the utility submits a transmission service request (TSR), the study would identify for the first time all network upgrades necessary to allow the QF's output to reach load on a firm

[78] *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38 (2013) (noting that FERC had "specifically held that . . . the purchasing utility cannot curtail the QF's energy as if the QF were taking non-firm transmission service on the purchasing utility's system"); *see also PacifiCorp*, 151 FERC ¶ 61,170 at P 27 (2015) ("[FERC] precedent requires electric utilities . . . to deliver QF's power on a firm basis.").
[79] *PacifiCorp*, 151 FERC ¶ 61,170 at P 27 (2015) ("[FERC] precedent . . . prohibits the curtailment of QF resources except under two very narrow circumstances . . .").
[80] *See, e.g.*, *Pro Forma* LGIP, Section 3.2.2.2.
[81] Order No. 2003-A at P 531-37 (explaining the relationship between NRIS and transmission service). To be clear, any type of interconnection service request can require the construction of network upgrades. Order No. 2003 at P 767. In the absence of transmission constraints, a generator may have little or no difficulty obtaining either ERIS or NRIS, and both types of interconnection may have the same cost and timing requirements. As system constraints increase, it may still be possible to grant a certain number of ERIS interconnections without the need for significant upgrades because that type of service does not involve a deliverability analysis.
[82] Order No. 2003-B at P 69.

basis, without curtailment. Any such upgrades—as well as the transmission service charges—would typically be paid for by the utility and passed on to utility customers.[83]

Staff's proposal to allow CSP QFs to receive ERIS would likely shift costs because under PURPA, the interconnection and transmission customer are different, as discussed above. In contrast, for FERC-jurisdictional interconnections where the interconnecting generator can select ERIS or NRIS, the interconnection customer also arranges for transmission service. Thus, as FERC explained, it should be of "no concern" where the network upgrades are identified because the interconnection and transmission customer are the same.[84] For QFs, however, it is of great concern because if the network upgrade is identified in the interconnection process, then the QF pays; if it is identified in the TSR, then utility customers pay.

When the Commission adopted the Oregon QF-LGIA and QF-LGIP—which explicitly require NRIS—there appears to have been no dispute that NRIS was appropriate for QFs.[85] Staff suggests that the Commission did not make a similar determination to require NRIS in the small generator interconnection rules and that the utilities have simply chosen to require it even though NRIS is not contemplated by the rules.[86] However, the principles supporting NRIS for large QFs are equally applicable to small QFs. Moreover, the

[83] Obtaining transmission service may require additional network upgrades beyond those required for interconnection service. *See, e.g.*, Order No. 2003 at P 767; *Interstate Power & Light Co. v. ITC Midwest, LLC*, 144 FERC ¶ 61,052 at P 36 (2013) ("[E]ach generator, or other transmission customer, seeking to use the transmission system to deliver power from the generator must take transmission service and pay the transmission provider's transmission service rates separate from paying for any interconnection-related network upgrade costs.").

[84] Order No. 2003-A at P 535 (stating the "fact that [ERIS], by itself, allows access to the existing capacity of the Transmission System only on an 'as available' basis should be of no concern to the" interconnecting generator because the generator "can simultaneously obtain firm deliverability to [] Network Loads by requesting the Transmission Provider ***to construct . . . any additional upgrades that may be necessary to ensure deliverability of the Network Resource to serve Network Load***." (emphasis added)).

[85] The NRIS requirement does not appear to have been challenged or questioned by any party, based on a review of the written comments in the docket. *See generally* Comments of Staff, Industrial Customers of Northwest Utilities, and Oregon Department of Energy in Docket UM 1401.

[86] *See* UM 1930 Staff Memo at 9.

utilities must offer small QFs standard avoided cost rates and have no ability to adjust them to account for any significant upgrade costs that would be imposed by the QF's interconnection and deliveries.[87] Given these considerations and that the QF-LGIP plainly requires NRIS, there is no reasonable basis to apply a different policy for small QFs.

Staff also attaches significance to the fact that FERC's *pro forma* SGIP and SGIA do not include NRIS as an option.[88] As explained above, however, FERC did not intend its interconnection policies to apply to QF interconnections.[89] And in fact, FERC did not foreclose NRIS for small generators; a small generator remains free to choose NRIS under the OATT by proceeding under the LGIP.[90] FERC made clear when it adopted the SGIP that it did not seek to provide for any particular delivery-related arrangements as part of the interconnection process, and that interconnection customers would remain responsible for making such arrangements.[91] FERC subsequently confirmed that deliverability may be studied as part of the FERC interconnection process for small generators.[92] Thus, the mere fact that the FERC's SGIP does not specifically include NRIS as an option does not provide a basis upon which to conclude that FERC deemed NRIS to be inappropriate for small QFs. Indeed, FERC expressly provides a path for small generators to use NRIS.

