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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

POST-HEARING REPLY BRIEF

OF THE ALLIANCE FOR SOLAR CHOICE

August 5, 2016

Arizona Corporation Commission
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The Alliance for Solar Choice ("TASC"), through its undersigned counsel, hereby submits its Post-Hearing Reply Brief.

MEMORANDUM OF POINTS AND AUTHORITIES

I. INTRODUCTION.

At their most basic, the utilities' arguments in this docket boil down to this; the utilities desire that the Commission select a methodology of valuing distributed generation solar ("DG") that, by its very nature, prohibits a full accounting of the benefits of DG. Rather than engage in a fair investigation of numerous benefits, the utilities advocate for methodologies that altogether proscribe the examination of key benefits. To ensure fair treatment of DG, an accurate valuation methodology must be employed for guidance in future rate cases that permits a meaningful investigation of the important benefits of solar. To be clear, TASC is advocating that the Commission employ a methodology in rate cases whereby benefits can be discussed, argued about, analyzed, and ultimately valued, while the utilities argue that benefits should be ignored, assumed away, or otherwise barred from consideration.

The utilities self-serving methodologies are flawed from the start and should be rejected. Cost of Service Studies ("COSS") are based on historical embedded costs and cannot, by their nature, capture the full benefits of DG. Likewise, utility-scale proxy methodologies are ripe for manipulation by utilities, do not take into account added benefits only found in DG, and conflate the retail product generated by DG with the utility scale wholesale product. Rather, DG is a demand-side resource and should be subjected to the same type of analysis used to assess the cost-effectiveness of other similar demand-side resources. Such a fair evaluation ensures that customer-focused demand-side resources are valued in a manner commensurate with the way utilities evaluate the cost-effectiveness of their own supply-side utility rate base additions.

Only a long-term avoided cost methodology has the ability to fully account, calculate and identify all of the relevant costs and benefits of a DG system. A long-term avoided cost methodology also ensures fair treatment of DG and considers the interests and costs of all those involved with DG - not just the utilities. The Commission should indicate that it would prefer that the long-term avoided cost methodology be further vetted in each utility rate case as it will result in an accurate assessment of the actual value of DG and further promote optimal DG policy.

II. A LONG-TERM AVOIDED COST ANALYSIS MUST BE PROMOTED TO VALUE DG BECAUSE IT IS THE ONLY METHOD THAT ACCURATELY CAPTURES THE FULL BENEFITS OF DG.

A. This Docket is Not about Rate Design.

The utilities assert that a long-term avoided costs methodology is not the proper methodology to analyze DG because it is not used to set customer rates and would lead to inaccurate rates. The utilities inappropriately conflate the way the Commission should evaluate the value of exported DG with the way the Commission sets the rates the utilities charge their customers. There is a clear distinction between the way rates DG customers pay for electricity they purchase from utilities is set and the way the Commission should look at valuing the credit customers receive for DG exports. There is nothing inconsistent with utilizing long-term, forward-looking benefits in the calculation of the value of the DG resource while continuing to look to embedded costs in setting retail rates. Long-term avoided cost is a tool to properly value DG exports, not a proposal to alter traditional ratemaking as the utilities seem to allege. In fact, a long-term avoided cost analysis is the only methodology that can fully review the full range of cost and benefits of DG. As highlighted by Administrative Law Judge Rodda in her Recommended Opinion and Order in the UNS Electric, Inc., ("UNSE") rate case:

> The Value of DG docket will not result in a specific rate that will be applicable to UNSE. It is anticipated, however, that the Value of DG docket will yield significant new information about how DG solar should be compensated. [1]

Try as the utilities might, this proceeding is not about subsidies, "cost-shifts," partial requirements customers or rate design. Rather, this proceeding focuses on a value of DG solar analysis and building a record regarding a methodology for conducting such an analysis.

B. Long-Term Forecasts are Commonplace and Necessary for DG Valuation

Integrated resource plans ("IRP") are a utility's plan for meeting forecasted energy demand through a combination of both generation and demand-side resources over a certain future time period. The timeframe used in IRPs is typically long enough to include much of the operating lives of resources in a utility's portfolio. The utilities, however, claim that long-term forecasting, and in fact,

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[1] Docket No. E-04204A-15-0142, Recommendation of Administrative Law Judge Jane L. Rodda. July 20, 2016 at 116:3-8 (ALJ Recommendation).

any forward-looking analysis, should be rejected.[2] Arizona Public Service Company ("APS"), however, has already commissioned two studies utilizing a long-term analysis and this was an option put forward by APS witness Albert.[3] Indeed, in any other context for any other asset, APS, and all utilities, thoroughly weigh benefits and costs on a going-forward basis, often decades into the future. The hypocrisy of this "do as I say, not as I do," recommendation is made clear by the continuous forecasting and planning that is a well-known hallmark of the energy industry. APS itself houses an entire department of employees dedicated to resource planning. The *entire purpose* of this department is long-term forecasting. To assist with the resource planning process, APS has a team of full-time employees evaluating and reporting on load forecasting, changing customer load shapes, the developing regulatory environment, and even renewable technology integration. Despite this, the company is unwilling to utilize any of these vast forecasting resources to consider the benefits of DG on a going-forward basis.

Indeed, APS relies on long-term forecasting to guide its own investments. Consider the rationale APS uses to justify its own Ocotillo Modernization project. "By 2021, APS anticipates needing over 3,800 megawatts ("MW') of additional resources to replace expiring purchase contracts and meet expected growth."[4] *Long-term forecasts* are the primary reason for Ocotillo's development. It should also be noted that, as the company describes, "the new GTs will use natural gas more efficiently, reducing emission rates for NOx and CO and decreasing water use rates at the Power Plant. The modernized Power Plant will also have nearly twice its current generating capacity without increasing noise levels. In essence, the Project, once approved, provides benefits for APS electric service reliability that other resources cannot provide."[5] This is of course, a detailed list of benefits, not an itemization of the costs involved to complete the project – which is the very opposite of how APS would have DG evaluated. The notion that long-term forecasting is inappropriate for a valuation of DG is quickly undermined by an examination of APS' own operations.

