ENTERED MAY 13 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Qualifying Facility Contracting and Pricing.	ORDER

DISPOSITION: UPDATES ADOPTED

I. INTRODUCTION

In Order No. 14-058, we opened this Phase II to continue our evaluation of policies and procedures to implement the Public Utility Regulatory Policies Act (PURPA). Specifically, we consider proposals to revise the rates, terms, and conditions for Qualifying Facility (QF) standard and non-standard contracts in Oregon. As in Phase I, we consider the proposals in the context of federal and state law and our prior orders addressing these issues, and decline to make changes without compelling evidence of a need for revision.

As outlined in this order, we decline to revise certain policies, adopt prospective changes to several policies, and reserve our decision on one issue. We summarize our decisions on the nine identified issues as follows:

Issue 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?*

We adopt no change. Once a utility is resource-deficient, then Renewable Energy Certificates (RECs) transfer to the utility for the remaining term of a standard contract, QFs will continue to be paid avoided cost prices based on the utility's next avoidable renewable resource for the first 15 years and market prices thereafter.

Issue 2: *Should avoided transmission costs for non-renewable and renewable proxy resources be included in the calculation of avoided cost prices?*

If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there will be a rebuttable presumption that there are no avoided transmission costs.

Issues 3 & 4: *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?*

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?

We correct the inadvertent error in Staff's capacity contribution calculation as applied to solar QFs under both the standard renewable and standard non-renewable avoided cost price streams, and as applied to wind QFs under the standard non-renewable avoided cost price stream.

Issue 5: *What is the appropriate forum to resolve litigated issues and assumptions?*

We adopt no change.

Issue 6: *Do the market prices used during the resource sufficiency period sufficiently compensate for capacity?*

No change; we affirm our previous position that market-based prices during resource sufficiency periods adequately compensate QFs for power produced. We agree with Staff and the Joint QFs that a certain amount of capacity deferral may not be valued when utilities assume in their IRPs that existing QFs nearing contract expiration will automatically renew. We direct each utility to work with parties to address this issue in its next IRP.

Issue 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?*

We adopt no change to how PGE and Idaho Power negotiate non-standard avoided cost prices.

PacifiCorp is authorized to use its Partial Displacement Differential Revenue Requirement (PDDRR) method to determine a starting point for non-standard contract avoided cost price negotiations; PacifiCorp will open access to its production cost model (GRID) and provide training and technical assistance upon request.

The floor for non-standard contract avoided cost prices will be the wholesale power price forecast that is used to set sufficiency period avoided cost prices in standard contracts.

Issue 8: *When is there a legally enforceable obligation (LEO)?*

A LEO will be considered established once a QF signs the final draft of an executable contract provided by a utility to commit itself to sell power to the utility. A LEO may be established earlier if a QF demonstrates delay or obstruction of progress towards a final draft of an executable contract, such as a failure by a utility to provide a QF with required information or documents on a timely basis. Through the complaint process, the Commission will resolve a dispute and determine the avoided cost price to apply on a case-by-case basis.

Issue 9: *How should third-party transmission costs to move QF output in a load pocket to load be calculated and accounted for in the standard contract?*

In Order No. 14-058, we deferred the questions of how to calculate and how to assign third-party transmission costs attributable to a QF. Staff and some parties request still more time to address these questions. We understand there has been substantial progress towards resolution of this issue. Rather than defer the issue to a Phase 3 proceeding, we direct staff and utilities to work with parties to resolve how to assign third party costs. We direct Staff to file a status report within three calendar months of this order indicating whether a resolution is forthcoming or recommending an alternative process.

II. PROCEDURAL HISTORY

In a ruling dated March 26, 2015, the jointly recommended issues list previously filed by Staff and the parties was adopted, with the addition of the solar capacity contribution issue (Issue 3).

The following parties filed testimony and briefs on one or more of the Phase II issues: Commission Staff; the Oregon Department of Energy (ODOE); PacifiCorp, dba Pacific Power; Portland General Electric Company (PGE); Idaho Power Company; Gardner Capital Solar Development, LLC (Gardner Solar); Small Business Utility Advocates (SBUA); the Renewable Energy Coalition (Coalition); the Community Renewable Energy Association (CREA); OneEnergy, Inc. (OneEnergy); and Obsidian Renewables, LLC (Obsidian). Coalition, CREA, OneEnergy, and Obsidian filed both individually and jointly as the Joint QF Parties (Joint QFs). No parties requested cross-examination on any issue and no hearing was held.

III. DISCUSSION

A. Green Tag Ownership

Issue 1 concerns who owns a QF's renewable energy credits (RECs, or green tags) during the last five years of a 20-year fixed purchase power agreement (PPA)—a period when the QF is paid rates that are based on market prices rather than avoided costs. This issue arises from a perceived conflict between two directives: (1) the directive in Order No. 05-584 that QFs be paid market rates during the last five years of a 20-year fixed-price contract;[1] and (2) the directive in Order No. 11-505 that when a utility is renewable resource deficient, a QF is paid standard renewable avoided cost prices based on the cost of the next avoidable renewable resource but must transfer its RECs to the utility.[2]

1. Parties' Positions

Staff: Staff argues that equity demands the RECs transfer to the QF during the last five years of the contract. According to Staff, the utility will be held harmless because the utility pays market prices during that period (that are not compensatory for the RECs) and had 15 years to plan how to acquire other RECs. Staff reasons that QFs would be harmed if they had to cede ownership of RECs during a period when they are not compensated for their value.

Staff argues that logic leads to the same result, concluding Order No. 11-505 links a QF's obligation to transfer RECs to the QF's receipt of compensatory prices. Staff reasons, Order No. 11-505 relied on 2010 FERC decisions allowing a multi-tiered avoided cost price structure with different avoided cost price streams for different resource types.[3] Staff explains, in these decisions, FERC allowed that states may consider state-imposed obligations such as a requirement that utilities purchase energy from renewable sources when determining what costs a utility avoids by QF purchases.

ODOE: Because a QF is not compensated for RECs when a utility pays market-based prices for output, ODOE argues that QFs should own the RECs during the last five years of a renewable standard contract.

PacifiCorp: PacifiCorp argues that the policy regarding ownership of QF RECs turns on a utility's resource sufficiency position at the beginning of a standard contract. It quotes Order No. 11-505: "[t]he renewable resource QF will keep all associated Renewable Energy Certificates (RECs) during periods of renewable resource sufficiency, but will

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[1] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584 at 19-20 (May 13, 2005).

[2] *In the Matter of Public Utility Commission of Oregon Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*, Docket No. UM 1396 (Phase II), Order No. 11-505 at 4. (Dec 13, 2011).

[3] Staff Prehearing Memorandum at 2-3 (Sep 2, 2015) (citing *California Public Utilities Commission*, 132 FERC ¶ 61,047, 2010 WL 2794334 (*Declaratory Order*); 132 FERC ¶ 61,047, 2010 WL 2794334 (*Oder Granting Clarification and Denying Rehearing*); 133 FERC ¶ 61,159, 2010 WL 4144227 (*Order Denying Rehearing*)).

transfer those RECs to the purchasing utility during periods of renewable resource deficiency."[4] PacifiCorp argues, consistent with this directive, QF RECs must transfer to a utility at the beginning of the utility's resource deficiency period (as identified in the utility's most recently acknowledged integrated resource plan (IRP)) and continue for the term of the contract. Since a renewable standard contract is based on a utility's avoidance of a renewable proxy, PacifiCorp reasons, "[f]rom the point in time that the deficiency period starts, through the end of the PPA, therefore, a utility should own the green tags associated with a QF PPA—consistent with the utility's avoidance of the renewable resource used in developing avoided costs for that PPA."[5]

PGE: PGE asserts that, in Order No. 11-505, we tied REC ownership to a utility's resource status. PGE reasons, energy purchased without green tags is not renewable energy and cannot be used for renewable portfolio standard (RPS) compliance, thereby contravening the purpose of a renewable standard contract (versus a regular standard contract). Countering arguments that ownership of RECs is linked to the price paid for QF power, PGE maintains that the price paid does not change the underlying purpose of the renewable contract. PGE argues that Order Nos. 11-505 and 05-584 do not conflict and are not connected because one addresses pricing and the other addresses REC ownership.[6]

Idaho Power: Idaho Power does not have an Oregon renewable portfolio requirement and does not currently challenge the position that a QF should own the green tags during the last five years of a 20-year standard renewable contract.

CREA: CREA asks that we "clarify that during all periods that the renewable QF is paid a rate other than the full renewable proxy rate, the QF retains ownership of the RECs."[7] CREA argues that a market-based price is an undifferentiated brown power price rather than a green power price—and a utility should not retain RECs when it does not compensate the QF for green power.

2. Resolution

We find no conflict between Order Nos. 05-584 and 11-505. In Order No. 05-584, we established a 20-year maximum term for a standard contract to facilitate QF financing, fixing prices for only the first 15 years to minimize forecasting error. In Order No. 11-505, we determined that a utility, once it becomes renewable resource deficient, receives a renewable QF's RECs for the remainder of the standard contract. Thus, Order No. 11-505 ties REC ownership to utilities sufficiency or deficiency position. Order No. 05-584 dictates the maximum term of any standard contract and that market prices replace avoided cost prices during the last five years of a 20-year standard contract. RECs continue to transfer to a utility at the beginning of the utility's resource deficiency period.

[4] Order No. 11-505 at 1.
[5] PacifiCorp Post Hearing Brief at 2 (Oct 13, 2015).
[6] *Id.* at 3.
[7] CREA Prehearing Legal Brief at 3 (Sep 2, 2015).

