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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	DOCKET NO. E-00000J-14-0023 **ARIZONA PUBLIC SERVICE COMPANY'S POST-HEARING BRIEF**

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I. INTRODUCTION

After years of claims that rooftop solar has not been properly valued, this proceeding provided an opportunity for rooftop solar leasing companies and their allies (Solar Interests) to present their best case regarding the value of solar. Instead of facts, however, the Solar Interests' best case only involves hypotheticals and predictions arrived at after making dozens of assumptions about what will happen over the next 20-30 years.

Yet, the Solar Interests admit that at least some of these assumptions are "inherently unknowable."[1] Determining a value of solar using "inherently unknowable" assumptions about future events is a profoundly flawed policy that should be rejected on its face. The electric industry already experimented with this type of policy under PURPA, where rent-seeking behavior caused inflated "avoided cost" pricing for renewable projects.[2] The result was disastrous for utility customers. When the predicted savings could be compared to actual events, it became clear that customers ended up overpaying for electricity by billions of dollars.[3]

Instead of predictions, the value of solar should be established using market or cost-based data. As Staff witness Howard Solganick testified, ratemaking is a zero sum game—amounts paid for or credited to rooftop solar customers today that exceed today's cost increase rates for all other customers.[4] It is only actual data, rather than predictions, that will protect customers. Cost of service study (COSS) and value of solar methodologies must be transparent and verifiable. This is the only way to maximize the value of solar for <u>all</u> customers, incentivize the most efficient and effective forms of solar, and create a sustainable foundation for the long-term development of solar.

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[1] Tr. 1938:1-21 (Beach).
[2] Brown Direct Testimony at 8-9; Overcast Direct Testimony at 8-9.
[3] *Id.*
[4] Tr. 1378:25 – 1379:22 (Solganick).

This proceeding is about developing two methodologies: one concerning the cost to serve customers with rooftop solar and one concerning the value of rooftop solar. APS has proposed methodologies for both aspects of this proceeding that rely on actual data, are transparent, can be verified, and fairly recognize the costs and benefits of rooftop solar. Based on the evidence presented in this proceeding, APS requests that the Commission find facts related to and adopt the following conclusions:

1) Rooftop solar customers are partial requirements customers and should be placed in their own separate class of customers;
2) APS's proposed cost of service study methodology—through which (i) costs are allocated using rooftop solar customers' entire load; and (ii) rooftop solar customers are fully credited for the verifiable energy and capacity benefits they supply to the grid—is appropriate and reasonable;
3) The amount paid for energy exported to the grid from rooftop solar should be based on market or cost-based data;
4) Either APS's Short-term Avoided Cost or Grid-Scale Adjusted value of solar methodologies should be used to determine the amount paid for energy exported to the grid from rooftop solar; and
5) Rates should be based on a COSS; long-term forecasts should not be used to set rates or establish the amount paid for energy exported to the grid from rooftop solar.

II. COST OF SERVICE RATEMAKING BACKGROUND

Getting the cost of service right is critical for treating utility customers fairly. Determining the cost to serve customers through a COSS is the technical foundation that establishes how much customers pay for electric service. Perhaps more importantly, it determines how costs are allocated between customers in the zero-sum game that is ratemaking.

A. A COSS is a Detailed and Transparent Analysis of Audited Financial Information that Results in an Objective and Fair Cost Allocation.

A key component of cost of service ratemaking is the actual study that determines the cost to serve utility customers—the COSS. This Commission and public utility commissions across the country rely upon COSS to set rates for utilities, including electric, water, and gas.[5]

A COSS is transparent. It is a detailed analysis of audited financial information and actual customer load data that assesses the responsibility of each customer group for the costs incurred to provide service during the relevant time period, normally a 12-month test year (Test Year).[6] The cost-allocation study enables the utility to determine its unit costs, by function, incurred to provide energy, demand, and customer services to each customer class and subclass, as well as the support to those costs that each customer group presently contributes through their rates.[7] The fulcrum of a COSS is cost causation—it allocates a utility's costs among its customers based upon their responsibility for incurring those costs. A COSS is foundational in developing appropriate pricing structures that align the rates customers pay for the services they receive.[8]

A COSS is objective and verifiable because it is based upon embedded historical costs.[9] It is extensive, but simple.[10] A COSS is guided by the following universally accepted principles: (i) costs must be approved by a regulator and based upon financial accounting costs adhering to Generally Accepted Accounting Principles (GAAP) and the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts; (ii) costs should generally be known and measurable; and (iii) cost allocation to customer

[5] Snook Direct Testimony at 7.
[6] Snook Direct Testimony at 7-8; O'Sheasy Direct Testimony at 4.
[7] *See* Snook Direct Testimony at 7; O'Sheasy Direct Testimony at 4-5.
[8] Snook Direct Testimony at 7.
[9] O'Sheasy Direct Testimony at 3; Snook Direct Testimony at 8.
[10] Tr. 1482:16-17 (Huber).

rate groups should be based upon cost-causation.[11] There should be no credible dispute that rates should be based on a COSS.

B. A COSS is a Tool to Protect Customers by Ensuring that Costs are Fairly Allocated.

The practice of setting rates based on the cost of service emerged to ensure that the price of electricity appropriately balances all interests.[12] Cost of service is an objective process,[13] and is part of a regulatory framework that protects captive customers who, for example, chose not to avail themselves of net metering.[14]

1. Fairly allocating costs through a COSS can address subsidies between customers and produce just and reasonable rates.

A COSS methodology must fairly allocate costs between customers. Staff witness Solganick testified that: "if you don't collect it from somebody at the time of setting rates, you have to find it from somebody else in order to, at least on paper, meet your revenue requirements that day."[15] In other words, if one group of customers avoids paying their allocated share of the revenue requirement, another group of customers pays the difference. In each rate case, Mr. Solganick testified that "the revenue requirements are rebalanced against rates. And to the extent that there are less energy units in the billing determinants, they are rebalanced, and the cost shift would then occur."[16] This cost shift is a subsidy.[17] As found by the Public Utilities Commission of Nevada, this subsidy is between customer groups, not paid by the utility:

> The subsidy to NEM ratepayers under NEM1 is not paid by the utility as some parties incorrectly suggest; rather, the subsidy flows from non-NEM ratepayers to NEM ratepayers, with the utility collecting the same amount regardless of how costs are allocated among the different ratepayers.[18]

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[11] *See* O'Sheasy Direct Testimony at 5.
[12] O'Sheasy Direct Testimony at 3.
[13] *Id.*; Tr. 514:8-14 (O'Sheasy).
[14] Overcast Direct Testimony at 8.
[15] Tr. 1379:5-8 (Solganick).
[16] Tr. 1336:17-23 (Solganick).
[17] Tr. 1339:13-21 (Solganick).
[18] Modified Final Order in Application of Nevada Power Co., Public Utility Commission of Nevada Docket No. 15-07041 at ¶ 90 (Feb. 12, 2016), APS Exhibit 11 (Nevada Order).