Similarly, a DG system should be valued over the long-term and should not be examined as a snapshot in time, which can never properly value benefits that flow over a DG system's life. The

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[2] APS Initial Post Hearing Br. at 39-43; TEP/UNSE Initial Post Hearing Br. at 7-8.
[3] Albert Direct Test., APS Ex. 5 at 20-21.
[4] Notice of Filing, Commission Docket No. L-00000D- 14-0292-00169, July 31, 2014 at ES-1
[5] *Id.* at ES-3.

benefits and costs of utilizing DG should be calculated over a period that relates to the "useful life" of a DG system, which can be from twenty to thirty years.[6] Therefore, analysis should develop 20+ year levelized benefits and costs for solar DG on the utility system. Doing so enables DG to be treated like a resource and evaluated in the same way that utilities consider the acquisition of other long-term resources.[7]

C. Forecasting Does Not Impose Undue Risk on Customers.

APS repeatedly insists that the use of forecasting will create undue risks to customers, and argues that the mere use of such forecasts is sufficient reason to ignore the proposals made by TASC, Vote Solar, and RUCO.[8] APS essentially asserts that because forecasting may be difficult or end up wrong, it is not worth trying.[9] That argument fails however, because it does not take into account the broader spectrum of the regulatory environment, and the fact that the ultimate methodology adopted in this docket will be considered in the context of individual utility rate cases.

1. Variables Always Abound in the Regulatory Environment and Rate Making.

APS cites a list of variables to support its claim that forecasts will result in a higher risk of customers paying rates that are not just and reasonable.[10] This red herring argument neglects a basic truth of utility regulation, which is that variables are abundant throughout the industry. Fuel adjustment mechanisms are continually recalibrated though true-up filings at the Commission to account for ever-changing prices.[11] Energy efficiency plans are filed every other year for Commission review and approval.[12] Environmental adjustors permit utilities to recover for investments made to meet ongoing changes in environmental regulations and are adjusted annually.[13]

Indeed, the very institution of the utility rate case exists for the purpose of updating rates to account for an ever-changing list of variables for utilities and customers. Rate cases themselves are based on variables, as there is no way of knowing just how accurate a particular test year will

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[6] Beach Direct Test., TASC Ex. 26 at 18:12-21.
[7] *Id.*
[8] APS Initial Post-Hearing Br. at 39-43, 49.
[9] *Id.* at 43:4-7.
[10] APS Initial Post-Hearing Br. at 40.
[11] Decision No. 73183, Attachment C, APS Power Supply Adjustment Mechanism Plan of Administration; Decision No. 73912, Attachment C, TEP Purchased Power and Fuel Adjustment Clause Plan of Administration.
[12] *See* A.A.C. R14-2-2505.
[13] Decision No. 73183, Attachment H, APS Environmental Improvement Surcharge Plan of Administration; Decision No. 73912, Attachment G, TEP Environmental Compliance Adjustor Plan of Administration.

ultimately be or even if there will be under-recovery in certain rate classes. It stands to reason that in the past, utilities were receptive of forecasts and risk due to their historic predilection for volumetric rate designs – which under growth conditions permitted over-recovery. While new power plants are commonly built, assumptions about the future price of the fuel feeding the plant or the future cost of alternative resources are always made and utilities and regulators move forward with such resources on the basis of key informed assumptions.

2. Rate Cases Exist to Protect Against Inaccurate Forecasts.

The utilities' complaints about forecasts also neglect that the purpose of this docket is to establish a guiding methodology to be considered *within* a rate case. APS seems to suggest that because a forecast could include a 20-year timeframe that it would bind the parties for that duration.[14] That is clearly false, as nothing will prevent APS (or any other utility) from re-visiting the final DG valuation figure contained in a current rate case when a subsequent case is filed. Outside of case-specific stay out provisions, utilities may file rate cases at their own discretion. The very purpose of rate case filings is to safeguard utilities when rates are no longer sufficiently reflective of the utility's financial need. There is no reason to believe that a DG valuation figure based on a methodology adopted in this docket, and subsequently tailored to an individual utility within a rate case, would not be subject to such scrutiny in future rate cases.

III. COST OF SERVICE STUDIES ARE NOT VALUATION TOOLS AND CANNOT BE USED FOR VALUATION PURPOSES.

Cost of Service Studies are not valuation tools. Nonetheless, the utilities, and APS in particular, strongly advocate for the use of a COSS methodology for valuing DG. APS, in fact, goes as far as making the claim that this entire proceeding is about "determining a COSS methodology."[15] APS does not stop there and proceeds to instruct the Commission to accept a litany of assumptions about the value of DG and the basis of its incomplete methodology proposal. These are a few of the many tenuous assumptions APS portrays as settled in its brief and devoid of any need for further analysis:

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[14] APS Initial Post-Hearing Brief at 41.
[15] *Id.* at 5.

- That APS' COSS methodology "accounts for all rooftop solar benefits."[16]
- That the APS COSS methodology "fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid."[17]
- "It is simply more appropriate to allocate APS' distribution costs based on NCP (Non-coincident peak)."[18]
- That "the rates would reflect that 19% demand credit on a continuous and ongoing basis as the benefit provided by rooftop solar is actually received."[19]
- DG customers are partial-requirements customers for their COSS.[20]

APS' clear self-interest emerges when it states its methodology should be "approved and adopted by the Commission to guide future *APS rate cases*."[21] Not only has APS set forth a myriad of self-serving assumptions, rather than aiding the Commission in evaluating a methodology for all of this docket's stakeholders, it instead urges the creation of its own special methodology designed by APS and solely for it. The purpose of this docket is to engage all stakeholders in a constructive process to create a record of a methodology that will be evaluated in utility rate cases, not for utilities to design exclusive, binding, and self-serving valuation schemes for their own individual use.

