PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 7, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

RE: UM 1610 Phase II—PacifiCorp's Reply Testimony

PacifiCorp d/b/a Pacific Power encloses for filing its Reply Testimony in the above-referenced docket.

If you have questions about this filing, please contact Erin Apperson, Manager Regulatory Affairs, at (503) 813-6642.

Sincerely,

R. Bryce Dalley / eaa

R. Bryce Dalley
Vice President, Regulation

Enclosure

Docket No. UM 1610
Exhibit PAC/1400
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Brian S. Dickman

August 2015

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Q. Are you the same Brian S. Dickman who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

Q. What is the purpose of your reply testimony?

A. My reply testimony responds to Issues 2, 3, 4, 6, and 7 as discussed in the response testimony filed by Philip Carver on behalf of the Oregon Department of Energy (ODOE); David Brown on behalf of Obsidian Renewables, LLC (Obsidian); John Lowe on behalf of the Renewable Energy Coalition (REC); Brian Skeahan on behalf of Community Renewable Energy Association (CREA); and Brittany Andrus on behalf of the Public Utility Commission of Oregon staff (Staff). Because the Company filed response testimony simultaneous with the other parties, many of the issues raised in others' response testimony have already been addressed, and I do not repeat all of the arguments included in my previous testimony.

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

Q. CREA interprets the Company's testimony to contend that there are never any transmission costs that PacifiCorp avoids as a result of the construction of an on-system QF. Is this correct?

A. No. In my response testimony I detailed the Company's position that it does not object to including the cost of specific transmission system upgrades that are directly associated with the proxy resource as included in the IRP. The Company does object, however, to CREA's proposal to include the cost of the Gateway West project or to impute savings in transmission service costs in avoided costs for the reasons included in my response testimony.

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

And

Issue 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. Did any party present new evidence in response testimony regarding the capacity contribution adder method as it applies to standard renewable and non-renewable avoided costs?

A. No. The testimony largely repeated arguments made in previous rounds of testimony. Obsidian, however, introduced a metaphor of two workers to support its arguments that the amount paid to a solar QF for capacity should be directly proportional to the capacity costs of the proxy resource.

Q. Obsidian claims the Company fails to recognize the difference between a renewable resource with a low capacity contribution and the standard proxy with a high capacity contribution. Do you agree?

A. No. As described in my response testimony, it is the difference between a non-dispatchable intermittent QF and a combined cycle combustion turbine (CCCT) proxy that supports maintaining the method adopted in Order No. 14-058. Application of Obsidian's metaphor to the calculation of avoided capacity costs fails to recognize the difference between the QF and the avoided proxy CCCT. In Obsidian's metaphor, the two workers are assumed to be of equal quality, the only difference being the amount of time worked by each. However, a natural gas resource and a solar resource are not the same and they are not always performing the same job. In addition to generating power, the natural gas resource can be dispatched, hold reserves, and be used to integrate intermittent resources. A solar resource is only able to generate power subject to the sun shining. A solar resource cannot be dispatched, it cannot hold reserves, and it cannot be used to integrate other intermittent resources. A worker that is only available to work in favorable conditions and is unable to perform advanced job functions should not be entitled to the same pay as the worker who has greater availability and abilities.

Q. What does the Company recommend concerning the solar capacity adder?

A. The Company recommends the current method for the solar capacity method remain in place and unchanged.

Q. How do you respond to Obsidian's argument that the Commission should require the Company to use updated capacity contribution values as contained in its 2015 IRP?

A. Obsidian's complaints regarding the capacity contribution values, and the appropriate source for such values, are not an issue for this portion of Phase 2 in this docket. In Order No. 14-058, the Commission ordered, "The assumed capacity contribution to peak load would be the contribution estimate used in the utility's acknowledged IRP for the specific type of generation (wind, solar, etc.)."[1] Obsidian is arguing for an out-of-cycle update to just one of the avoided cost inputs. The Company is supportive of out-of-cycle updates so long as other avoided cost inputs are also subject to update.

[1] Order No. 14-058 at 15.