Although this subsidy is embedded in rate design,[19] it can also be partially embedded in how costs are allocated through a COSS. Addressing the subsidy embedded in the COSS methodology requires fairly allocating costs. To do so, a COSS methodology must strive to align cost causation with cost responsibility.[20] That is what this proceeding is about: determining a COSS methodology that fairly allocates costs and appropriately assigns cost responsibility to cost causers.

2. Not using cost to set rates imposes risks on customers and reduces the likelihood of just and reasonable rates.

Cost of service ratemaking provides checks and balances for the ratemaking process. To the extent that ratemaking moves away from embedded costs, and instead relies upon speculation and conjecture, the greater the likelihood that the rates will not be just, reasonable, and in the public interest.[21] That is because the assumptions, projections, and presumed benefits that comprise the speculative "value" might not materialize, and customers would be paying for benefits that they did not receive.[22] Similarly, RUCO witness Lon Huber testified that looking at embedded costs is a more accurate approach than projecting 20 years into the future.[23]

Setting rates based on cost protects customers. APS witness Ashley Brown testified that abandoning cost of service ratemaking for an "approach that insulates rooftop solar from the pressures of the market and cost based regulation, [...] would leave customers having to pay excessive prices for rooftop solar" and that "those prices

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[19] Tr. 1336:24 – 1337:3 (Solganick).
[20] O'Sheasy Direct Testimony at 4.
[21] *See* Tr. 514:25 – 515:18 (O'Sheasy); *see also* Tr. 1992:5-10 (Beach); *City of Tucson v. Citizens Utilities Water Co.*, 17 Ariz. App. 447, 481, 498 P.2d 551, 555 (1972) (reversing Commission's rate decision because "[m]ere speculation and arbitrary conclusions are not substantial evidence and cannot be determinative."); *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 149, 294 P.2d 378, 380-81 (1956); *see also* Overcast Direct Testimony at 3-4; Snook Direct Testimony at 7; Tr. 1049:19 – 1051:8 (Hedrick).
[22] Tr. 1049:19 – 1051:8 (Hedrick); *see also*, Tr. 1391:13-16 (Solganick); 1095:14-18 (Hedrick).
[23] Tr. 1501:17-20 (Huber).

would less and less be advantageous to customers."[24] IBEW witness Scott Northrup stated that his members' principal concern with abandoning cost of service ratemaking

> is that solar customers use and rely on the grid without contributing a fair share to the cost of its maintenance, thereby requiring utilities to either absorb or shift the cost to other users, and fundamentally destabilizing the environment in which utility workers do their jobs.[25]

Staff witness Solganick succinctly summed up the risk when he stated: (i) "As soon as you are finished forecasting you are wrong;" and (ii) that those who are harmed when projected benefits are not realized are "the customers who paid the money."[26] Rates should be based on actual costs to avoid this harm to customers.

II. APS'S PROPOSED COSS METHODOLOGY USES ACTUAL COSTS AND ACCOUNTS FOR ALL ROOFTOP SOLAR BENEFITS.

In this proceeding, APS proposed a methodology to determine the cost to serve rooftop solar customers that is based upon sound ratemaking principles, and is consistent with the methodologies that it uses and that have been approved by this Commission in the past. APS's COSS methodology was prepared using industry-accepted functionalization, classification, and allocation principles.[27] And as stated by APS witness Leland Snook, the methodology includes both the costs ***and*** benefits of rooftops solar

> [APS's COSS methodology] takes into account not only the cost to serve customers with rooftop solar, but also all of the demonstrable benefits which include all of the energy produced by the rooftop solar system and a 19 percent credit for capacity savings.[28]

The Commission should adopt APS's COSS methodology for future rate cases.

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[24] Brown Rebuttal Testimony at 7.
[25] *See* Northrup Direct Testimony at 6.
[26] Tr. 1353:12-24 (Solganick); Tr. 1345:10-14 (Solganick); *see also* Tr. 1522:5-10 (Huber).
[27] Snook Direct Testimony at 8.
[28] Tr. 103:22-104:2 (Snook).

A. APS's Proposed COSS Methodology Relies on Actual Data to Account for All Rooftop Solar Costs and Benefits.

APS's COSS methodology involves several standard steps. First, the data set was collected using actual cost data from the most recent calendar year available, the twelve-month period ending December 31, 2014, which comprised the Test Year.[29] Second, APS grouped rooftop solar customers currently on energy-based rate schedules, which includes customers both on inclining block and time-of-use rate schedules, and separately grouped rooftop solar customers on demand-based time-of-use rate schedules.

With the data collected, and all rooftop solar customers segregated out, APS began the third step: allocating costs. To do so, APS used the data for the rooftop solar customer's entire load, both the load served by APS and that served by the customer's rooftop solar system, as the starting point for allocating costs. Notably, TASC witness Monsen conceptually accepted using total site load, testifying that one option for developing a net cost of service for rooftop solar customers is to base the COSS on "gross household load less credits for energy generated by NEM customers."[30] From the entire-load data set, APS developed the traditional coincident peak (CP), non-coincident peak (NCP), and Sum of Individual Max demand allocations, as well as the energy allocations. In the fourth and final step, APS credited the rooftop solar customer for (i) all of their self-provided capacity based on a comparison to the APS-delivered customer load; and, (ii) their entire energy production, including both what the customer consumed on site and what was delivered from the rooftop solar customer to the grid.

To determine the energy credit, APS simply took metered data of energy produced by rooftop solar and credited each kWh at APS's filed avoided cost.[31] To

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[29] Snook Direct Testimony at 8.

