BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1716

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation to Determine the Resource Value of Solar.

THE ALLIANCE FOR SOLAR CHOICE

REPLY TESTIMONY

OF

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I. Introduction

Q: Please state your name.

A: My name is Eliah Gilfenbaum. My background and contact information were provided in my Initial Testimony filed on May 5, 2017.

Q: What is the purpose of this reply testimony?

A: My reply testimony will respond to recommendations offered by parties in testimony provided on May 5, 2017. I discuss the limitations of using a utility-scale proxy methodology, particularly if that methodology were to be used to calculate the value of resources whose generation profiles differ from that of utility-scale solar, such as distributed solar resources paired with storage. Rather, I recommend that each of the approved value categories be quantified separately, and I reiterate my support for using the existing methodologies used by the utilities to evaluate the cost effectiveness of demand side resources like energy efficiency and demand response as a starting point in Phase II.

I also emphasize the importance of using data with hourly level granularity when it is readily available, and note that a strict adherence to using the data from the utilities' IRP "Preferred Cases" can be problematic when evaluating categories like generation capacity value. In some instances, data from the sensitivity cases may provide equally useful information for evaluating long-term value.

Finally, I offer suggestions on how to proceed in Phase II in a manner that allows for meaningful participation by parties and ample opportunity to vet utility proposals.

II. Reply to Party Testimony on the Straw Proposal

Q: Pacificorp witness Rick Link states that "Mr. Olson proposed replacing certain RVOS elements—hedging, environmental compliance, renewable portfolio standards (RPS) compliance, energy generation, capacity integration and ancillary services, administration, market price response with the cost of a utility scale solar resource built in a similar location."[1] Do you agree with this characterization of Mr. Olsen's discussion of the utility-scale solar proxy method?

A: No. That is not my interpretation of Mr. Olsen's statements. My interpretation was that this proxy method would be used to provide additional information, but would not be a substitute for a full RVOS accounting based on each of the approved value categories. While Witness Olsen did suggest it would be reasonable for utilities to calculate such a proxy value, he seemed to agree that whether such a value should be used for determining the appropriate compensation for rooftop solar or community solar customers warrants additional discussion. While I would not be opposed to utilities making this calculation to create additional information for the docket, I do not think that replacing RVOS elements with the utility-proxy value would be appropriate, as I discuss below.

[1] PAC/300 at p. 4, ln. 14-17.

Q: Witness Link states that "this [utility-scale proxy] approach has the potential to greatly simplify the RVOS process."[2] Do you agree?

A: I would not oppose utilities calculating this value for informational purposes. But as I discussed at the January 31st hearing and in opening testimony, this methodology is of limited use for several reasons. First, this approach is not well suited to assessing the value of resources with generation profiles that differ from utility-scale solar.[3] This is especially true when solar is paired with energy storage, where capacity-related values in particular could be quite different.[4] In addition, the utility-scale proxy would not account for avoided transmission and distribution ("T&D") benefits, where there is the most disagreement on how the category should be valued. Because there is wide consensus on the approaches to valuing many of the other categories, it is unclear how much this approach would simplify Phase II, and it may even trigger new and additional controversies which will bog down the process rather than helping to resolve it.

Q: Are there any examples where using a utility scale proxy for determining long-term avoided cost has been struck down by a Commission?

A: Yes. The Public Utilities Commission of Nevada ("PUCN") in its recent decision on Sierra Pacific Power Company's ("SPPC") Integrated Resource Plan ("IRP"), determined that the Company's approach to capping long-term avoided costs ("LTAC") for compensating Public Utility Regulatory Policies Act ("PURPA") Qualifying Facilities

[2] PAC/300 at p. 5, ln. 10.
[3] TASC/300 at p. 14, ln. 13-15.
[4] TASC/300 at pp. 8, ln. 8-20 – 9, ln. 1-3.