Issue 6: Do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

Q. CREA argues that the Company's decision to rely on the market for its capacity needs in the short term does not justify paying market prices to QFs during the sufficiency period. Do you agree?

A. No. CREA recognizes that the resource plan in the Company's IRP is a "matter between PacifiCorp and the Commission" but disregards the Commission's past direction that avoided costs must be based on the utility's Commission-acknowledged IRP and the accompanying resource portfolio. CREA's criticism of the Company's support for continuing to use on- and off-peak market prices for standard avoided costs during the sufficiency period also disregards the Commission's finding in Order No. 05-584:

> When a utility is in a resource sufficient position, we adopt Staff's recommendation that QF capacity be valued based on the market. Although valuation of QF capacity based on the market price of capacity itself has significant appeal, we are concerned about inconsistent evidence regarding the viability of the market for capacity. Consequently, of the two market-based valuation methodologies proposed by Staff, we adopt the methodology that values 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. We agree with Staff that this approach embeds the value of incremental QF capacity in the total market-based avoided cost rate.[2]

Q. REC argues that using market prices during the sufficiency period fails to recognize that the timing of new resources in PacifiCorp's IRP is likely to be inaccurate. Is this a reason to impute additional capacity costs during the sufficiency period?

A. No. REC argues that the Company's IRP resource portfolio may change if the

[2] Order No. 05-548 at 27-28 (internal citations omitted).

assumptions used in the IRP prove inaccurate.[3] This has always been true, and was true when the Commission determined in Order No. 10-488 that the resource sufficiency period should extend until the first major resource acquisition in the most recently acknowledged IRP. REC cites as an example the Company's acquisition of the Chehalis generating plant in 2008 even when the IRP at the time did not include a new thermal resource until 2012. REC fails to recognize, though, that the opposite has also occurred. For example, from April 2012 through August 2014 the Company's standard avoided costs were based on the 2011 IRP that anticipated a new CCCT would be acquired in 2016. In September 2012, the Company communicated to the Commission that it planned to cancel the then-pending RFP for the 2016 resource based on a Resource Needs Assessment Update that no longer showed a need for the 2016 CCCT. Even though it turned out the Company did not need this resource, avoided costs had been set with a deficiency period beginning in 2016, and 19 QFs totaling 161 MW of nameplate capacity executed contracts with the inaccurate rates.

Q. REC refers to ongoing proceedings in Washington related to PacifiCorp's standard avoided costs, and cites a proposal by the Washington Utilities and Transportation Commission Staff to include capacity costs in the sufficiency period. What is the effect of the proposal by Washington Staff?

A. The Washington Staff proposal is to calculate sufficiency period avoided costs as the displaced cost of market transactions and existing resources plus the fixed costs of a CCCT for the entire sufficiency period, regardless of the timing or need for the CCCT in the Company's IRP.

[3] Coalition/500, Lowe/8.

Q. Is the Washington Staff proposal relevant in this case?

A. No. The proposal made by Washington Staff in the pending Washington proceeding is not the approved method for calculating avoided costs in Washington, and no party in this proceeding has made such a proposal for Oregon avoided costs.

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?

Q. Do you agree with the claim made by ODOE that the Company's partial displacement differential revenue requirement (PDDRR) proposal for non-standard avoided costs goes back to the decremental generation cost approach that was discarded in Order No. 05-584?

A. No. As described by the Commission in Order No. 05-584, the decremental generation cost approach used prior to Order No. 05-584 calculated avoided costs during the sufficiency "based only on the variable costs of operating existing generating resources."[4] This is not the Company's proposal at all. The PDDRR utilizes the Generation and Regulation Initiative Decision Tools model (GRID) to reflect the changed operation of the Company's system with the addition of a QF. The highest cost displaceable resource utilized in each hour is eligible to be displaced by QF generation, including market purchases. The model also recognizes when the additional energy from a QF will enable wholesale market sales, and such sales are included in the avoided cost prices. The benefit of using a production dispatch model is that system resource constraints are accounted for, such as transmission capacity, rather than making the simplifying assumption that QF energy *always* displaces market purchases or facilitates additional market sales during the sufficiency period.