Similarly, APS and the utilities are such strong proponents of a COSS method because it will inevitably undervalue DG, which is to their advantage. To accomplish this undervaluation, they promote using a COSS for an unintended purpose – DG valuation. Obviously, using the wrong tool will yield a flawed result. Several key flaws with a COSS method are discussed below.

A. A New Methodology is needed to Value DG Since COSS Cannot Value the Benefits of DG.

A COSS is intended to consider all the costs and services that a utility provides to its ratepayers, and is used to determine how those respective costs may be recovered from particular groups of customers, generally on a rate class basis.[22] During a rate case, the study is used simply to guide

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[16] *Id.* at 6.
[17] *Id.* at 10.
[18] *Id.* at 12.
[19] *Id.* at 14.
[20] *Id.* at 14-15.
[21] *Id.* at 14.
[22] *Id.* at 3:2-4.

allocation of costs for ratemaking purposes, nothing more. It contains no resource valuation measurements whatsoever. The proposed use of a COSS does not advance this docket's purpose. Rather, a COSS method frustrates the goal of obtaining a true means of valuation by stopping short of creating a real metric that will accomplish that objective.

The inadequacy of this substitute for valuation purposes is illustrated by the fact that the utilities themselves do not use a COSS to value their own generation resources. Not only are COSS not used to value generation, utilities do not use them to value demand side resources either.[23] Instead, utilities analyze assets by fully considering the benefits and costs of those assets in a long-term, contextual manner through integrated resource planning. Indeed, it is impossible to imagine a circumstance wherein a utility attempts to justify a capital expenditure in its infrastructure to stakeholders with merely an examination of costs associated with that expenditure on a historical basis. Instead, regulators and ratepayers demand a thorough accounting of the benefits *and* costs when such expenditures occur. If the utilities do not use a COSS for that purpose, it certainly does not follow that the Commission should.

B. COSS Are by Their Nature Backwards Looking.

Issues related to the time used within a COSS further impede its use for valuation. A COSS is retroactive. A utility will conduct a COSS based on the test year used in its rate case, which may well be 1-2 years prior to the time of filing. It is therefore impossible to capture future resource benefits because it reflects only costs that have occurred previously. Indeed, one of the primary benefits of DG is its ability to offset the need for future utility infrastructure development, be it transmission, distribution, or generation upgrades – and a COSS takes none of these costs into account.

The retroactive nature of a COSS is not the only timing flaw that inhibits its use for valuation purposes either, because a COSS also involves a duration of only one year, which is particularly uninformative about the current cost incurred by historical, depreciated investments. Compare this brief, retroactive, single year window of time that the utilities urge the Commission to accept with the forward-looking basis on which utilities enter purchase power agreements ("PPA") for utility-scale solar generation, or evaluate any conventional long-lived investment. The majority of utility-scale

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[23] Beach Tr., Vol. X at 1847:1-1849:15; Beach Rebuttal Test., TASC Ex. 27 at 6:1-15.

PPAs for renewable generation are 10-20-year fixed or escalating contracts and are evaluated over their life spans.[24] A static, single year, post-dated metric is unheard of for resource procurement purposes in the utility industry.

C. COSS is a Cost Allocation Tool and cannot provide the Proper Depth of Analysis and Data Needed to Value DG.

Not only are the timing and use of a COSS flawed for valuation purposes, the COSS is also severely lacking in the depth of information it provides. As discussed above, the COSS is traditionally used as a cost allocation tool, not a measurement of value. This is a sharp contrast to the practice of IRP conducted by utilities.

IRP is the culmination of painstakingly thorough, long-term, contextual analyses, which utilities routinely engage in as they seek to value resources. IRPs detail how a utility will meet the energy requirements of its customers in a responsible and cost-effective manner on a going-forward basis for a 15-year timeframe, and these plans encompass all sources of energy, including demand side resources like energy efficiency. Certainly, common industry practice requires consideration of long-term benefits and costs of infrastructure investments, be it generation facilities or transmission lines.[25] This is true for all generation resources, including the utilities' own solar facilities. Despite this, DG is the *only* resource the utilities argue should be evaluated differently.[26] If the utilities weigh the benefits of their own infrastructure investments this thoroughly, certainly Arizona ratepayers are entitled to a more rigorous analysis when considering DG, not just a cursory look at historic costs.

D. COSS Create the Risk of Manipulation.

Although unsuitable for valuation, the COSS is an excellent tool for allocating costs. Unfortunately, this gives rise to another critical problem, which is the risk of manipulation that is invited when a utility is administering such a study in the context of DG valuation. A COSS methodology gives the utility a perverse incentive to heavily allocate costs to DG customers. In turn, those higher cost allocations are used as a rationale for diminished DG benefits. Unsurprisingly, this problem surfaces in both the APS and TEP/UNSE proposals. The proposals set forth by each utility

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[24] Kobor Rebuttal Test., Vote Solar Ex. 8 at 31:19-25.
[25] *Id.* at 31:7-9.
[26] *Id.*

contain an over-allocation of costs to serve DG customers, albeit with slightly different, yet equally unreliable, results.

