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

TESTIMONY

OF

ELIAH GILFENBAUM

May 5, 2017

Table of Contents

I. Introduction

Q: **Please state your name and business address.**

A: My name is Eliah Gilfenbaum. I am Manger of Energy Policy for Tesla, Inc. (Tesla). My business address is 444 De Haro Street, San Francisco, California 94110

Q: **Please state your qualifications and relevant experience.**

A: I have over 10 years of experience in the energy industry working on carbon markets, renewable energy procurement, utility resource planning, and rate design. I spent 4 years at Pacific Gas and Electric Company (PG&E) as an expert analyst in their resource planning department, where I conducted various types of modeling that was incorporated into resource valuation protocols. Examples include Loss of Load Probability (LOLP) studies to assess the Effective Load Carrying Capability (ELCC) and capacity value of renewable resources, and production cost modeling to assess resource integration cost.

In that role I also familiarized myself with various approaches to avoided cost modeling for the cost-effectiveness evaluation of demand side resources. Two years ago I joined the Policy and Electricity Markets team at SolarCity Corporation, now a subsidiary of Tesla. In that time I have participated in various proceedings across the country focused on rate design and calculating the value of distributed energy resources.

Q: **On whose behalf are you testifying in this proceeding?**

A: I am testifying on behalf of The Alliance for Solar Choice (TASC).

Q: **What are your overall recommendations?**

A: My testimony focuses on three main areas. I explain in Section II that the resource value of solar (RVOS) should not be developed in a vacuum, and that determining the appropriate compensation level for customer-sited exported generation must look at the wider policy context and state policy goals under development. Future compensation frameworks will impact the ability of distributed solar to contribute to these policy goals, so coordination is important.

In Section III, I offer specific comments and recommendations on the staff straw proposal for calculating each benefit category within the RVOS process. I present evidence to support TASC's position that the starting point for these methodologies should be the energy efficiency (EE) cost-effectiveness protocols used by the Energy Trust of Oregon to evaluate utility EE programs, and not Public Utility Regulatory Policies Act (PURPA) Qualifying Facility (QF) compensation. I also explain why the framework must be flexible enough to address solar paired with other technologies, especially energy storage.

Finally, in Section IV, I offer recommendations on how to proceed in Phase 2. I recommend that the methodologies developed in Phase 2 account for the value of distributed storage that will increasingly be paired with solar energy systems, and I discuss the ways benefit categories, particularly capacity-related benefits, will see higher values due to the unique capabilities and generation profiles of paired systems. Additionally, I discuss why using utility scale solar as a proxy for certain value categories for distributed solar is problematic and should not be used as a basis for compensating customer-sited generation.

II. Wider Policy Context

Q: **Are there any public policy objectives in Oregon that should be considered if and when RVOS is implemented as a basis for compensating solar customers?**

A: Yes. The way RVOS is developed and applied must take into account the larger context of active dockets and policy mandates within the state. For instance:

- The Clean Electricity and Coal Transition Plan (SB 1547), passed by the State Legislature in 2016, requires the state's utilities to eliminate the use of coal-generated electricity by 2030,[1] and requires that 50 percent of electricity in the state come from renewable resources by 2040.[2]
- HB 2193 created a statewide storage mandate requiring the state's largest utilities to procure at least 5 MWh of energy storage by 2020.[3] The Commission has adopted guidelines for implementing this goal in UM 1751. As the Oregon Department of Energy (ODOE) and the Joint Parties[4] have noted, there is

[1] SB 1547 (2016) § 1.
[2] SB 1547 § 5 (as codified in ORS § 469A.052(1)).
[3] HB 2191 (2015) § 2.
[4] Joint Parties include Renewable Northwest (RNW), the NW Energy Coalition (NWEC), Northwest Sustainable Energy for Economic Development (NW SEED), and the Oregon Solar Energy Industries Association (OSEIA).

opportunity for the RVOS being developed in this docket to benefit from the work done in UM 1751.[5]

- Additionally, the role storage can play in ensuring grid resiliency in the face of natural disasters has been acknowledged by state agencies. For instance, ODOE has focused on efforts to improve grid resilience through energy storage including efforts such as the 2015 Eugene Water & Electric Board energy storage and microgrid pilot program. This initiative sought to improve grid resilience and responsiveness to emergency situations.[6]
- The State's Green Jobs Growth Plan was established in 2009 by HB 3300. This initiative directs the State Workforce Investment Board, in consultation with the Governor and other parties, to "develop a plan for a green jobs growth initiative to promote the development of emerging technologies and innovations that lead to, create or sustain family wage green jobs."[7] The plan identifies industry sectors that promise the greatest growth in green jobs, including renewable energy and transmission, distribution and storage.[8]

Each of these policy goals should be considered in the context of the RVOS docket.