B. Issue 2: Clarification Regarding Inclusion of Avoided Transmission Costs in Avoided Cost Prices

In Order No. 14-058, entered in Phase I of this docket, we addressed the inclusion of avoided transmission cost in avoided cost prices as follows:

> We affirm the existing policy that if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of the third-party transmission are avoided, and are therefore included in the calculation of avoided cost prices. This is the situation for PGE, and it was not contested in these proceedings.
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> If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided costs prices. This is the situation for Pacific Power.[8]

OneEnergy and CREA seek clarification of our decision, expressing concern that the second paragraph could be interpreted to disallow the inclusion of transmission costs in *any* calculation of avoided costs for PacifiCorp, even despite evidence that PacifiCorp *would* avoid such costs with a QF purchase.[9]

1. Parties' Positions

Staff: Staff finds the language in Order No. 14-058 ambiguous. Staff explains that it is unclear whether the language means that: (1) no party demonstrated that PacifiCorp would avoid third-party transmission costs when the resource is on-system, so that inclusion of third-party transmission costs is not appropriate; or (2) it is not appropriate to include third-party transmission costs in avoided cost calculations even if evidence shows PacifiCorp would avoid third-party transmission costs.

Staff indicates that some parties believe PacifiCorp will incur transmission costs for its next avoidable renewable resource, identified in its 2013 IRP as a Wyoming wind resource. Despite being directly connected to PacifiCorp's system, parties allege that output will exceed load in the area. They ask if PacifiCorp acquires transmission to transmit energy from its proxy renewable resource, would such costs be included in PacifiCorp's standard renewable avoided cost prices. Staff concludes that, under Order No. 14-058, these costs could not be included in avoided cost prices even if it could be shown that PacifiCorp would avoid them with a QF purchase.

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[8] Order No. 14-058 at 17 (Feb 24, 2014).

[9] Motion for Clarification and Application for Reconsideration by OneEnergy, Inc. and the Community Renewable Energy Association (Apr 24, 2014). We invited the parties to raise the issue here. *See* Order No. 14-229 (Jun 20, 2014).

Staff found sufficient evidence to conclude that PacifiCorp *may* avoid transmission costs even when the proxy resource is on-system. Staff suggests we leave open the possibility of including such costs in the avoided cost calculation and address this factual question, as appropriate, in the review process following a utility's avoided cost filing.

PacifiCorp: PacifiCorp contends it is not appropriate to include transmission costs as no party has demonstrated a utility would avoid transmission costs—third-party or other—when the utility's proxy resource is on-system. PacifiCorp rebuts assertions that there is evidence that PacifiCorp *may* avoid transmission costs, countering that these assertions fail to take into account that the federal transmission planning process, not QF development, drives the company's decisions. Even if specific transmission costs might be incurred to accommodate an on-system proxy resource, PacifiCorp argues, these costs would not be avoided by QF resources.

PacifiCorp also opposes Staff's proposal to leave this issue open, asserting that a "factual" determination whether there are avoidable transmission would involve complex legal questions, state and federal policy reconciliation issues, and implementation intricacies. PacifiCorp asserts that OneEnergy's test (discussed below) analyzing whether an on-system proxy resource can be designated as a network resource at its full capacity fails to account for federal transmission planning implications, confuses the different types of transmission services and associated requirements, and overlooks nearly insurmountable implementation issues.

PGE: PGE posits that transmission costs should be included only if they are truly avoided. PGE includes avoided transmission costs in avoided cost prices for off-system proxy resources that incur transmission costs. PGE argues that any transmission costs associated with an on-system proxy resource would not actually be avoided and should not be included in the calculation of avoided cost prices.

Idaho Power: Idaho Power's proxy resource is an on-system resource, so the company indicates there are no avoided transmission costs to be included in the calculation of its avoided cost prices.

OneEnergy: OneEnergy argues that transmission upgrades needed to transmit output from PacifiCorp's wind proxy resource can be avoided by QF purchases and should be included in the avoided cost. OneEnergy asserts that Order No. 14-058 should be interpreted to mean no party *had demonstrated* PacifiCorp would avoid third-party transmission costs when a proxy resource is on-system rather than transmission costs *could never* be avoided. It contends this interpretation is consistent with PURPA, particularly in the context of the Commission's other determination that QFs must pay third-party transmission costs associated with moving output from an on-system QF to load. OneEnergy maintains that an interpretation that transmission costs can never be avoided when a utility's proxy resource is on-system violates PURPA and is discriminatory.

CREA: CREA contends that "[e]xcluding transmission costs required to bring generation output from a utility proxy to load undermines the very concept of *avoided* costs."[10] It adds that doing so contradicts the policy that on-system QFs pay for third-party transmission costs associated with moving output between PacifiCorp's load pockets.[11] CREA argues that it would be discriminatory to assign transmission costs to on-system QFs but not attribute transmission costs to on-system proxy resources.

2. Resolution

In Order No. 14-058, we addressed the question of whether avoided third-party transmission costs associated with the proxy resource should be included in avoided costs. With regard to a proxy resource used to calculate a utility's avoided costs for an on-system resource, we concluded that there are no avoided transmission costs so that no cost of third-party transmission should be included in the calculation of avoided cost prices. We acknowledge the concern that this statement is too definitive, precluding incremental transmission costs from *ever* being included in the calculation of avoided costs even if a party demonstrates that the purchase of QF power actually avoided incremental transmission costs. Thus, we modify the statement in Order No. 14-058 as follows:

> If the proxy resource used to calculate a utility's avoided costs is an on-system resource, there is a rebuttable presumption that there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided cost prices. This is the situation for Pacific Power.

To rebut the presumption, evidence offered by Staff and other parties must demonstrate that a renewable proxy resource has incremental transmission costs that can actually be avoided by the purchase of QF energy. The evidence must be compelling and, therefore, factual and not anecdotal. We recognize PacifiCorp's advisement that a factual determination about whether there are avoidable transmission costs associated with a renewable proxy resource, will involve resolving complex legal questions, reconciling state and federal policy issues, and working through implementation intricacies. We recommend that the issue of whether a renewable proxy resource has incremental transmission costs be raised in a 30-day review of a renewable standard contract.

C. Issues 3 and 4: Modifications to Capacity Contribution Adder

In Phase I, Staff recommended we modify the calculation of standard renewable and standard non-renewable avoided cost prices offered to QFs for on-peak hours during a utility's resource deficiency period so that the capacity contribution portion of the prices would reflect the inherently different contributions to peak load (CTP) of different QF resource types. For the Standard Method, Staff proposed to multiply the embedded

[10] CREA Prehearing Legal Brief at 6 (citing CREA/500, Skeahan/12).
[11] *Id.* (citing CREA/500, Skeahan/20-21).

capacity component by a "capacity contribution factor" equal to the expected CTP of the specific QF resource type, as set forth in a utility's IRP. For the Standard Renewable Method, Staff proposed adjusting the capacity component implicit in the renewable on-peak price by the incremental capacity contribution of the specific QF resource type. We agreed and adopted Staff's proposed methodologies.[12]

Issue 3 addressed Obsidian's request that we reconsider our adoption of Staff's capacity contribution adjustment for standard renewable avoided cost prices as applied to solar QFs, noting the methodology resulted in *two* discounts to the capacity payment to solar QFs: one that seemed intended by Order No. 14-058 as it was based on a solar QF's CTP, and another based on a QF's on-peak capacity factor (CF)[13] that seemed unintended. Issue 4 addresses whether any changes made for solar standard renewable avoided cost prices should also apply to standard non-renewable avoided cost prices.

1. Parties' Positions

Staff: Staff asserts the avoided capacity contribution calculation adopted in Order No. 14-058 is flawed with respect to solar QFs under both the standard renewable and standard non-renewable avoided cost price streams, and with respect to wind QFs under the standard non-renewable avoided cost price stream. Staff states it intended to calculate the capacity contribution to be included in the on-peak avoided cost price paid to a QF during a utility's deficiency period by multiplying the CTP of the QF's resource type by the capacity cost of the utility's avoided proxy resource. For example, if the CTP of a QF resource type is 15 percent, Staff intended the capacity contribution to the total avoided cost price would be 15 percent of the capacity cost of the avoided proxy resource. Staff explains it erred in using a volumetric (per MWh) capacity price to represent the dollar value of capacity, rather than the cost itself, resulting in two discounts to capacity payments: one for a QF resource type's CTP, and another for the QF's on-peak CF.

Staff proposes to adjust the avoided capacity cost to be included in the total on-peak standard avoided cost rate paid to a renewable QF of a particular resource type on a dollar-per-unit basis (kW or MW of capacity) prior to calculating the on-peak payment rate. The steps are as follows: (1) adjust the CTP of the proxy renewable resource to account for the CTP of a solar resource relative to utility's renewable proxy resource (i.e., wind) and then, apply that differential to the value of capacity; (2) the value of the solar capacity would then be spread over the QF's expected on-peak generation by applying the on-peak CF for solar to the total number of on-peak hours per year.[14] Staff asserts that the methodology for calculating the avoided capacity contribution for standard non-renewable avoided cost prices should be similarly adjusted.[15]

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[12] Order No. 14-058 at 15.
[13] A capacity factor is the ratio of the energy produced over a period of time (MWh) to the total that could be generated at maximum capacity (MW) over that same period.
[14] Staff/500, Andrus/18-20.
[15] Staff/500, Andrus/21.

Staff contends that rather than layer two different adjustments on the capacity component of avoided cost prices, the Commission intended to *replace* the adjustment based on a QF's on-peak CF with an adjustment based on the CTP of the QF's resource type. Staff notes, in Order No. 14-058, the Commission explicitly stated that it expected capacity payments to wind QFs under the adjusted standard renewable avoided cost price stream would not change but that capacity payments to solar QFs selecting the standard renewable avoided cost price stream would increase.[16] Yet, Staff points out, the calculations have resulted in capacity payments for both wind and solar far below what they would have received under the previous methodology, and not commensurate with the CTPs of the two QF resource types.

ODOE: ODOE agrees with Staff that the avoided capacity contribution adjustments adopted in Order No. 14-058 are flawed, resulting in double-discounts that severely undercompensate QFs selecting either standard renewable or standard non-renewable avoided cost price streams. ODOE endorses Staff's two-step revision.

PacifiCorp: PacifiCorp urges that we not change the avoided capacity contribution calculation adopted in Order No. 14-058, explaining, we correctly adjusted the capacity contribution in Phase I to account for how intermittent QFs contribute (or do not contribute) to the peak-hour capacity needs of utilities in resource deficiency periods. PacifiCorp argues it is appropriate to convert the adjusted capacity contribution of a solar QF to a dollar-per-megawatt-hour and apply it to only the QF's on-peak hours.