E. COSS Can Lead to Issues with Transparency.

All parties can agree that any methodology must be transparent, use accurate data and be fully assessable. Unfortunately, both APS' and TEP's COSS were lacking full transparency and accessibility. Both of the utilities used third-party proprietary systems to create their COSS, which limited the parties' ability to verify data and assess the results.[27] Rather a long-term avoided cost approach would set out categories cost and benefits for independent analysis and formulation rather than the parties just accepting a COSS. In essence, under a long-term avoided cost methodology, the parties can be part of the process rather than just receiving the results.

F. Utility Specific Issues.

1. APS.

As noted in TASC's Initial Post-Hearing Brief, APS' COSS is based on a proprietary model that limits full evaluation of its assumptions and inputs.[28] Perhaps not surprisingly, and as discussed above, APS' cost-shift allegations are based on a heavy over-allocation of costs to serve NEM customers.[29] For instance, APS did not properly align costs for DG customers based on their delivered load.[30] That single improper alignment caused the alleged energy-related demand costs to serve DG customers to be inflated by 28-38% in APS' COSS.[31]

On the other side of the equation, APS essentially assigns no benefits to DG in its COSS.[32] The limited credits APS uses within the study assume no benefits of DG on costs for transmission or distribution service.[33] APS also ignores the generation demand reductions associated with NEM deliveries to its distribution grid in its COSS.[34] As TASC witness William Monsen describes, "[g]iven that the very purpose of this proceeding is to establish the value of solar and methodologies for

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[27] *Id.* at 8:18-9:9.
[28] *Id.* at 15:3-14.
[29] Kobor Tr., Vol. IX at 1709-1711.
[30] Snook Tr., Vol. I at 136:20 – 137:11.
[31] Kobor Rebuttal Test., Vote Solar Ex. 8 at 16-17 and Table 2.
[32] Snook Tr., Vol. I at 136:20 – 137:11.
[33] Snook Tr., Vol. I at 111:2-12; 133:6-19; Monsen Rebuttal Test., TASC Ex. 29 at 19:21-30; Beach Rebuttal Test., TASC Ex. 27 at 19-21.
[34] Beach Rebuttal Test., TASC Ex. 27 at 19-21.

quantifying it, it seems premature to file a cost study that has already determined the value of solar to be zero."[35]

2. *TEP/UNSE*

Much like APS, the TEP/UNSE COSS also features a heavy-handed cost allocation to DG customers. The allocation factors included in the COSS include factors that are simply not associated with cost causation.[36] TEP/UNSE similarly neglect any long-term benefits associated with DG.[37] The utilities again tip the scales in their favor by calculating the cost to serve DG customers based on the TEP rate case application, which seeks a 12% increase in test year revenues of $109.5 million, while revenues collected from DG customers were based on *actual* revenue received. This discrepancy in the COSS misrepresents DG benefits by over representing the cost to serve and underrepresenting revenue collected. At a minimum, the utilities should be expected to conduct a COSS that is not blatantly one-sided.

a) TEP's Comparative Cost of Service Approach or "Utah Model" Must Be Rejected.

TEP/UNSE also set forth a Comparative Cost of Service Approach. This method would involve using two studies, one that is an "actual" cost of service study ("ACOS"), which includes DG customers, and another, "counterfactual" cost of service study ("CFCOS") without.[38] The difference between the ACOS and CFCOS would theoretically represent the costs and benefits of DG, and exported energy from DG would be compensated based on this value.[39]

This approach suffers from all of the same flaws described above as the study is only based on a past historical test year. The utilities have already demonstrated the ease with which a COSS can be manipulated to undervalue DG, and adding another layer to a COSS does nothing to alleviate the problem. The COSS is still fundamentally a cost allocation tool, and the addition of a comparative cost allocation tool only adds complexity and increases the possibility of corrupted results. For example, several assumptions need to be made regarding a DG customer's load shape and the utilities'

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[35] Monsen Rebuttal Test., TASC Ex. 29 at 19:28-30.
[36] Kobor Tr., Vol. IX at 1713-1715.
[37] *Id.* at 1714:19-20.
[38] TEP/UNSE Post-Hearing Br. at 5.
[39] *Id.* at 5.

costs to even get to the point of trying to compare a utility with and without DG.[40] A Comparative Cost of Service Study adds no more depth the value analysis, and the risk of manipulation remains. Accordingly, the methodology should be denied in its entirety.

IV. UTILITY GRID SCALE SOLAR IS SIGNIFICANTLY DIFFERENT FROM DG AND CANNOT BE USED AS A PROXY.

The utilities have each proposed methodologies that are based on the use of utility-scale solar as proxy for the value of exported energy from DG. While both utility scale and DG utilize solar technologies, there are numerous key differences that must be considered. The size of the system, target customer, competitive forces, location, interconnection, and investment are completely different, and these distinctions make such a comparison inappropriate. The utility-scale methods suffer from similar risk of manipulation issues as those described under the COSS method. Utilities are incentivized to choose a portfolio of projects for comparison that result in the lowest proxy for NEM. The same problem could ultimately affect Staff's resource comparison method, because as time progresses utilities will undoubtedly advocate that only those projects resulting in minimal DG export rates be used as a proxy. Further, the purpose of valuation is not to value something that has similarities to the thing you want to value, but rather to actually value the thing you are attempting to value. In this case, if we are attempting to develop a record about the value of DG, we should look directly at the benefits of that resource, and not a different resource at the urging of utilities.

A. There are Numerous Critical Differences that Exist between DG and Utility Scale.

There are many critical differences between utility-scale and DG. Some of these major differences include:

1) DG can be deployed with a much shorter lead time than utility-scale projects and when complemented with other distributed resources helps provide more local service resiliency;[41]

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[40] Kobor Rebuttal Test., Vote Solar Ex. 8 at 27:11-17.
[41] Beach Direct Test., TASC Ex. 26 at 31:30-45.