Q: **Are there any active legislative initiatives or policy developments that could impact the solar industry and its contribution to the above policy objectives?**

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[5] ODOE Cross Responsive Testimony, UM 1716, ODOE/200 at 6-7 (citing RNW, OSEIA, NWEC, NW SEED/100, O'Brien/7, lines 1-2).
[6] See ODOE Energy Storage Grant to Spur Eugene Water & Electric Board Toward a Cleaner, More Resilient Energy System (Dec. 16, 2015), https://energyinfo.oregon.gov/2015/12/16/odoe-energy-storage-grant-to-spur-eugene-water-electric-board-toward-a-cleaner-more-resilient-energy-system/.
[7] HB 3300 (2009) § 3(1).
[8] 3E Strategies, Green Jobs Growth Plan 2011 to 2019 at 3, *available at* https://www.oregon.gov/ccwd/pdf/OregonGreenJobs11-19.pdf.

A: Yes. The Oregon legislature is currently considering renewal of a tax credit, the Residential Energy Tax Credit (RETC). For residential solar customers in Oregon the availability of the maximum amount of the credit, $6000 taken in $1500 amounts over four years, is a factor for many customers in determining whether to install a system or not. Incentive payments available through the Energy Trust of Oregon also play a role in supporting the residential solar industry.

Q: **Why are these policy developments relevant to the RVOS proceeding?**

A: Significant changes to these policies could compound one another, creating significant headwinds for the industry. For example, reductions to the tax credit coupled with steep reductions in the compensation for exported generation could dampen the growth of the distributed solar industry far more than either of those changes would individually.

III. Response to Straw Proposal

Q: **Do you have any concerns with the specific methodological recommendations within the Straw Proposal?**

A: Yes, a number of recommendations within the straw proposal run counter to industry best practices with respect to the valuation of behind the meter resources. As discussed at the hearings on January 31, 2017, I believe that methodologies consistent with how utilities evaluate cost effectiveness of demand side resources like energy efficiency and demand response would be the most appropriate starting point for the avoided cost categories evaluated under RVOS. Instead, the straw proposal bases a number of values on the methodologies for determining compensation for QF resources under PURPA.

Q: **Why do you believe that the cost-effectiveness protocols used for energy efficiency are the most appropriate starting point?**

A: First, the point of interconnection is the same. Demand-side technologies interconnect behind the customer's meter, and therefore line losses and avoided transmission and distribution benefits need to be evaluated as part of the cost-effectiveness determination. This is already done by the Energy Trust of Oregon as part of their assessment of EE measures, and those same approaches could be leveraged in the RVOS process.

Second, typical cost-effectiveness tests (like those based on California's Standard Practice Manual), are flexible enough to assess different types of resources with different hourly shapes and different capabilities.[9] For example these methods have been used to evaluate energy efficiency[10] and demand response[11] programs, as well net metering policies for photovoltaic (PV) and PV plus storage.[12] The avoided costs calculated for PURPA QF generators result in averaged monthly prices, which systematically undervalues resources whose generation has a greater coincidence with hours that drive

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[9] *See*, Cal. Pub. Util. Comm'n, Cost-Effectiveness, http://www.cpuc.ca.gov/General.aspx?id=5267.
[10] *See* Cal. Pub. Util. Comm'n, Energy Efficiency Policy Manual (Jul. 2013), *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/EE_and_Energy_Savings_Assist/EEPolicyManualV5forPDF%20(1).pdf.
[11] *See* Cal. Pub. Util. Comm'n, Demand Response Cost-Effectiveness Protocols, *available at* http://www.cpuc.ca.gov/General.aspx?id=7023.
[12] *See* Cal. Pub. Util. Comm'n, Public Process to Develop Proposal for the Net Energy Metering Successor Tariff, http://www.cpuc.ca.gov/General.aspx?id=11285.

system costs. Given that solar paired with other technologies like storage will be increasingly common in the future,[13] the framework must be flexible enough to account for the benefits of those types of systems. The QF framework is not well suited to that.