According to PacifiCorp, Issue 3 "boil[s] down to a proposal that the solar capacity adder should be paid as a fixed dollar amount and that each solar QF should receive the fixed dollar amount regardless of its actual output during on-peak hours."[17] PacifiCorp argues that this would pay a solar QF for avoided capacity of a base load resource regardless of whether the QF actually provides generation needed to offset the resource, let alone benefits such as operating reserve capacity and the ability to be dispatched on an as-needed basis in all hours (which a solar resource does not provide).

PGE: PGE argues that the capacity contribution adder approved in Order No. 14-058 is correct. PGE refutes arguments that we did not intend to do what the order stated—i.e., apply the capacity contribution percentage of a QF resource type directly to the on-peak dollar-per-megawatt-hour. PGE insists that spreading fixed capacity costs over the proxy resource's on-peak generation and compensating a solar QF for the hours it is actually available is not a discount but rather an accurate representation of the costs actually avoided by a utility. PGE cautions that, under Staff's methodology, if a QF has a CF greater than a utility's IRP solar resource, the utility will pay more than avoided costs for the QF's capacity.

Idaho Power: Idaho Power argues that the calculation under Order No. 14-058 does not involve any discount, whether single or double; rather it appropriately accounts for two

[16] Staff Post Hearing Brief at 6 (Oct 13, 2015) (citing Order No. 14-058 at 15).
[17] PacifiCorp Prehearing Brief at 12.

different aspects of capacity—CTP and annual CF—and disregarding either aspect of a QF's capacity value would be inconsistent with sound utility resource planning. Idaho Power explains, when a utility evaluates a resource it considers how much the resource can contribute during the utility's hour of peak load, as well as the percentage of the resource's nameplate capacity that will be contributed during all hours in a year.

Obsidian: Obsidian maintains that we intended in Order No. 14-058 that a base load QF would receive a full capacity payment, while a variable QF would receive a capacity payment commensurate with the CTP of its resource type and reflecting the resource's reduced availability during peak hours. Obsidian argues that the unintended result has been a double discounted capacity payment for solar QFs. Nothing, Obsidian contends, in Staff's testimony in Phase I or Order No. 14-058 indicates the intent to apply a double discount to the value of capacity contributed by solar QFs.

The problem with the approach in Order No. 14-058, Obsidian indicates, is the solar capacity component—which is discounted to account for the fact that the capacity contribution of solar is less than a CCCT[18]—is applied as an "adder" to the power rate rather than as a stand-alone payment for capacity. The result, Obsidian explains, is the capacity payment paid to solar QF projects is discounted once to reflect the resource-specific capacity rate, and then again by applying that rate for only some high load hours. Obsidian concludes, the problem lies in simultaneously discounting two variables—the rate and the number hours over which the rate is paid—to account for one characteristic, the reduced availability of a variable resource. Obsidian offers an analogy involving two workers, one full-time and one half-time, who do the same job to illustrate the double-discount. If the workers' compensation is proportionate to their work, the part-time worker should make half as much as the full-time worker, but under Order No. 14-058, the part-time worker gets paid half of the hourly rate as the full-time worker and only gets paid for half as many hours as the full-time worker, resulting in the half-time worker getting paid one quarter of the total compensation of the full-time worker.

Obsidian notes that Staff has squarely rejected the notion that it intended to apply a double discount to renewable solar QF capacity payments. Obsidian contends that the utilities mistakenly assert in this proceeding that Staff is advocating for a fixed capacity payment—one that is paid even when the resource is not generating—which results in an overpayment to solar QF projects, when Staff has been very clear in asserting that the revised payment amount would only be paid to a QF when its facility is actually generating.

CREA: CREA argues that the same mathematical correction must be made with regard to standard (non-renewable) wind and solar avoided cost rates under the new capacity CTP methodology and failing to correct the error would systematically underestimate the actual avoided costs in violation of PURPA.

[18] Combined cycle combustion turbine generator.

2. Resolution

We concur with Staff and other parties that that the avoided capacity contribution calculation we adopted in Order No. 14-058 contains an inadvertent flaw with respect to solar QFs under both the standard renewable and standard non-renewable avoided cost price streams, and with respect to wind QFs under the standard non-renewable avoided cost price stream. Staff recommends an adjustment to fix the error and we adopt the adjusted calculation, as it is specified in Staff's testimony at Staff/500, Andrus/18-20 and Staff/500, Andrus/21, respectively, attached as Appendix A.

D. Appropriate Forum

Issue 5 asks whether our adopted process to update a utility's avoided costs is sufficient. Under that process, a utility submits updated avoided costs: (1) within 30 days after we acknowledge the utility's IRP; and (2) on May 1 every other year. Staff and interested parties then have the opportunity to seek suspension of the prices to allow additional investigation into whether the prices comply with our methodologies for establishing avoided cost prices. If no party asks for additional investigation, the prices will become effective 30 days after the filing date.[19]

1. Parties' Positions

Staff: Staff recommends continuing to use the IRP and avoided cost filing processes outlined in Order Nos. 05-585 and 06-358 and our administrative rules. Staff notes this process has been in place since before 2005 and has not led to undue litigation. Staff finds no cause to think the situation will change going forward.

Staff recommends one change to that process, however. Staff asks we require the utilities to satisfy minimum filing requirements (MFRs) when making avoided cost filings as it can be difficult to discern what inputs a utility has used to calculate avoided cost prices, leading to suspension, investigation, and rounds of discovery. Staff's proposed MFRs would require the utilities to identify specific information, including the year demarcating between resource sufficiency and deficiency periods, the location and nameplate capacity of the utility's proxy resource, and the source of the utility's gas price forecast. Staff's list of proposed MFRs is attached as Appendix B.

Staff disagrees with proposals to expand the IRP process to include final determinations on avoided cost prices, implement a process that runs concurrently with the IRP, or essentially eliminate any process to determine avoided cost prices outside the traditional IRP. Staff emphasizes that the IRP is intended as informational and does not necessarily involve an opportunity for final resolution on disputes. Staff is concerned that adding litigation of inputs would make it difficult to complete an IRP process within the six months contemplated by the Commission's IRP guidelines. Staff worries that a separate process concurrent or after the IRP process would use inputs not yet acknowledged by the

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[19] OAR 860-029-0040(4)(q).

Commission and be unwieldy and damage the collaborative and transparent nature of the IRP.

ODOE: ODOE proposes a two-step process. First, a utility would simultaneously make an IRP and a preliminary avoided cost filing at the start of the IRP process. The preliminary avoided cost filing would include the MFRs proposed by Staff, with some amendments.[20] The IRP docket would remain primarily informational, but the filing of preliminary avoided costs at the same time would allow comments on the inputs underlying calculation of the avoided costs. The Commission would not be required to rule on avoided costs at the time, but commentary about avoided cost inputs could influence decisions regarding action items. Second, a utility would make a final avoided cost filing, docketed as a contested case, within the same timing of 30 days after acknowledgement of the utility's IRP.

ODOE argues that its proposal to have utilities file preliminary avoided costs at the same time as their IRP encourages QF participation in the IRP process, encourages discussions about the deficiency date and its effect on avoided costs, and will inform the Commission's acknowledgement order. ODOE maintains that discussing the deficiency date and effects on avoided costs during the IRP process would have only small administrative costs yet potentially large benefits. ODOE adds that having these discussions in the IRP process would also facilitate the subsequent contested case avoided cost docket.[21]

PacifiCorp: PacifiCorp asserts that the IRP process is the proper forum to develop and vet *all* assumptions and inputs used in calculating avoided costs. PacifiCorp argues, "[u]tility IRPs are developed through a well-established, robust, and transparent process with opportunity for input and challenges from Commission Staff and stakeholders, as well as meaningful review by the Commission."[22] PacifiCorp observes that the IRP process is governed by guidelines that require extensive public input. PacifiCorp claims that the IRP process provides sufficient opportunity to challenge the assumptions and inputs underlying IRP calculations.

PacifiCorp finds additional opportunities for parties to challenge IRP assumptions and inputs problematic. PacifiCorp posits that protracted litigation outside of the IRP process would interfere with the regular update of avoided costs (and potentially harm customers), undermine the openness of the IRP process, interfere with utility planning, and undercut the Commission's acknowledgement of the IRP.

PGE: PGE argues that parties provided no compelling evidence that the current process is insufficient. PGE observes that we have repeatedly examined the assumptions and

[20] *See* ODOE/1100, Carver/4.
[21] ODOE Post Hearing Brief at 6 (Oct 13, 2015).
[22] PacifiCorp Prehearing Brief at 14.

inputs that underlie avoided costs, most recently in Order No. 14-058 where we indicated they derive from the utility's IRP where they are subject to full stakeholder review.[23]

PGE opposes Staff's proposed MFRs. PGE allows that it is willing to provide citations in its avoided cost filings to IRP assumptions, as it did in its most recent avoided cost update. PGE urges caution when imposing additional requirements and supports SBUA's concern about too much burden on QFs to be involved with utilities' IRPs, which are expansive in nature and involve issues not pertinent to QFs.

Idaho Power: Idaho Power worries that a policy encouraging QFs to use avoided cost filings to challenge inputs would provide incentive and opportunity to delay the approval of new prices. Idaho Power argues that the better approach would be a separate complaint proceeding. Idaho Power asserts that its proposal will: (1) result in the administratively efficient adoption of updated avoided cost prices; (2) preserve parties' ability to challenge aspects of the avoided cost prices in a contested case; and (3) prevent gamesmanship to delay avoided cost updates.

SBUA: SBUA contends an IRP is not a proper forum to fully vet the assumptions and inputs that underpin avoided costs because there is no opportunity for cross-examination. SBUA asserts the scope of IRPs and their continuous nature may put an onerous administrative burden on QFs if they must participate in dockets involving more issues and complexity than relevant to the QFs.

CREA: CREA asserts that recent disputes regarding utilities' avoided cost filings show that the existing process is insufficient. CREA suggests the current IRP process does not provide a meaningful opportunity for QFs to dispute avoided costs calculations, as there is no evidentiary hearing and the process is not designed to review and approve rates. CREA asks the Commission to clarify how and when avoided costs are subject to full review. CREA supports Staff's proposed MFRs.

