BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1610 (Phase II)

In the Matter of

PUBLIC UTILITY COMMISSION STAFF

Investigation into Qualifying Facility Contracting and Pricing.

STAFF PREHEARING MEMORANDUM

8/15

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I. Introduction.

In this prehearing memorandum, Staff addresses the nine issues regarding qualifying facility (QF) contracting and pricing presented to the Commission in Phase II of Docket No. UM 1610.

II. Analysis of the nine issues presented in Phase II.

Issue No. 1: Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QF are at market?

Staff position: QFs are not compensated for the Green Tags associated with their generation when they are paid market-based prices and should therefore own the Green Tags when they are paid market-based prices, even if the utility is renewable resource deficient.

A. There is potentially conflicting language in Order No. 05-584 regarding the term of QF contracts and in Order No. 11-505 directing utilities to offer renewable avoided cost prices.

This issue arises because of potentially conflicting language in two orders – the Commission's 2005 order deciding QFs must be paid market-based rates during the last five years of a 20-year fixed-price contract and its 2011 order directing QFs to cede "Green Tags," (hereinafter referred to as renewable energy credits (RECs)), to utilities during the utilities' deficiency periods. In Order No. 05-584, the Commission decided that utilities should offer QFs fixed-rate contracts with terms up to 20 years.[1] Because of the speculative nature of forecasted prices for such an extended term, the Commission decided that the fixed-rate portion of a 20-year

[1] Order No. 05-584 at 19-20.

contract should be 15 years, and that rates paid in the last five years should be based on market prices.[2]

In 2011, the Commission ordered PacifiCorp and Portland General Electric Company (PGE) to offer Standard Renewable Avoided Cost prices based on costs of the next avoidable renewable resource in their integrated resource plans (IRPs). The Commission specified that when the utility is renewable resource deficient, Standard Renewable Avoided Cost prices are based on the costs of the next avoidable renewable resource.[3] During periods of renewable resource sufficiency, Standard Renewable Avoided Cost prices are based on market prices.[4] The 2011 order specified that during periods of resource deficiency, QFs receiving the Standard Renewable Avoided Cost prices must transfer RECs associated with energy sold to the utility, but may keep the RECs during the utility's resource sufficiency periods.[5]

B. The rationale for renewable avoided cost prices in Order No. 11-505 supports the renewable QF's ownership of RECs during the periods the QF receives market-based rates.

Requiring QFs to cede RECs to utilities *only* when the QFs are receiving payments based on deficiency period prices under the Standard Renewable Avoided Cost price stream is consistent with the rationale underlying the Commission's 2011 decision to authorize Standard Renewable Avoided Cost prices. The Commission's decision relied on 2010 rulings issued by the Federal Energy Regulatory

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[2] Order No. 05-584 at 20.
[3] Order No. 11-505 at 19.
[4] Order No. 11-505 at 19.
[5] Order No. 11-505 at 19.

Commission (FERC) concluding that a multi-tiered avoided cost price structure allowing different avoided cost price streams for different resource types is permissible.[6] In those rulings, FERC explained that when determining what costs the utility would avoid, states may take into account state-imposed requirements, such as a requirement that utilities purchase energy from particular sources of energy or for a long duration.[7]

Allowing a renewable QF to choose between renewable and non-renewable avoided cost price streams is consistent with FERC's ruling clarifying the right of the states to determine the avoided cost associated with utility purchases of energy "from generators with certain characteristics." Renewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation to meet their RPS requirements. These QFs should be offered an avoided cost stream that reflects these particular costs the utility will avoid.[8]

Order No. 11-505 links the QF's obligation to transfer RECs to the receipt of prices designed to compensate for the value of the RECs.[9] Meaning, the QF is required to transfer RECs to the utility to be eligible for avoided cost prices based on the fixed costs of the next avoidable renewable resource. The QF should not be required to transfer RECs to the utility when it is not receiving compensation that includes the value of these RECs.

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[6] *California Public Utilities Commission*, 132 FERC 61,047, 2010 WL 2794334 (*Declaratory Order*); 132 FERC 61047, 2010 WL 2794334 (*Order Granting Clarification and Denying Rehearing*); 133 FERC 61,159 (2010 WL 4144227)(*Order Denying Rehearing*).

[7] *Id.*

[8] Order No. 11-505 at 9.

[9] See Order No. 11-505.

C. PGE's and PacifiCorp's reliance on the Commission's statement in Order No. 11-505 that QFs must transfer RECs to utilities during the utilities' deficiency periods ignores the reason QFs must transfer RECs to utilities.

PGE asserts that under the Commission's 2011 order implementing Standard Renewable Avoided Cost prices, QFs must always transfer RECs to the utility during the utility's deficiency period no matter whether the QF is receiving deficiency period prices based on the fixed costs of the next avoidable renewable resource.[10] PGE testifies that the purpose of entering into a standard renewable contract is to obtain the QF's green tags during resource deficiency periods.[11] PGE testifies that "[i]f the utility is entering into a standard renewable PPA and guaranteeing that it will purchase the QF power, the utility should own the Green Tags regardless of the price of purchase during a period of resource deficiency."[12]

PacifiCorp notes that the Commission decided that QFs should receive market-based prices during the last five years of a standard contract in order to reduce the risk of forecasting prices for a 20-year contract while still facilitating financing for the QF.[13] PacifiCorp asserts that there is no relationship between the Commission's order regarding market-based prices in the last five years of a standard contract and RECs. Instead, REC ownership is related to the utility's resource position.[14] Relying on these points, PacifiCorp asserts that REC ownership

[10] PGE/500, Macfarlane-Morton/4-6.
[11] PGE/500, Macfarlane-Morton/6.
[12] PGE/500, Macfarlane-Morton/6.
[13] PacifiCorp/1000, Griswold/4.
[14] PacifiCorp/1000, Griswold/6-7.

must pass to utilities during their resource deficiency periods notwithstanding "a QF's voluntary option to accept market prices during the last five years of a PPA."[15]

The arguments of PGE and PacifiCorp overlook the rationale underlying the Commission's requirement that QFs transfer RECs to utilities. The Commission is authorized to include the value of environmental benefits represented by the RECs in avoided cost prices when purchases from the QFs allow utilities to avoid the cost of acquiring these benefits/RECs in another way. In other words, the utilities' obligation to pay prices based on the costs of the next avoidable renewable resource and the QFs' obligation to transfer RECs are inextricably linked. Neither obligation should be imposed unilaterally.

Issue No. 2: Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?

Staff position: If a utility will avoid transmission costs as well as the costs of the proxy resource, the avoided transmission costs should be included in the calculation of avoided cost prices, even if the proxy resource is an on-system resource.

A. The Commission concluded in Order No. 14-058 that PacifiCorp would not have avoided transmission costs for its on-system proxy resources, but some evidence shows that this may not always be true.

This issue is presented at least in part to clarify or modify the Commission's decision in Order No. 14-058 that PacifiCorp has no avoided transmission costs because its proxy resource is on-system. Specifically, the Commission concluded in Order No. 14-058 that "[i]f the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus

[15] PacifiCorp/1000, Griswold/7.

the costs of third-party transmission are not included in the calculation of avoided cost prices. This is the situation for Pacific Power."[16] Staff believes there is evidence in the Phase II record that supports the conclusion that PacifiCorp may have avoided transmission costs even though its proxy resource is an on-system resource. [17] Because it appears that it is possible PacifiCorp may have avoided transmission costs for its avoided proxy resource, Staff recommends that the Commission modify its decision in Order No. 14-058 and specify that if PacifiCorp would avoid costs to build or acquire transmission for an on-system proxy resource, avoided transmission costs should be included in the calculation of avoided cost prices.