[4] Order No. 05-584 at 27.

Contrary to Mr. Carver's statement, ratepayers are not kept whole to the extent a QF is paid market prices but the utility cannot actually avoid a market transaction.

Q. Do you agree with ODOE's proposal that wholesale prices should set the floor for avoided cost prices at all times?

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

Q. Does REC accurately characterize your testimony when it claims "PacifiCorp states that only two of the seven FERC factors are accounted for?"[5]

A. No. In my testimony I stated that the Commission only adopted adjustments to the avoided cost calculation for two of the seven factors identified in the FERC regulations in 18 CFR § 292.304(e)(2), and that three factors were addressed in contract provisions rather than as adjustments to avoided costs. The remaining two factors addressing the individual and aggregate value of energy and capacity from QFs on the utility system and the smaller capacity increments and shorter lead times available from QFs were not addressed by the Commission—a fact that REC acknowledges. REC argues that both of these factors should increase avoided costs, and that the Commission allowed the QF and utility to account for them if they could agree on a method. In my direct testimony I explained that these two factors are "easily accounted for in a modeled approach that recognizes all of the executed and

[5] Coalition/500, Lowe/11.

proposed QFs expected to connect to PacifiCorp's system."[6] REC has not proposed an alternative method of accounting for these two FERC factors.

Q. Why is it appropriate to consider QF specific factors such as the QF's location, delivery pattern, and capacity contribution in the calculation of avoided costs?

A. As I described in my direct testimony, when calculating the avoided costs for large QFs in particular, it is critical to account for the specific characteristics of each QF that materially impact the value of energy and capacity on the Company's system. REC claims that if an item is not specifically listed as one of the seven items in 18 CFR § 292.304(e)(2) then it cannot be considered in the avoided cost calculation. REC's argument if misplaced. In Order No. 07-360, the Commission adopted adjustments for the seven FERC factors that were allowed to be made to the standard avoided cost rates. The standard rates are, in the first instance, a simplified calculation of the avoided energy and capacity due to the addition of a QF. The Company's proposal in my direct testimony is to refine the calculation of avoided energy and capacity costs to recognize the individual characteristics of large QFs. Indeed, in Order No. 14-058, the Commission subsequently adopted recognition of different capacity contributions in the calculation of standard avoided cost prices.

Q. How do you respond to REC's argument that the Company should not be allowed to update the calculation of non-standard avoided costs to reflect new QFs with signed or proposed PPAs because these QFs are unlikely to reach commercial operation?

A. In my response testimony I described that since preparation of the 2013 IRP, which is still being used as the basis for Oregon standard avoided cost prices, the Company

[6] PAC/800, Dickman/21.

has executed contracts with QFs totaling over 1,100 MW of additional nameplate capacity. The Company is obligated by PURPA to accept delivery from QFs at avoided cost prices under these contracts and must plan accordingly. Not recognizing the aggregate impact of these contracts when calculating the cost of energy and capacity that will be avoided by the next QF in line will overstate avoided costs that are ultimately passed on to the Company's retail customers. In addition, a QF's ability to establish a legally enforceable obligation[7] at some point in time prior to execution of the PPA by both parties, supports inclusion of proposed QFs in the calculation of avoided costs for the next QF to ensure ratepayers are protected against an avoided cost rate that overestimates the costs that will actually be avoided by the Company.

Q. REC disagrees with Staff's recommendation that PacifiCorp be allowed to use its GRID model for determining avoided costs. Do you agree with REC's assertions regarding the GRID model?

A. No. REC first argues that the GRID model was designed to estimate power costs, not set avoided costs. REC's statement can only be based on a misunderstanding of the GRID model or its application to avoided costs. The GRID model calculates net power costs by solving for the least-cost solution to balance the Company's system based on a set of resources, load, and operational constraints. Incremental changes to the model, such as the addition of QF generation in Oregon, result in incremental increases or decreases in the Company's net power costs. The addition of QF generation in the model displaces the highest-cost purchases or generation or results

[7] The legal enforceable obligation (LEO) is currently under litigation in this docket.

in incremental market sales. In this sense the GRID model is ideally suited for calculating the costs avoided with the addition of a QF.