Q: **Please describe any specific comments you have on the methodology proposed for each of the value categories within the Straw Proposal.**

A:

Energy

The straw proposal proposes to use marginal cost of energy values consistent with current methods to quantify avoided costs for QFs (i.e. average monthly values with on and off-peak blocks). As described in my original testimony from June 30, 2016, using monthly averages, or even daily or weekly averages, obscures important information about which hours are of highest value.[14] Given the fact that solar PV produces energy coincident with the highest cost hours, averaging across periods with lower cost energy systematically underestimates the value of solar generation.

To the extent hourly data is available, it should be utilized in order to produce the most accurate results possible. Despite the fact that a significant amount of energy is purchased in the wholesale market as High Load Hour or Low Load Hour blocks, these products are not a reflection of the hourly marginal cost of energy. If it is recognized in this proceeding that solar generation avoids marginal energy costs, rather than average energy

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[13] R. Manghani, The Future of Solar-Plus Storage in the U.S., Greentech Media (Dec. 2014), *available at* https://www.greentechmedia.com/research/report/us-solar-plus-storage.
[14] TASC Response Testimony of Eliah Gilfenbaum (TASC/100), at pp. 7-8.

costs or baseload power, then hourly marginal values should be utilized to the extent possible.

Generation Capacity

The straw proposal recommends using the resource sufficiency/deficiency demarcation from each utility's integrated resource plan (IRP), basing value on market prices when resource sufficient and assessing value based on a proxy resource when deficient, scaling for solar's contribution to peak. As with other value categories below, the generation capacity avoided cost methodology should be flexible enough to calculate the value for solar plus storage paired systems, particularly since this value category could be much higher for paired systems. As an example, take the value for Fixed Tilt PV from Pacificorp's recent 2017 IRP. In the West BAA, of which Oregon is a part, the calculated capacity contribution is 53.9%.[15] This is based on the passive generation from PV systems according to a fixed generation profile. While there is some coincidence with peak system needs, that level of coincidence essentially provides 53.9% of the capacity value that a perfect resource would provide.

PACIFICORP – 2017 IRP APPENDIX N - CAPACITY CONTRIBUTION STUDY

Table N.1 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
2017 IRP Results	15.8%	37.9%	59.7.8%	11.8%	53.9%	64.8%
2015 IRP Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

[15] 2017 Pacificorp IRP; Appendix N: Capacity Contribution Study, at p. 316.

Solar paired with dispatchable storage will have a different hourly generation profile that will be better matched to the hours of highest system need, and the capacity contribution would likewise be higher.

<u>Line Losses:</u>

As with other value categories, the more granularly this category can be evaluated, the more accurate the ultimate value calculation will be. If hourly marginal loss values are available, they should be used. If hourly values are not available, the most granular time step available should be used that captures the coincidence of solar generation with the highest load hours, when losses are highest.

<u>T&D Avoided Costs:</u>

The straw proposal suggests that utilities should develop system-wide average avoided cost value attributable to incremental solar which can avoid growth-related transmission and distribution (T&D) infrastructure investments. However, in previous testimony in this docket, some utilities have insisted that they are not prepared to estimate this value of avoided T&D.[16] Given this apparent conflict, the Commission should provide guidance to ensure that in Phase 2 of the proceeding, certain value categories are not assumed to be zero value simply because utilities claim the values cannot be quantified.

In the purported absence of quantifiable T&D benefits, PGE's proposes the following:

[16] Portland General Electric Company, Response Testimony of Stefan Brown and Darren Murtaugh (PGE/100) (June 30, 2016), at p. 10.