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[87] ORS 758.525(1) (requiring utilities to prepare and file fixed avoided cost schedules for the subsequent 20 years).
[88] UM 1930 Staff Memo at 9 ("Notably, NRIS is not available to small generators under FERC's SGIP.").
[89] Order No. 2006 at P 102 ("[A] QF selling at retail is not eligible to interconnect under either Order No. 2003 or Order No. 2006. Under the Public Utility Regulatory Policies Act of 1978, such interconnections are governed by state law." (internal citations omitted)).
[90] *See* Order No. 2006 at P 140 ("[W]e do not want to preclude [a small generator] from choosing [NRIS]. If it wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it may do so. However, it must request interconnection under the LGIP and execute the LGIA.").
[91] Order No. 2006 at P 139; Order No. 2006-A at P 4 n.9.
[92] *See Cali. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,223 (2010). In this 2010 order, FERC approved the CAISO's merger of its LGIP and SGIP into a single GIP. As part of that merger, the CAISO explained that it would need to transition two types of SGIP customers: those that requested energy-only delivery status and those that requested the CAISO's version of NRIS—referred to as "full capacity deliverability status." 133 FERC ¶ 61,223 at P 25. In approving the CAISO's consolidation of its LGIP and SGIP mechanisms, FERC specifically approved making both delivery options available to all generators. 133 FERC ¶ 61,223 at P 96.

Finally, the Utah Public Service Commission (PSC) considered and resoundingly rejected a QF's claim that it should not be required to obtain the robust level of state interconnection service required to accommodate its output:

> [The QF] emphasizes that QFs are responsible for delivering their output to the point of interconnection and that, thereafter, the utility is responsible for transmitting the output to load. This is precisely the reason it is essential that interconnection costs, including [interconnection-driven] investments in transmission infrastructure, be accurately estimated and assessed ***as a component of interconnection costs***.[93]

For these reasons, it is appropriate for the utilities to require QFs to receive NRIS, and removing this requirement for CSP QFs would shift costs to customers.

b. Under Staff's cost-allocation proposal, all or most of any necessary network upgrade costs would be paid by utility customers.

Interconnection network upgrade costs necessitated by a QF and allocated pursuant to FERC's non-QF methodology, as Staff suggests, would be rolled into the utility's transmission rate base and shared by all users of the utility's transmission system through increased transmission rates.[94] For each of the Joint Utilities, the primary user of the transmission system is the utility's merchant function (load serving entity), whose transmission rates are paid by its customers. Specifically, over 88 percent of PacifiCorp Transmission's annual transmission revenue comes from providing load service to PacifiCorp's retail customers. Similarly, PGE Merchant is the primary customer of PGE Transmission, holding more than 90 percent of the long-term transmission rights. For Idaho Power, 75 percent of transmission peak demand was attributable to retail customer load service in 2018. Thus, any network upgrade costs that are allocated to all of the utilities'

[93] Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC's Request for Agency Action to Adjudicate Rights and Obligations under PURPA, Schedule 38 and Power Purchase Agreements with Rocky Mountain Power, Utah Pub. Serv. Comm'n Docket Nos. 17-035-26, 17-035-28, 17-035-36, Consolidated Order at 31 (Dec. 22, 2017) (hereinafter "Glen Canyon Order") (emphasis added).

[94] Potentially including customers from states other than Oregon.

transmission service customers, as Staff proposes, would primarily be paid by the utilities' retail customers—thereby increasing retail rates in violation of PURPA and FERC's policy underlying its allocation of network upgrade costs.

c. For CSP QFs, network upgrade costs must be captured in the interconnection context to uphold customer indifference.

When adopting its PURPA rules, FERC decided "to separate the utility's avoided costs with regard to purchases from qualifying facilities, from the costs incurred as a result of interconnection with a qualifying facility."[95] However, in drawing this distinction, FERC emphasized that ***customers should be held harmless from both categories of costs***, stating "legitimate costs not recovered pursuant to this section [regarding interconnection costs] can be netted out in the calculation of avoided costs."[96] FERC also has clarified that, "transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations may be accounted for in the determination of avoided costs if they have not been separately assessed as interconnection costs."[97]

FERC's definition of "interconnection costs" "is designed to provide the State regulatory authorities . . . with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility."[98] FERC has not wavered from its position that "under these rules the utility is not obligated to incur ***any additional costs*** by reason of interconnected operation with these facilities."[99] This is