REC also claims that the litigation of modeling adjustments in rate cases undermines the accuracy of the GRID model. I disagree. In a rate case context, intervenors and their experts are motivated to find ways to change the model to produce lower net power costs that will be reflected in customers' rates. These types of adjustments do not undermine the accuracy of the model or its ability to calculate the incremental cost of resources on the Company's system.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM 1610
Exhibit PAC/1500
Witness: Ted Drennan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Ted Drennan

August 2015

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PURPOSE AND SUMMARY OF TESTIMONY 1

CONCLUSION... 4

Q. Are you the same Ted Drennan who previously submitted direct and response testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. The purpose of my reply testimony is to respond to response testimony filed by John Lowe on behalf of the Renewable Energy Coalition (REC), Phil Carver on behalf of the Oregon Department of Energy (ODOE), and Brian Skeahan on behalf of the Community Renewable Energy Association (CREA) related to Issue 5 listed in Attachment A – UM 1610 Phase II Issues List as included in Administrative Law Judge Traci Kirkpatrick's March 26, 2015 Ruling:

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

Q. Does the fact that you are not commenting on other issues raised in the direct or response testimony of these or other witnesses indicate that you agree with their positions?

A. No. I believe that other issues raised by witnesses for parties opposing the Company's application have been more than adequately addressed in the direct testimony and response testimony filed by the Company's other witnesses.

Q. Is the Company filing reply testimony of any other witness in this Docket?

A. Yes. Company witness Mr. Brian S. Dickman responds to the response testimony of several parties on avoided cost methodology and pricing issues including Issues 2, 3, 4, 6, and 7 from the UM 1610 Phase II Issues List. Mr. Bruce W. Griswold responds to the response testimony of several parties on Issues 8, and 9.

Q. Please summarize your testimony.

A. My reply testimony is limited to address concerns raised by other parties with the use of an Integrated Resource Plan (IRP) docket for litigating assumptions and inputs, as well as clarify some misconceptions and concerns raised by other parties related to the use of the IRP for litigating issues and assumptions.

Q. Does REC correctly summarize your position?

A. No. REC vastly overstates PacifiCorp's position. The first statement of REC's summary[1] is correct: "Inputs and assumptions should be based on the utilities' acknowledged IRP." However, there are problems with the remainder of the summary. PacifiCorp does not believe that there are issues that parties should not have the ability to address or challenge.[2] As I previously testified, the proper venue for review of assumptions and inputs for avoided costs is in the IRP docket, not in consecutive or concurrent dockets. Avoided costs are based on avoided resources which are determined in the IRP. PacifiCorp is not proposing that the "Commission itself would be taken out of the process of reviewing the inputs and assumptions."[3]

Q. Do you agree with ODOE that the Commission "addresses only the assumptions in these IRP action items."[4]?

A. No. The Commission will acknowledge the IRP Action Plan, which is generally limited in scope to near-term actions. However, these actions are not divorced from

[1] Coalition/200 Lowe/3 at 31-35.
[2] Coalition/500 Lowe/3 at 10-13.
[3] Coalition/500 Lowe/5 at 17-18.
[4] ODOE/900 Carver/7 at 10-11.

longer range forecasts. In fact, in Order No. 08-246, the Commission did not acknowledge PGE's 2007 IRP in part for failing to perform its analyses over a 20-year planning horizon as required by Guideline 1(c) which states, in part:

> The planning horizon for analyzing resource choices should be at least 20 years and account for end effects.

In this order, the Commission found fault with PGE's 2007 IRP for locking loads at seven years, and resource additions at five years.[5] The Commission clearly articulated concerns with assumptions outside of the first four years of the IRP, i.e. the action plan time horizon.

