ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

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AND HAND DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attn: Gary Widerburg
Commission Secretary

RE: Reply Comments
Docket 15-035-T06 – Schedule 37
In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities

Background

On April 30, 2015, PacifiCorp, dba Rocky Mountain Power ("Company"), filed an updated Electric Service Schedule No. 37, "Avoided Cost Purchases from Qualifying Facilities" ("Schedule 37"), of Tariff P.S.C.U. No. 50. In addition to updating inputs to the avoided cost calculation, the Company proposed two changes to the avoided cost method, as described in the direct testimony of Mr. Brian S. Dickman.

On June 16, 2015, the Division of Public Utilities ("DPU") and Office of Consumer Services ("OCS") each filed separate comments supporting the Company's proposed updates and method changes, and each recommended the Commission approve the Company's filing. The Renewable Energy Coalition ("REC") also filed comments, claiming the Company's filing violates the law and recommending an entirely new proposal to include as avoided capacity costs during the sufficiency period the cost of environmental upgrades at the Company's existing coal-fired generation facilities. The Company respectfully submits the following comments in response to the issues raised by REC in its comments.

Comments Responding to REC

1. The Company's Proposal is Consistent with PURPA and Utah Law.

REC claims that the Company's proposal "to eliminate capacity payments" violates the law and is inconsistent with how the Company will acquire and maintain capacity resources. REC's claim is misplaced for several reasons. First, the Company is not proposing to eliminate capacity payments in this case. The Company's foremost proposal is to eliminate the assumed avoidance of a hypothetical SCCT during the sufficiency period because avoided costs reflect the avoidance of wholesale market purchases to meet capacity needs. The direct testimony of Mr. Brian S. Dickman filed in this case explained, "Rather than imputing capacity costs based on a fictitious SCCT, avoided costs during the sufficiency period should be calculated using the GRID model including the value of short-term firm market purchases that can be displaced by a qualifying facility ("QF")." During the sufficiency period the Company has no plans to procure additional thermal capacity resources. The 2015 Integrated Resource Plan ("IRP") calls for the Company to utilize front office transactions ("FOTs"), which represent short-term firm wholesale market purchases, to meet its capacity needs.

Second, FERC has recognized that avoided capacity may be in the form of purchases from other providers, or, as is the case here, the avoidance of FOT purchases that are the lowest-cost, least-risk option for addressing capacity shortages. FERC Order No. 69 states: "If [a QF] demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit *or the purchase of firm power from another utility*, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs."[1] The Company's proposed avoided cost prices include avoidance of short-term firm market transactions. Including a thermal resource capacity adder on top of the price of avoided market transactions would over-compensate QFs and would squarely conflict with PURPA's "customer indifference" standard.[2]

Third, the Utah Public Service Commission has already determined that displacement of FOTs properly reflects the avoided capacity costs during the sufficiency period. In Docket No. 12-035-100 the commission found, "The evidence proffered by PacifiCorp and the Office shows a QF's displacement of FOTs, as determined within the GRID model, results in what PacifiCorp would have otherwise paid for capacity purchases. Thus, the inclusion of additional capacity value when a FOT is displaced would over-compensate the QF and violate the ratepayer neutrality objective."[3]

2. REC's Proposal to Include the Cost of Environmental Upgrades at Existing Coal-Fired Generation Facilities is Fundamentally Flawed.

REC attached to its comments the testimony of Mr. Kevin Higgins filed in Oregon docket UM 1610. Mr. Higgins' Oregon testimony recommends that the Public Utility Commission of Oregon adopt an 'interim capacity pricing mechanism' for renewable and zero-emitting QFs until the uncertainty surrounding the rules proposed by the Environmental Protection Agency ("EPA") under Section 111(d) of the Clean Air Act is resolved. REC doesn't appear to make a specific recommendation to the Utah Commission regarding the disposition of Mr. Higgins'

[1] Order No. 69, 45 Fed. Reg. 12,214, 12,225 (Feb. 25, 1980)(emphasis added).
[2] *Southern Cal. Edison Co., et al.,* 71 FERC 61,269, 62,080 (1995) (In enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.")
[3] Docket No. 12-035-100, August 16, 2013 Order at 35.

Oregon testimony; however, at the conclusion of its comments REC requests that the Commission reject the Company's proposed revisions to Schedule 37 and require the Company to refile 'and include the appropriate capacity payments.'

In his Oregon testimony Mr. Higgins suggests that EPA's then proposed Section 111(d) rules create a significant incentive for the Company to acquire renewable resources but that the long sufficiency period in the Company's 2015 IRP discourages development of renewable and zero-emitting QFs. Mr. Higgins then conflates issues surrounding compliance with Section 111(d) rules and certain planned and potential capital investments at existing coal facilities during the resource sufficiency period to comply with the EPA's Regional Haze Rule under the Clean Air Act – an entirely different compliance issue.