1. OneEnergy presented evidence to show that PacifiCorp may have avoided transmission costs for its on-system resource.

OneEnergy, Inc. (OneEnergy) testifies that there is at least one PacifiCorp proxy resource for which PacifiCorp would incur transmission costs that it may not incur for a resource in a different location.[18] OneEnergy testifies that PacifiCorp's renewable avoided cost prices are based on a proxy wind plant to be located in the "Aeolus wind bubble" in Wyoming.[19] OneEnergy states that it "is widely known that insufficient transmission exists today to get new generation resources from the wind bubble to PacifiCorp load. Recent wind QF agreements with projects in this area have required the QF to accept a reduced purchase price to account for

[16] Order No. 14-058 at 17.
[17] *See e.g.*, OneEnergy/400, Eddie/4-5.
[18] OneEnergy/400, Eddie/2-3.
[19] OneEnergy/400, Eddie/2-3.

PacifiCorp's curtailment of other Network Resources using the same transmission paths."[20]

2. PacifiCorp's testimony that it will never have avoided transmission costs is not consistent with some of its other testimony in Phase II.

PacifiCorp testifies that avoided cost prices should not include avoided costs for "Company-owned infrastructure and third-party rights" to move energy across the Company's multi-state service territory because purchasing from a QF does not allow it to avoid transmission costs.[21] PacifiCorp asserts that this is because "Company-owned transmission infrastructure and contractual rights on third-party systems are needed to operate PacifiCorp's system whether it adds QFs or non-QF resources."[22]

PacifiCorp's testimony that it will never avoid transmission costs with a QF purchase is inconsistent with its own testimony. PacifiCorp testifies that it will incur third-party transmission costs for some QFs because they are located in load pockets.[23] Presumably, PacifiCorp would incur the same type of costs if its next avoidable resource is in a load pocket.

B. It is not necessary to determine the factual question of whether PacifiCorp will ever avoid transmission costs before modifying the Commission's previous holding.

This docket is intended to resolve policy questions, not factual issues. Accordingly, it is not necessary for the Commission to find that PacifiCorp will avoid

[20] OneEnergy/400, Eddie/3, *citing* Eddie/1; Response to OneEnergy Data Request 6.1 (OneEnergy/401).
[21] PacifiCorp/800, Dickman/5.
[22] PacifiCorp/800, Dickman/5.
[23] PacifiCorp/1000, Griswold/25-26.

transmission costs when its avoidable proxy resource is on-system. Staff recommends that the Commission merely leave open the possibility that such costs can be included in the calculation of avoided cost prices. Whether there are such avoided transmission costs is a factual question that should be informed by PacifiCorp's integrated resource plan (IRP) and addressed, if necessary, in the process used to determine avoided cost prices.

C. The test recommended by OneEnergy for determining whether there are avoided costs for on-system proxy resources can inform resolution of this question in the process to determine avoided cost prices.

OneEnergy recommends the following test to determine whether there are avoided transmission costs:

> If the on-system proxy resource cannot be designated a Network Resource at its full capacity without transmission upgrades and without a de-rating or curtailing other Network Resources, then the cost of transmission upgrades necessary to make it a Network Resource should be included in avoided cost prices.[24]

Staff thinks this test could inform the determination of avoided cost prices in the Commission's review process for avoided cost price filings, but does not support OneEnergy's recommendation that the Commission order this test be used to finally determine the question of avoided transmission costs in every case. Instead, the Commission should clarify that there may be situations in which avoided transmission costs should be included in the calculation of avoided cost prices when the proxy resource is an on-system resource, and that parties may address the issue

[24] OneEnergy/400, Eddie/2-3.

on the facts for a particular proxy resource in process following the avoided cost filings made within 30 days of an acknowledged IRP.

Issue No. 3: Should the Commission revise the methodology approved in Order No. 14-058 for determining the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices? If so, how?

and

Issue No. 4: Should the capacity contribution calculation for standard non-renewable avoided cost prices be modified to mirror any change to the solar capacity contribution calculation used to calculate the standard renewable avoided cost price?

Staff position: The method used to calculate the capacity contribution adjustment for both the Standard Renewable and Non-renewable Avoided Cost prices should be modified so that the capacity payments to QFs are based on the QF resource type's contribution to meeting the utility's peak load.

A. The Staff-recommended capacity contribution calculation adopted by the Commission in Order No. 14-058 is flawed.

The capacity contribution calculation adopted by the Commission in Order No. 14-058 ("the Current Method") is flawed with respect to solar QFs under both the Standard Renewable and Non-Renewable Avoided Cost price streams and wind QFs under the Standard Non-Renewable Avoided Cost price stream.[25] When it proposed this methodology in Phase I, Staff intended to determine the appropriate avoided capacity cost to include in the on-peak price during the utilities' deficiency periods by multiplying the QF resource type's contribution to peak by the capacity cost of the utility's avoided proxy resource. So for example, if the QF resource type's contribution to peak is 15 percent, the appropriate avoided cost for purposes of determining the avoided cost price would be 15 percent of the capacity costs of the avoided proxy resource.

[25] Staff/300, Andrus/7.

Staff's error was in using the volumetric (per-MWh) capacity price to represent the "dollar value of capacity," rather than the cost itself. The consequence is that capacity payments to solar QFs under both the renewable and non-renewable avoided cost price streams are subject to two discounts, one for the QF resource type's contribution to peak and the other for the QF's on-peak capacity factor.

1. The Commission's traditional rate design for avoided cost prices is based on the characteristics of a CCCT.

In Oregon, the calculation of standard avoided cost prices has long been differentiated by the utility's resource position.[26] For periods when the utility is forecasted to be resource deficient, avoided cost prices include both the variable and fixed costs of a planned resource in order to reflect the actual deferral or avoidance of that resource. In periods of resource sufficiency, avoided costs do not include fixed costs of avoided resources.[27]

To determine this fixed cost (capacity) portion of standard avoided cost prices, the three utilities convert the fixed costs for the capacity of a proxy combined cycle combustion turbine (CCCT) to a dollar-per-megawatt hour (MWh) rate based on the on-peak capacity factor (CF) of the CCCT. To determine the fixed costs of a CCCT that are for capacity, utilities use estimates of the fixed costs of a pure capacity resource, a single-cycle combustion turbine (SCCT)).[28]

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[26] *See* Order No. 05-584 at 24.
[27] *See* Order No. 05-584 at 26.
[28] *See* Order No. 05-584 at 26. This method was used for Standard Non-Renewable Avoided Cost prices, which were the only standard avoided cost prices authorized until Order No. 11-505. In Order No. 11-505, the Commission authorized Standard Renewable Avoided Cost prices based on the next avoidable renewable resource in the utilities' IRPs. The utilities' compliance filings with standard renewable rates never became effective, however. In Order No. 14-058, the Commission authorized capacity contribution adjustments to Standard Non-Renewable Avoided Cost prices obtained from the traditional method for determining avoided capacity costs (based on capacity costs of CCCT).

After determining the amount of avoided capacity costs of a CCCT, the utilities' first step in designing the volumetric rate is to determine the number of hours that should be used to "spread" the costs. The utilities spread the avoided costs to a subset of on-peak hours, rather than all on-peak hours, because the proxy CCCT is not expected to be available in all on-peak hours. Accordingly, the utilities spread the avoided costs to the number of on-peak hours the proxy CCCT is expected to be available.

The utilities determine the appropriate number of hours to spread the avoided costs by multiplying the number of on-peak hours in a year by the on-peak CF of the proxy CCCT.[29] On-peak hours are defined by the North American Electric Reliability Corporation (NERC) as 6:00 a.m. to 10:00 p.m. Monday through Saturday, except certain holidays.[30] Approximately 57 percent of the hours in a year are "on-peak" hours.[31] The exact number of annual on-peak hours varies slightly by year, depending on whether designated holidays fall on Sunday when there are already no peak hours and other factors. For purposes of this testimony, Staff will assume there are 4993 on-peak hours in a year.

The CF of a resource is the ratio of the MWh generated over a designated period of time to the product of the capacity of the resource and the number of hours in the designated period of time (e.g., 8,760 hours for an annual CF, 24 hours for a daily CF, etc.). The *on-peak* CF is the ratio of the MWh generated in the on-peak hours of a designated period to the product of the capacity of the resource and the number of on-peak hours in the designated period. The determination of the proxy CCCT's on-peak CF is based on inputs from the utilities' IRPs.