Coalition: Coalition recommends we create a separate proceeding to run concurrent with a utility's IRP to review the inputs and assumptions used in the calculation of avoided costs. Coalition argues that a concurrent process will ensure that all issues are fully addressed and that rates are consistent with an acknowledged IRP and are approved more quickly.

2. Resolution

We are cautious about instituting changes to long-established regulatory processes such as the IRP or the avoided cost filing. We are not convinced by any evidence in this docket that these processes are broken and need revision. We agree with Staff that there is value in the sequential nature of reviewing avoided costs after acknowledgement of a utility's IRP and, therefore, decline any proposals to institute concurrent or simultaneous

[23] Order No. 14-058 at 12.

processes. We also are conscious of the need to minimize the administrative burden on all parties.

Consequently, while we value Staff's proposed MFRs because they identify the information and inputs that utilities need to provide, we decline to add potentially significant administrative burden and time to the front end of the process. Utilities have provided such information upon Staff's request. We urge the utilities to continue to provide all information called for in the MFRs as a matter of course. Regularly providing such in a clear and consistent format will facilitate the timely adoption of avoided cost prices.

E. Issue 6: Compensation for Capacity During Resource Sufficiency

Issue 6 asks whether market prices continue to adequately compensate QFs for capacity provided to a utility during a period of resource sufficiency for the utility.

In Order No. 05-584, we adopted a bifurcated methodology based on whether a utility is resource deficient or sufficient. During a utility's sufficiency period, the utility uses monthly on- and off-peak forward market prices to calculate avoided cost prices.[24] We reasoned that this market-based pricing approach for incremental QF capacity is appropriate because a utility would be expected to use market purchases to meet gaps between demand and resources when the utility is not in the process of acquiring new resources.[25] We concluded that this approach "embeds the value of incremental QF capacity in the total market-based avoided cost rate."[26]

1. *Parties' Positions*

Staff: Staff finds that utilities continue to meet capacity needs during sufficiency periods with short-term market purchases. Staff concludes that a sufficient relationship still exists between a utility's capacity needs during a sufficiency period and the market-based prices the Commission adopted in 2005. Staff recommends we authorize the continued use of market-based prices, and points out that the process for reviewing avoided cost price filings will allow parties to challenge these prices on the ground that they do not represent the cost of market purchases the utility will actually make.

Staff recommends we reject the Joint QFs' interim capacity pricing mechanism as inconsistent with PURPA. Staff reasons, PURPA does not allow capacity payments in avoided cost prices that would compensate QFs for costs that *may* be avoided in the future, or that are intended to *incent* QF development rather than account for real avoided costs. Although the mechanism would be based on the costs of projected capital improvements by utilities, these costs represent the risk of environmental regulations rather than costs actually avoided by QF purchases. Staff validates PacifiCorp's

[24] Order No. 05-584 at 28.
[25] *Id.*
[26] *Id.*

explanation that environmental upgrades at plants outside Oregon will not be avoided by QF purchases in Oregon. Staff also notes that prior orders do not support layering any costs of upgrades at baseload coal plants for the purposes of determining avoided costs.

Staff is also unpersuaded that the increasingly long length of a utility's sufficiency period, the potential for federal environmental regulations, or a utility's underestimation of its need for capacity are valid reasons to increase avoided cost prices during sufficiency periods. Staff notes that we use frequent updates to avoided cost prices, including fully-updated avoided cost prices every two years (after IRP acknowledgement) with certain inputs updated annually, along with additional revisions in the event of significant changed circumstances. Staff posits that frequent updates to IRP prices are sufficient protection against incorrect estimates about a utility's next resource acquisition.

Staff agrees with the Joint QFs' 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.

ODOE: ODOE maintains that a forecast of forward wholesale power prices is a reasonable estimate of avoided costs during a utility's sufficiency period if the utility's power purchasing behavior is consistent with the type of prices being forecast. ODOE argues that whether the cost of retrofitting PacifiCorp's existing coal plants with air pollution controls should be incorporated into the company's avoided cost rates is a fact-specific issue better addressed in the next IRP.

PacifiCorp: PacifiCorp recommends no change in our policy. PacifiCorp argues that market prices continue to adequately compensate QFs for capacity when a utility is in a sufficiency period. PacifiCorp contends that its current IRP demonstrates that short-term market purchases are still used to meet capacity needs during a sufficiency period.

PacifiCorp rebuts the Joint QFs' request for interim capacity pricing based on planned environmental upgrades, arguing that it is based on costs that cannot be avoided. PacifiCorp refutes implications that environmental upgrades at its coal plants in other states can be avoided by purchases from renewable and non-emitting QFs in Oregon. PacifiCorp explains that these upgrades must be done for compliance with the Environmental Protection Agency (EPA) Regional Haze Rule, and that some planned upgrades may turn out not to be needed. FERC has stated, PacifiCorp notes, that avoided cost calculations prohibit payment for environmental costs unless such costs are "real costs that would be incurred by utilities," and could actually be avoided.[27]

PacifiCorp also criticizes the Joint QFs' proposed methodology because it fails to account for benefits such as low-cost base load generation, operating reserves, and load following capability, if environmental upgrades are not done and certain plants can no longer be operated. PacifiCorp reasons, given the operational characteristics of a coal-fired plant

[27] PacifiCorp Prehearing Brief at 26 (Sept 2, 2015) (citing Staff/600, Andrus/19 and quoting *So. Cal. Edison*, 71 FERC ¶ 61,269 at 62,080 (1995)).

and those of renewable QFs, it is impractical to replace an entire coal plant with many individual QFs.

To the Joint QFs' allegation that PacifiCorp's IRP assumes 122 MW of QF contracts will be renewed upon expiration thereby inappropriately extending the sufficiency period, PacifiCorp counters that it also does not account for 1,100 MW of new QF contracts coming online.

PacifiCorp challenges the Coalition's argument that a renewing QF receiving capacity payments should continue to receive such payments. PacifiCorp calls this an attempt to lock in capacity payments beyond the 20-year term of a standard contract, countering that avoided costs must be updated when the term of a new standard contract begins.

PGE: PGE recommends no change in the Commission's policy, claiming no evidence was presented that the market prices paid by PGE during its sufficiency period inadequately compensate any QF for capacity.

With regard to speculation that a utility's sufficiency period is being lengthened by improving thermal resources and uncertainties about environmental laws, PGE argues that no evidence was presented that QFs have been or would be inadequately compensated for capacity in either situation. PGE argues that the Commission should not change a well-established methodology in response to speculation.

Idaho Power: Idaho Power recommends no change in the Commission's policy. Countering arguments that market prices do not compensate QFs for capacity, Idaho Power asserts that market prices embed the value of incremental capacity and thereby compensate for capacity. Idaho Power contends when a utility is resource (and therefore capacity) sufficient, market prices actually overcompensate QFs for capacity. Idaho Power notes that FERC has been clear that a QF is not entitled to capacity payments when a utility does not avoid capacity.[28]

Idaho Power charges that one example of a utility adding a resource sooner than predicted does not prove that utilities are systematically overstating resource sufficiency periods. Idaho Power stresses that regulatory uncertainty applies to all aspects of trying to calculate avoided costs for extended periods of time. The IRP process, Idaho Power advises, is the appropriate forum for addressing resource sufficiency/deficiency issues, not this docket. Idaho Power notes that to the extent new environmental regulations affect resource planning, such impacts will be accounted for in the utility's IRP and its analysis of least cost/least risk resource portfolio options. It is inappropriate to inflate a QF's avoided cost rate because the QF is emission free, Idaho Power asserts, because legally the avoided cost rate must tie directly to actual costs avoided as established in a utility's IRP. Idaho Power adds, inflating an emission free QF's avoided cost rates to

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[28] *Id.* at 11-12 (citing *Small Power Production and Cogeneration Facilities: Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978*, Order No. 69, 45 Fed.Reg. 1, 214, 12,225 (Feb 19, 1980)).

incent development during extended resource sufficiency period is also inappropriate because it is contrary to Commission policy.[29]

Joint QFs: Coalition, CREA, One Energy and Obsidian jointly recommend that the Commission revisit the decision in Order No. 05-584 to value QF capacity based on market prices during a utility's sufficiency period. They urge we reexamine this policy and make two changes.

The Joint QFs note several problems with the current methodology for setting avoided cost rates during sufficiency periods: (1) the rates fail to include utilities' actual incremental investments made to retain existing capacity resources; (2) the utilities have extremely long resource sufficiency periods that are being extended by these investments; and (3) the demarcation between resource sufficiency and deficiency is historically inaccurate and will likely be more inaccurate in the future due to uncertainty related to environmental laws. The result, the Joint QFs conclude, is renewable and zero emitting QFs receive the message that their capacity is of little long-term value, thereby discouraging their development at a time when they are needed to meet environmental regulations.

The primary change recommended by the Joint QFs is to revise avoided cost prices so that a QF will be paid a capacity payment that is based on incremental costs a utility spends to retain existing capacity resources. The Joint QFs recommend that avoided cost prices be revised to include PacifiCorp's planned incremental capacity costs related to environmental upgrades that are necessary to continue operating its coal plants. The Joint QFs calculated the value of PacifiCorp's capacity retentions by using the company's IRP to identify specific upgrades (and their estimated cost) planned during the company's sufficiency period, and converting the average capacity value of these deferrable investments into on-peak energy prices consistent with PacifiCorp's Schedule 37.

To PacifiCorp's claim that this is an inappropriate environmental adder based on environmental upgrades that cannot be avoided by an Oregon QF, or are uncertain and might not happen at all, the Joint QFs counter that it is not what an individual QF purchase allows a utility to avoid but rather what QFs in the aggregate allow the utility to avoid. The Joint QFs posit that environmental costs based on generation that a utility would otherwise build or buy should be directly included in calculation of a utility's actual avoided cost. The Joint QFs ask we take official notice of an order by the Washington Utilities and Transportation Commission (WUTC) in docket UE-144160 that

[29] Idaho Power Post-Hearing Brief (Oct 13, 2015) (citing Order No. 84-742 at 3) ("The Commission believes that the best balance between the two goals [QF development and reasonable rates] is to set rates equal to avoided costs. In periods of surplus, such as now, fewer projects are needed. When deficits are projected, avoided costs will rise and opportunities for profitable facility development will expand. Therefore, as a general policy, the Commissioner endorses adherence to avoided costs as the best pricing method.")).

directs PacifiCorp and the other parties to develop a capacity adder to be applied to avoided cost rates paid to QFs during PacifiCorp's sufficiency period.[30]

The Joint QFs also argue that the capacity value provided by existing QFs is not appreciated. The utilities plan in their IRPs on existing QFs to renew contracts, thereby allowing deferral of capacity investments, yet QFs are not compensated for the capacity value associated with the deferral and are effectively providing it for free. The Joint QFs argue that avoided cost rates should reflect that existing QFs provide capacity value by helping to defer the utilities' need to buy or build new resources.