2) Utility-scale solar generates a different product – wholesale electricity. The value proposition for wholesale energy that requires delivery to an end-user differs greatly from the on-site retail product generated by DG;[42]
3) The distributed nature of DG makes it more reliable and better at reducing intermittency than utility scale; [43]
4) Unlike utility-scale, DG has the capability to provide deferral of local distribution capacity and operational expenses (voltage control, transformer loading);[44]
5) DG's location, at or near the site of consumption, means that the energy generated from utility scale solar incurs greater line losses prior to delivery than does DG energy;[45]
6) The majority of the output of a rooftop solar facility provides power directly to end-use retail loads, behind the meter, where it displaces retail power from the utility whereas utility-scale solar power is often delivered over high-voltage transmission systems in competition with other large power sources;[46] and
7) DG represents a more efficient usage of environmental resources via avoidance of biological impacts of the significant land areas and costly transmission facilities required by utility-scale solar projects.[47]

In addition, the Commission has already recognized a difference between DG and utility-scale solar with the adoption of the DG "carve out" in the REST rules that requires utilities to meet 30% of their total renewable requirements with DG solar or other distributed resources and adding additional requirements and safeguards when utilities seek to alter NEM tariffs.[48] The DG carve out illustrates that the Commission treats DG and utility-scale solar as two distinct resources.

B. The Utility-Scale and DG Energy Off-takers are Significantly Different.

A further major distinction between each resource is who can take the power they generate. DG customers are very limited in this regard, because when power is exported, a customer may only

[42] Beach Direct Test., TASC Ex. 26 at 29-33.
[43] Beach Direct Test., TASC Ex. 26 at 29-30.
[44] *See* TASC Ex. 19.
[45] Volckmann Rebuttal Test., Vote Solar Ex. 4 at 15-16.
[46] Beach Direct Test., TASC Ex. 26 at 29:11-20 (the "minority of power is exported to the distribution grid, where it immediately serves neighboring loads, also displacing retail power from the utility.").
[47] *Id.* at 30:16-23.
[48] *See* A.A.C. R14-2-1805(B), -2305, -2307.

transmit its power to one entity – their serving utility.[49] There is no other option or competitive alternative available. On the other hand, utilities enjoy numerous options for utility-scale products with utility customers. Utilities can choose from different solar generating technologies, and select from different system sizes and locations. The utility may construct its own generation or it could acquire solar power from another provider through a PPA. Grid-scale solar developers themselves enjoy a multiple options for generated power as well, in that the energy generated can be sold on the wholesale market to any interconnecting utility.

The combination of numerous technical differences, significant differences in both energy buyers and product attributes, along with the danger of manipulation and conflicts of interest raised in such methodologies simply result in grid-scale solar making an unsuitable as a proxy for DG.

C. Utility Specific Issues.

1. APS

APS' grid-scale adjusted valuation methodology would start with current market prices for a utility scale PPA and then make certain adjustments in the pricing for "recognized valuation differences" between DG and utility scale solar.[50] These "adjustments" would reduce the PPA proxy price by as much as 20%.[51] APS would then cap the result at the price paid for utility scale with adjustments as the value of DG.[52] Amazingly, APS states their "grid-scale methodology sidesteps the need for the Commission to consider and quantify the intangible 'value' of indivisible solar attributes."[53] TASC objects to APS' characterization that DG benefits are "intangible" as several studies by APS *do show* DG provides value to utilities by as much as 14.11 cents/kWh in present value.[54] APS, of course, wants the Commission to ignore these benefits and now the whole purpose of these proceedings by asserting that the Commission should just "side-step" the whole issue.

TASC, along with Staff, agree there are several problems with APS' grid-scale approach. These problems, in addition to the inherent difference between utility scale and DG discussed above, include:

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[49] Kobor Rebuttal Test., Vote Solar Ex. 8 at 33:1-16.
[50] Albert Direct Test., APS Ex. 5 at 28:25-29:5.
[51] Albert Tr., Vol. XI at 2094:2-2095:10.
[52] Albert Direct Test., APS Ex. 5 at 27.
[53] APS Initial Post Hearing Br. at 33:3:6.
[54] Kobor Direct Test. Vote Solar Ex. 7 at 14-15, n.7.

1) APS is conflating a wholesale product with a retail one;
2) APS has set forth no justification to "cap" the rate;
3) Using only one PPA as a proxy can lead to manipulation by the utility;
4) The "adjustments" by APS are subjective do not take into account the full value of DG; and
5) APS is not even using its own PPA as a proxy, but rather a PPA from another utility in Nevada or California and has provided no justification for using these out of state proxies.[55]

2. TEP/UNSE

TEP/UNSE proposes a new NEM tariff based on a Renewable Credit Rate ("RCR") for DG exports along with the elimination of NEM "banking." The RCR rate would be based on a single utility scale PPA and would act as proxy from NEM exports. TASC and Staff share the same concern that a single PPA is not representative of a utility's avoided costs let alone the full value of DG. TEP/UNSE has provided scant information to illustrate that the PPA selected is representative of its utility-scale solar costs. Further, the RCR also deprives the solar customer of certainty. Since the RCR would be based on the "most recent" utility scale project, how and when the RCR rate will be updated are complex questions. PPAs from utility-scale suppliers are entered into for long term fixed prices yet TEP/UNSE seeks to subject its own DG customers to constantly adjusting prices that no renewable project developer would ever agree to.

V. <u>DG CUSTOMERS ARE NO DIFFERENT FROM OTHER CUSTOMERS AND SHOULD NOT BE IN A SEPARATE RATE CLASS.</u>

APS, TEP/UNSE and AIC all argue that DG customers should be placed in a separate rate class as part of their COSS methodology. Such arguments are unsupported and discriminatory against DG customers. Further, it appears that as part of their COSS, the utilities have already decided for the Commission to place DG customers in a separate rate class thus skewing their results. Notwithstanding the inherent issues with their COSS as discussed above, separate rate classes should be identified in rate making[56] and not as part of this generic docket.