("QFs") was flawed, and "inappropriately puts downward pressure on LTAC rates."[5] Rather than using the proposed Capped Methodology, the Commission instructed the utility to use the Uncapped Methodology, which it had been using for a number of years, whereby the energy and generation capacity values are based on the Company's long-term forecast within the IRP, rather than utility-scale solar prices from recent solicitations. The Commission found that "the uncapped LTAC values represent the actual marginal energy and capacity value of generation to SPPC and as such should be the basis for long-term energy rates."[6]

Q: What methodologies do you propose using instead of the utility-scale proxy method and why?

A: I continue to believe the methodologies used by the utilities to evaluate the cost effectiveness of demand side resources like energy efficiency ("EE") and demand response ("DR") are the most appropriate. As discussed at the hearings, the point of interconnection is the same, and therefore line loss and T&D benefits will be similar. The cost effectiveness tests for EE and DR are also flexible enough to assess different types of resources with different generation profiles, like solar paired with storage. The methodologies are already used to evaluate these existing demand-side resources, and would therefore not add administrative burden or implementation complexity.

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[5] PUCN, Order on Phase II and Phase III, Docket No. 16-07001, 16-07007, 16-08027 (Dec. 23, 2016), at p. 52.
[6] *Id.* at pp. 52-53.

Q: Witness Link states that "Utilities should have flexibility in determining how to best treat solar PV resources in their load and resource balances."[7] Do you agree?

A: I believe that forecasts of future behind the meter solar should not be assumed to be in place; otherwise there is a risk of creating a circularity that has been discussed at length throughout the hearings and testimony.[8] The Joint Parties noted this in testimony, and recommended the Commission follow Staff Witness Olson's recommendation that "any solar resources whose compensation is tied to the RVOS should be excluded from the utility's forecast of the resource-balance-year."[9]

Q: PacifiCorp witness Rick Link states that the cost-effectiveness analyses for EE and DR are not preferable to avoided cost pricing because EE and DR represent reductions in energy use whereas distributed generation is a substitution of customer generation for utility generation. Do you agree and do you think this is a meaningful distinction?

A: No. Rooftop solar has characteristics of both load reduction and third-party generation. It is not strictly one or the other, which is why it is not as straightforward to value. For the portion of generation that is consumed behind the meter, it is very similar to demand-side resources in that it reduces the load that needs to be served by the utility to the retail customer. Therefore, from the utility's perspective, aggregate solar resources impact the system like EE or DR.

[7] PAC/300 at p. 10, ln. 11-12.
[8] *See, e.g.*, TASC Initial Brief at pp. 4, 7-8; TASC/200 at p. 5, ln. 9-20 – p. 6, ln. 1-12.
[9] Joint Parties/300 at pp. 6-7 (quoting Staff/400 at p. 15).

For the portion of rooftop solar generation that is exported to the utility, it is important to remember that this generation is still typically consumed toward the edge of the distribution network, even if it is not strictly consumed behind the individual's meter. It is therefore inaccurate to assert that such generation is simply a substitution of one type of generation for the other.

III. Comments on Specific Value Categories

Energy

Q: PacifiCorp states in testimony that for some elements, such as Energy, "it is unlikely that an hourly level of granularity will provide additional precision."[10] Do you agree?

A: No. Using monthly, weekly or daily averages obscures important information about which hours are of highest value. Solar production coincides with higher cost high-load hours, and averaging across periods underestimates the value of solar generation.[11] If hourly data is already available for calculating these values, it will inherently be more accurate and will not add administrative burden to the process. The assertion that the hourly values and monthly strips are effectively the same is not supported by the record. The use of monthly averages seems best applied in cases where it would relieve the administrative burden for utilities that do not currently calculate energy values on an hourly basis. This is not the case for all Oregon utilities, as Pacificorp states in testimony

[10] PAC/300 at p. 7, ln. 10-14.
[11] *See* Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan (Feb. 2010), Appendix D, at p. 4, *available at* https://www.nwcouncil.org/media/6302/SixthPowerPlan_Appendix_D.pdf.

that it produces long-term forecasts on an hourly basis in its IRP.[12] Therefore, the RVOS should use this granular data wherever available, rather than create an avenue for utilities to reduce the accuracy of currently available information.

Generation Capacity

Q: The Straw Proposal proposes that the resource sufficiency/deficiency demarcation shall come from the utilities' IRPs. Do you have any concerns with that approach?