[95] Order No. 69 at 12,217.
[96] Order No. 69 at 12,217.
[97] *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38 n.73 (2013).
[98] Order No. 69 at 12,217.
[99] *Small Power Production and Cogeneration Facilities—Qualifying Status*, Order No. 70, 45 Fed. Reg. 17,959, 17,965 (1980) (subsequent history omitted) (emphasis added).

consistent with PURPA's central tenet of customer indifference.[100]

Under the CSP, where CSP QFs are selling as-available and not receiving avoided cost rates that account for interconnection network upgrade costs,[101] the only way to hold customers indifferent is to ensure that the costs CSP QFs impose are captured in the interconnection context. To do otherwise would impermissibly shift costs to utility customers.

Outside of the community solar context, the Commission could theoretically require the utilities to adjust their standard or negotiated avoided cost rates to account for interconnection network upgrade costs imposed by Staff's proposed revisions to the state's QF interconnection policies. However, because interconnection network upgrades are highly dependent on the QF's location, size, and design, it would be difficult, if not impossible, to accurately estimate these costs on a "standard" basis. Likely for this reason, this Commission currently directs utilities to charge these costs to QFs in the interconnection process—rather than adjusting avoided costs.[102] The Commission should not revise its interconnection-cost policy in an emergency rulemaking without considering corresponding adjustments to avoided costs.

As noted by the Utah PSC—which has similarly concluded that interconnection-driven network upgrades need to be borne by the QF in the interconnection context:

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[100] *See, e.g.*, 18 C.F.R. § 292.304(a)(2) ("Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases."); 18 C.F.R. § 292.101(b)(6) (defining "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility . . . , such utility would generate itself or purchase from another source."); Order No. 69 at 12,222 (discussing industry comments on section 304(a) of the then-new regulations noting that utility customers "are kept whole").

[101] *See* OAR 860-088-0140(1)(a).

[102] In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities, Docket UM 1129, Order No. 07-360, App'x A at 4 (Aug. 20, 2007) ("The utility should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept QF power. Such costs should be separately charged [to the generator] as part of the interconnection process.").

> Even if . . . transmission upgrades beyond the point of interconnection are not assessable as interconnection costs, it would not alleviate our responsibility to identify those costs and ensure they are properly accounted for in [the QF's] transactions with [the utility]. The alternative would be to load such costs into the avoided cost methodology, which would decrease, probably significantly, the price [the utility] must pay to [the QF] for its output.[103]

In sum, PURPA prohibits this Commission from promoting the interconnection of CSP QFs at the expense of customers, and Staff's proposals to shift QF interconnection costs to customers—without any attendant avoided cost adjustments to hold customers indifferent—must be rejected.

d. Network upgrade costs can be substantial—even for small projects—and network upgrades do not necessarily benefit customers or the system as a whole.

The costs of network upgrades associated with a QF's interconnection can have a significant impact on customer rates—particularly when QFs choose to site their projects in either transmission-constrained areas or discrete load centers where there is insufficient load to sink additional generation. In such circumstances, the QF's siting decision may require significant network upgrades to facilitate the interconnection or to make the QF eligible for firm delivery to load, which may be located beyond the constraint.

Staff appears to believe that, because CSP QFs are less than 3 MW in size, they are unlikely to require expensive upgrades.[104] But this is not necessarily the case. In fact, in 2016, PacifiCorp issued an interconnection study for a small 2-MW solar project located in Klamath County, Oregon.[105] The study identified nearly $4.5 million of interconnection costs, the majority of which related to a required line reconductoring that would not have

[103] Glen Canyon Order at 31.
[104] UM 1930 Staff Memo at 10 (stating that small generators have a "minimal impact" on the system while nonetheless being required to bear "the cost of higher queued generators").
[105] This project was assigned interconnection queue number Q0758; the study described is publicly available here: https://www.oasis.oati.com/PPW/PPWdocs/Q758SIS.pdf.

been performed but for the QF's siting decision. Similarly, in 2015 Idaho Power had a 5-MW solar generation interconnection request that resulted in estimated network upgrade costs of $27,609,000, and in 2013, Idaho Power had a 10-MW QF solar generation interconnection customer come online after paying for over $4.7 million of network upgrades. Yet, under Staff's proposals, the costs of these upgrades would be paid for by customers, not the QF. Notably, Staff includes ***no limitation*** on the costs that customers would be required to bear to facilitate a CSP QF's interconnection, which means that the consequences of Staff's proposal could be significant and irreversible.