Q. Do you support ODOE's suggestion to limit the IRP acknowledgement order to focus only on assumptions within four years of the IRP filing?[6]

A. No. As stated above, near-term decisions also depend on the long-term outlook. ODOE's suggestion appears to further bifurcate the IRP from an avoided costs process, which would lessen the value of the IRP in general.

Q. Do you agree with Mr. Skeahan that "PacifiCorp is not typically subject to discovery, clarification, and cross examination as part of their IRP process."[7]

A. No. While cross examination is not part of the IRP process, discovery and clarification certainly are included. As discussed in my response testimony, there were 435 data requests from Oregon stakeholders in PacifiCorp's 2013 IRP; as of July 29, 2015, there have been 142 such requests in the 2015 IRP. Additionally, the Commissioners issued 13 bench requests in the 2013 IRP. This demonstrates that the

[5] As correctly stated in its 2007 IRP, PGE froze long-term resource additions in 2012 and froze loads in 2014. Order No. 08-246 at 12.
[6] ODOE/900 Carver/ 6 at 13-19.
[7] CREA/600 Skeahan/7 at 16-17.

assumptions included in IRPs are subject to rigorous discovery by stakeholders and thoroughly vetted by the Commission.

CONCLUSION

Q. Please summarize your position on Issue 5.

A. As discussed above and in earlier testimony, the Company's IRP is the proper forum to litigate issues and establish modelling assumptions used for determination of the characteristics of the costs and timing of a utility's avoided resource. Alternative or expanded processes that move toward de-linking the IRP and avoided costs are inappropriate, and not consistent with Commission precedent.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM 1610
Exhibit PAC/1600
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Reply Testimony of Bruce W. Griswold

August 2015

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PURPOSE AND SUMMARY OF REPLY TESTIMONY 1

ISSUES 2

Q. Are you the same Bruce W. Griswold who previously submitted direct and response testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF REPLY TESTIMONY

Q. What is the purpose of your reply testimony?

A. The purpose of my reply testimony today is to respond to parties' response testimony as filed on July 24, 2015 on Issues 8 and 9. I will be responding to the comments by Brittany Andrus on behalf of Public Utility Commission of Oregon (Commission) Staff (Staff); John Lowe on behalf of Renewable Energy Coalition (REC); Diane Broad on behalf of the Oregon Department of Energy (ODOE); and Brian Skeahan on behalf of the Community Renewable Energy Association (CREA).

Q. How is your testimony organized?

A. My testimony is organized consistent with the list of issues identified for Phase II and presented in my direct and response testimony including:

- Issue 8. – When is there a legally enforceable obligation?
- 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?

Q Does the fact that you are not commenting on other issues raised in the direct or response testimony of these or other witnesses indicate that you agree with their positions?

A. No. I believe that other issues raised by witnesses for parties opposing the Company's application have been more than adequately addressed in the testimony filed by the Company's other witnesses.

Q. Is the Company filing reply testimony of any other witness in this Docket?

A. Yes. Company witness Mr. Brian S. Dickman responds to the direct testimony of several parties on avoided cost methodology and pricing issues including Issues 2, 3, 4, 6, and 7 from the UM 1610 Phase II Issues List. Mr. Ted Drennan responds to parties' direct testimony on Issue 5 related to the forum for resolving litigated issues and assumptions used when developing avoided cost prices.

ISSUES

Issue 8: When is there a legally enforceable obligation?

Q. Has your recommendation changed from your direct and response testimony?

A. No. The Company recommendation that the Commission set criteria for establishing a legally enforceable obligation (LEO) using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37[1] is still unchanged. It remains a clean and fair approach for ensuring that both parties have completed and agreed on all components in the standard PPA. The process described in Schedule 37 as approved by the Commission lays out all the necessary information required for the Company to draft a contract for the QF. Schedule 37 processes, timelines and standard contracts were vetted by parties and approved by the Commission, thus meeting any and all project information requirements in the contract, and agreeing to final draft agreement should be the milestone for establishing a LEO by both parties. In the case of disputes over information and timeliness, the QF already has a dispute resolution process through Schedule 37

[1] While the focus of my testimony on Issue 8 is toward Schedule 37, the testimony is meant to be inclusive of Schedule 37 and Schedule 38 QF contracts.

where the Commission can determine what appropriate avoided cost price that should apply when it resolves the contractual dispute.