[30] Monsen Rebuttal Testimony at 4. As discussed below, TASC's disagreement is with how APS calculated energy and credits.

[31] Snook Direct Testimony at 16-17.

determine the capacity credit, APS used actual metered data to determine how much rooftop solar was produced at the time of APS's coincident (or system) peak and at the time of the residential non-coincident (or class-specific) peak.[32] This constituted the capacity contribution of rooftop solar to APS's peak needs.[33] APS then took half of the coincident capacity contribution and half of that non-coincident capacity contribution—consistent with the Average and Excess method for allocating demand costs[34]—to arrive at a capacity credit of 19% to demand-related costs.[35]

1. Allocating costs based on entire load is necessary to fairly account for all costs incurred to serve rooftop solar customers.

Using a rooftop solar customer's entire load to allocate costs, and then separately crediting back energy and capacity savings, is the only way to fully account for all costs and all benefits associated with rooftop solar. The sole alternative to using entire load to allocate costs is to use delivered load—the load directly served by the utility. But using delivered load would underestimate the costs incurred to serve customers with rooftop solar and embed subsidies in cost allocation because it would not capture all the services provided to the customer.[36]

Vote Solar claims that a COSS methodology should ignore behind-the-meter services and the costs associated with providing them.[37] This is based on the mistaken belief that utilities do not provide services to rooftop solar customers when the customers are supplying their own energy.[38] No evidence was introduced substantiating this claim. Instead, it appears to be the opinion of Vote Solar witness Kobor offered in pre-filed testimony. And it is an opinion that she subsequently repudiated during the hearing.

[32] Snook Direct Testimony at 16.
[33] Snook Direct Testimony at 18.
[34] Snook Direct Testimony at 16.
[35] *See* Snook Direct Testimony at 16.
[36] Tr. 109:24 – 110:19 (Snook).
[37] Kobor Rebuttal Testimony at 10:7-16.
[38] Kobor Rebuttal Testimony at 10.

During the hearing, several witnesses (APS's Snook, AIC's O'Sheasy, TEP's Overcast, and Staff's Solganick) provided a significant amount of consistent testimony refuting Ms. Kobor's unsubstantiated statement regarding behind-the-meter services. The Solar Interests engaged in little cross examination, if any. When it was Ms. Kobor's time to testify, she appeared to revise her prior opinion, testifying that net metering customers continually rely on the electric grid, even when not using energy supplied by the grid.[39]

The fact is that utilities supply several services to rooftop solar customers, even while those customers are supplying a portion of their own energy needs. Those services include generation backup in case the rooftop solar system fails or is turned off; start-up power needed to power larger motors, such as air conditioners and pool pumps; and voltage quality to ensure the operation of sensitive equipment.[40] Each of these services causes utilities to incur costs.[41]

Because utilities incur real costs to provide these behind-the-meter services, those costs must be fairly allocated in a COSS. Staff witness Solganick testified that in order to find "all of the costs and all of the values" associated with serving rooftop solar customers, a COSS should reflect these behind-the-meter services and the related costs.[42] This is true even though these costs result from customer activity behind the meter:

> Q. But if what happens behind the meter imposes costs on all other customers, it becomes the business of all those other customers, doesn't it?
>
> A. Yes, it does. If those costs are imposed on other customers, yes.[43]

[39] Tr. 1748:11-15 (Kobor).
[40] Tr. 1369:9-24 (Solganick).
[41] Tr. 1375:6-12 (Solganick); Tr. 1380:5-14 (Solganick); *see* Tr. 1377:4-16 (Solganick).
[42] Tr. 1369:9-24 (Solganick).
[43] Tr. 1373:10-14 (Solganick).

This is the same conclusion reached by the Public Utilities Commission of Nevada when it rejected parties' arguments to ignore the standby service provided by NV Energy to net metering customers:

> Of particular note, the other parties' proposals for load shapes afford no weight to the standby service that NV Energy provides to partial-requirements NEM ratepayers, which would effectively shift the cost burden to non-NEM ratepayers—such cost shifting is not reasonable or in the public interest.

APS's proposal to start cost allocation using rooftop solar customers' entire load is an appropriate and reasonable way to fairly and accurately account for the very real costs utilities incur to provide numerous behind-the-meter services to rooftop solar customers.[44]

2. APS's proposed energy and capacity credits fully account for all demonstrable benefits of rooftop solar.

APS's proposed COSS methodology fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid by their rooftop solar systems. "The appropriate level of compensation for offsetting demand-driven infrastructure costs should be based on how effective the NEM customer's solar system is at offsetting APS's peak loads."[45] This is what APS's methodology does. It uses actual metered data to determine how much rooftop solar is producing at the time of APS's coincident and non-coincident peaks.[46] In fact, TEP witness Overcast testified that APS's method ***overcompensates*** rooftop solar customers because it effectively gives them a 19% credit on all of APS's demand-related costs, including generation with much higher capacity (but much lower energy) costs, like the Palo Verde Nuclear Generating Station, that rooftop solar could never mitigate.[47]

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[44] Tr. 109:9-23 (Snook).
[45] Snook Direct Testimony at 16.
[46] Snook Direct Testimony at 16.
[47] Tr. 859:4-23 (Overcast).

3. Criticisms of APS's COSS methodology are based on opinion, not data, and should be disregarded.

a. TASC's criticisms of APS's COSS methodology

As noted above, TASC agreed in concept with allocating costs using a rooftop solar customer's entire site load.[48] TASC did not agree, however, with the next step. TASC claims that after allocating costs using a customer's entire load, APS did not properly calculate how to credit rooftop solar production. TASC's arguments lack merit.

First, TASC disagreed with APS regarding credits for transmission and distribution. APS did not include either category of costs or benefits in its original methodology, and TASC states that both categories should have been included. APS agrees.[49] What TASC may not realize, however, is that incorporating transmission and distribution into the COSS methodology will mean allocating both the associated benefits ***and*** costs.[50] And because only a portion of rooftop solar production occurs during peak periods,[51] incorporating the transmission and distribution categories as TASC insists upon will ***increase*** the net costs being allocated to rooftop solar customers.