As a solution, the Joint QFs cite the Coalition and ODOE recommendation in Phase I that existing QFs that renew their contracts receive follow-on contracts with no resource sufficiency period. In the alternative, the Joint QFs recommend that an alternate IRP scenario be performed to calculate a portion of the benefits provided by renewing QFs. The Joint QFs explain that the alternate IRP scenario would assume that QFs did not renew their contracts, thereby becoming a proxy for some of the capacity benefits provided. This would not change how the utilities' plan on QFs renewing contracts, but would attempt to estimate the associated capacity value.

Coalition: Coalition urges the Commission to revise the methodology for calculating avoided cost rates during the resource sufficiency period to include the utilities' planned capacity costs during the sufficiency period, whether these costs derive from extensive market purchases or environmental upgrades.

2. Resolution

We affirm our policy that avoided cost pricing should be market-based when a utility is resource sufficient. We are not persuaded by arguments that capacity prices paid to QFs should reflect the actual incremental capacity investments that utilities are currently making to retain existing capacity resources. Those arguments fail to rebut evidence that such costs cannot be avoided by QF purchases in Oregon. PacifiCorp indicates that the investments are being made to plants outside of Oregon in response to environmental laws that are specific to natural resources in those states. Staff agrees with PacifiCorp's position. Accordingly, we conclude that it would be inappropriate to base avoided cost rates on costs that will not be avoided. We are also concerned about the flux in pertinent environmental regulation and the lack of certainty about related investments that will actually be made by PacifiCorp.

We agree with Staff and the Joint QFs that a certain amount of capacity may not be valued if utilities assume in their IRPs that existing QFs nearing contract expiration will automatically renew. We direct each utility to work with parties to address this issue in its next IRP.

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[30] The motion is granted and we take official notice of the WUTC order. Any party may object to the notice within 15 days of this order. *See* OAR 860-001-0460(2).

F. Issue 7: Calculating Non-Standard Avoided Cost Prices

Issue 7 reexamines methodologies for calculating non-standard avoided cost prices and reconsiders whether the same methodology should be used for all three electric utilities operating in Oregon (PGE, PacifiCorp, and Idaho Power). In Order No. 07-360, we set forth guidelines for negotiating non-standard contracts and established methodologies for calculating non-standard avoided cost prices. For PGE and PacifiCorp, standard contract avoided cost prices are the starting point for price negotiations, with modifications allowed to address the seven factors enumerated at 18 C.F.R. § 292.30(e). For Idaho Power, the starting point for price negotiations is the avoided cost prices calculated under the modeling methodology approved by the Idaho Public Utilities Commission (IPUC), as refined by this Commission to incorporate stochastic analyses of electric and natural gas prices, loads, hydro, and unplanned outages.

1. Parties' Positions

Staff: Staff supports continued use of the methodologies previously approved by the Commission for PGE and Idaho Power, but also supports PacifiCorp's request to change to a model-based methodology.

Staff does note the complexity of PacifiCorp's use of its PDDRR methodology that is based on its production cost model (GRID). The PDDRR methodology runs GRID two times: first using the preferred portfolio from PacifiCorp's last IRP, and then adding the operating characteristics of a proposed QF project with an adjustment (proportionate to the QF's capacity) to the company's next deferrable resource. Staff concludes this methodology is justified for larger QFs as it more accurately quantifies the impact of a particular QF. Staff notes, however, that transparency must accompany this methodology and recommends we adopt rules requiring PacifiCorp work cooperatively with QFs and run the GRID scenarios and sensitivity analyses in a transparent manner reasonably accessible to QFs.

Staff supports ODOE's recommendation that market-based prices be the floor for non-standard avoided cost prices during either a utility's sufficiency or deficiency period. Prior to 2005, the utilities used decremental generating costs to determine standard avoided cost prices during sufficiency periods.[31] In Order No. 05-584, Staff indicates, the Commission decided such prices did not sufficiently compensate QFs for capacity and ordered utilities to value "avoided costs when a utility is in a resource sufficient position at monthly on-and off-peak forward market prices as of the utility's avoided cost filing."[32] Although that order applied to the calculation of standard avoided cost prices, Staff argues the same reasoning supports the use of wholesale prices as a floor when calculating non-standard avoided cost prices.

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[31] Staff/700, Andrus/11 (citing Order No. 05-584 at 27 ("When in a period of sufficiency, PGE and PacifiCorp have historically calculated avoided costs based only on the variable costs of operating existing generating resources.")).
[32] *Id.* (citing Order No. 05-584 at 28).

ODOE: ODOE contends it is appropriate for the methodologies to differ across utilities so long as one principle is applied: the floor for non-standard avoided cost prices is the wholesale power price forecast used to set sufficiency period avoided cost prices in standard QF contracts. ODOE asserts that, regardless of a utility's decremental cost of operation, the utility either buys from the wholesale market or sells (or has the opportunity to sell) into the wholesale market. ODOE posits that by paying market prices to a QF, ratepayers are kept whole because the value of power during periods of deficiency is what the utility could sell it for or what it would buy it for, regardless of decremental costs of generation.

PacifiCorp: PacifiCorp asks to use its PDDRR method to calculate non-standard avoided cost prices for large QFs, contending this method more accurately values energy and capacity on its system. PacifiCorp explains the PDDRR method compares two GRID simulations to determine the system energy value of a QF resource, taking into account a QF's specific operating characteristics and point of delivery on the company's system. It accounts for factors such as a QF's location, delivery pattern, and capacity contribution. PacifiCorp uses this method in Utah, Wyoming, and Idaho.

With regard to concerns that the PDDRR methodology is overly complex, PacifiCorp responds that computer models are vital to managing and pricing resources in a complex modern energy industry. PacifiCorp argues it is important to use modern tools to develop avoided costs for large, non-standard QFs and send efficient price signals to at least one subset of Oregon QFs. PacifiCorp agrees that QFs developers should have access to and assistance with GRID. PacifiCorp indicates it has made the GRID model available at no cost, along with assistance and training, to QF developers in other states. PacifiCorp suggests we require utilities make their models available to QF developers and provide assistance and training upon request. A dispute that arises regarding an avoided cost calculation developed under a model should be brought to the Commission under the existing dispute resolution process, PacifiCorp advises. PacifiCorp opposes rigid rules for the use of computer models during negotiations, but counsels that any rules that are approved should allow for various outcomes that may work well for different developers.

PGE: PGE asserts that standard contract avoided cost prices should continue to be PGE's starting point for non-standard QF price negotiations, with adjustments only for the seven factors in 18 C.F.R. § 292.30(e). PGE maintains the utilities should have flexibility with regard to the adjustments, including the ability to utilize production cost models that are used to set net variable power costs. Noting that such models have already been vetted in the IRP process, PGE asserts that the models can be used to assess interdependencies across the seven factors, and ensure greater precision and accuracy. PGE indicates that model-based adjustments are readily observable in a standard spreadsheet.

Idaho Power: Idaho Power argues it is important that the company's avoided cost prices, procedures, and implementation are consistent between its jurisdictions to prevent QFs from taking advantages of differences. Idaho Power argues there is no need to depart from the Incremental Cost IRP Methodology approved by the IPUC for use in Idaho and approved by the Commission for use in Oregon to determine the starting point for negotiating non-standard avoided cost prices. Idaho Power explains, this method captures accuracy and realizes efficiency using the AURORA program, which is also used in Idaho Power's IRP and power cost dockets.

Coalition: Coalition asserts no changes should be made to the current methodologies for calculating non-standard avoided cost prices. Coalition observes that PacifiCorp has not established that a change to a model-based methodology is warranted, having identified no flaws in the current methodology. Coalition worries that use of a model-based methodology would allow PacifiCorp too much discretion to unilaterally lower large QF avoided cost prices. Coalition points out that PacifiCorp has admitted in other dockets that its computer model consistently under forecasts net power costs, suggesting avoided costs will also be underestimated.[33] Coalition worries that a model-based method will increase negotiating costs for QF and intensify disputes.

CREA: CREA recommends we retain the current approach to calculating non-standard avoided cost rates, concluding no party identified any flaws with the current methods. CREA asserts that Idaho Power seeks to use a new methodology, the Incremental Cost IRP Methodology approved by the IPUC in 2012, not previously approved by the Commission. CREA urges us to reject PacifiCorp' recommendation to adopt a computer modeling methodology for calculating non-standard avoided cost rates. A computer model is problematic for a QF developer, CREA explains, because of the need to retain outside technical expertise. Without such expertise, CREA contends, a proprietary model is essentially a "black box." CREA worries that PacifiCorp's proposal will require QF developers to incur significant costs very early in the development process.

Should we adopt PacifiCorp's proposal, CREA asks we adopt rules requiring the utilities to run scenario and sensitivity analyses at the QF's request. CREA agrees with ODOE's recommendation that wholesale market prices should serve as a floor to the avoided cost rates under any modeling methodology.

2. Resolution

We will continue to allow PGE, PacifiCorp, and Idaho Power to use different methodologies to negotiate and calculate non-standard avoided cost prices. Although the question was raised in this Phase II whether this practice should continue, no party advocated that it should be changed.