Q. Do you agree with Mr. Lowe that Staff and REC's LEO proposals are basically the same?

A. No. Staff's proposal as provided by Ms. Andrus defines the LEO at execution of the final draft executable standard contract[2] with the caveat that the QF would have the opportunity to establish a LEO without the execution of the final draft contract should the utility not operate within the bounds of Schedule 37 or state or federal policy. That proposal is more consistent with PacifiCorp's proposal as noted by Ms. Andrus.[3] Mr. Lowe, on the other hand, proposes that a QF should be able to "lock in" certain avoided cost prices if there are disputes that cannot be resolved before an avoided cost update goes into effect. His proposal allows QFs to unilaterally trigger a LEO (and lock in avoided cost prices on the cusp of a price revision) by claiming there are disputed contractual terms and keeping those prices while going through dispute resolution rather than letting the Commission decide the appropriate pricing as part of the dispute resolution.

Q. Do you agree with Mr. Lowe's proposal to allow an existing QF to renew their QF contract three years in advance of the existing contract expiration?

A. No. As I understand Mr. Lowe's proposal, he is recommending that an existing QF can seek a new QF contract up to three years before their existing QF PPA expires. There are some inherent issues with that proposal. For example, let's say a QF renews and executes a new PPA three years in advance of their existing PPA

[2] Staff/600, Andrus/23.
[3] Staff/600, Andrus/24.

expiration date. During that three-year period, avoided costs will have been updated each year. What if the avoided cost prices go up in that time period? Would the QF seek to terminate their new PPA and claim a LEO on the higher avoided cost? While the current Schedule 37 QF contract provides for a level of protection in the event the QF terminates and then seeks a new QF contract, it does not mean there would not be a dispute regarding this issue. It is more appropriate to complete a new PPA within a year of the existing PPA expiring. The Company's experience has shown that a one year planning horizon provides the QF with certainty on the avoided costs, plenty of time to complete a new QF PPA, and adequate time to complete any modifications to the QF's interconnection.

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

Q. Do you agree with the parties' statements that QFs should have options to choose the type of transmission service to move the QF's power out of a load pocket?

A. No. Ms. Andrus, Ms. Broad, Mr. Lowe, and Mr. Skeakan seem to ignore PURPA and FERC rules and procedures. PURPA is very clear on this issue. It is not the QF's option to choose the transmission service type; rather, it is the utility's mandatory obligation to acquire firm transmission service from the point of delivery by the QF to the utility's load. Under PURPA rules and procedures, utilities have a mandatory obligation to purchase a QF's net output, as well as to make firm transmission arrangements to deliver that QF power to its network load. That is consistent with PacifiCorp's merchant's historical and current business practice to designate QF PPAs, both on-system and off-system, at their full nameplate capacity rating as network resources on a year-round basis in order to secure the requisite firm transmission service to deliver that QF power to its network load. It also allows the Company to secure roll-over rights to that same amount and type of transmission service, ensuring that the Company maintains its mandatory obligation to purchase the net output and long term firm transmission for the term of the PPA.

Q. How does that apply to a QF located in a load pocket?

A. The decision on transmission service type out of a load pocket still remains the responsibility of the utility because it is a continuation of the transmission service obligation by the utility to move the QF power to the utility's load. In the case of PacifiCorp, if this situation is expanded to where an on-system QF directly interconnected to the Company's electrical system but located in a load pocket, PacifiCorp merchant requests network resource designation from PacifiCorp transmission under their open access transmission tariff (OATT) for the full nameplate capacity rating of the QF resource so that merchant could utilize firm network transmission to move the QF net output away from the point of delivery to serve network load.[4] PacifiCorp transmission completes its studies and responds per its OATT with designation of the requested nameplate capacity rating conditioned on PacifiCorp merchant acquiring long-term firm (LTF) point-to-point (PTP) transmission service from the requisite third-party transmission provider(s) used to deliver the Company's energy to the load pocket and providing that documentation to PacifiCorp transmission. PacifiCorp merchant then seeks the LTF PTP transmission from the third-party transmission provider for the capacity identified by PacifiCorp transmission in their transmission service system impact study. This is accomplished