Second, TASC disagreed with how distribution costs and benefits should be allocated. APS has allocated distribution costs using a NCP for decades.[52] And doing so is consistent with the National Association of Regulatory Utility Commissioners (NARUC) cost allocation manual, which states that certain facilities, like the subtransmission facilities in question here, are designed and used to meet maximum non-coincident peak loads.[53] TASC apparently ignores this guidance, and instead claims that distribution costs should be allocated using the Peak Capacity Allocation Factor

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[48] Monsen Rebuttal Testimony at 4 and 19.
[49] Tr. 111:7-8 (Snook).
[50] Tr. 111:9-12 (Snook).
[51] *See* Albert Rebuttal Testimony at 14-15.
[52] Tr. 111:18-22 (Snook).
[53] *Id.*

(PCAF) and final line transformer (FTL) load cost allocation methods adopted by a single California utility—Pacific Gas & Electric.[54]

What TASC misses, however, is that PG&E's use of the PCAF/FTL allocation method reflects the characteristics of its service territory. TASC admits that PG&E's system peak and load shape differs from that of APS, and that different system and load characteristics can justify using different cost allocators.[55] It is true that APS data show a correlation between the PCAF/FTL allocators and distribution feeder loads. But unlike PG&E, APS's data show an even stronger correlation between non-coincident peak class loads and distribution feeder loads in APS's service territory.[56] It is simply more appropriate to allocate APS's distribution costs based on NCP. Adopting TASC's proposed allocation method would not only ignore the NARUC cost allocation manual, but also the actual data from APS's system regarding when costs are incurred.

The final primary complaint TASC has regarding APS's COSS methodology concerns generation credit. TASC admits that APS gave generation credit for rooftop solar production that immediately serves the rooftop solar customer's load. TASC claims, however, that APS did not appropriately credit the generation demand savings resulting from exported energy.[57] This is not true, and is an example of why APS's data-driven COSS methodology is a superior means to determine cost allocation.

APS did recognize the impact of export energy on APS's cost structure. It is just that there is no impact. Exported energy simply does not occur in any significant quantities during APS's peak periods.[58] If exported energy had occurred in a meaningful quantity during peak periods, APS's COSS methodology would have recognized that fact because the methodology is based on ***actual data***. But the data make clear that

[54] Monsen Rebuttal Testimony at 29.
[55] Tr. 2047:17-25 (Monsen).
[56] Tr. 111:23 – 112:10 (Snook).
[57] Monsen Rebuttal Testimony 18.
[58] *See* Albert Rebuttal Testimony at 16.

exported energy did not occur during the relevant time periods. As a result, exported energy does not affect the capacity cost drivers that are measured by coincident peak and noncoincident peak.[59]

TASC's remaining, secondary criticisms of APS's COSS methodology merit little attention. TASC claims that its own calculation of APS's avoided energy cost—4.215 cents per kWh—should be used to determine avoided energy costs in a COSS.[60] APS, however, used its filed avoided cost figure of 2.895 cents per kWh, and TASC offers no reason why any deviation should be made from APS's filed rate.

Similarly, TASC offers no legitimate reason for changing the target percent of cost to serve for rooftop solar customers. The target % of cost to serve for all customers in a COSS is 100%, even though policy decisions by the Commission have resulted in residential customers only paying 87% of the cost to serve.[61] Instead of the 100% target used for residential customers, however, TASC asserts that 87% should be the targeted % of cost to serve for rooftop solar customers.[62]

This proposal can only be described as changing the rules of the game to achieve a particular outcome favorable to rooftop solar customers. It is only logical and fair to run a COSS that assumes customers pay 100% of the cost to serve as the starting point. It is true that subsequent adjustments are made for a variety of reasons, including the Commission's historical policy rationales for having residential customers pay less than the cost to serve. But favoring rooftop solar customers by having them start the COSS at the lower 87% target can only be characterized as putting a thumb on the scale to arrive at a desired outcome, rather than a legitimate and reasoned decision regarding how to develop a COSS methodology.

[59] Tr. 112:11-22 (Snook).
[60] Monsen Rebuttal Testimony at 30.
[61] Tr. 838:24 – 839:13 (Overcast).
[62] *See* Monsen Rebuttal Testimony at 31.

b. **Vote Solar's criticism of APS's COSS methodology**

Vote Solar's fundamental criticism with APS's COSS methodology is that it doesn't recognize the long-term benefits of rooftop solar. This isn't true. Payment for value should only occur when that value is produced. For rooftop solar energy consumed on site, the recognition of this value occurs through the cost allocation developed in the COSS and is recognized in each rate case:

> Q. But if that benefit were to, in fact, materialize in the future, and the evidence would support that it was known and measurable and continuing in nature, in a future rate case would that benefit then get picked up in a future rate case and get incorporated into the rate base going forward?
>
> A. Yes.[63]

APS's COSS methodology allocates a demand credit of 19% to rooftop solar.[64] If rates for rooftop solar customers were to be set using APS's COSS methodology, the rates would reflect that 19% demand credit on a continuous and ongoing basis ***as the benefit provided by rooftop solar is actually received***. APS's COSS methodology recognizes the long-term benefits of rooftop solar. It just does so at the time those benefits actually occur.

The record in this proceeding clearly demonstrates that APS's proposed COSS methodology appropriately allocates costs to net metering customers, and accurately recognizes the benefits of rooftop solar. APS's COSS methodology should be approved and adopted by the Commission to guide future APS rate cases.

B. Overwhelming Evidence Demonstrates that Rooftop Solar Customers Should be in Their Own Customer Subclass.

In a COSS, similarly-situated customers are grouped into rate classes (and subclasses) and costs are allocated to those classes (and subclasses) on the basis of how they cause costs.[65] It is appropriate to put a sub-group of customers into a separate class

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[63] Tr. 1094:19-25 (Hedrick).
[64] Snook Direct Testimony at 19.
[65] O'Sheasy Direct Testimony at 4.

if the service, load, ***or*** cost characteristics of the sub-group are sufficiently different from their current customer classification.[66] In developing its COSS methodology, APS's data demonstrate that ***all three*** of these characteristics are very different for rooftop solar customers.[67] Based on this data, and the other overwhelming evidence in the record regarding the differences in service, load, and costs characteristics of rooftop solar customers, it is appropriate to evaluate rooftop solar customers as a separate subclass.[68]

1. As partial requirements customers, rooftop solar customers have different load shapes, require different services, and cause different costs.

a. Rooftop solar customers have very different load profiles than typical residential customers.