Staff's Memo also appears to assume that all network upgrades will benefit the transmission system—and by extension the utility and its customers.[106] However, this is not universally true. Upgrades and facilities identified in the QF interconnection process are specifically selected, designed, and scaled to accommodate the specific generation project and typically do not have additional, independent system-wide benefits that would be pursued without the addition of the QF generator. For instance, in the PacifiCorp example discussed above, the line reconductoring required to interconnect the 2-MW solar project would provide little to no system-wide benefits.

Staff states that FERC presumes network upgrades benefit all users of the transmission system—suggesting that this Commission should make the same assumption.[107] However, FERC's decision to liberally define the benefits of network upgrades was a policy determination designed to encourage wholesale competition—not a fact-specific

[106] UM 1930 Staff Memo at 10 ("[N]etwork upgrades are likely to benefit the utility and other transmission customers").
[107] UM 1930 Staff Memo at 8.

determination that each network upgrade has a measurable benefit to the system.[108] This distinction is important in the PURPA context where the must-purchase obligation removes wholesale competition and utility customers must be held indifferent to QF generation and therefore cannot be required to pay for hypothetical or attenuated benefits that they do not clearly and directly receive.

Finally, even if a network upgrade triggered by a QF were to provide some incremental capacity or system reliability benefit, the utility and its customers should not be forced to pay for an upgrade that they would not otherwise choose to make simply because a QF elected to site in a location triggering the upgrade and without any consideration of whether the upgrade was cost-effective. Indeed, the utility's obligations under PURPA and the CSP statute should not be understood to upend the utility's responsibility to prudently plan for and invest in cost-effective transmission and distribution system upgrades, or the Commission's responsibility to ensure that the rates customers pay are fair and reasonable.

Moreover, Staff's proposal to relieve CSP QFs of a portion of their interconnection costs removes a key incentive for developers to efficiently site their projects. As discussed above, network upgrades need not be substantial and can, in fact, be relatively small or non-existent if a QF carefully sites its project. However, by shifting the costs of the developer's siting decision to customers, Staff's proposal removes the incentive to appropriately site CSP QFs, thereby undermining the Commission's repeated assertion that its policies should encourage *efficient* QF development.[109]

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[108] *Entergy Servs. v. FERC*, 319 F.3d 536, 543-44 (D.C. Cir. 2003) (concluding that FERC's decision to credit network upgrades "reflects its policy determination that a competitive transmission system . . . is in the public interest").
[109] *See, e.g.*, Order No. 18-025 at 4.

4. <u>Staff's proposals will not stimulate "creative" solutions, and alternative approaches may also shift costs to customers.</u>

Staff's Memo echoes a theme the utilities have heard often: if the utilities merely tried harder and were more creative, they could come up with solutions that allow QFs to avoid network upgrade costs.[110] Staff offers no support for this vague assertion, which is quite simply incorrect.

Although there may be ways to mitigate the need for upgrades in some cases, they cannot be relied upon to mitigate QF-imposed costs in every instance, meaning that some QFs would still cause network upgrade costs that shift to customers under Staff's proposals. Importantly, any solution that may avoid some upgrades would presumably come with its own costs. Hoping for a creative solution is no substitute for the robust customer protections provided by the Commission's well-reasoned and long-standing QF interconnection policies.

B. Staff's proposal to allow CSP QFs to share distribution upgrade costs with each other appropriately maintains cost responsibility with the QFs and could be workable—provided that other interconnection customers are not adversely impacted.

The Joint Utilities tentatively support the concept behind Staff's proposal to allow CSP QFs to share distribution upgrade costs among themselves, because this proposal does not appear to shift costs to customers. However, the Joint Utilities recognize that additional discussions and development of this proposal will be necessary to understand how it would work in practice and to ensure that other, non-CSP interconnection customers would not be affected.

The Joint Utilities understand Staff's proposal to be akin to a line extension policy—the initial CSP QF would pay for the full cost of the upgrade and then any other CSP QFs

[110] UM 1930 Staff Memo at 13 (stating that Staff's proposals will "test the extent to which these utilities are empowered to find creative solutions and efficiencies in identifying interconnection upgrades").

applying to interconnect in that area that benefit from the upgrade would reimburse the initial CSP QF commensurate with their use of any available capacity created by the upgrade.[111] Under Staff's proposal, the Joint Utilities would continue processing all interconnection requests in serial queue order and allocating initial distribution upgrade costs to the QF pursuant to the current rules. The proposal would not permit interconnection out of queue order, or "leap frogging,"[112]—a concept with which the Joint Utilities are uncomfortable given the inherently intertwined nature of the FERC- and state-jurisdictional interconnection processes.[113] The Joint Utilities also understand that the proposal would not require the utilities to conduct cluster studies.