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[29] Staff/400, Andrus/4.

[30] Staff/300, Andrus/8.

[31] See PAC/600, Duvall/2 ("On-peak hours are defined as 6 AM to 10 PM Monday through Saturday, excluding holidays, or 57 percent of hours in a year.")

Staff used 91.8 percent as the on-peak CF for the proxy CCCT in the example equations in its Phase I testimony.[32] Assuming the proxy CCCT has an on-peak CF of 91.8 percent and assuming there are 4993 on-peak hours in the year, the equation to determine the number of hours to use to spread the capacity costs of the proxy CCCT looks like this:[33]

91.8% x 4993 = 4586

[on-peak CF of CCCT x annual on-peak hours = CCCT adjusted on-peak hours]

Once the capacity costs of the CCCT and the CCCT adjusted on-peak hours are determined, the utilities then determine the volumetric rate (price) for capacity by dividing the total annual capacity costs of the CCCT per MW by the number of CCCT adjusted on-peak hours. Using $140,320 as the estimated annual capacity costs of the proxy CCCT[34] and the CCCT adjusted on-peak hours from the equation above, the equation to determine the volumetric rate (price) is as follows:

$140,320 ÷ 4586 hours = $30.61 per hour

[annual capacity costs of CCCT ÷ CCCT adjusted on-peak hours = MWh price]

Under the traditional method, the MWh price for capacity obtained from this calculation, $30.61, is added to the on-peak energy price for all on-peak hours.

The discussion above shows that the design of the traditional volumetric rate for avoided capacity is specific to the operating characteristics of a CCCT. The utilities use the capacity costs of a CCCT to determine their annual avoided capacity costs and use the on-peak CF of the CCCT to determine the subset of on-peak hours to use to spread the CCCT's capacity costs. This means that when the utilities create the volumetric rate, they base the rate on the assumption the proxy resource will

[32] Staff/400, Andrus/8-9. The on-peak CF for the proxy resources used to calculate the adder would be based on inputs from the utilities' IRPs. (Staff/300, Andrus/13.)

[33] Staff/400, Andrus/8-9.

[34] Staff used this amount in its example equations in its testimony. (Staff/400, Andrus/8-9.)

not be available to operate in all on-peak hours (e.g. because of scheduled maintenance, etc.). In other words, the rate is designed to recover 100 percent of the capacity costs of the CCCT in less than 100 percent of the on-peak hours.

If the utilities based the volumetric rate on the total number of annual on-peak hours, rather than a subset during which the resource is expected to be available, the rate could not as a practical matter flow through 100 percent of the capacity costs because resources generally are not available 100 percent of the time.

2. Staff's Proposed Method is based on the characteristics of the QF resource type.

Staff's Proposed Method for determining the capacity contribution adjustment for solar QFs selecting the Standard Renewable or Non-Renewable Avoided Cost price stream and for wind QFs selecting the Standard Non-Renewable Avoided Cost price stream uses the same rate design methodology used to design the traditional avoided cost price for capacity described above. But, Staff's Proposed Method uses the operating characteristics of a proxy solar and proxy wind resource to determine the incremental amount of capacity costs that are avoided and how those costs should be spread.

As with the Current Method, Staff's Proposed Method for the capacity contribution adder for solar QFs selecting standard renewable avoided cost prices is based on a proxy solar resource's incremental contribution to peak (CTP), relative to the avoided proxy renewable resource in the utility's IRP.[35] As PacifiCorp states in its testimony, the CTP "of a generating resource takes into account the time of the generation and how it contributes to system reliability."[36] There are multiple ways

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[35] Aside from the capacity contribution adder, standard renewable avoided cost prices are based on the costs of the next avoidable renewable resource in the utility's IRP, which is currently a wind resource for both PGE and PacifiCorp.

[36] PAC/600, Duvall/4. *See also* Idaho Power/600, Youngblood/7 ("[CTP] is a measure of how much capacity a resource is provided on-peak when the Company needs it most.").

to determine the CTP of a resource, including the "Exceedance Method" and the Effective Load Carrying Capability (ELCC) Method.[37] Staff does not have a recommendation for a specific method to determine the CTP of a proxy solar resource. Instead, Staff has recommended using inputs from the utilities' IRPs.[38] The inputs for CTPs would be subject to review in the same manner as other inputs.[39]

The proxy solar resource's incremental CTP represents the amount of additional capacity the solar resource would provide over the proxy wind farm. It is determined by subtracting the CTP of the proxy renewable resource in the utility's IRP from the CTP of the proxy solar resource.

The proxy solar resource PacifiCorp used to determine the CTP for its Phase I compliance filing has a CTP of 13.6 percent.[40] The proxy wind resource that is the basis of PacifiCorp's standard renewable avoided cost calculations has a CTP of 4.2 percent. Using these inputs, the equation to determine the solar resource's incremental CTP looks like this:

13.6% - 4.2% = 9.4%

[solar proxy CTP – renewable resource proxy CTP = incremental solar CTP]

Once the incremental solar CTP is determined, the next step is to determine the incremental capacity costs that the solar resource allows the utility to avoid, over the avoided capacity costs for the proxy renewable resource. The incremental avoided capacity costs are determined by multiplying the incremental solar CTP by the annual CCCT capacity costs. Using the same annual CCCT capacity costs used in

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[37] See Obsidian/300, Brown/11.
[38] Staff/300, Andrus/13.
[39] The Commission has opened a docket to investigate methodologies to determine renewable generators' contribution to meeting peak capacity. (See Docket No. UM 1719.)
[40] See Obsidian/300, Brown/11.

the examples above and 9.4 percent as the incremental solar CTP, the equation is as follows:

\$140,320 x 9.4% = \$13,190

[CCCT capacity cost x incremental solar CTP = incremental solar capacity cost][41]

Next, the number of hours over which the incremental capacity costs will be spread is determined as it was in the traditional method, except using the on-peak CF of the solar proxy rather than the on-peak CF of the proxy CCCT. Under Staff's Proposed Method, the on-peak CF of the proxy solar resource is based on inputs from the utilities' IRPs, and subject to review as are other inputs to avoided cost prices.[42]

For purposes of this brief, Staff will assume the on-peak CF of the proxy solar resource is 27.5 percent.[43] Using this input and 4993 as the number of annual on-peak hours, the equation to determine the number of megawatt-hours (MWh) to which to spread the incremental avoided capacity costs of the proxy solar resource is as follows:

27.5% x 4993 hours = 1373 MWh[44]

[on-peak CF of solar resource x annual on-peak hours = solar adjusted on-peak hours]

Once the incremental amount of avoided capacity costs and the appropriate adjustment to on-peak hours are determined, the volumetric rate for the capacity contribution adder is determined by dividing the incremental avoided capacity costs for the proxy solar resource by the number of solar adjusted on-peak hours. This volumetric rate shows how much should be charged during on-peak hours so that a

[41] Staff/400, Andrus/8-9.
[42] Staff/400, Andrus/13.
[43] This is the percentage used in examples in Staff testimony. (Staff/400, Andrus/9.)
[44] Staff/400, Andrus/9.

solar QF operating consistently with the CF of proxy solar resource could recover the value of its capacity contribution. Using $13,190 as the incremental amount of avoided capacity costs for the solar proxy resource and 1373 as the number of solar adjusted on-peak hours, the equation to determine the volumetric rate for the capacity contribution adder for a solar QF is as follows:

$13,190 ÷ 1373 MWh = $9.60 per MWh[45]

[incremental capacity costs for solar QF ÷ solar adjusted on-peak hours = price per MWh]

As with the traditional method, the price per MWh for the solar QF capacity contribution adder is added to the avoided cost price for energy and paid to solar QFs for generation during on-peak hours.