A significant distinguishing feature of rooftop solar customers is that they are partial requirement customers, meaning they supply a portion of their own energy needs.[69] No party appears to contest that rooftop solar customers are partial requirements customers. The consequence of being a partial requirements customer is that rooftop solar customers have load shapes that differ substantially from the typical residential customer. APS presented two charts that compared daily load shapes for typical solar and non-solar customers on a summer and winter day.[70] These charts were prepared using actual APS customer data and stand uncontroverted in the record. They make clear that peak demand and energy characteristics are very different for rooftop solar customers as compared to other residential customers:

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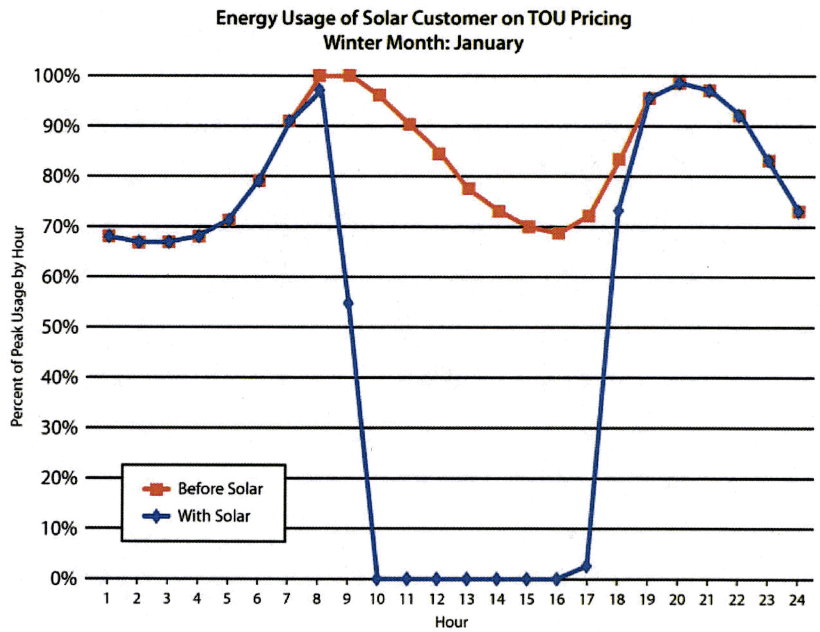
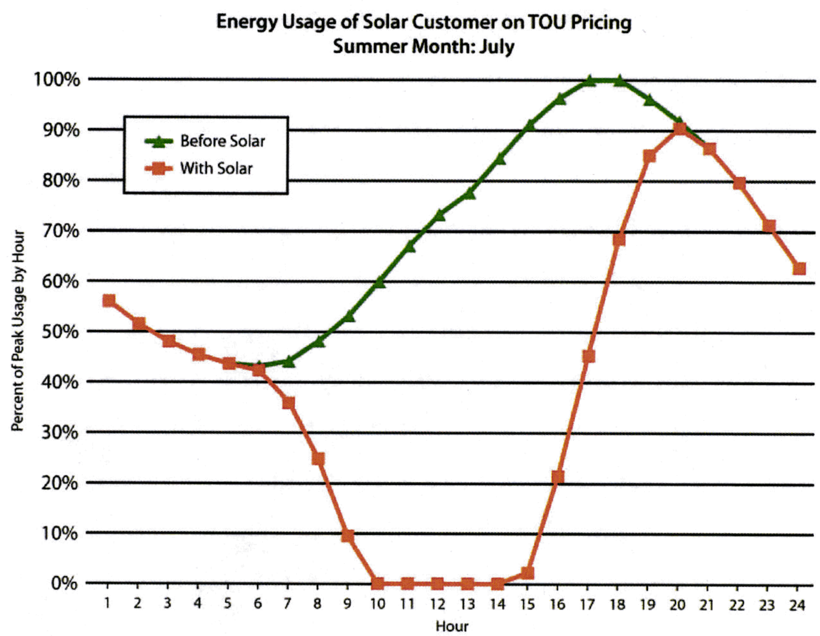
[66] Snook Direct Testimony at 11; Overcast Direct Testimony at 11.
[67] Snook Direct Testimony at 4, 11; Tr. at 116:1-8 (Snook); Tr. at 519:9 – 521:6 (O'Sheasy).
[68] Tr. at 517:18 – 520:2 (O'Sheasy).
[69] Tilghman Rebuttal Testimony at 5, 8; Tr. at 174:13-18 (Snook); 108:13-23 (Snook); 110:13-19 (Snook); 174:13-18 (Snook); 834:10 – 835:6 (Overcast); 841:5-10 (Overcast); 1374:10 – 1376:13 (Solganick).
[70] Snook Direct Testimony at 12 at Figures 2, 3.





Looking at these charts sheds light on why the typical rooftop solar customer requires only 30% of the energy used before adopting solar, but still requires approximately 81% of the capacity.[71] Rooftop solar permits the customer to supply a

[71] Snook Direct Testimony at 12.

significant portion of their energy, but it does not abate the need for the infrastructure required to serve that customer during the bulk of the customer's peak demand.[72] The profile reflected in these charts is significantly different than typical residential customers without solar, regardless of size.[73]

Other parties agreed that partial requirements have significantly different load profiles. RUCO witness Huber testified that rooftop solar customers are remarkably different than other residential customers, and in particular that their load profile is completely different from other residential customers.[74] Staff witness Solganick testified that the load characteristics of partial requirements customers are different, and at certain times, significantly different.[75] TEP/UNS witness Overcast agreed, testifying that it is unusual for residential customers to have the low load factors that are typical of partial requirements customers like those with rooftop solar.[76] In fact, Dr. Overcast testified that it is statistically impossible for rooftop solar customers to fall within the normal load variations of the residential class.[77] This is because the NCP for rooftop solar customers is in the spring, but the NCP for typical residential customers is in the summer.[78] The evidence regarding different load profiles is so overwhelming that even TASC witness Monsen had to concede that "[t]here is no question that NEM customers do not have delivered load shapes that mimic those of other residential customers."[79]

b. **Rooftop solar customers receive services that typical residential customers do not.**

Concluding that partial requirements customers have significantly different load profiles, including very low load factors, is only part of the story regarding why these