Based on their current understanding of the proposal and subject to additional discussions about how it would be implemented, the Joint Utilities support Staff's proposal as a solution that could facilitate CSP QF interconnection without imposing costs on customers in violation of PURPA.

C. The Joint Utilities support transparency and look forward to discussing Staff's proposal to address the perceived backlog of interconnection studies.

Staff recommends that the utilities be required to file a plan with the Commission to address the backlog of studies, and that "each utility file a summary of outstanding

[111] UM 1930 Staff Memo at 13.
[112] *See* UM 1930 Staff Memo at 15 (proposing to "[a]llow leap frogging based on readiness," and presumably even allowing a state-jurisdictional interconnection request to "leap frog" over a FERC-jurisdictional interconnection request, as a potential solution for consideration in Docket UM 2000).
[113] *See, e.g.*, Order No. 2006-A at P 105 ("The Commission encourages development of state interconnection programs, and interconnections with state jurisdictional facilities continue to be governed by state law. However, if an Interconnection Customer seeks to interconnect[] with a facility under federal jurisdiction, a state program cannot displace federal rules for interconnections."); *San Diego Gas & Elec. Co.*, 147 FERC ¶ 61,093, P 9 (2014) (letter order) ("Consistent with our findings for SoCal Edison and PG&E, we find that coordinating the cluster study processes for interconnection requests to SDG&E's distribution system and the CAISO-controlled transmission system will achieve greater efficiency and effectively manage network impacts on both systems."); *see also* Order No. 2006 at P 502 ("[W]e hope to minimize the federal-state division and promote consistent, nationwide interconnection rules.").

interconnection studies and forecasted timeline to process the studies." [114] The Joint Utilities are unclear about the scope of Staff's proposal. However, the Joint Utilities welcome continued conversations regarding what additional information they could provide to increase transparency and respond to Staff's concerns.

First, it is unclear what interconnection studies Staff intends the reporting requirement to encompass (e.g., both FERC- and state-jurisdictional? both large and small generators?). It is also unclear which studies would be considered "outstanding," and what it means to "process the studies." [115] The Joint Utilities look forward to better understanding Staff's proposal at the upcoming workshop. Second, the Joint Utilities would like to discuss potential overlap with the interconnection reporting requirements already adopted in Docket UM 2001 and to understand what additional information not captured in Docket UM 2001 Staff would like the utilities to provide. Finally, any new reporting requirement should balance the additional burden imposed with the new value added by the reporting.

In sum, the Joint Utilities support transparency and welcome the opportunity for continued conversations to clarify the proposed reporting requirements and understand what additional information the utilities can provide to increase transparency without over-burdening the utilities' interconnection personnel.

V. Conclusion

The Joint Utilities share Staff's desire to promote development of CSP projects and ensure that CSP QFs—and all interconnection customers—experience a fair and functional interconnection process. To that end, the Joint Utilities support efforts for increased

[114] UM 1930 Staff Memo at 14.
[115] UM 1930 Staff Memo at 14.

transparency and also support Staff's proposal to allow CSP QFs to share costs, because it appropriately maintains cost responsibility with the QFs.

However, the Joint Utilities believe that no process can be considered fair if it allows generators to make costly siting decisions and forces utility customers to pay for the costs resulting from those decisions. As explained in these comments, at this point it appears that most CSP QFs' interconnections are likely to be feasible and reasonably economical, but Staff's proposals to facilitate all CSP QF interconnections at utility customers' expense are contrary to PURPA and also find no support in FERC's reasoning, Commission precedent, or the CSP statute itself.

Staff's dramatic proposals regarding CSP interconnection are all the more concerning because they are proposed to be implemented through an emergency rulemaking—which will not provide adequate time and process to fully vet the significant changes to existing policy that Staff proposes, or their factual underpinnings. If Staff and the Commission nevertheless elect to proceed with the articulated proposals—despite the legal impediments and lack of adequate process—the Joint Utilities request the opportunity to provide additional comments regarding the practical aspects of implementing these proposals.

In closing, the Joint Utilities note that PURPA's must-take and customer-indifference requirements and FERC's firm-delivery and limited-curtailment requirements make QFs particularly challenging to integrate into constrained or generation-heavy areas of a utility's system. These are complex problems that are not easily solved by a quick reversal of long-standing policy, and the Joint Utilities look forward to helping all parties fully understand the factual and legal issues implicated and to participating in continued collaborative discussion of these important issues.

Respectfully submitted this 24th day of July, 2019.

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