[55] Albert Rebuttal Test, APS Ex. 6 at 6:1-8.
[56] *See* A.A.C. R14-2-2305.

A. Separate rate class design takes place in Rate Cases.

The goal of this docket is to investigate the benefits and costs of distributed solar generation and to create a record that may be accessed for potential use in future dockets wherein the value of solar and the specific valuation method is being dealt with for each utility. Rather than follow these precepts, the utilities are trying to single out DG customers and urging the Commission to place DG in a separate rate class as part of *this* docket.[57] A fully transparent COSS may be useful in a rate case, but separate rate design is irrelevant for the primary purpose of determining a valuation methodology for DG exports here. Calculating the costs and value of DG will be guided on the methodologies ultimately adopted in this docket. It is completely improper, before the methodology and analysis is even determined, to come to the conclusion that DG must be placed in a separate rate class. Such blatant discriminatory objectives by the utilities must be rejected.

B. DG is Similar to Other Demand-Side Technologies.

The utilities again show their true motives toward DG by arguing that DG customers should be put into a separate rate class because they have allegedly different load profiles from the residential class. The same could be said, however, for many other sets of customers that are currently in the residential customer class.[58] Other demand-side technologies can also produce significant changes in customers' load profiles.[59] The utilities ignore that there are significant variations in load shapes, both among customers with similar end uses in their residences and between customers that have installed various load-modifying technologies in their homes.[60] Yet, the utilities are insisting that only DG customers be put into a separate rate class. Staff has also already specifically rejected these false arguments and believes there is no justification for breaking DG customers into their own class.[61] The Commission should also recognize these attempts to engage in discriminatory treatment of DG customers and reject them.

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[57] APS Initial Post-Hearing Br. at 14-15; TEP/UNSE Initial Post-Hearing Br. at 9:4-13.
[58] Monsen Rebuttal Test., TASC Ex. 29 at 9:12-28.
[59] *Id.*
[60] *Id.* at 10:1-13.
[61] *See* Solganick Tr., Vol. VII at 1371:7-20 (Q. Would you agree that the characteristics of rooftop solar customers as they relate to service load and costs from the utility perspective justify putting them into a separate rate class? A. No.); *see also* Direct Testimony of Thomas M. Broderick, Docket No. E-04204A-15-0142, December 9, 2015 at 6-7; Direct Testimony of Eric Van Epps, Docket No. E-01575A-15-0312, March 18, 2016 at 2.

VI. APS MISREPRESENTS TASC'S PROPOSAL.

APS attacks any valuation proposal that includes long-term forecasts by questioning the motivation for such proposals. These allegations fall apart simply by considering their source.

A. APS is engaged in Rent Seeking.

APS characterizes TASC and Vote Solar's proposals involving long-term analysis as "rent seeking."[62] The clear inverse of this allegation, however, is that APS' advocacy before the Commission in this docket meets the rent-seeking definition exactly.

As stated by Organization for Economic Cooperation and Development ("OECD"), "[t]he opportunity to capture monopoly rents provides firms with an incentive to use scarce resources to secure the right to become a monopolist. Such activity is referred to as rent-seeking. Rent-seeking is normally associated with expenditures designed to persuade governments to impose regulations which create monopolies."[63] This behavior is precisely what APS is engaged in, both in this proceeding and within its own rate case before the Commission. APS is threatened by even the smallest measure of competition from DG, and now is attempting to persuade the Commission to protect its interests by making sure its customers have no alternative but to purchase all their electric needs from APS. The combination of COSS-based valuation proposals which undervalue DG-resources in this proceeding, along with mandatory residential demand charges and increased customer charge proposals contained in its rate case,[64] are squarely aimed at accomplishing this objective. Advancing APS' goals are clearly not in the public's (or ratepayers') best interest.

B. Valuation Proposals Are Not Merely Based on Desired Growth.

APS cites TASC witness Beach to support its assertion that the rooftop solar industry's objective is to simply market its product and grow.[65] Aside from omitting relevant language from Mr. Beach's response, (Mr. Beach actually states "that what the solar industry wants to do is *have a*

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[62] APS Initial Post-Hearing Br. at 26.
[63] OECD, *Glossary of Industrial Organization Economics and Competition Law*, (July 16, 1993), http://www.oecd.org/regreform/sectors/2376087.pdf
[64] APS Rate Case Application filed June 1, 2016, Commission Docket No. E-01345A-16-0036.
[65] APS Initial Post-Hearing Br. at 47.

reasonable chance to grow,"[66]) APS simply uses this language to vilify the rooftop solar industry along with conflating credit scores with wealth to demonize solar interests.[67]

TASC has made a good faith effort at establishing a workable methodology for use in this proceeding, and ultimately, ongoing rate case proceedings. The long-term avoided cost methodology proposal is the only proposal that is free of the problems outlined in this brief, and it is the only method that can include the full benefits of DG. TASC is not seeking to "put a thumb on the scale,"[68] it is simply attempting to ensure that an honest value assessment takes place. TASC's proposed methodology merely permits a full examination of benefits, while APS and TEP/UNSE demand an approach that excludes and literally prohibits the consideration of real long-term benefits. Which party is merely trying to protect its interests?

VII. OTHER PARTIES POSITIONS AND PROPOSALS.

A. Staff.

Staff is offering two valuation methodologies in this docket. The first methodology is based on traditional avoided costs analyzing the respective costs and benefits of DG. The second methodology is a weighted average of utility owned solar facilitates and PPAs.