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[72] *Id.*
[73] Snook Direct Testimony at 11.
[74] Tr. 1525:6-17 (Huber); *see also* Tr. at 842:3-6 (Overcast).
[75] Tr. 1376:2-13 (Solganick).
[76] Tr. 841:11-20 (Overcast).
[77] Tr. 846:14-23 (Overcast); 848:12-19 (Overcast).
[78] Tr. 847:23-848:19 (Overcast).
[79] Monsen Rebuttal Testimony at 9; Tr. 2054:2-11 (Monsen).

customers should be in their own class. In large part because rooftop solar customers have different load profiles, utilities must provide these customers different services, and incur different costs in providing those services. Rooftop solar customers can go from exporting excess energy to the grid one moment and suddenly importing energy the next. "This could occur as a cloud passes over the neighborhood that that circuit is in. All of the solar drops to zero. And the utility immediately has to pick them up with standby service."[80] The Public Utilities Commission of Nevada recently relied on the provision of standby service, among other reasons, to find that it was just, reasonable, and in the public interest to analyze net metering customers as a separate rate class for cost of service purposes:

> It is just and reasonable and in the public interest to establish separate rate classes for all NEM ratepayers based on both the cost differentiation and load (usage) differentiation between NEM ratepayers and non-NEM ratepayers. Different services have different costs and thus require different rate classes. NEM ratepayers are partial-requirements service ratepayers. The Commission has historically established separate, optional rate schedules for ratepayers who self-select to become partial-requirements ratepayers. Partial-requirements service ratepayers are ratepayers whose electric requirements are partially or totally provided by non-utility generation. There is a significant difference in the load (usage) profiles between partial-requirements NEM ratepayers and full-requirement ratepayers. **NEM ratepayers can rapidly go from exporting unused electricity to importing needed electricity from the local grid. As a result, NV Energy provides a distinct service to partial-requirements ratepayers who choose to purchase some, but not all, of their energy needs from the utilities.**[81]

Aside from providing standby service, utilities must provide partial requirements customers with other services, such as virtual storage, frequency, voltage quality, and start up loads (also called "inrush current").[82] Utilities simply provide a different and

[80] Tr. 843:18-21 (Overcast).
[81] Nevada Order at ¶ 91 (emphasis added).
[82] Tr. 843:1-25 (Overcast); 1362:15 – 1363:12 (Solganick); 1364:2 – 1367:11 (Solganick); 1368:7 – 1369:24 (Solganick).

distinct suite of electric services to rooftop solar customers than they do to typical residential customers.[83]

c. **The special services that rooftop solar customers receive cause costs.**

These distinct services cause utilities to incur costs.[84] TEP/UNS witness Tilghman summarized some of the distinguishing cost components associated with rooftop solar customers as follows:

> However, the assumption that there are no costs associated with net metering is inaccurate and fails to acknowledge real-time system operational issues. As Mr. Beach noted previously, the customer bears no responsibility for the movement of that energy once the utility takes ownership at the meter. Distribution wheeling is not free. Losses incurred are not free. Ramping and cycling of power plants is not free. Providing phase balancing and voltage stabilization is not free. The delivery of DG excess energy to the utility creates costs related to these aspects of grid management. All of these costs are borne by the utility and are typically recovered through the volumetric rate design. Net metering allows the DG customer to avoid paying those costs, which are, in fact, paid for by the utility and ultimately by the non-DG ratepayer.[85]

Staff witness Solganick agreed, testifying that utilities incur different costs to serve partial requirements customers.[86]

d. **Rooftop solar customers might actually impose new costs.**

In addition to partial requirements customers requiring separate services that trigger additional costs, evidence presented suggests that partial requirements customers might in fact increase utility costs due to how they impact the grid. Factors such as phase imbalancing and two way flows uniquely add to the costs of serving partial requirements customers.[87] Evidence in the record also shows that rooftop solar customers are responsible for additional costs due to increased voltage levels.[88] APS

[83] Tr. 842:2-6 (Overcast).
[84] Overcast Rebuttal Testimony at 38-39.
[85] Tilghman Rebuttal Testimony at 7-8.
[86] Tr. 1375:2-9 (Solganick).
[87] Tr. 607:6-9 (Tilghman); 824:9-12 (Tilghman).
[88] Tr. 368:3-11 (Albert).

witness Albert testified that to manage increased voltage levels attributable to DG, utilities may need to install voltage regulation equipment in the future.[89] TEP/UNS witness Tilghman also referred to the impact that DG has on system load in the form of the "duck curve," which requires additional infrastructure that adds cost for all residential ratepayers.[90]

e. **Every measurement warrants putting rooftop solar customers in their own class.**

There can be no credible dispute that partial requirements customers require special services that result in additional costs, and might cause other costs, that typical residential customers do not. Staff witness Solganick agreed with the following conclusion by the Public Utilities Commission of Nevada that rooftop solar customers underpay for the services they receive:

> In other words, the reduction in the amount of electricity delivered to the NEM ratepayer after the installation of the NEM system does not result in a proportional decline to the cost of providing service. The prices charged does not equate to the cost to provide service. As a result, NEM ratepayers are under-paying, and the difference has to be collected from non-NEM ratepayers (eventually via reallocation in the next general rate case) if NEM ratepayers are not in separate classes.[91]

When compared to typical residential customers, partial requirements customers—such as rooftop solar customers—have different load profiles; require different services; cause utility costs to provide those services; and might actually cause additional costs to the system. Consistent with COSS principles of cost causation and allocation, it is appropriate to analyze customers with rooftop solar as a separate subclass of partial requirements customers.

[89] Tr. 371:16 – 372:15 (Albert).
[90] Tr. 656:3 – 657:16 (Tilghman).
[91] Tr. 1378:4 – 1379:15 (Solganick), citing Nevada Order at ¶ 90.

2. Rooftop solar customers bear little resemblance to other customers, such as energy efficiency or apartment customers.

The Solar Interests did not introduce any data disputing the differences between partial requirements customers, such as customers with rooftop solar, and typical residential customers. Instead, the primary argument against putting rooftop solar customers into a separate subclass appears to be that ***other*** customer subclasses similarly have different load shapes.[92] That other customers might also have different load shapes, however, does not justify ignoring the need to address the rapidly growing subset of customers installing rooftop solar. Even if the Solar Interests were correct, two wrongs don't make a right. In any event, the Solar Interests are incorrect. The overwhelming evidence makes clear that the load shape of rooftop solar customers does not resemble any other sub-group identified by the Solar Interests.