We also make no changes in how PGE and Idaho Powers negotiate non-standard avoided cost prices. PGE will continue to use standard contract avoided cost prices as the starting point for price negotiations, with modifications allowed to address the seven factors in 18 C.F.R. § 292.30(e). Idaho Power will continue to use, as the starting point for price negotiations, the avoided cost prices calculated under the modeling methodology approved by the IPUC for QFs greater than the standard eligibility cap, with some refinements for Oregon. We reauthorize Idaho Power to use this methodology for the

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[33] Coalition Prehearing Brief at 13 (Sep 2, 2015) (citing *In the Matter of PacifiCorp, dba Pacific Power 2016 Transition Adjustment Mechanism*, Docket No. UE 296, PAC/100, Dickman/21).

ongoing reason that consistency between Idaho Power's jurisdictions with regard to the calculation of avoided cost pricing remains important.

We approve PacifiCorp's request to use its PDDRR method going forward. We agree this GRID model-based method more accurately values energy and capacity on PacifiCorp's system by taking into account the unique characteristics (including location, delivery pattern, and capacity contribution) of each QF. Although Coalition and CREA suggest it is unnecessary to fix what is not broken, we are responsible under PURPA to improve our implementation to benefit both QF development and ratepayer cost neutrality. We are persuaded that the PDDRR method improves non-standard QF avoided cost pricing for QFs selling to PacifiCorp and we adopt it.

In approving this change, we recognize that use of GRID and the PDDRR method to establish nonstandard avoided cost prices should be as transparent and comprehensible as possible to QF developers and all interested parties. PacifiCorp has offered to make GRID open to QF developers and to provide training and technical assistance upon request. We thank PacifiCorp for this offer and ask PacifiCorp to make access, training, and technical assistance available upon entry of this order. We encourage QF developers to work with PacifiCorp to obtain the access, training and technical assistance needed, but want them to know that they may raise concerns or issues about access and use of GRID and the PDDRR method.

Finally, we approve one change to be applied to all three utilities. We adopt ODOE's recommendation, supported by Staff, to set the floor for non-standard avoided cost prices at the wholesale power price forecast that is used to set sufficiency period avoided cost prices in standard QF contracts. We are persuaded that the benefit of QF developers understanding the price floor outweighs the minimal risk described by PacifiCorp that avoided cost prices produced by the PDDRR method would be lower than market.

G. Issue 8: Legally Enforceable Obligation (LEO) Formation

Issue 8 addresses when a LEO arises outside of an executed contract. The current rule provides that outside of a PPA, a LEO exists only if a QF and a utility agree in writing that it does.[34] This may conflict with FERC precedent suggesting a LEO is broader than a contract between a QF and a utility, with the purpose of preventing a utility from circumventing PURPA requirements by refusing to execute a contract.[35]

In 1987, the Oregon Court of Appeals addressed when a LEO is established. In *Snow Mountain Pine v. Maudlin,* the Court declared that the utility's purchase obligation "is not created by common law concepts of contract law," but rather "created by statutes,

[34] OAR 860-029-0010(29) provides that a LEO exists on the earlier of (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 and capacity; 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.
[35] *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006, 2011 WL 4710843, (citing Order No. 69, FERC Stats. & Regs. 30,128 at 30,889).

regulations and administrative rules."[36] The court concluded that a QF has the power to determine the date for which avoided costs are calculated by obligating itself to provide power.

1. Parties' Positions

Staff: Staff argues that the decision in *Snow Mountain Pine v. Maudlin* should shape a new rule.[37] Staff explains, all three utilities have similar processes for developing and executing a standard contract: (1) a QF initiates the process by submitting certain information, the utilities then have 15 days to provide a draft standard contract; (2) the QF may agree to the terms of the draft contract and ask the utility to provide a final executable contract, or suggest changes; (3) the utility provides iterations of the draft standard contract no later than 15 days after each round of comments by the negotiating QF; and (4) when the QF indicates that it agrees to all the terms in the draft contract, the utility has 15 days to forward a final executable contract to the QF.

Staff concludes that a QF is obligated to provide power once it is subject to penalty for failing to deliver energy on a scheduled commercial on-line date.[38] Staff suggests this obligation triggers when a QF signs a final draft of an executable standard contract that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries.

Staff adds a caveat: 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 schedule or state or federal policies, the QF should have the opportunity to establish a LEO notwithstanding the fact that it has not yet executed a contract. In such case, the Commission should determine the avoided cost price case-by-case. Staff suggests this case-by-case basis would reduce any incentive for a party to submit a dispute to the Commission as a means of "locking-in" a particular avoided cost price.

PacifiCorp: PacifiCorp argues that a LEO's purpose is to provide recourse when a utility refuses to sign a PPA rather than allow a QF to lock in an avoided cost rate, avoid providing important contractual information, or bypass the standard contracting process.

PacifiCorp notes that Oregon already has more detailed procedures for QF-utility negotiations than other states. Noting that its Schedule 37 processes, timelines and standard contracts were already vetted and approved by the Commission, PacifiCorp claims that a good reference point for establishing a LEO already exists within the tariff. PacifiCorp points to the QF's approval of a final draft PPA under section B(5) of

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[36] *Snow Mountain Pine Co. v. Maudlin*, 84 Or App 590, 598 (1987).
[37] Staff/500, Andrus/38.
[38] Staff Prehearing Memorandum at 39 (citing *Armco Advanced Materials Group v. Pennsylvania PUC*, 579 A2d 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.")).

Schedule 37, noting this is the point when a QF has provided all project information required by a PPA and has accepted a final draft agreement. PacifiCorp contends that requiring a QF satisfy all project information requirements in the contract and accept a final draft agreement is a fair milestone for establishing a LEO. PacifiCorp asserts this milestone provides a clear definition of QF commitment. PacifiCorp indicates that Schedule 37 also provides relief should a QF believe the utility is thwarting a contract. PacifiCorp suggests that in the event of dispute, the Commission should determine the avoided cost price.

PacifiCorp opposes the Coalition's suggestion that an existing QF should be able to seek a new QF contract up to three years before their existing QF PPA expires. PacifiCorp counters that, in its experience, a one year planning horizon is more appropriate and provides the QF with certainty on the avoided costs, adequate time to complete a new PPA, and adequate time to complete any modifications to the QF's interconnection.

PGE: PGE recommends that we set criteria for establishing a LEO based on a QF's commitment to deliver energy by signing a final executable draft contract. PGE notes that the terms and conditions of a QF's commitment are not sufficiently known and clear until the utility provides a final executable draft PPA. Under PGE's Schedule 202 governing negotiated QF contracts, information necessary to establish the terms and conditions of a QF's commitment to deliver energy may be exchanged until a final draft of an executable contract is issued by the utility.

PGE asserts that concerns about a utility's ability to delay execution are already mitigated by the timelines in the utilities' tariffs, the dispute resolution process in Order No. 07-360, and prohibitions on delaying negotiations in the utilities' avoided cost schedules. To the extent a dispute is not resolved before a utility's avoided cost update takes effect, PGE recommends we determine the avoided cost price that should apply. PGE notes that making the Commission responsible for this decision should remove a QF's incentive to prematurely submit a draft contract for dispute resolution.

Idaho Power: Idaho Power recommends we require a two-part showing to establish a LEO. First, the QF must show an unreasonable refusal or delay by the utility to contract. Since a LEO is intended to protect a QF from utility delay, Idaho Power argues a QF must show the utility purposefully prevented or delayed commitment to purchase power from the QF. Second, the QF must show "but for" the utility's refusal to enter into a contract, there would be a contract at a particular price and terms. Idaho Power explains that before a LEO can be formed, a QF must have provided the utility all information required for a contract and demonstrated the intent to be obligated, including willingness to provide a specific amount of energy under specific terms and conditions. Idaho Power suggests the QF should be required to show it can deliver its electrical output within 365 days of the Commission's determination that a LEO was created. Although parties counter that a QF developer will not be able to meet this deadline because financing will be unavailable until a contract is executed or a LEO is formed, Idaho Power argues the deadline reasonably balances the interests of QF developers and utility customers, noting several states have a similar or shorter time limit.

Coalition: When seeking the right to sell power to PacifiCorp at avoided cost rates, Coalition agrees that the QF should follow the first four steps outlined in PacifiCorp's Schedule 37. Under these steps, Coalition notes, the QF will provide all required information as well as reasonable additional information. If a dispute exists after the QF complies with the first four steps, Coalition recommends that a QF and PacifiCorp be required to negotiate for 15 business days. After this period, a QF should be allowed to commit itself to sell power under the existing rates and the QF's proposed contract terms while continuing negotiations with the utility, or seeking Commission resolution. If the QF files a complaint and the Commission finds the utility unreasonably delayed negotiations, imposed inappropriate or unapproved terms and conditions, or strayed from the approved process and timelines, then Coalition recommends the QF should be permanently awarded the avoided cost prices in effect when the dispute began. If the Commission rules against the QF, however, the QF would have to accept the utility's position on any disputed terms or conditions in order to retain the avoided cost prices in effect.

To PacifiCorp's argument that an existing QF should not be allowed to enter into a new contract more than a year before expiration of its current contract, Coalition argues the issue was raised too late and need not be resolved. Should we decide to address the issue, Coalition urges we allow both new and existing QFs to have the same amount of time to enter into new contracts. Coalition disagrees that one year is sufficient time for all existing QFs to enter into new contracts. Although a year may be sufficient for a QF that will have no changes in its operations and no need to modernize or upgrade, a QF that needs to make generation or interconnection upgrades that entail financing and planning may need to enter into a new contract more than two years before the existing contract expires.

CREA: CREA asks that we adopt a policy allowing a QF to obligate itself to sell energy and capacity pursuant to a LEO, with rates calculated on the date the obligation is incurred, by filing an unexecuted contract filing after negotiating with a utility to the point of impasse. CREA clarifies that the QF cannot simply sign a form contract at the first point of contact with a utility; instead, the QF must attempt to proceed through the Commission-approved contracting process to a point where the utility refuses to provide a contract that is acceptable to the QF, or otherwise fails to timely process the contract request in accordance with its tariff. By filing a disputed, unexecuted PPA with the Commission, CREA contends, a QF would formally agree to be bound by the terms ultimately deemed reasonable by the Commission, thereby creating a LEO.[39]

Gardner Solar: Gardner Solar recommends the following criteria for establishing a LEO: (1) the utility has approved avoided cost rates; (2) the utility has an approved standard

[39] CREA likens the process to FERC's unexecuted policy for transmission contracts. CREA Post Hearing Legal Brief at 4 (citing *Florida Power & Light Co.*, 98 FERC ¶ 61,324 at P 80 (2002) (under FERC's unexecuted filing policy, the "request obligates the transmission customer to agree to compensate the transmission provider at whatever rate [FERC] ultimately determines to be just and reasonable and to comply with the other terms and conditions of the tariff")).

contract; and (3) the QF has submitted a complete application that identifies all relevant project parameters to the utility.