[4] PacifiCorp Transmission's OATT Section 30.2.

through discrete transmission service requests to the third-party provider. An example of the designation response from PacifiCorp transmission for the 10.0 MW Elbe Solar Center, LLC project is attached as Exhibit PAC/1601. In this example, Elbe Solar is located in the Madras load pocket and requires two wheels for their excess generation out of the load pocket. The critical language is noted lines 4-6 of the first paragraph, "….long-term, firm point-to-point transmission service with Portland General Electric ("PGE") and Bonneville Power Administration ("BPA")." This demonstrates that the required transmission service type acquired by PacifiCorp merchant must be long-term firm point-to-point to have the resource designated as a network resource. FERC essentially is saying that it is the merchant function's decision to choose how best to schedule and deliver the QF's power to load once it reaches the utility's system.

Q. What if the system impact study for network resource designation shows a capacity less than the full nameplate of the QF project?

A. If that is the case, then PacifiCorp merchant only needs to acquire the capacity amount identified in the system impact study, not the full nameplate capacity, to have the resource designated as a network resource. The difference is the amount of load within the load pocket served by the QF. As I stated in my previous testimony, the details of the third-party transmission required are not available until PacifiCorp merchant receives information on low load conditions and excess generation from PacifiCorp Transmission under its OATT and also contacts the third-party transmission provider through a transmission service request per that transmission provider's OATT. PacifiCorp merchant will have secured firm transmission service over the term of the PPA both inside the load pocket and to export the remainder to load.

Q. Can curtailment of the QF resource be used an alternative to long-term firm transmission service or in conjunction with a lesser quality level of transmission service to move QF power out of a load pocket?

A. No. Again, FERC has been very clear on the use of curtailment with QFs. There are two areas of federal law that govern a utility's right to curtail QFs: (1) PURPA, including FERC's PURPA regulations; and (2) FERC transmission open access principles.

PURPA places on a utility a statutory obligation to take a QF's power (the so-called "must take" obligation). This fact makes QFs different than all other designated network resources of a utility (for which the utility has the option to dispatch or not). Further, FERC has only recognized limited circumstances under which a utility can curtail purchases from a QF, primarily to meet system emergency conditions. Section 307(b) of FERC's regulations govern system emergency conditions and states that, "During any system emergency, an electric utility may discontinue: (1) Purchases from a qualifying facility if such purchases would contribute to such emergency…" The regulations define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." Second, with regard to transmission open access policy, FERC's open access principles, which are embodied in the pro forma OATT, require transmission providers to curtail transmission on a non-discriminatory and pro rata basis among network customers.

Therefore, the alternatives proposed by Ms. Broad and Mr. Skehan in their direct and response testimony, cannot be implemented without the Company violating PURPA regulations and/or OATT procedures.

Q. Do you agree with Ms. Andrus' recommendation to provide the QF multiple options to allow the QF to select third party transmission that is most cost effective for the QF?

A. No. As I have discussed above, it is not the QF's option to select the transmission service for the utility to deliver the QF's generation to network load. FERC has already established that transmission service is the responsibility of the utility. In order to comply with the transmission provider's OATT and secure the designation of network resource status for the QF, the utility must secure long-term firm transmission, including when a load pocket exists and generation exceeds load, LTF PTP from the third party transmission provider in order maintain the network resource designation.

Q. Do you agree with Ms. Broad, Ms. Andrus, Mr. Lowe, and Mr. Skeahan's recommendations regarding what information should be provided by the utility on load pockets?