TASC witness Monsen asserted that rooftop solar customers have load profiles similar to customers who have installed energy efficiency measures, including smart thermostats.[93] Mr. Monsen relies on a simulation of 20 homes in North Carolina to reach this conclusion.[94] Instead of evaluating load profiles, however, the simulation actually tested whether time-of-use rates could cause customers to use energy at a different time.[95] Thus, Mr. Monsen's evidence does not demonstrate that energy efficiency customers with smart thermostats have inherently different load shapes. Instead, Mr. Monsen's evidence indicated that under a simulation of 20 homes, simulated customers reacted to price signals embedded in rate design. It was this reaction to price signals that caused the change in load profile, not some inherent characteristic of the simulated energy efficiency mechanisms.

[92] *See, e.g.,* Monsen Rebuttal Testimony at 9.
[93] Monsen Rebuttal Testimony at 11-13.
[94] Monsen Rebuttal Testimony at 11.
[95] Monsen Rebuttal Testimony at 12.

In fact, a review of actual data (as opposed to a simulation) reveals that energy efficiency customers, who create a permanent load reduction, do not resemble partial requirements customers:

> But energy efficiency, as you refer to it, that has a long-term effect. It is a permanent reduction in load. So there should be a commensurate reduction in costs down the road in that particular case. So EE, energy efficiency, and DG are quite different products.[96]

Energy efficiency mechanisms, like efficient air conditioners, don't change a customer's load shape, but instead reduce the overall magnitude of the existing load curve.[97] With rooftop solar, on the other hand, "you get something very different":

> You get a load shape that is potentially negative in the summer during the middle part of the day when its output is the maximum and the loads are low, and then you get no contribution to load at all in the evening hours after the sun has set. So it has a very different impact on the load curves that the utility has to serve with respect to those customers.[98]

According to Staff witness Solganick, rooftop solar customers are the sub-group that can be considered partial requirements customers, not energy efficiency customers, seasonal customers, vacant homes, customers with swimming pools, or apartment dwellers.[99] None of these other sub-groups have the load profile of partial requirements customers; none require the services of partial requirements customers; and none cause the costs that partial requirements customers cause. Comparing rooftop solar customers with other customer sub-groups only underscores that rooftop solar customers are truly in a class of their own on the basis of load, service, and cost.

III. VALUE OF SOLAR: A TRANSPARENT, DATA-DRIVEN ALTERNATIVE TO NET METERING IS NEEDED.

For the second half of this proceeding, the parties essentially agreed that the value of solar methodology adopted in this proceeding should be used to establish the

[96] Tr. 570:18-23 (O'Sheasy).
[97] Tr. 845:11-25 (Overcast).
[98] Tr. 846:4-12 (Overcast).
[99] Tr. 1374:10-25 (Solganick).

price paid by utilities for rooftop solar energy exported to the grid.[100] Under the status quo, utilities purchase exported energy at the full retail rate through net metering. Although the utility initially purchases this energy, it is actually utility customers that ultimately fund the purchase through rates.[101] And this is true regardless of who installs the rooftop solar system:

> Q. Okay. Wouldn't it be fair to say that whether the utility installs the solar or the DG customer installs the solar system, that it is ultimately the ratepayer who actually ends up paying for the system through net metering subsidies and cost recovery mechanisms?
>
> A. Yes. I think that's basically our concern, is that there is an inequity with regard to the current system in terms of net metering. It provides a subsidy. It creates a subsidy.[102]

A. The "Rough Justice" of Net Metering is no Justice at all, but Instead a Subsidy that Increases Customers' Bills.

The status quo, in which non-DG customers pay retail prices for exported energy, needs to change. Net metering forces non-DG customers to overpay for exported energy. In APS's service territory, buying exported energy through net metering means that customers without rooftop solar pay approximately 14-16 cents per kWh for energy exported to the grid.[103] Yet, this is a retail rate being paid for a wholesale product; energy exported to the grid is resold to other customers just like any other energy that APS purchases for resale.[104] Instead of buying this wholesale exported energy for 14-16 cents per kWh, utility customers could pay approximately 4 cents per kWh ***for even more valuable solar energy*** from grid-scale solar facilities.[105] Adding insult to injury,

[100] Of the parties that submitted substantial evidence on this topic, RUCO appears to be the outlier, taking the position that a value of solar methodology should be used to set the price for the entire output of rooftop solar, not just exported energy.
[101] Tr. 1337:18 – 1338:1 (Solganick).
[102] Tr. 1073:22 – 1074:6 (Hedrick).
[103] Tr. 477:23 – 478:5 (Albert).
[104] Tr. 1935:13-25 (Beach).
[105] Tr. 365:21 – 366:8 (Albert); *see* Albert Direct Testimony at 27-32 (describing why energy supplied by grid-scale solar facilities is more valuable than the energy supplied by rooftop solar facilities).

net metering is not based on data. Instead, the Solar Interests refer to net metering as "a rough justice kind of approach."[106]

The absence of data justifying net metering—a regulatory policy that requires ***captive*** utility customers to pay the full retail rate for a wholesale product—is not any form of justice at all. The rooftop solar industry has testified that its interest in this proceeding is to "have a reasonable chance to grow, you know, and to market its product."[107] The fact is, however, that although net metering might give the rooftop solar industry the chance to make more money, net metering is a subsidy that unnecessarily increases customers' bills. These customers rely on regulation for protection,[108] and this proceeding represents an opportunity to grant that protection. APS has proposed alternatives to the status quo that would establish a price for exported energy based on actual data from either the market or based on cost. These proposals would balance the interests of all customers with the rooftop solar industry's desire to make money.

B. APS's VOS Proposals Encompass the Full Spectrum of Options for Rebalancing Rooftop Solar Compensation.

This brief focuses on two of APS's proposals: the short-term avoided cost and the grid-scale adjusted methodologies. APS witness Brad Albert testified that these methodologies account for the full range of appropriate values for rooftop solar. The short-term avoided cost method is at the lower end of the spectrum. It would provide a lower incentive to rooftop solar, but would reduce costs for all of APS's customers and largely reflects the cost that would have been incurred to replace the actual energy exported by rooftop solar facilities with other power sources. The grid-scale adjusted method is at the higher end of the spectrum. It would provide a higher incentive to rooftop solar, but would also result in all other non-solar customers paying higher rates.