Under Staff's Proposed Method, the incremental avoided capacity costs for a proxy solar resource are spread to a subset of MWh so that the rate is designed to recover, on an expected basis, 100 percent of the incremental capacity costs in less than 100 percent of the on-peak hours, as is done in the traditional method. The following table shows the similarity of the two methods with a side-by-side comparison of the calculations in each:

Table 1: Calculation of Avoided Capacity Costs

Calculations to determine:	**Traditional Method**	**Staff Proposed Method**
Avoided capacity costs	Fixed costs of SCCT	Fixed costs of SCCT x incremental CTP of solar resource
MWh over which to spread avoided capacity costs	On-peak CF of proxy CCCT x annual # of on-peak MWh	On-peak CF of proxy solar resource x annual # of on-peak MWh
MWh price	Avoided capacity costs of	Incremental avoided

[45] Staff/400, Andrus/9.

	CCCT ÷ CCCT Adjusted MWh	capacity costs for solar resource ÷ Solar Adjusted MWh
Hours to which MWh price for capacity applies	All on-peak hours in which the CCCT generates	All on-peak hours in which the solar resource generates

B. Staff's Proposed Method is permissible under PURPA and does not compensate QFs for capacity they do not provide.

The three utilities assert that Staff's Proposed Method is a departure from the Commission's long-standing policy of basing avoided cost prices on the characteristics of the proxy resource and that Staff's Proposed Method would result in paying solar QFs for capacity they do not provide.[46] Using characteristics of the QF resource type rather than those of the avoided proxy resource is a departure from the Commission's traditional avoided cost methodology, but one the Commission authorized in Order No. 14-058. And, as discussed below, Staff's Proposed Method does not result in paying solar QFs for capacity they do not provide.

1. Basing avoided cost prices on characteristics of the QF is authorized by the Commission and is consistent with PURPA.

In Phase I, Staff proposed that the Commission depart from precedent and consider the capacity value that different QF resources bring to the utilities' systems when setting avoided cost prices. As the utilities point out in their testimony, the Commission's traditional method is based strictly on costs of the proxy resource. The point of Staff's Phase I recommendation was to more accurately match the utility's avoided cost prices to the value of each resource type's contribution to meeting the utility's peak load.

[46] *See e.g.*, PAC/700, Duvall/2, PGE/500, Macfarlane/4, Idaho Power/600, Youngblood/14-16.

As explained above, Staff's Phase I proposal (now the "Current Method") for calculating the capacity contribution adder for solar QFs is flawed because the rate design used to determine the price for the incremental avoided capacity provided by the solar QF is still based on the characteristics of a CCCT. This flaw is addressed with Staff's Proposed Method in which both the incremental amount of avoided capacity costs attributable to a solar QF and the design of the rate to pay solar QFs are based on the characteristics of a proxy solar resource.

Although the Current Method is a departure from the Commission's previous avoided cost methodology, it is consistent with the Public Utility Regulatory Policy Act (PURPA) and implementing regulations. Under 49 C.F.R. § 292.304, standard avoided cost prices can vary by resource type.

In its order adopting rules to implement PURPA, FERC noted that characteristics of the QF may impact standard avoided cost rates:

> [49 C.F.R. §292.304(3)(vi)] provides that rates for purchase shall take into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system . . ." * * * To the extent that this aggregate capacity value can be reasonably estimated, it must be reflected in standard rates for purchases.[47]

In the same order, FERC used contributions to meeting peak summer loads by solar QFs as an example of when a state may incorporate the value of the generation from the QF into avoided cost rates.

> Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the

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[47] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (45 Fed. Reg. 12,214, 12,224) (Feb. 25, 1980).

> qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.[48]

Staff's Proposed Method is consistent with FERC's observations regarding the potential value of capacity provided by solar QFs during on-peak hours. As Idaho Power notes in its testimony, "[c]apacity contribution is a measure of how much capacity of a resource is provided on-peak, when the Company needs it the most."[49] Staff's Proposed Method for calculating the capacity contribution adder for solar QFs under the Standard Renewable Avoided Cost price stream allows solar QFs to receive capacity payments that are commensurate with the value of their contributions to meeting the utility's peak load.

2. QFs will not be paid for capacity they do not provide under Staff's Proposed Method.

The utilities are incorrect that Staff's Proposed Method would result in utilities paying solar and wind QFs more than the utilities' avoided capacity costs.[50] Staff's testimony includes examples of what a solar QF resource could expect to be paid for capacity under the avoided cost price method used prior to adoption of standard renewable avoided cost prices in Order No. 11-505 ("the Previous Method),[51] the Current Method (adopted in Order No. 14-058), and Staff's Proposed Method, when the CTP for solar resources in the utility's Integrated Resource Plan is 13.6 percent, the CTP for the proxy wind resource is 4.2 percent, the on-peak capacity factor of the proxy CCCT is 91.8 percent, and the utility's estimated avoided annual capacity costs are approximately $140,000 per MW.

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[48] *Id.*, 45 Fed. Reg. at 12225.
[49] Idaho Power/600, Youngblood/7. *See also* PacifiCorp/600, Duvall/4.
[50] Pac/600, Duvall/8.
[51] This investigation interrupted the review of the utilities' filings submitted in compliance with Order No. 11-505, and so the methodology adopted in that order has never become effective.

Under the Previous Method, a solar QF could receive a percentage of the total avoidable capacity costs roughly equal to that QF's on-peak capacity factor. Assuming the individual QF resource had an on-peak capacity factor of 27.5 percent, the solar QF could expect capacity payments for each on-peak MWh to be equal to approximately 30 percent of the fixed costs of a SCCT, $42,000 per year per MW.[52]

Under the Current Method, a solar QF could receive just under $4,000 annually for capacity – less than three percent of the utility's estimated costs for capacity.[53]

Finally, under Staff's Proposed Method, when the solar QF proxy has an incremental CTP of 9.4 percent, the solar QF could expect to receive an adder to its on-peak rate that is roughly equal to 9.4 percent of the avoided capacity costs of the CCCT.[54]

These comparisons show that the utilities' assertion that Staff's Proposed Method would result in payments for costs that are not avoided is incorrect. The proxy solar resource in PacifiCorp's IRP is forecasted to provide PacifiCorp approximately 13.6 percent of the capacity a CCCT could provide over the course of a year. Of that 13.6 percent, 9.4 percent is incremental to the forecasted capacity provided by the proxy wind resource that is the basis for PacifiCorp's standard renewable avoided cost prices. Under Staff's Proposed Method, a solar QF could receive added capacity payments roughly equal to 9.4 percent of the capacity costs of the CCCT.

Contrary to PacifiCorp's assertion, the Staff Proposed Method does not guarantee that a solar QF will receive a "set dollar amount for capacity over the course of the year regardless of how many hours it generates during on-peak

[52] Staff/400, Andrus/5.
[53] Staff/400, Andrus/5.
[54] Staff/400, Andrus/5.

hours."[55] How much a solar QF actually receives will depend on the number of on-peak MW hours it generates.

The same is true with respect to both solar and wind QFs selecting the Standard Non-Renewable Avoided Cost Price Stream. The methodology discussed in Staff's testimony for the Standard Renewable Avoided Cost price stream would apply to wind and solar QFs selecting the Standard Non-Renewable Avoided Cost price stream.

Issue No. 5: What is the appropriate forum to resolve litigated issues and assumptions?

Staff position: Staff recommends that the Commission continue to use the process outlined in Order Nos. 05-584 and 06-358 and in administrative rules to determine avoided cost prices, but also require utilities to meet minimum filing requirements (MFRs) when they make their avoided cost filings.

A. Under the Commission's current process, avoided cost price filings are based on inputs from the utilities' IRPs and subject to a suspension and investigatory process.

Utilities are required to submit updated avoided cost filings within 30 days of acknowledgment of their IRPs and on May 1 of every other year. Utilities are required to base their avoided cost prices on inputs and assumptions in their IRPs. Once they are submitted, "[a]voided cost filings are subject to suspension and the same investigatory process that any tariff filing may undergo."[56]

The Commission discussed this suspension/investigation process in a 2006 order addressing a challenge to the natural gas forecast used as a basis for avoided cost prices as follows:

> We reminded parties [in Order No. 05-584], however, that a utility's natural gas forecasts could be examined and challenged during review

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[55] PAC/700, Duvall/2.
[56] Order No. 05-584 at 36-37.