A. No. As I have discussed in my response testimony, a load pocket is a dynamic situation, going up or down as load and generation is added or removed, so updating and publishing load pockets with every Schedule 37 update would be burdensome and likely become stale. Information from a map or a table, even if updated annually, may be misguided. However, more importantly, under FERC, PacifiCorp merchant relies on PacifiCorp Transmission to calculate the minimum load conditions in the load pocket to determine if excess generation will exist, and only receives information that would be publically available on OASIS. The QF can access OASIS information, the same as PacifiCorp merchant, and asking PacifiCorp merchant to provide such information would potentially put merchant in violation of the OATT. PacifiCorp merchant does not receive hourly load profile information in the load pocket as recommended by Ms. Broad. PacifiCorp merchant can use OASIS information to determine at a high level if the addition of a new generator will cause an excess condition but the Company has to comply with any OATT requirements and cannot determine the minimum load condition amount of excess MW until it completes a transmission service request per the OATT. Under current OATT practices, the QF will receive some preliminary information regarding excess generation conditions and minimum loads when it conducts its interconnection studies through PacifiCorp Transmission.

Q. Has your recommendation and proposal changed after reviewing all the parties direct and response testimony on the load pocket issue?

A. No, none of the comments and suggestions has been persuasive. In fact, some of the recommendations are in direct violation of existing FERC and OATT rules and regulations. The Company's proposal secures LTF PTP in compliance with the OATT's network resource designation procedure to deliver the excess generation of the minimum load conditions to load elsewhere on the Company's system on a long-term firm basis. PacifiCorp's proposal does not purchase third-party LTF PTP transmission service at the full nameplate capacity if not needed, which is based upon the requirements from PacifiCorp Transmission to designate the QF as a network resource. It is the best method of capturing and passing through the actual costs of third-party transmission to an individual QF project using the standard Schedule 37 contract between the QF and Company with an addendum to the agreement, and it addresses the uniqueness of each project based on geographical location and the local electrical system loads and resources.

Q. Do you believe the Company's proposal for acquiring transmission service from load pockets is fair to QFs while ensuring its customers receive the QF output on a firm basis?

A. Yes. The Company's proposal is in compliance with PURPA and FERC. It ensures that the Company can deliver the QFs output to load on a long-term firm basis. It follows the transmission service practices and procedures as provided in PacifiCorp Transmission's OATT as well as the third-party transmission provider's OATT. The OATT is published including all transmission service costs. The available transmission capacity is contained in OASIS, a public source, and the QF receives preliminary information from PacifiCorp Transmission on minimum loads from its interconnection studies.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UM 1610
Exhibit PAC/1601
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Bruce W. Griswold

August 2015

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

P.O. Box 2757
Portland, OR 97208-2757

October 3, 2014

Jim Schroeder
Manager, C&T Contract Administration
PacifiCorp Merchant Function ("C&T")
825 NE Multnomah St., 600-LCT
Portland, OR 97232

Re: Approval of Request to Designate Elbe Solar Center, LLC QF PPA a Network Resource (OASIS AREFs 80159367 and 80159387)

Dear Mr. Schroeder:

On September 4, 2014, C&T requested to designate the 10.000 MW Elbe Solar Center, LLC as a network resource effective October 31, 2016 through October 31, 2036. This service will be accommodated using two AREFs: AREF 80159367 will provide network service to Madras area load. If necessary, AREF 80159367, in conjunction with long-term firm point-to-point transmission service with Portland General Electric ("PGE") and Bonneville Power Administration ("BPA"), and AREF 80159387 with PacifiCorp, would combine to integrate surplus Madras generation during low load hours to the Prineville bubble. As of today's date, C&T has not secured transmission with PGE or BPA.

C&T's request is hereby approved in accordance with section 30.2 of PacifiCorp's Open Access Transmission Tariff provided that 1) all facilities and requirements identified in the associated generation interconnection queue request are installed, tested, and in-service, and 2) point-to-point transmission service with PGE and BPA is acquired.

AREFs 80159367 and 80159387 will remain in RECEIVED status until such time as facilities are in service and C&T provides documentation of valid point-to-point transmission with PGE and BPA. If you have any questions, please call me at (503) 813-6958.

Sincerely,

Veronica Stofiel
Account Manager, Transmission Services