"Due to the locational variability of the infrastructure deferral benefit, PGE recommends using the net present value (NPV) of the revenue requirement of the deferred capacity investment over the period of the deferral. This would be only for solar systems that are capable of reliably delivering output during a system peak event, as mentioned above, and are large enough, in aggregate, to defer the needed capacity."[17]

It should not be a requirement, as PGE proposes, that a specific project be capable of deferring or avoiding a specific upgrade on its own. Rather, the entire fleet of distributed resources should be viewed as capable of contributing to that deferral in aggregate, and the distribution planning process that identifies potential upgrades should take the existence of that fleet into account when determining whether new capital expenditures are necessary.

There are tangible examples from other states where distributed resources in aggregate have avoided significant transmission and distribution infrastructure. In California, PG&E announced that it is cancelling 13 sub-transmission projects, which would have cost $192 million, as a result of "a combination of energy efficiency and rooftop solar."[18] In New York, ConEdison is deferring the need for a $1 billion investment in a new substation through the Brooklyn Queens Demand Management (BQDM) program, which

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[17] PGE, Response Testimony of Stefan Brown and Darren Murtaugh (PGE/100), p. 11, ln. 6-10.
[18] See "Cal-ISO Board Approves Annual Transmission Plan," *California Energy Markets* (No. 1379, April 1, 2016) at p. 10.

combines distributed generation and demand response to provide capacity during summer peaks.[19]

Integration/Ancillary Services

The straw proposal recommends basing integration costs on wind/solar integration studies that have been acknowledged in utility IRPs, and presumes that there is no benefit from reducing the requirements for ancillary services. While the source for integration costs seems reasonable, assuming zero benefit for reducing ancillary services cost is not consistent with industry best practices, including methodologies used by staff's own consultant E3. In other regions such as California[20] and Nevada,[21] E3 has evaluated the avoided cost value of ancillary services by estimating the proportion of energy costs typically spent on these services, and assuming that the benefit of reducing the need to procure those services is a similar proportion of avoided energy costs. A similar approach should be taken for RVOS.

Furthermore, assuming zero value does not account for the benefits that storage could provide by proactively providing services rather than simply avoiding the need to procure them. Providing grid services is one of the main use cases for storage that the state is actively promoting. Failing to recognize this as a value within the RVOS methodology

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[19] Con Edison, BQDM Demand Response Auction Home, https://conedbqdmauction.com/.
[20] California Net Energy Metering Ratepayer Impacts Evaluation, Appendix C at p. C-39, *available at* www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4292.
[21] E3, Nevada Net Energy Metering Impacts Evaluation (Jul. 14), at p. 55, *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf.

conflicts with the intent of those policies, and potentially actively discourages a distributed storage industry from developing.

IV. How to Proceed in Phase 2

Q: **While originally scoped as a means to value distributed solar resources, do you believe it is appropriate for the RVOS methodologies developed in Phase 2 to also account for the value of distributed storage?**

A: Yes, particularly given that in the future, solar plus storage systems will increasingly be paired together. Failure to make the RVOS methodology flexible enough to assess these types of distributed resources will lead to one of two outcomes. One possibility is that the methodologies will be inadequate for assessing the value of these paired systems and paired systems would face uncertainty with respect to how they are compensated for exporting energy. Or alternatively, paired systems would inaccurately be compensated using an RVOS based on standalone PV, and therefore only a subset of the value they are capable of providing would be recognized. In either case, the uptake of solar plus storage systems would be severely inhibited.

Q: **Please explain why exports from paired systems could potentially be more valuable than exports from standalone PV systems.**

A: Solar paired with storage systems (or other load modifying devices for that matter) are a fundamentally different product than standalone PV. Paired systems have the capability to dispatch stored energy when it is most valuable to the system, proactively helping to address constraints on the transmission and distribution system, as well as reducing the need for new generating capacity significantly more than standalone PV can. It really comes down to having a dispatchable resource (which can also absorb energy when needed) versus one with a fixed generation profile that is partially coincident with system needs.