> of the utility's avoided cost filing. Indeed, we encouraged parties to seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts or any other aspect of a utility's filing. We also observed that Staff, or any other party, could introduce during a future investigation of a utility's avoided costs filing, an independent natural gas forecast for comparison purposes.[57]

Similarly, the Commission's administrative rules specify that avoided cost filings are subject to suspension and modification by the Commission.[58]

B. The Commission should retain the current process, with the addition of minimum filing requirements (MFRs).

The current process, with the addition of minimum filing requirements (MFRs), remains the most appropriate process to determine a utility's avoided cost prices. This Commission has stated "the goal of calculating avoided costs is to accurately estimate the costs a utility would incur to obtain an amount of power that it purchases from a QF, either by the utility's self-generation or by purchase from a third party.[59] Information from the utilities' own resource plans is the best indicator of what prices the utilities will avoid in the future.

The Commission's process has been in place since before 2005. Contrary to concerns voiced by the utilities, this process has not led to litigation of every input from the utilities' IRPs and Staff does not think it will do so in the future. Staff does suggest one improvement to the process, however, the addition of MFRs.

Staff's proposed MFRs would require utilities to expressly identify the inputs used to determine avoided cost prices and where stakeholders and Staff may find these inputs in the utilities' IRPs. Staff believes the MFRs will hasten the review of

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[57] Order No. 06-538 at 44.

[58] OAR 860-029-0080(6) ("Any standard rates filed under OAR 860-029-00040 shall be subject to suspension and modification by the Commission.").

[59] Order No. 05-584 at 20.

avoided cost price filings and that the clarity and transparency added by the MFS may eliminate some disputes.

C. The Commission should reject proposals to materially change the process to determine avoided cost prices.

Staff disagrees with proposals to 1) expand the IRP process to include final determinations of avoided cost prices,[60] 2) implement a process that runs concurrently with the process for utilities' IRPs,[61] or 3) essentially eliminate any process to determine avoided cost prices outside the traditional IRP process.[62]

Expanding the IRP process to determining avoided cost prices would materially change and complicate the IRP process. Currently, the Commission reviews a utility's IRP for adherence to the procedural and substantive requirements in Order No. 89-507 and acknowledges the plan if the Commission finds it "reasonable based on information available at that time" or "return[s] it to the utility with comments." The Commission may also decline to acknowledge specific action items if the Commission questions whether the utility's proposed resource decision presents the least cost and risk option for its customers.[63]

Expanding the IRP process to include litigation of various inputs departs significantly from the purpose of the IRP, which is primarily informational. It could

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[60] ODOE/1100, Carver/4.

[61] See ODOE/700, Carver/4-10. (In reply testimony, ODOE withdrew its proposal for concurrent process for avoided cost price filing review and now supports determining avoided cost prices within the IRP. (ODOE/1100, Carver/4.)

[62] PAC/900, Drennan/2-12.

[63] See e.g., Order No. 14-252 at 1.

also be difficult to complete an expanded IRP process in the six months contemplated by the Commission's IRP Guidelines.[64]

A process that runs concurrently with the IRP is not optimum because the determination of avoided cost prices turns on what costs the utility will avoid. The utility's IRP is the best indicator of what costs the utility will actually avoid. Litigating the costs the utility will avoid prior to the time the Commission reviews the utilities' planned resource actions turns the determination of avoided cost prices on its head.

PacifiCorp's recommendation to limit litigation regarding avoided cost price inputs to the current IRP process is also untenable.[65] PacifiCorp argues that there should be no additional process "whereby stakeholders could litigate inputs and assumptions developed in an acknowledged IRP."[66] PacifiCorp asserts that such a process would undermine the collaborative, transparent IRP process, be duplicative and slow the implementation of updated avoided cost prices.[67] Staff disagrees.

As noted above, the current process has been in place for at least ten years and there has been little "duplicative process." Staff agrees that updated avoided cost prices would be implemented sooner if there was no or extremely limited additional process after IRP acknowledgment. But Staff believes that any harm from delay is outweighed by the benefit of providing an opportunity for stakeholders to challenge avoided cost prices.

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[64] Order No. 07-002 (IRP Guideline 3.c.)("Commission Staff and parties should complete their comments and recommendations within six months of IRP filing.").
[65] PacifiCorp/900, Drennan/10-11.
[66] PacifiCorp/900, Drennan/10.
[67] PacifiCorp/900, Drennan/10-11.

Finally, Staff believes that Idaho Power has misunderstood Staff's position regarding the appropriate process to review avoided cost filings. Idaho Power testifies that "[t]he utilities basically agree with Staff that the current process should not be changed, asserting that parties have the opportunity to challenge assumptions used in the IRP during the public process already in place in developing a utility's IRP.[68] However, Staff's position is more closely aligned with those of Renewable Energy Coalition (REC) and the Community Renewable Energy Association (CREA), which Idaho Power describes as follows:

> REC and CREA believe that parties should be provided an opportunity to review, challenge and obtain Commission resolution on all inputs and assumptions before the avoided cost rates become effective."[69]

As noted above, Staff believes parties should be allowed the *opportunity* to challenge inputs from the IRP, including the demarcation of resource sufficiency and deficiency periods, but does not expect that every input will be challenged in each avoided cost price process.

Issue No. 6: Do market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

Staff position: Staff recommends that the Commission (1) continue using market-based prices during the utilities' resource sufficiency periods, (2) reject the Joint QF Parties' interim capacity pricing mechanism because it is inconsistent with the Commission's implementation of PURPA, and (3) direct PacifiCorp to not assume that QFs will automatically renew expiring contracts when determining resource sufficiency/deficiency for avoided cost prices.

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[68] Idaho Power/1300, Alphin/5.
[69] Idaho Power/1300, Alphin/5.

A. Current methodology to determine avoided cost prices during sufficiency periods.

Prior to 2005, the utilities usually based sufficiency period avoided cost prices on the utilities' variable costs of operating existing generating resources.[70] Staff and other parties challenged this practice because these prices did not compensate QFs for capacity.[71] In Order No. 05-584, the Commission determined that it would use a "market-based valuation methodology" to compensate QFs for capacity during periods of resources sufficiency.[72] Specifically, the Commission "adopt[ed] the methodology that values avoided costs when a utility is in a resource sufficient position at the monthly on- and off-peak forward market prices as of the utility's avoided cost filing."[73] The Commission concluded that this method "embeds the value of incremental QF capacity in the total market-based avoided cost rate."[74]

Staff believes this method continues to appropriately compensate QFs for capacity during the utilities' periods of resource sufficiency. When it adopted market-based prices for the sufficiency periods, the Commission noted the market-based prices are appropriate given the utilities' tendency to acquire capacity during a sufficiency period with short-term market purchases:

> We find [using on- and off-peak forward market prices during the sufficiency period] to be appropriate given the likelihood that a utility will address probable gaps between increasing demand and actual resources, in the absence of incremental QF capacity, with purchases of energy and capacity on the market. Indeed, we find PGE's recent history of buying significant resources on the market prior to a commitment to build new utility plant to be illustrative.[75]

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70 See Order No. 05-584 at 27.
71 Order No. 05-584 at 27.
72 Order No. 05-584 at 28.
73 Order No. 05-584 at 28.
74 Order No. 05-584 at 28.
75 Order No. 05-584 at 28.

The utilities' practice of meeting their capacity needs with short-term market purchases has continued and the market-based prices adopted by the Commission in 2005 are still appropriate.

B. Interim capacity pricing mechanism.

1. The interim capacity pricing mechanism appears to compensate QFs for the value of the utilities' avoided risk associated with Section 111(d) rules.