A: Relying on the IRP filings for information regarding the resource sufficiency/deficiency demarcation makes sense. However, relying exclusively on the utility's "Preferred Case" from that filing may be inadequate. Some assumptions may only exist as sensitivity cases in the IRP filings and may not be part of a utility's Preferred Case, but nonetheless may be reasonable to consider in this assessment. For example, incorporating an estimate of future coal retirements driven by economics (and not environmental compliance) may fall outside of a utility's Preferred Case for various reasons. In particular, such retirements may not be relevant for near-term resource sufficiency decisions over the next 3 years. However, such retirements are relevant for determining a resource balance year that could form the basis for long-term compensation for a given resource.

Incorporating these kinds of assumptions can lead to substantial differences in the resource balance year. For example, in the Northwest, there are a number of coal plants that are not assumed to be retired in the PacifiCorp Preferred Case, but which the Northwest Power and Conservation Council, in its 2021 assessment, assumes to be

[12] PAC/300 at p. 6, ln. 10-13.

retiring.[13] While PacifiCorp assumes to have sufficient capacity through 2028 in its Preferred Case, the Northwest Power and Conservation Council highlights the need for 1,400 MW of new capacity in the region by 2021, while only 550 MW are planned to be built.[14] The difference between a resource balance year of 2021 versus 2028 can have a big impact on capacity value: approximately 25% based on the E3 calculator developed for this docket.[15]

Transmission and Distribution Avoided Costs

Q: Do you agree that "the value should only be non-zero if there are actual T&D investments that can be deferred with incremental additions of solar resources"?[16]

A: No. The entire fleet of distributed resources should be viewed as deferring marginal T&D capacity costs in the aggregate, as is done for other demand-side programs like energy efficiency. For example, PacifiCorp assumes a $13.56/kW-yr capacity credit for energy efficiency programs in its latest IRP.[17] While I would argue this value is low for solar resources, it makes clear that utilities in Oregon do assume a T&D deferral value for a fleet of distributed assets, and they should do the same in the RVOS context.

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[13] *See* Pacific Northwest Power Supply Adequacy Assessment for 2021, at pp. 8-9, *available at* https://www.nwcouncil.org/media/7150591/2016-10.pdf; PacifiCorp, 2017 Integrated Resource Plan, vol. 1 (Apr. 4, 2017), at pp. 6-7, *available at* http://pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf.
[14] *See* PacifiCorp, 2017 IRP at p. 2; Pacific Northwest Power Supply Adequacy Assessment for 2021, at p. 8.
[15] Assumes the following inputs for the E3 Tool: $172/kW year CONE, 37.9% ELCC based on PacifiCorp IRP, $62/kW-yr net energy margins, $32/kW-yr short-run capacity costs.
[16] PAC/300 at p. 12, ln. 20-21.
[17] PacifiCorp 2017 IRP at p.137.

Integration and Ancillary Services

Q: Idaho Power states that it does not believe that solar resources provide ancillary services benefits. Do you agree?

A: No. To the extent a balancing area authority procures ancillary services based on a percentage of load, reduction in retail load as a result of distributed solar generation reduces the need for these services. E3 has made this finding more than once. In the 2013 NEM Evaluation Report E3 authored for California, E3 acknowledged that "reductions in demand at the meter result in additional value from the associated reduction in required procurement of ancillary services."[18] Again, in Nevada, it its 2014 PUCN NEM Report, E3 estimated ancillary benefits by taking the total projected spinning reserve spending divided by the total energy production cost spending to calculate ancillary services avoided costs as a share of energy generation avoided costs.[19]

PacifiCorp states that its reserve modeling reflects reliability standard BAL-002-WECC-2, contingency reserves are set to 3% of retail load plus 3% of generating resources.[20] Given that behind the meter resources reduce retail load, this requirement for contingency reserves driven by the retail load component would be reduced.