Alternatively, Gardner Solar recommends we adopt Staff's proposal with one modification. Staff indicated that QFs could use the dispute resolution process to show a LEO was established before a final draft executable version of a standard contract was tendered to the utility. If such dispute process is initiated, Gardner Solar suggests that there also be a rebuttable presumption that a LEO exists on behalf of a QF that has filed a statement with the Commission indicating Staff's criteria have been met, with the utility having the obligation to rebut the presumption by clear and convincing evidence.

Gardner Solar also supports the Coalition's proposal.

Gardner Solar raises two concerns with other proposals. Gardner Solar indicates that FERC has opined that it is unreasonable for a state commission to require a QF to file a complaint as a precondition to establishing a LEO.[40] Gardner Solar asserts that Idaho Power's proposal essentially means that a QF could only secure a LEO if it were able to deliver power to the utility within one year of the LEO. From a practical standpoint, Gardner Solar explains, most QFs (particularly small QFs that are eligible for standard contracts) could not comply with this requirement as it generally takes longer than a year for a QF to order equipment, arrange for contractors, and construct a project.[41]

2. *Resolution*

We concur with Staff and the other parties that our existing LEO rule is inconsistent with FERC precedent and should be modified. We agree that there is no LEO until a utility and a QF have undertaken the contracting process, and negotiations have progressed beyond initial contact by a QF.

We adopt Staff's proposal that a LEO exist when a QF signs a final draft of an executable standard contract that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date.

We acknowledge, however, that problems may delay or obstruct progress towards a final draft of executable contract, such as failure by a utility to provide a QF with required information or documents on a timely basis. In the event of a dispute between a QF and a utility during the contracting process, we adopt Staff's proposal that we determine, on a case-by-case basis, when a LEO is formed for the purpose of establishing an avoided cost price. A QF should alert us of a dispute by filing a complaint. Through the complaint process, the QF and the utility will have the opportunity to fully explain any concerns and

[40] *Id.* at 6 (citing *Grouse Creek*, P 40).

[41] *See generally* Coalition/100, Lowe/16-17; Redacted CREA/100, Hilderbrand/20-21.

present arguments regarding the formation of a LEO and an avoided cost price to be applied.

H. Issue 9: Third-Party Transmission Costs Calculation and Accounting

Phase I of this docket addressed the issue of whether the costs or benefits associated with third party transmission should be included in the calculation of avoided cost prices, or otherwise accounted for in a standard contract. In Order No. 14-058, we concluded that any costs imposed on a utility by a QF in excess of the utility's avoided costs must be assigned to the QF in order to comport with PURPA's avoided cost principles.[42] We also determined, however, that Staff and the other parties had not fully addressed how to calculate and assign third-party transmission costs attributable to a QF.

1. Parties' Positions

PacifiCorp: When third-party transmission is required to move a QF's output from a load pocket to load, PacifiCorp proposes to procure long-term, firm, point-to-point transmission for the entire term of the PPA and assign costs assigned to the QF through a PPA addendum. PacifiCorp describes the complexity of arranging third-party transmission service and the reasons for addressing the associated costs on an individual QF basis. PacifiCorp argues that the fixed adjustments proposed by other parties would inaccurately pass through third-party transmission costs and fail to keep customers indifferent to QF power. PacifiCorp refutes the ability of a utility to resell or redirect third-party transmission services and questions the legality and capability of PacifiCorp to provide load pocket maps to QFs.

PacifiCorp urges we not defer this issue to Phase III. It does not strongly object to Staff's recommendation to modify PacifiCorp's proposal, but worries that clear guidance from the Commission is needed to avoid problems. PacifiCorp warns that transmission costs could increase upon renewal every five years and advises that QFs be so advised and be asked to assume the risks.

Staff: Staff recommends that we allow yet more discussion, deferring this issue to Phase III. In the alternative, Staff supports a modified version of PacifiCorp's proposal.

Staff finds PacifiCorp's proposal to capture third-party transmission costs and benefits associated with a particular QF load on an individual QF project basis in a PPA addendum consistent with PURPA, and agrees with PacifiCorp that it may be the only proposal that is consistent with PURPA. Nevertheless, Staff finds PacifiCorp's proposal troubling because it requires a QF located in a load pocket at the time the PPA is executed to pay for third-party transmission for the entire fixed price period of the standard contract, even though the load and resource balance in the load pocket is subject to change over time. Staff observes, "[i]f the conditions creating a load pocket are so dynamic that it is unreasonable to require PacifiCorp to describe them every two years,

[42] Order No. 14-058 at 22.

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."[43]

Staff suggests a modification. Since PacifiCorp indicated there is a minimum five-year commitment to obtain renewal rights for long-term firm point-to-point transmission from Bonneville Power Authority (BPA), PacifiCorp could offer a QF located in a load pocket two options for a contract addendum addressing third-party transmission costs: (1) establish a price for third-party transmission costs for the entire term of the contract; or (2) permit the cost of the transmission to be reset every five years concomitant with PacifiCorp's renewal of its long-term contract.

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

ODOE: ODOE agrees with Staff that this issue should be deferred to Phase III. ODOE seeks further opportunity to investigate PacifiCorp's assertion that options other than a long-term fixed assessment are either not allowable under FERC regulations or present unacceptable risk to the company and ratepayers. ODOE also sees a need to more clearly delineate a load pocket. ODOE asserts that third-party transmission costs must be assigned to QFs with options and transparency so that a QF may make an informed choice. ODOE also maintains that the options should include flexibility to address changing circumstances.

PGE: PGE argues that the price a utility pays to a QF should be adjusted to compensate for third-party transmission costs or benefits. PGE reasons, whether the QF chooses a standard or a negotiated PPA, the price should be adjusted to compensate the utility for third-party transmission costs incurred to deliver the QF's energy to load. PGE asserts this treatment is consistent with the requirement for an off-system QF to pay the transmission costs of delivering QF generation to the utility's system and our earlier position that transmission costs are only added to the avoided cost calculation when the QF allows the utility to in fact avoid such transmission costs. PGE notes, if the price the QF is paid is not adjusted for third-party transmission to move QF output in a load pocket to load, then the utility pays a price higher than its avoided cost. PGE does not propose a specific method for assessing the transmission costs associated with moving QF energy from load pockets to load.

CREA: CREA advises that PURPA provides three relevant guiding principles: (1) although PURPA entitles a QF to compel the utility to accept and purchase all of its delivered net output, PURPA allows for adjustment to avoided cost prices to account for transmission limitations on the utility's side of the QF delivery;[44] (2) PURPA entitles a

[43] Staff Prehearing Memorandum at 42.

[44] CREA Prehearing Legal Brief at 23-24 (citing 16 U.S.C. § 824a-3(a)(2); 18 C.F.R. § 292.303(a); *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, at P 41 n.79 (2013)).

QF to compel the utility to pay fixed avoided cost rates; and (3) a QF may agree to terms and conditions different from those it may compel through the mandatory purchase obligation.[45] CREA concludes that we must mandate that a fixed reduction to standard contract rates be made available to QFs located in a load pocket. CREA contends a fixed rate is required to meet the second principle and is needed because many QFs require a fixed price in order to obtain construction financing. CREA points out that PacifiCorp has already shown the ability to offer this option, having entered into at least one PPA with a fixed-price reduction for transmission to standard avoided cost rates. CREA concludes that we should authorize alternative rate options that a QF may choose instead of a fixed price reduction.[46] For example, an option allowing a QF to enter into an addendum to the standard contract accounting for the purchasing utility's actual costs of third party transmission costs, and a second option allowing a QF to waive its rights to sell all delivered net output and sign a standard contract addendum authorizing curtailment of the QF to address a load pocket problem. CREA asserts that these two options will often be economically efficient for a QF since the record demonstrates that a load pocket problem may present in very limited circumstances, or as PacifiCorp acknowledges, may dissipate if a large new load comes online.

Coalition: Coalition urges that QFs must be provided with key information about a load pocket situation early in the contracting process. Coalition asserts that a QF should have the right to require a utility to acquire the lowest cost, most reliable transmission option that is available to move the QF's net output to load. Coalition also argues that QFs with existing contracts should be grandfathered.

2. Resolution

In Order No. 14-058, we deferred the questions of how to calculate and how to assign third-party transmission costs attributable to a QF. Staff and some parties request still more time to address these questions. We understand there has been substantial progress towards resolution of this issue. Rather than defer the issue to a Phase 3 proceeding, we direct staff and utilities to work with parties to resolve how to assign third party costs. We direct staff to file a status report within three calendar months of this order indicating whether a resolution is forthcoming or recommending an alternative process.

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[45] *Id.* (citing 18 C.F.R. § 292.301(b) and *Cedar Creek Wind LLC*, 137 FERC ¶ 61,1. FERC has explained: "Section 292.301(b)(1) permits a QF and an electric utility to enter into a contract containing agreed-to rates, terms, or conditions that may differ from those that would otherwise be required by [FERC's] regulations concerning the determination of avoided-cost rates." *Cedar Creek Wind LLC*, 137 FERC ¶ 61,006, at P 39 n.73.

[46] *See Winding Creek Solar LLC*, 151 FERC ¶ 61,103, at P 6 (2015) ("as long as a state provides QFs the opportunity to enter into long-term legally enforceable obligations at avoided-cost rates, a state may also have alternative programs that QFs and electric utilities may agree to participate in . . . ."); *Otter Creek Solar, LLC*, 143 FERC ¶ 61,282, at P 4 (2013), *recons. denied*, 146 FERC ¶ 61,192 (2014) ("Nothing in [FERC's] regulations limits the authority of either an electric utility or a QF to agree to rates for any purchases or terms or conditions relating to any purchases which differ from the rates or terms or conditions which would otherwise be required by the [FERC's] regulations.").