The Joint QF Parties recommend that the Commission adopt an "interim capacity mechanism" under which renewable and zero-emission QFs in PacifiCorp's territory would receive additional payments for capacity during PacifiCorp's resource sufficiency periods.[76] Under the mechanism, the capacity of renewable and zero-emission QFs would be valued at the net present value of revenue requirement associated with environmental upgrades that are planned for the sufficiency period.[77] The mechanism would apply under both Standard Renewable and Non-Renewable Avoided Cost price streams during PacifiCorp's resource sufficiency periods.[78]

The Joint QF Parties' description of the interim capacity mechanism suggests that the mechanism calculates additional compensation for QF capacity during sufficiency periods to monetize avoided 111(d) risk and to incent development of renewable and zero-emission resources.[79] For example, in their opening testimony, the Joint QF Parties assert market-based prices do not adequately compensate

[76] Joint QF Parties/100, Higgins/5-6.
[77] Joint QF Parties/100, Higgins/6.
[78] Joint QF Parties/100, Higgins/17-18.
[79] *See* Joint QF Parties/100, Higgins/5.

PacifiCorp QFs because "the extraordinarily long sufficiency period indicated by the 2015 PacifiCorp IRP is sending a price signal to prospective QFs that the long-term value of their capacity has no value except for the relatively small premium that may be included in the price of firm energy based on projected market prices."[80] And, the Joint QF Parties recommend compensating QFs for capacity during PacifiCorp's sufficiency period "while the uncertainty surrounding the implications of 111(d) on the Company's resource planning is being sorted out" rather than sending a signal to QFs that their capacity has no value.[81]

PURPA does not allow a capacity payment to compensate QFs for costs that may be avoided in the future or that is not based on real avoided costs but is intended to incent development.[82] For example, in 2010 FERC addressed whether PURPA would allow implementation of California legislation authorizing the California Public Utilities Commission to impose a ten percent adder ("location bonus") to prices for generation from resources located in transmission-constrained areas to account for avoided costs to construct transmission and distribution. FERC explained, "an avoided cost rate may not include a 'bonus' or 'adder' above the calculated full avoided cost of the purchasing utility to provide additional compensation for, for example, environmental externalities above avoided costs. But, if the environmental costs are 'real costs that would be incurred by the utilities," then they "may be accounted for in a determination of avoided cost rates.'"

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[80] Joint QF Parties/100, Higgins/5.
[81] Joint QF Parties/100, Higgins/14.
[82] See e.g., *California Public Utilities Commission,* 133 FERC 61,059, 61,268 (2010 WL 4144227 at 10), *quoting SoCal Edison*, 71 FERC, 61,269 at 62,080 (1995 WL 327268).

In their reply testimony, the Joint QF Parties dismiss Staff's assertion that the mechanism appears to place a value on the avoided 111(d) risk associated with capacity offered by renewable or zero-emission QFs by asserting that the mechanism does not value environmental externalities but the costs of capital improvements.[83] Staff agrees that the value obtained under the mechanism is based on the costs of capital improvements. But, at its core, the mechanism merely uses the costs of the capital improvements to place a value on the risk of associated with 111(d) rather than value costs that the utility will avoid with purchases from the QF.

When a utility's purchases from renewable or zero-emission resources will allow the utility to avoid costs to comply with 111(d), those avoided costs should be included in the calculation of avoided cost prices. Until such costs are actual costs that the utility can avoid with the purchase from a QF, it is not appropriate to include them in the calculation of avoided cost prices.

2. Avoided cost prices must take into account all alternate resources available to the utility.

"Avoided costs" are "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."[84] To determine avoided costs, the Commission must consider the costs of every source that is available to the utility in order to determine its incremental costs.[85] The Joint QF Parties' proposal to base a capacity adder on the cost of environmental upgrades to certain coal facilities is inconsistent with FERC opinions that Commission must

[83] Joint QF Parties/200, Higgins/4-5.
[84] 18 C.F.R. 292.101(b)(6).
[85] *SoCal Edison*, 70 FERC 61,215 (1995 WL 169000).

consider all sources available to the utility to determine what costs a utility will avoid. FERC has stated "regardless of whether the State regulatory authority determines avoided cost administratively, through competitive solicitation (bidding), or some combination thereof, it must in its process reflect prices available from *all sources* able to sell to the utility whose avoided cost is being determined."[86]

3. Adding costs from an avoidable resource investment to the market-based rates for the sufficiency period is not appropriate.

The investments at coal plants are not costs that PacifiCorp would avoid with purchases from QFs during the utility's sufficiency period under the Commission's implementation of PURPA. The Commission has decided that the utilities will avoid market purchases during a sufficiency period. Nothing in the Commission's previous orders regarding PURPA implementation support increasing the utilities' avoided costs with incremental costs associated with a certain type of resource.

PacifiCorp asserts that the environmental upgrades that would serve as the source of the capacity valuation include capital investments in other states that cannot be avoided by the addition of an Oregon QF, even one that is renewable or non-emitting.[87] The distinction PacifiCorp draws between the environmental upgrade costs and costs that are avoided is consistent with how the Commission has previously implemented PURPA. The Commission looks to the utilities' IRPs to determine the utilities' next avoidable resource. For renewable avoided cost prices,

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[86] *Id. See also So Cal Edison,* 71 FERC 61269 (*Order denying reconsideration*) ("[S]tate authorities must determine the cost the utility avoids by considering the cost of all alternative sources of power available to the utility, not just the cost of a select group of resources.").

[87] PAC/100, Dickman/12-13.

the proxy resource is the next avoidable renewable resource in the utilities' IRPs and for non-renewable avoided cost prices it is a CCCT. The Commission's prior orders do not support layering costs of upgrades at baseload coal plants onto the avoided costs of these resources to determine an avoided cost for capacity.

C. When determining when it will need capacity for purposes of calculating avoided cost prices, PacifiCorp should include QF contracts in its resource stack using the contracts' actual terms rather than assuming they will exist indefinitely.

The Joint QF Parties recommend that PacifiCorp change the assumption regarding renewing QF contracts for purposes of establishing avoided cost price to ensure the prices are not based on an artificially extended sufficiency period.[88] The Joint Parties explain that once a QF contact is included in PacifiCorp's resource stack in its IRP, it remains in the resource stack even after the contract term expires.[89] Accordingly, when a QF negotiates a renewal of the contract, PacifiCorp's avoided cost prices are based on sufficiency/deficiency periods that already assume the existence of the contract the QF is attempting to procure. As Mr. Higgins notes in his testimony, "when the purpose of the exercise is to determine the value of QF capacity, the act of assuming that all or a portion of the QF capacity that is being valued simply "shows up" via contract extension improperly predetermines the answer to the valuation question—and will understate the value of the QF capacity."[90]

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[88] Joint QF Parties/100, Higgins/8-9.
[89] Joint QF Parties/100, Higgins/7-8.
[90] Joint QF Parties/100, Higgins/7.

Staff agrees with the Joint Parties' recommendation to require PacifiCorp to stop basing its Standard Renewable and Non-Renewable Avoided Cost prices on a resource stack that assumes never-ending QF contracts.

D. ODOE's concern regarding market prices can be addressed in the review process for avoided cost price filings.

The Oregon Department of Energy (ODOE) testifies that whether market prices sufficiently compensate for capacity depends on whether the forecasted market prices in the IRP (and avoided cost prices) reflect the utility's actual practices.[91] ODOE notes that a utility may use Mid-C monthly wholesale power prices in IRP, but if it typically purchases capacity separately from its energy purchases or if it contracts for a longer term at fixed prices, the forecast is unlikely to reflect the costs the utility will actually avoid.[92]

Staff believes that the process for reviewing avoided cost price filings will allow parties to challenge the utility's market-based prices on the ground they do not represent the cost of market purchases the utility will actually make. Accordingly, it is not necessary to address ODOE's concern by changing the methodology for determining avoided cost prices during the sufficiency period.

Issue No. 7: What is the most appropriate methodology for calculating non-standard avoided cost prices? Should the methodology be the same for all three electric utilities operating in Oregon?

Staff position: It is not necessary for all three utilities to use the same methodology to determine non-standard avoided cost prices. PacifiCorp and Idaho Power should be allowed to use their proposed model-based methods and PGE should be allowed to continue to use the currently approved methodology.