1. Staff Methodology No. 1: Traditional Avoided Cost Calculation.

TASC is generally supportive of this approach as it is the only methodology that can truly analyze the costs and benefits of DG and going forward when future technologies become part of the valuation equations such as battery storage. Staff states such an avoided costs methodology can be done either on a short-term or long-term basis. TASC does not agree that such an avoided costs methodology can accurately reflect the value of DG if done on a short-term basis. A DG system must be valued over the long-term and should not be examined as a snapshot in time, which can never properly value the actual benefits that flow over a DG system's life. The benefits and costs of utilizing DG should be calculated over a period that relates to the "useful life" of a DG system, which can be from twenty to thirty years.[69] Therefore, analysis should develop 20+ year levelized benefits and costs for solar DG on the utility system. Doing so enables DG to be treated like a resource and evaluated in

[66] Beach Tr. at 2019:22-23.
[67] APS Initial Post-Hearing Br. at 47.
[68] APS Initial Post-Hearing Br. at 13.
[69] Beach Direct Test., TASC Ex. 26 at 18:12-21.

the same way that utilities consider the acquisition of other long-term resources.

Staff and TASC generally agree on the categories of the avoided cost methodology, which include: (1) avoided energy costs, (2) avoided generating capacity benefits, (3) avoided transmission and distribution capacity cost benefits, (4) environmental benefits, and (5) grid support services. Staff, however, takes the position that fuel hedging cost benefits, and environmental and societal benefits should not be included in the valuation methodology. TASC supports these categories for several reasons and urges the Commission to adopt them as part of a methodology.

First, there is no reason to exclude a category solely for the reason that it may not be "quantifiable" today. A valuation of DG is an ongoing process and carte blanch elimination of categories of benefits without any analysis in a rate case is premature at best. In any upcoming rate case, a party may be able to quantify those benefits and these should be looked at to determine a value of DG. For example, if APS saved 50 million gallons of water due to DG and by using APS' 2012 IRP of $1,114 per acre foot for water, such an avoided cost can easily become quantifiable. Even Staff concedes that environmental costs could be considered an avoided cost if it is identified in a utility's IRP.[70]

Second, there are societal benefits from DG that do not directly impact utility rates, but are conferred on all citizens. For instance, everyone benefits when DG takes the place of conventional fossil fuel generation, which in turn leads to reductions in air pollutants that harm people's health and the environment. Further, as DG deployment increases, demand on water supplies is correspondingly reduced.[71] By siting energy generation upon developed properties as DG does, more land is left available to be utilized for other uses or to be preserved in its natural state.[72] Similarly, the jobs created by the burgeoning solar industry also provide a boost to the local economy. These adders should be looked at by the Commission in determining the value of solar. In addition, they should be looked at from a policy perspective as well. If a value for NEM exports is to low, these benefits will never accrue and a valuation should look at these "adders" in promoting clean energy. Without doing so,

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[70] Staff Initial Closing Br. at 18:9-11.
[71] Beach Direct Test., TASC Ex. 26 at Ex. 2, p. 17 thereto.
[72] *Id.*

the Commission would be taking a counter-productive approach to its goals of promoting a healthy DER market and for REST compliance.

Finally, fuel hedge costs are quantifiable and do reduce a utility's exposure to fossil fuel price volatility. As APS correctly surmised in their 2012 IRP, "renewable resources have the ability to diversify the overall portfolio of resources and provide mitigation against the inherent price volatility risks associated with a natural-gas dominated energy mix."[73] In response to a Vote Solar data request, it was revealed that APS' efforts to hedge fuel averaged $50 million a year based on the utility's gas purchases. These costs, therefore, are quantifiable and part of the avoided cost of gas burns caused by DG.[74]

2. *Staff's Methodology 2, Weighted Average of Utility Scale and PPAs, must be rejected because of inherent issues with the proxy.*

The second methodology offered by Staff is a weighted average cost of utility owned solar facility and PPAs for a given utility. TASC cannot support this methodology for a number of reasons.

First as set forth above, comparing solar DG and utility-scale solar is largely an "apples to oranges" comparison. The differences between DG and utility-scale are substantive and numerous. DG solar is a retail product whereas utility-scale produces energy as a wholesale product.[75] When a generation facility is located behind a residential customer's meter, at the point of consumption, it has added benefits that a utility-scale solar facility simply cannot provide (further described above).

Second, the purpose of this proceeding is to create a record regarding accurate ways to value DG. A methodology that allows for flexibility from all perspective and adapts to changing technology should be adopted. If DG with battery storage is implemented in the future and the value of DG goes up, such a value cannot be analyzed under this methodology. Instead, DG would be locked in at some utility scale/PPA value in the future regardless of this increase in the value of DG.

Third, the methodology opens a "can of worms" and instead of the Commission's resources being spent on analyzing real DG value the Commission would be mired in dispute over what the weighted average should include under the methodology. This would be a waste of resources when

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[73] *Id.* at n.16.
[74] Docket #13-0248, Technical Conferences on DG and NEM.
[75] Beach Tr., Vol. X at 1855:9-11; *see also* Brown Tr., Vol. VI 1202:17-25, 1204:6-24 ("Not the same level of transaction costs for a microtransaction as you do for a macrotransaction.").

the weighted average is not a true proxy for DG value. For example, the parties would inherently argue about: (1) which utilities to include in the weighted average; (2) what timeframe the analysis should look back to; (3) to include or not include certain PPA escalators in the average; (4) whether the analysis should be done with a levelized or non-levelized function; (5) inclusion or exclusion of certain production tax credits; (6) whether to use just PPAs or utility owned in the proxy since they produce different average costs; and (7) even the percentages of the proxies to be used in the weighted average (i.e., 40% PPA and 60% utility scale vs. 50% PPA, 50% utility scale). Importantly, unlike TASC's proposed methodology, all these arguments would be to arrive at a value that is clearly not the right value. Time would be better spent addressing the true value instead of arguing about inputs to an imperfect proxy.