IV. ORDER

IT IS ORDERED that:

1. Within 60 days of the date of this order, each electric utility will file by application, and serve upon all parties to these proceedings, revised standard contract forms that set forth standard rates, terms and conditions that are consistent with the resolutions made in this order.

2. The revised standard contract forms shall become effective 30 days after the date of filing, unless otherwise suspended by the Oregon Public Utility Commission.

3. Each electric utility will also file revised avoided cost schedules that implement the resolutions made in this order.

4. Staff is directed to file reports as specified in certain resolutions made in this order.

Made, entered, and effective MAY 13 2016.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

Q. How does Staff propose to correct this shortfall in the capacity payments to QFs?

A. Staff proposes to adjust the avoided value of capacity to derive a value for the solar capacity on a dollar-per-unit basis (kW or MW of capacity) prior to calculating the on-peak payment rate.

Q. Please provide an example calculation for the value of solar capacity.

A. First, adjust the CTP of the proxy renewable resource to account for the CTP of solar resources relative to the renewable avoided resource, which is wind. Then, apply that differential to the value of capacity:

(CTP of solar minus CTP of wind) x value of capacity = value of solar capacity

(39% - 5%) x $104/kW-year = $35.36/kW-year solar capacity value, or $35,360/MW-year

Q. How would the on-peak MWh payment for capacity be calculated?

A. The value of the solar capacity is spread over the expected on-peak generation by applying the on-peak capacity factor for solar to the total number of on-peak hours per year:

> Value of solar capacity per MW per year/(solar on-peak capacity factor x on-peak hours/year)
>
> $40,560/MW-year / (37.4% x 4,912) = $22.08 per On-peak MWh

Q. Please provide a graphical representation of CTP and on-peak capacity factors.

A. Figure 1 below portrays a one-day view of a utility system load, a CCCT, and a solar resource, with the on-peak hours bounded by the dotted lines. Figure 1 is also included as Exhibit 502.

The CTP and the on-peak capacity factor for the CCCT and the solar resource are calculated as follows:

CTP:

300 MW CCCT

Generation at hour of peak / Capacity = CTP

300 MW / 300 MW = 100 percent CTP

100 MW Solar QF:

Generation at hour of peak / Capacity = CTP

39 MW / 100 MW = 39.0 percent CTP

On-peak Capacity Factor:

300 MW CCCT:

On-peak MWh / (On-peak hours * Capacity) = On-peak capacity factor

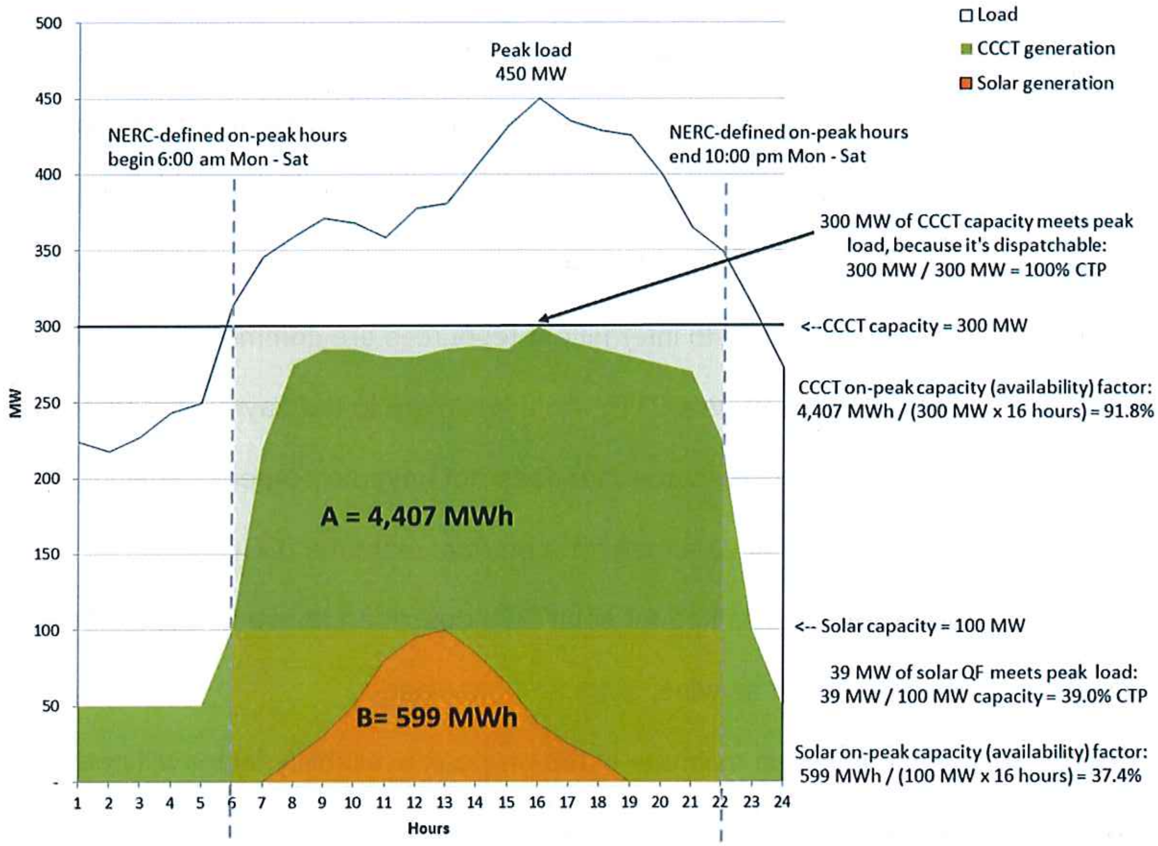
4,405 MWh / (16 hours * 300 MW) = 91.8 percent On-peak capacity factor

100 MW Solar QF:

On-peak MWh / (On-peak hours * Capacity) = On-peak capacity factor

599 MWh / (16 hours * 100 MW) = 37.4 percent On-peak capacity factor

Figure 1.



Q. How does this graphic illustrate the problem with the Current Method?

A. The ratio of CCCT MWh generation over on-peak hours to the maximum that could be generated is significantly larger than that same ratio for the solar resource. Once the amount of dollars for the relative capacity contributions are spread over the number of on-peak MWh generated, an accurate on-peak energy rate is calculated that will provide each resource the correct annual compensation for its capacity.

Issue 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?

Q. What is Staff's position on this issue?

A. Staff believes that the Commission should also revise the methodology for calculating the capacity contribution adjustment under Standard Non-Renewable Avoided Cost prices so that the annual amounts for avoided capacity costs paid to intermittent resources are commensurate with the intermittent resource's CTP. An adjustment to the payment methodology must be made for any resource that does not have an on-peak capacity factor equivalent to that assumed for a thermal resource (CCCT).

Q. How would the method for solar QFs described above in Issue 3 be applied to other QFs such as wind, solar and baseload?

A. In each case, an estimate of the on-peak availability factor will need to be calculated and applied. The CTP would continue to come from the IRPs, as would the value of capacity based on the SCCT costs. The formula would be as follows:

(Value of capacity x CTP x QF Capacity) /

On-peak availability factor x On-peak hours

Staff Proposed Minimum Filing Requirements

The list below contains the minimum filing requirements (MFRs) to be provided for standard (for qualifying facilities 10 MW or less) avoided cost compliance filings. These MFRs apply to both nonrenewable and renewable standard avoided cost prices. As part of its filing, the utility will provide workpapers, including spreadsheet files in electronic format with formulae intact, supporting the avoided cost prices.

For items directly from the Integrated Resource Plan (IRP), the utility will provide the document name, date, and page number. For items not directly from the IRP, the utility will provide explanations in its application.

I. Resource Sufficiency/Deficiency Demarcation	**IRP Reference**
1. Nonrenewable: Identify the demarcation year for the end of sufficiency period/start of deficiency period.	
2. Non-renewable: Identify the major resource to be acquired (>100 MW and longer than 5 years) at end of sufficiency period.	
3. Renewable: Identify the demarcation year for the end of sufficiency period/start of deficiency period.	
4. Renewable: Identify the major resource to be acquired (>100 MW and longer than 5 years) at end of sufficiency period.	

II. Gas Price Forecast	**IRP Reference**
1. Identify the source of the gas price forecast.	
2. If the forecast source differs from that used in the most recent approved avoided cost filing, explain the reason(s) for the change.	
3. Provide the yearly forecast price by year, and identify any rounding that has been applied.	
4. Quantify and describe the extent to which the gas price forecast differs from the most recent approved avoided cost filing. Include a description of carbon cost/tax assumption(s).	

III. Sufficiency Period Prices	IRP Reference
1. List the market hub(s) used for market price projections, the source for the forward price curves, and any adjustments or blending used in deriving the sufficiency period prices.	
2. Provide the transmission costs assumed used in sufficiency period prices.	
3. Provide all other component(s) used to calculate sufficiency period prices.	

IV. Standard Rates Deficiency Period Resource	IRP Reference
1. Provide the resource type, geographic location, nameplate capacity, and annual capacity factor.	
2. Provide the source of natural gas supply, and the costs assumed for interconnection, infrastructure upgrades, transmission, storage, and any other costs necessary to deliver gas.	
3. Provide the assumed heat rate. Include assumptions to account for elevation, temperature, and cooling method.	
4. List the costs assumed for interconnection facilities.	
5. List the components of transmission costs used and their respective values.	
6. List the tax assumptions used.	

V. Renewable Rates Deficiency Period Resource	IRP Reference
1. Provide the resource type, geographic location, nameplate capacity, and annual capacity factor.	
2. Provide assumptions used for mechanical availability, annual hours of curtailment, and annual MWh of energy curtailed.	
3. List the costs assumed for interconnection facilities.	
4. List the components of transmission costs used and their respective values.	
5. List the tax assumptions used. This includes assumed taxes paid (federal, state, local), and assumed tax benefits (e.g., PTC, ITC, grants in lieu of credits).	
6. Provide the capacity contribution value, and the method used to derive the capacity contribution value, for solar and wind resource types.	
7. Provide the wind integration cost used, and the method used to derive the wind integration cost.	