Notwithstanding the unusual approach to REC's comments, the Company responds that the arguments contained in Mr. Higgins' Oregon testimony are fundamentally flawed for the following reasons:

- The referenced environmental upgrades include capital investment that cannot be avoided by the addition of a Utah QF, even one that is renewable or non-emitting.
- Several of the referenced environmental upgrades that were included in the IRP for planning are not currently required, and alternative compliance scenarios may eliminate the need for the investment irrespective of any new QF generation.
- There is no accounting for the benefits of the existing generation resources that will be lost if the environmental upgrades are eliminated.

Mr. Higgins' testimony implies the environmental upgrades at specific coal plants located in Utah, Wyoming, Colorado, Montana, and Arizona can be avoided by renewable and non-emitting QFs in Utah. This is incorrect. In reality, all of the upgrades listed by REC and Mr. Higgins are for compliance with the EPA's Regional Haze Rule, which is intended to improve the air quality and visibility in national parks and wilderness areas in the proximity of the emitting resource. PacifiCorp cannot avoid these compliance costs by simply adding small QFs, and assuming such will overstate avoided cost prices in Schedule 37. Construction of several of the projects referenced is already underway, underscoring the fact that costs cannot be avoided and should not be included in the determination of avoided costs. In fact, the Hayden 1 SCR has already been placed in service. Engineering, design, and procurement for the Hayden 2, Jim Bridger 3, and Jim Bridger 4 SCR projects are likewise already underway.

Mr. Higgins' proposal is also flawed because the list of capital projects he relies on includes SCR projects for which there is no such requirement yet in place (including SCRs at Hunter 1, Hunter 3, and Huntington 1). Despite this lack of requirement, Mr. Higgins recommends that the entire list of projects be used to calculate an average cost of capacity to be included in avoided costs during the sufficiency period. Potential alternatives to meeting Regional Haze compliance without installing SCR technology include retiring the unit altogether or converting it to be fueled by natural gas. The timing of such compliance alternatives is often different than the SCR installation, and the Company's IRP provides extensive inter-temporal and fleet trade-off analyses related to Regional Haze compliance.

Mr. Higgins' proposal is further flawed because it fails to account for the significant impact on the Company's generation portfolio if the required environmental upgrades are eliminated. Coal plants provide low-cost base load generation as well as operating reserves and load following capability. The decision to invest in environmental upgrades is evaluated in the Company's IRP, and considers the value of retaining the generation from the plant. Eliminating an environmental upgrade that is specifically required to comply with Regional Haze means the Company will no longer be able to operate the plant as a coal-fired generator. Mr. Higgins' proposal ignores the obvious impracticality of replacing an entire existing coal unit with many individual renewable QFs. For example, the second project on the list is the SCR at Jim Bridger unit 3, which is scheduled to be placed into service in December 2015. Using the capacity contribution of 36.7 percent for a single-axis tracking solar project (the highest of the wind and solar capacity contributions) listed in the 2015 IRP equates to a need for over 950 MW of new solar capacity from QFs to replace PacifiCorp's approximately 350 MW share of the capacity lost by eliminating Jim Bridger unit 3. This already unrealistic result does not account for the lost dispatchability and lost energy from a base load generator.

3. Potential Future Environmental Requirements Should not be Included in Avoided Costs.

REC cites the acquisition of the Chehalis plant in 2008, a transaction that was not anticipated in the IRP at the time, as support for the conclusion that the sufficiency period in the 2015 IRP is likely inaccurate. REC further cites a string of future hypothetical scenarios that 'could result in a reduction in coal generation, and an increase in renewables, baseload gas, and peaking gas generation well before 2027.'

The fact that there is uncertainty about future environmental regulations, including the impact of Section 111(d) rules, does not lend credence to arguments made by REC or in Mr. Higgins' testimony. On the contrary, this uncertainty is one more reason to reject REC's proposal to artificially inflate avoided costs. REC also fails to acknowledge that the resource acquisition plan in the Company's IRP may also change in a way that delays acquisition of future thermal resources. For example, the Company's 2011 IRP anticipated a new CCCT would be acquired in 2016. In September 2012, the Company communicated to the Commission that it planned to cancel its RFP for a 2016 resource based on a Resource Needs Assessment Update that no longer showed a need for the 2016 CCCT.[4] On February 21, 2013, the Commission approved the Company's cancellation of the RFP.

The preferred portfolio in the Company's 2015 IRP minimizes cost and risk in complying with draft Section 111(d) rules. The Company continues to evaluate the final Section 111(d) rules and will provide an update to the 2015 IRP next year, along with a new IRP in 2017. These will look at the current evolution of requirements under the Clean Power Plan ("CPP") as well as incorporate information as states begin to develop their CPP implementation plans. In Docket

[4] Docket No. 11-035-73, *In the Matter of the Application of PacifiCorp, by and through its Rocky Mountain Power Division, for Approval of a Solicitation Process for an All-Source Resource for the 2016 Time Period*, Correspondence from RMP, September 28, 2012.