Q: **Which benefit categories in particular would have different values due to the unique capabilities and generation profiles of paired systems?**

A: All value categories could potentially be different for standalone solar vs. paired systems, but the biggest difference in value will come from capacity-related benefits. For example, energy avoided costs could be marginally higher for paired systems to the extent that storage systems absorb energy during lower value hours and re-dispatch it to higher value hours. This could lead to an incrementally higher energy avoided cost value for paired systems. For avoided capacity value, however, the value could be significantly higher. As described earlier in my testimony, a fixed tilt PV system with a capacity contribution of ~54% (as Pacificorp estimates in its 2017 IRP[22]) could increase to close to 100% when paired with storage with sufficient duration. Similarly for transmission and distribution avoided costs, the higher coincidence of storage dispatch with the hours used to allocate T&D capacity costs would increase the value of paired systems significantly.

Q: **How can paired systems best be incentivized to be dispatched in such a way as to maximize the value they are providing?**

[22] 2017 Pacificorp IRP; Appendix N: Capacity Contribution Study, at p. 316.

A: Some type of time varying price signal could help maximize the value from paired systems. For example, a time-of-use rate would encourage customers to store excess energy during offpeak hours and discharge during the onpeak hours when it is more valuable. However, it should be noted that to develop time varying rates appropriately, marginal cost information would need to be calculated on an hourly basis so the on and offpeak periods can be properly designed.

Q: **The staff Straw Proposal indicates that utilities "shall produce an alternative estimate of RVOS using a utility scale solar resource." Do you agree?**

A: No. As discussed very briefly towards the end of the hearing on January 31st, it is not appropriate to use utility scale solar as a proxy for value categories for distributed solar. Using this value as the basis for compensating customer-sited generators is problematic. In particular, I am concerned that using this type of proxy approach is not well suited to assessing the value of resources with generation profiles that are different than utility scale solar, such as solar paired with storage. As described above, the generation capacity value in particular could be very different for paired systems than the utility-scale proxy method would suggest. Because using a utility-scale solar resource as a proxy for these values implicitly assumes that the generation profile of the resource being assessed is very similar to utility-scale solar, this method would not accurately reflect the value of paired systems.

Q: **In a recent Arizona decision in the Value of Solar docket (E-00000J-14-0023), the Arizona Corporation Commission moved to end retail net metering and replace it**

with a value based on utility-scale solar power purchase agreements (PPAs). Are there any aspects of that decision that should be noted for this proceeding?

A: First, with respect to Arizona, it is important to note that the state has robust installation of solar, both distributed and grid scale, that far surpasses penetration levels in Oregon. The movement away from full retail net metering only occurred after penetration levels reached a high level. Second, the way the Arizona decision proposes to calculate the Resource Comparison Proxy (RCP) is very specific. The decision requires the RCP to be based on a weighted average of utility-scale PPAs over a prior five-year period.[23] Importantly, Arizona's RCP value is based on projects that came online in the last five years, not PPAs entered over the last five years.[24] This is a critical distinction because a PPA that is signed today is for a project that may not come on line for several years, and the price that is negotiated will reflect the developer's expectation of where prices will be in a few years' time. It would be fundamentally unfair to establish a resource value of solar for today that reflects best guesses as to where prices will be in a few years. That is why Arizona uses only projects that are online in its RCP value, and Arizona uses a rolling five-year average of prior projects so that the RVOS is not based on a small data set.

Finally, Arizona's value of solar decision made a number of missteps and should not be looked to by the Commission as it undertakes its value of solar study. First, the Arizona decision excluded any consideration of societal, economic development, or fuel hedging

[23] *See* Arizona Corp. Comm'n, Decision No. 75859, Docket No. E-00000J-14-0023 (Jan. 3, 2017), at pp. 134, 147-48, 171 (Finding of Fact 144).
[24] *Id.*

impacts.[25] The decision also asserted that distributed generation customers cause a cost shift without an adequately inclusive analysis of the benefits of distributed solar.[26] The decision also mandated that distributed generation customers interconnecting to the grid under the new export rate be grandfathered for only 10 years despite taking great pains to state that customers interconnected prior to the adoption of the new export rate should be grandfathered for 20 years.[27] As a result of these shortcomings, the Arizona value of solar decision does not serve as a helpful precedent for the Commission to follow.

Q: Does this conclude your testimony?

A: Yes it does.

[25] *Id.* at p. 170, ln. 15-18.
[26] *See Id.* at p. 180, ln. 1-8.
[27] *Id.* at pp. 175, ln. 2-6, 178, ln. 21 – 179, ln. 16.