Finally, the methodology would make it very difficult for non-DG (and therefore non-grandfathered) customers looking to adopt DG to understand what the future NEM export rate would be worth and make a sensible investment decision. Generally, an avoided cost methodology would not vary greatly once the methodology was adopted from rate case to case. In contrast, the proxy methodology could result in an abrupt drop by several cents in the export rate, for example, if certain utility grid scale or PPA projects expire or are left out of updated weighting. This is especially true for smaller utilities that have few PPAs or utility grid scale projects where the average is based on a smaller sample size. Not only would the principles of gradualism be ignored, but a non-DG customer would not make an investment in DG when the export rate could be slashed at any given point. No rational prospective purchaser of DG would be willing to take the enormous step of getting solar on their rooftop if they are confused as to what the export rate will be. After all, customers need regulatory certainty as much as regulated utilities.

Accordingly, the weighted average cost of utility owned grid-scale solar and solar PPA resources proposed methodology should be rejected.

B. RUCO's Proposed Step down Value of Solar Methodology.

Despite the fact that there were months of discovery, two rounds of pre-filed testimony and thirteen hearing days resulting in over 2,300 pages of transcript of live testimony, RUCO now suggests that the Commission adopt a methodology it proposed for the very first time on the twelfth day of the hearing. RUCO's "step down" proposal is quite literally the least vetted proposal that was made in this proceeding with absolutely no evidence offered in support of it and not a single witness providing any testimony in reaction to the proposal that RUCO's own witness termed a "friendly amendment" when bringing up for the first time on the penultimate day of the hearing.[76] Simply put, the evidentiary record in this proceeding does not support the adoption of RUCO's new proposal.

This alternative methodology would first start with Staff's weighted average number as a "solar offer rate," whereby DG customer's would have two options: (1) self-consume on whatever plan they utilize but the export rate is fixed on the solar offer rate that eventually declines as more DG customers come on line, or (2) a buy-all/sell-all arrangement where the entire solar production is credited at the solar offer rate.

TASC appreciates RUCO's attempt at providing an alternative methodology, unfortunately however, in addition to simply being unsupported in the record, RUCO's approach would further complicate Staff's weighted average method. As discussed above, Staff's weighted average methodology is already subject to several arbitrary inputs. RUCO's approach would only add another layer of confusion and problems to the weighted average approach because the "solar offer rate" would arbitrarily decrease over time and further divorce the rate from the true value of DG. The parties would again be mired in disputes over the length of time to use, the proper "step-down" amount, and the percentages of DG penetration needed to institute "step-downs." Rather resources should be spent deriving the actual value of DG after examining the full set of benefits.

RUCO offers no rationale or proposal regarding how or when and under what circumstances the proposal would trigger steps to lower the rate. Without this basic information that could have been developed in the record and challenged by other parties if RUCO had presented its recommendation in the normal course like other intervenors, it is impossible to adopt RUCO's proposal in this proceeding. While RUCO's steps are unclear and unsupported, if the value of DG exports does in fact decline over time, a long-term avoided cost methodology will already reflect that going forward in future rate cases where the value would be calculated and recalculated. Similarly, increases in value over time could also be recognized.

[76] Huber Tr., Vol. XII at 2165:14.

RUCO's "step-down" methodology sows confusion, is unsupported in the record, and should be rejected. Focusing on a value of solar methodology that focuses on long-term avoided costs will provide a more accurate value of solar methodology and better inform stakeholders and the Commission in later rate cases.

C. Grand Canyon State Electric Association.

While Grand Canyon State Electric Association is not submitting a proposal for valuing DG, it does appear to argue that any methodology adopted applicable to cooperatives should only include fuel and energy avoided costs. TASC believes the purpose of this docket is not to adopt separate methodologies for cooperative and utilities and such a framework should be rejected by the Commission. Cooperative rate cases would be the correct place to evaluate the costs and benefits of DG with the aid of the record created in this docket.

VIII. <u>CONCLUSION.</u>

DG technology has evolved, and will continue evolving, in new and exciting ways so long as customers are allowed to benefit from investment in clean and self-reliant energy technologies such as DG solar. Although the utilities have a stake in the outcome of this docket, so too do both current and potential DG customers and society as a whole.

For the reasons stated above, the following actions should be taken:

(1) The Commission should advocate for use of a framework that incorporates a methodology premised on the long-term avoided costs of DG;

(2) The Commission should place no weight on the COSS provided in this docket;

(3) Such framework should also include a methodology that analyzes and accounts for the non-economic and societal benefits the Commission determines are created via the adoption of DG;

(4) This docket should reject proposals to set compensation rates premised on a proxy rate set by utility-scale solar rates;

(5) Current NEM Rules should remain in force;

(6) This docket should not recognize or provide for the creation of a wholly new class for DG residential customers;

(7) Regardless of any action taken in this docket, the Commission should recognize the right of all DG customers that have submitted interconnection applications for DG systems prior to any final Order issued in any rate case where changes to NEM or rate design are considered be fully grandfathered and continue to utilize currently-implemented rate design and NEM and be subject to currently-existing rules and regulations impacting DG;

(8) The Commission should issue an Order acknowledging that any action taken herein is advisory or informational only and the specific elements of any methodology utilized in future rate cases will be subject to review in each individual rate case and that the ultimate applicability of any value determined in a rate case can be acknowledged in rates in various ways to be determined separately in each utility rate case.

RESPECTFULLY SUBMITTED this 5th day of August, 2016.

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