[91] ODOE/700, Carver/10.
[92] ODOE/700, Carver/10.

A. The current methodology.

The current non-standard avoided cost price methodology in Oregon is found in Order No. 07-360. That order directs that the utilities adjust their standard avoided cost prices, which are based on a proxy CCCT and a proxy wind resource for nonrenewable and renewable avoided costs respectively, using the seven factors enumerated at 18 C.F.R. §292.304(e).[93]

B. Proposed changes to the current methodology.

PGE supports the continuation of the methodology established in Order No. 07-360, and states that the three utilities should have "flexibility in the implementation of adjustments using the seven FERC adjustment factors."[94] PacifiCorp proposes to use a model-based approach using its Generation and Regulation Initiative Decision Tools (GRID) production cost model because it is more accurate than using the proxy method as the starting point for calculating large QF avoided costs.[95]

Idaho Power explains that in 2007, the Commission authorized Idaho Power to use the same model-based methodology to calculate non-standard rates in Oregon that Idaho Power used in Idaho.[96] Idaho Power asks the Commission for authority to continue using the model-based methodology.[97]

C. Staff position.

Staff does not believe it is necessary that all three utilities use the same methodology to determine non-standard avoided cost prices. Staff supports PGE's

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[93] Order No. 07-360 at 15-16.
[94] PGE/500, Macfarlane – Morton/10.
[95] PAC/Dickman/16-28.
[96] Idaho Power/900, Alphin/6.
[97] Idaho Power/900, Alphin/6.

and Idaho Power's continued use of the previously-approved methodologies and supports PacifiCorp's request to change to a model-based methodology.

Staff agrees with PacifiCorp that the current method of adjusting the standard avoided cost prices ignores the interdependencies across the seven FERC factors, and therefore recommends that utilities be conditionally allowed to use a computer based model to calculate negotiated avoided costs.[98] Staff believes that an accurate accounting for the impacts on individual utility systems can be achieved through the use of the production cost models. The production cost models are used to estimate and set rates for power costs each year and have been vetted by the companies and by Staff.[99]

Staff also agrees with CREA that a level of transparency must accompany this recommendation.[100] If allowed, the Commission should adopt rules requiring the IOU to work cooperatively with the QF, and to run scenario and sensitivity analysis in a transparent manner reasonably accessible to the developer in order to develop a fair and equitable non-standard avoided cost rate.[101] The Commission should also require utilities using a model-based approach to provide QFs with the base assumptions and inputs to a production cost model, as well as a thorough description of the model run(s).

D. The Commission should establish market-based prices as the floor for non-standard avoided cost prices.

[98] Staff/600, Andrus/21-22.
[99] Staff/600, Andrus/22.
[100] Staff/600, Andrus/22.
[101] CREA/500, Skeahan/18.

ODOE recommends that the Commission continue its requirement that non-standard avoided cost prices can go no lower than market-based prices during sufficiency periods.[102] ODOE notes that allowing utilities go below market prices goes back to the decremental generation methodology that the Commission rejected in 2005 because it does not compensate utilities for avoided capacity costs.[103] PacifiCorp opposes this recommendation,

> [t]his proposal is troubling in that it seems to discard the notion that avoided cost rates should reflect no more or less than the costs that would otherwise be incurred by the utility but for the addition of a QF. There are many times when the incremental cost of energy and capacity that would be incurred by a utility will be less than market, including times during the deficiency period.[104]

Staff supports ODOE's recommendation. As noted by ODOE, the Commission has previously rejected sufficiency period avoided cost prices that are below market-based prices because such prices do not compensate QFs for capacity.[105]

Issue No. 8. When is there a legally enforceable obligation?

Staff position: The Commission's current criteria for a legally enforceable obligation should be modified so a legally enforceable obligation is created when the QF executes the final draft executable contract. The Commission should also allow QFs to establish a legally enforceable obligation earlier in the contracting process if the utility does not comply with its own schedule regarding the contracting process or state or federal policy.

A. Legally enforceable obligations under PURPA.

Under PURPA rules, a QF may sell energy as available or may sell capacity and energy pursuant to a "legally enforceable obligation."[106] FERC has explained that

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[102] ODOE/900, Carver/10.
[103] ODOE/900, Carver/10.
[104] PAC/1400, Dickman/7.
[105] Order No. 05-584 at 26-27.
[106] 18 C.F.R. §292.304(d) provides:

Footnote continued...

"[u]se of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible facility merely by refusing to enter into a contract with a qualifying facility:[107]

> [U]nder our regulations, a QF has the option to commit itself to sell all or a part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA.[108] Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.[109]

B. Legally enforceable obligations in Oregon.

In 1987, the Oregon Court of Appeals addressed the issue of when a legally enforceable obligation is established in *Snow Mountain Pine v. Maudlin*, interpreting PURPA and its implementing regulations much as FERC did in the 2011 ruling

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(...continued)

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised at the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

[107] *Cedar Creek Wind, LLC,* 137 FERC 61006 (2011 WL 4710848), *citing* Order No. 69, FERC Stats. & Regs. 30,128 at 30,889.

[108] *Id., citing New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, FERC Stats. & Regs. Par. 31,233 at p 212 (2006), *order on reh'g,* Order No. 688-A, FERC Stats. & Regs. 31,250, at p 136-37 (2007), *aff'd sub nom. American Forest and Paper Association v. FERC,* 550 F.3d 1179 (D.C. Cir. 2008), *see also Midwest Renewable Energy Projects, LLC,* 116 FERC 61,017 (2006 WL 1877187).

[109] *Id., citing JD Wind 1,* 129 FERC 61,148 at p 25 (2009 WL 3954726).

excerpted above.[110] The Court noted that the utility's obligation to purchase from the QF,

> is not governed by common law concepts of contract law; it is created by statutes, regulations and administrative rules. ORS 758.525 requires a utility to purchase power from a qualifying facility. Similarly, 18 C.F.R. 292.303(a) and OAR 860-020-0030 provide that an electric utility "shall purchase" any energy and capacity "which is made available from a QF." Thus, the obligation to purchase power is imposed by law on a utility; it is not voluntarily assumed.[111]

The Oregon Court of Appeals observed that to permit a utility to delay the date used to calculate the purchase price simply by refusing to purchase energy would expose qualifying facilities to the harm that Congress and the Oregon Legislature intended to prevent.[112] Based on this observation, the Court of Appeals concluded that a QF has the power to determine the date for which avoided costs are to be calculated "by tendering an agreement that obligates it to provide power."[113]

A few months after the Court of Appeals issued its opinion in *Snow Mountain Pine*, the Oregon Public Utility Commissioner adopted an administrative rule governing legally enforceable obligations under which a legally enforceable obligation is established the earlier of the date of an executed PPA between the QF and utility or the date, "agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate."[114]

OAR 860-029-0010(29) provides,

> (29) "Time the obligation to purchase the energy capacity or energy and capacity is incurred" means the earlier of:

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[110] *Snow Mountain Pine Co. v. Maudlin*, 84 Or App 590, 598-99 (1987).
[111] *Id.*
[112] *Id.*, at 599-600 ("To permit a utility to delay the date to be used to calculate the purchase price simply by refusing to purchase energy would expose qualifying facilities to risks that we believe Congress and the Oregon Legislature intended to prevent.")
[113] *Id.*
[114] Order No. 87-1154; *See* OAR 860-029-0010(29).

(a) The date on which a binding, written obligation is entered into between a qualifying facility and a public utility to deliver energy, capacity, or energy; or

(b) The date agreed to, in writing, by the qualifying facility and the electric utility as the date the obligation is incurred for the purposes of calculating the applicable rate.