No. 12-035-100 the Commission ordered that the IRP is the appropriate venue for addressing the impact of future environmental risks or other factors that may alter the Company's resource plans, stating "to the extent potential costs associated with environmental risks…can be projected and factored into Company decision making, they should be accounted for in PacifiCorp's IRP modeling and resource evaluation process where cost, risk and uncertainty are evaluated to identify a least-cost, risk-adjusted, long-term resource plan."[5]

The Company will continue to plan future resource acquisitions through its IRP to minimize costs and risk to customers while meeting known and assumed state and federal policies. Avoided costs will be updated on an annual basis to reflect the latest long-term resource plan resulting from IRP analyses. Imputing additional costs into the avoided cost formula on the premise of unknown and uncertain future changes to the proposed regulations, and based on unrelated Regional Haze compliance investments, will only overstate avoided costs and violate the ratepayer indifference standard embodied in PURPA.

4. Reliance on Front Office Transactions is Evaluated in the Integrated Resource Plan.

REC incorrectly claims the Company has not conducted an analysis to determine if there will be sufficient market liquidity to enter into the market purchases planned in its IRP and states broadly that the Northwest Power and Conservation Council estimates an overall Northwest market shortfall. In its 2015 IRP the Company explains, "PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply."[6] In fact, the Northwest Power and Conservation Council's assessment indicates that the power supply in the Pacific Northwest is expected to be adequate through 2020, even without accounting for generation additions already planned for the region. Appendix J of the 2015 IRP contains the Company's Western Resource Adequacy Evaluation. Of note, the amount of front office transactions utilized in the 2015 IRP preferred portfolio is lower than the 2013 IRP Update which forms the basis of the current Schedule 37 avoided cost prices.

5. QFs Renewing Existing Contracts Should be Treated Like Other QFs Seeking Contracts.

REC argues that renewing QFs should receive a capacity payment, claiming that the Company plans on existing QFs selling power after the expiration of their contracts. REC's proposal is merely an attempt to lengthen the availability of fixed avoided cost prices beyond the maximum 20-year contract term currently allowed in Utah. This issue of the appropriate contract term for QF contracts is currently being addressed by the Commission in Docket No. 15-035-53.

A utility's avoided costs are not static, and for this reason, it is logical that avoided cost prices need to be updated to account for changes in market and system conditions, including changes in a utility's capacity needs over time. As avoided cost prices are updated and new contracts

[5] Docket No. 12-035-100, August 16, 2013 Order at 41. (Internal citations omitted.)
[6] PacifiCorp 2015 IRP, Volume 1 at 129.

sought, the most current avoided cost price information should be applied to the new contract consistent with the customer indifference standard under PURPA.

Guaranteeing a capacity payment to renewing QFs as REC argues magnifies the risk and potential harm to customers by providing fixed avoided cost prices for excessive time periods. QF projects are not procured in the same way as utility-owned resources. Given the typical contracting and hedging horizons for energy contracts in the utility industry, which are commonly limited to less than 36 months, it is rare for a utility to voluntarily enter into a longer-term fixed-price energy contract without a specified energy resource need due to concerns about price risk, market liquidity, prudency challenges, and other risk considerations. Furthermore, the Company has no ability to require the QF to continue to provide its generation to the Company after the contract expires.

REC cites that in its 2015 IRP the Company is planning on the availability of 255 MW of QFs to meet its system peak in each and every year of the sufficiency period, and that this indicates that the Company delays its commitment to firm resources based on the expectation of contract renewal. These claims misstate the assumptions underlying the 2015 IRP. The 255 MW is contained in Table 5.2 which reports the contribution of several resources to the forecasted system peak in 2015. Furthermore, PacifiCorp's IRP does not include a blanket assumption that all existing QFs will renew; instead, it only assumes that certain small QFs are extended through the end of the planning period while contracts with other QFs will expire according to their terms.[7] In fact, Mr. Higgins points out in his Oregon testimony that existing QF contracts with a combined nameplate capacity of only approximately 122 MW were assumed to be renewed before the next thermal resource acquisition in 2028. Most of these QFs are hydro projects that have existed for many years. The magnitude of generation from these QFs at the time of peak load is less than the nameplate capacity and is not significant enough to have a material impact on the timing of the next major thermal resource acquisition in the IRP.

The combined effect of REC's proposals in its comments would be to pay a QF fixed costs related to a base load thermal resource from the beginning of the QF purchase in perpetuity, regardless of the Company's resource procurement plans. A QF seeking a new contract upon expiration of an existing contract should be treated the same as other QFs and avoided cost prices should reflect the utility's energy and capacity needs at the time of renewal.

Recommendation

Based on the foregoing comments, the Company recommends the Commission reject REC's proposals and approve the Company's updated Schedule 37 avoided cost prices as filed.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

[7] PacifiCorp 2015 IRP, Volume 1 at 75.

By E-mail **(preferred)**: datarequest@pacificorp.com
bob.lively@pacificorp.com

By Regular Mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Bob Lively at (801) 220-4052 or Brian Dickman at (503) 813-6484.

Very truly yours,

Jeffrey K. Larsen
Vice President, Regulation

Cc: Service List