[18] E3 2013 NEM Evaluation Report, at p. C-39, *available at* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4292.
[19] E3 PUCN NEM Evaluation, p. 55, *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf.
[20] Appendix A, PacifiCorp Avoided Cost (Partial Displacement Differential Revenue Requirement) Model Updates through August 2016, Docket No. 03-035-14, Docket No. 16-035-29, at p. 3, *available at* https://pscdocs.utah.gov/electric/16docs/1603529/289212AppAUT2016Q2DiffWrite-Up9-26-2016.pdf.

In addition to the impact of reducing the requirement for ancillary services by reducing retail load upon which such requirements are based, fleets of advanced distributed energy resources, such as PV with smart inverters or dispatchable batteries, have the ability to provide grid services to meet those requirements. For example, SolarCity (now Tesla Energy) has built the capability to provide a number of grid services to utilities, including frequency regulation, flexible ramping, spinning reserves, and voltage support to enhance existing conservation voltage reduction ("CVR") schemes.[21]

Environmental Compliance

Q: The Straw Proposal directs utilities to estimate avoided environmental compliance costs based on the future carbon regulation assumptions in their IRP. Do you agree with this approach?

A: Yes, this is a reasonable approach, and reflects the same assumptions that the utilities would use for planning conventional resources.

Q: PacifiCorp objects to this approach stating that "speculative assumptions about future requirements should not be used to establish pricing in long-term contracts," and that while considering potential future environmental compliance is important in resource planning, "it does not make sense to lock in payments based on regulatory requirements that may or may not materialize ten or fifteen years from

[21] SolarCity, Distributed energy solutions for the 21st century grid, http://www.solarcity.com/utilities/distributed-energy-solutions.

now."[22] Do you believe PacifiCorp's argument is persuasive and that future environmental regulation assumptions should not be included in the RVOS?

A: No. While PacifiCorp argues that consideration of future environmental compliance scenarios is too speculative to be included in the RVOS, the utility clearly feels it is sufficiently able to evaluate anticipated environmental standards for the purpose of its own IRP. The argument that resource planning does not "lock-in payments" for resources selected through that process rings hollow given that long-term contracts are sometimes entered into by the utility based on modeling that includes environmental compliance costs, and because any rate-based infrastructure also "locks in" payments in the sense that additions to the rate base are recovered gradually and built into retail rates for decades.

For a vertically integrated utility building utility-owned generation, there are no pricing terms: new power plants are simply rate-based, and the choice of whether it makes economic sense to do so is largely driven by the very scenarios witness Link claims should not be used for long-term valuations. This represents a double standard. For example, the carbon price assumed in the utility's IRP may have an impact on the choice of whether to install selective catalytic reduction ("SCR") technology on an existing coal plant, or to retire that plant and build a new gas-fired unit. The CO_2 price forecast is a component of the overall economic decision to build the new plant or not, and is essentially locked in for the long-term once the decision to build the plant is made. Simply because a utility-owned plant does not receive a price that directly accounts for

[22] PAC/300 at p. 20, ln. 19-21 – p. 21, ln. 1-7.

environmental compliance costs does not mean those costs are detached from the decision to make that investment.

IV. <u>How to Proceed in Phase II</u>

Q: The Straw Proposal provides that the utilities will propose values for the majority of RVOS elements. These valuations will then be examined via workshops and technical conferences. Do you believe this proposed process is sufficient?

A: No. The proposed next steps for Phase II grant the utilities a substantial amount of deference by seeking only their recommendations on the values of the RVOS elements. The subsequent process (workshops/technical conferences) does not provide sufficient opportunity for parties to assess and respond to the utilities' proposed values. Although workshops and technical conferences can be beneficial for discussing methodologies and approaches to valuation, on their own, they do not give parties sufficient opportunity to request information from the utilities and develop their own proposed valuations.

Q: What additional or alternative procedures would you prefer to see in Phase II?

A: Phase II should provide ample opportunity for utility proposals to be vetted through a formal proceeding allowing for discovery and adequate response from interested parties. Workshops and conferences alone are insufficient for this purpose. The procedures also need to provide explicit opportunities for parties to provide evidence for their own valuations for the RVOS elements in a manner that allows these proposals to be considered fairly and on par with the utility proposals.

Q: Does this conclude your testimony?

A: Yes it does.