In 2009, the OPUC addressed whether a QF had established a LEO under which PacifiCorp must purchase its capacity and energy even though PacifiCorp had not signed a power purchase agreement (PPA). The OPUC rejected the QF's reliance on *Snow Mountain Pine,* observing that the administrative rule regarding LEOs had changed since the court issued its opinion in that case, and the definition of "the time the obligation is incurred" now "looks to either an executed agreement or a written agreement between the parties as to the date a LEO was triggered."[115]

C. It is appropriate to change the criteria for a legally enforceable obligation in Oregon.

Staff recommends that the Court of Appeals' analysis in *Snow Mountain Pine v. Maudlin* inform the Commission's decision regarding the creation of legally enforceable obligations. The court's 1987 interpretation of when a legally enforceable obligation arises is much closer to FERC's interpretation and implementation of PURPA than the Commission's current rule. The current rule requiring the utility to agree in writing to a certain avoided cost prices before a legally enforceable obligation can be established undermines the purpose of a legally enforceable obligation, which is to protect QFs when utilities refuse to enter into a contract. Requiring a QF to obtain the utility's written agreement to a purchase price is little different than requiring the QF to obtain an executed PPA. In both circumstances, the QF's right to sell is dependent on the utility's written agreement to purchase. But, FERC has stated that a QF must be able to establish a legally enforceable obligation notwithstanding a utility's attempt to circumvent its obligation to purchase QF energy and capacity.

[115] *International Paper Co. v. PacifiCorp,* Order No. 09-439.

D. Recommended criteria for a legally enforceable obligation.

Under *Snow Mountain Pine v. Maudlin,* which interprets Oregon statute and PURPA, a legally enforceable obligation is established when a QF tenders an agreement that obligates it to provide power to the utility.[116] Staff concludes that a QF is "obligated" to provide power when it is subject to penalty for failing to deliver on the scheduled commercial on-line date.[117] Generally, this would occur no sooner than the point in the contracting process between the QF and utility when the QF executes the final draft executable standard contract provided by the utility, which will include a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries.

PacifiCorp, PGE, and Idaho Power all have similar processes for entering into standard contracts. All require the QF to initiate the standard contracting process by submitting certain information, after which the utilities have 15 days to provide a draft standard contract.[118] Once provided with a draft contract, the QF may agree to the terms of the draft contract and ask the utility to provide a final executable contract, or provide comments regarding suggested changes. Thereafter, the utilities will provide iterations of the draft standard contract no later than 15 days after each round of comments by the negotiating QF. When then QF indicates that it agrees to all the terms in the draft contract, the utilities have 15 days to forward to the QF a final executable contract. When the QF executes the final executable contract, the QF has obligated itself to sell power and the Commission should find a legally enforceable obligation in this circumstances.

There is a caveat to Staff's position. If the utility does not provide the QF with the required information or documents within the time specified in its tariff, or does not act consistently with its own schedule or state or federal policies, the QF should

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[116] Staff/500, Andrus/38, *quoting Snow Mount Pine v. Maudlin*, 84 Or App 590, 598-99 (1987).

[117] See e.g., *Armco Advanced Materials Group v. Pennsylvania PUC*, 579 A.2d 1337 (1990)("A LEO does not exist at a time during "serious negotiations" between the parties (whether at the time of the agreement in principle on price or otherwise) when the qualifying facility has not yet obligated itself to deliver power and remains free to walk away from the negotiations without liability.").

[118] Staff Exhibit 504.

have the opportunity to establish a legally enforceable obligation notwithstanding that the QF has not yet executed a final draft executable standard contract.

Issue No. 9: How should third-party transmission costs to move QF output in a load pocket be calculated and accounted for in the standard contract?

Staff position: The Commission should defer resolution of this issue until Phase III of Docket No. UM 1610, or in the alternative adopt PacifiCorp's proposal as modified by Staff.

A. PacifiCorp's proposed method to recover third-party transmission costs is consistent with PURPA.

PacifiCorp proposes that when third-party transmission is necessary to move QF output from a load pocket to PacifiCorp's load, PacifiCorp will procure long-term firm point-to-point transmission for the QF generation that exceeds the minimum load conditions in the load pocket. PacifiCorp proposes that the costs and benefits associated with the transmission should not be incorporated into the actual calculation of the standard avoided cost but should be captured on an individual QF project basis between the QF and Company as an addendum to the agreement.[119] The addendum executed concurrently with the standard contract would include transmission costs for the entire term of the contract.

Staff believes PacifiCorp's proposal is consistent with PURPA. It provides the QF with a fixed price that is known at the time of contracting and does not allow PacifiCorp to curtail the QF's generation when transmission is unavailable.

[119] PAC/1300, Griswold/21-22.

B. No other proposal regarding third-party transmission presented in this docket appears to be consistent with PURPA.

PacifiCorp's assertion that no other proposal submitted in this process regarding recovery of costs for third-party transmission is consistent with PURPA is well taken. The Commission cannot adopt a standard contract provision that allows utilities to curtail QF generation in lieu of charging for transmission.[120] And, under PURPA, the QF is entitled to "fixed prices." This means the standard contract must not include provisions under which the payments to QFs are subject to change annually, or that are offset by transmission costs as they are incurred by PacifiCorp.

C. If adopted, PacifiCorp's proposal should be modified.

Although PacifiCorp's proposal appears to be permissible under PURPA, it is troubling because it requires the QF located in a load pocket at the time of contracting to pay for third-party transmission for the fixed-price portion of a standard contract even though the load and resource balance in the load pocket is subject to change over time. Notably, PacifiCorp asserts that it is too burdensome to show in every Schedule 37 avoided cost filing where load pockets exist on its system because "a load pocket is a dynamic situation, going up or down as load and generation is added or removed, so updating and publishing load pockets with every Schedule 37 update would be burdensome and likely become stale."[121]

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[120] *Pioneer Wind Park, LLC*, 145 FERC 61, 215 (2013 WL 6637352 at p 10)(Noting that under PURPA a utility may curtail a QF in only two circumstances – during a system emergency and under "as available" contracts in certain light load hours and cannot curtail a QF in any other circumstance.).

[121] PAC/1500, Griswold/8.

If the conditions creating a load pocket are so dynamic that it is unreasonable to require PacifiCorp to describe them every two years, PacifiCorp's proposal to establish a transmission charge to move generation out of a currently-existing load pocket for a term of up to 20-years is remarkably unappealing.

In its final round of testimony, Staff suggested the Commission postpone this issue to Phase III of this docket. Staff's suggestion was based in part on the fact the load pocket in which a QF is located could cease to be a load pocket during the term of the contract, but the charges to the QF to transmit generation out of the load pocket would not. Staff was hoping a more flexible solution could be found if the Commission indicated it found the inflexible proposal by PacifiCorp is not acceptable. Second, PacifiCorp has asked to reduce the eligibility cap for standard contracts. The limitations imposed by PURPA on standard contracts (no curtailment and fixed prices for the term of the contract) do not apply to non-standard contracts. Staff was unsure if a QF that is eligible for a standard cap under a reduced eligibility cap would create the same need for third-party transmission on PacifiCorp's system.

However, Staff recognizes that parties need resolution to this issue and believes PacifiCorp's proposal with one modification is acceptable. As PacifiCorp notes in its testimony, a minimum five-year commitment is required to obtain renewal rights for long-term firm point-to-point transmission from Bonneville Power Administration (BPA).[122] If PacifiCorp acquires firm long-term transmission from BPA for a period of more than five years, it would renew its transmission contract with BPA every five years. Accordingly, PacifiCorp could offer a QF located

[122] PAC/1000, Griswold/24.

in a load pocket with two options for a contract addendum addressing transmission costs. One option would establish a price for transmission for the entire term of the contract and the other would allow the cost of transmission to be re-set every five years concomitant with PacifiCorp's renewal of its long-term contract. The second option would be available but not mandatory for the QF if PacifiCorp has procured a five-year long-term point-to-point contract with BPA.

D. Information available to QFs at time of contracting

Staff recommends the Commission require that PacifiCorp make information on load pockets available to QFs on request. Staff recommends that the Commission direct PacifiCorp to propose a detailed description of the load pocket data it will make available to prospective QF, and the process by which it proposes to provide it.

DATED this 2nd day of September, 2015.

Respectfully submitted,

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