[106] Tr. 2019:21 – 2020:3 (Beach).
[107] *Id.*
[108] Tr. 852:15-24 (Overcast).

A benefit of both methods is that they are both derived from competitive market sources. The short-term avoided cost method uses realized wholesale market energy prices while the grid-scale adjusted method uses actual reported prices for grid-scale solar PPAs.[109]

APS has not recommended which of these methodologies the Commission should adopt. Any decision between the two requires a policy determination on how to balance the incentives given to rooftop solar with the resulting rate increases for all other customers. In no event, however, should a value of solar rate exceed the price paid for grid-scale solar energy. Both rooftop and grid-scale solar facilities rely on the same basic technology—solar photovoltaic panels.[110] As a result, both offer the value of solar to APS customers:

> Because both rooftop and grid-scale solar applications contribute the same benefits to the system, the goal should be to reduce costs to customers by obtaining those benefits for the least amount of money.[111]

In fact, because of operational differences, grid-scale solar is more valuable than rooftop solar.[112] If customers can obtain a higher value of solar at a quarter of the price with grid-scale solar, why pay more for the same sun?

C. APS's Short-Term Methodology Produces the Cost of Buying the Same Solar Energy from the Market using Actual Data.

The short-term avoided cost approach is based upon the avoided energy costs and energy losses in a near-term period. It can be readily calculated using third-party sources of data, and its results can be easily quantified and verified. This methodology involves looking at when APS actually received exported energy from rooftop solar customers in 2015 based on production meter data. Then, APS cross-referenced the timing of that production with the price at the Palo Verde Hub for short-term solar energy. The result

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[109] Albert Direct Testimony at 3.
[110] Albert Direct Testimony at 27.
[111] Albert Direct Testimony at 3; *see* Tr. 388:23 – 389:13 (Albert); 484:5 – 10 (Albert).
[112] *See* Albert Direct Testimony at 27-32.

is the short-term avoided cost methodology, which can be averaged over the year for a single per kWh payment for all exported energy.

1. The short-term methodology is transparent, verifiable, and avoids rent-seeking.

All other methodologies proposed in this proceeding require some degree of judgment to administratively determine a price for exported energy. Administratively determining a value of solar, however, invites rent-seeking behavior that can harm utility customers:

> Well, rent seeking is an activity by a person or firm that tries to obtain special treatment by legislation or intervention in a regulatory arena, and typically the benefit consists of some subsidy that goes their way. It may be, for example, seeking investment tax credits for a particular class of investment, such as we have for solar DG. And it may be, it may also be things that inhibit competitors, such as promoting inefficient regulated rates. I mean, it's obvious here that the more you put on the energy charge, the more economic solar is. So you find these solar DG intervenors trying to do everything they can to raise the energy charge, because that's in their best interest for promoting solar. And it's also creating a subsidy as well. So they win on both sides.
>
> Q. And the subsidy you're discussing is a cross-subsidy, meaning other customers pay for it; is that right?
>
> A. Yes.[113]

The short-term avoided cost methodology is the only methodology that entirely avoids the risk of rent seeking. It does not require judgment or invite administrative advocacy. Instead, it simply requires cross-referencing the timing of exported rooftop solar energy with the market price of the same product: short-term solar energy. This methodology does not, for instance, rely on forecasts of future fuel prices, underlying customer growth, future estimates of capacity needs, and the myriad of other forecast variables required to develop long-term avoided cost figures. The short-term avoided cost methodology has the advantage of being transparent while also fairly reflecting

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[113] Tr. 851:5-24 (Overcast).

objective market costs. It is also consistent with the "historic test year" method established for setting utility rates.[114]

Parties generally acknowledged that avoided cost is a sound basis for valuing solar. AIC witness O'Sheasy testified that setting the price for exported power based upon avoided costs is fair and appropriate.[115] Staff witness Solganick agreed that avoided cost should be a focal point for setting the price for exported energy.[116] Even TASC witness Monsen testified that avoided cost methodologies would be an appropriate methodology to value solar.[117]

2. Criticisms of the short-term avoided cost methodology aren't evidence-based, but only inconsistent policy disagreements.

Only Vote Solar witness Kobor directly addressed APS's short-term avoided cost methodology. In her Rebuttal Testimony, Ms. Kobor asserted that short-term market prices shouldn't be used to compensate exported energy because rooftop solar is a long-term resource.[118] According to Ms. Kobor, it is standard practice to evaluate the long-term costs and benefits of utility investments. Because there is no reason to believe that a significant number of rooftop solar systems will fail over their useful life, rooftop solar systems should similarly be evaluated over the long term.[119]

a. **Long term valuations are not used to set rates.**

A fundamental flaw in Vote Solar's argument, however, concerns the nature of these long-term evaluations. It is true that utilities use long-term evaluations to assess resource procurement decisions. But utilities do not use long-term value projections to establish the amount customers pay for those resources.[120] The question of ***whether*** to procure a resource is not the same as ***how much customers pay*** for that resource. The

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[114] Albert Direct Testimony at 17; *see also* Tr. 360:19 – 361:8 (Albert); 1501:17 – 1502:2 (Huber).
[115] O'Sheasy Rebuttal Testimony at 6-7.
[116] Solganick Direct Testimony at 19.
[117] Tr. 2059:18-22 (Monsen).
[118] Kobor Rebuttal Testimony at 31.
[119] *Id.*
[120] Snook Rebuttal Testimony at 5.

former looks at long-term values, but the latter must only involve actual cost to protect customers and ensure just and reasonable rates:

> Actual costs are used for the ratemaking process in a COSS, not the type of assumptions that are used during the resource planning process. To base rates on anything but actual costs would create significant risks based upon the accuracy of assumptions used, which accuracy no one can guarantee. As opposed to just and reasonable rates, customers could be unfairly subject to rates that were too high and have no basis in fact. Alternatively, if the rates were too low, a utility would be at risk for not having sufficient resources to maintain the grid or pay back investors. Neither scenario could be said to involve just or reasonable rates.[121]

Moreover, long-term resource evaluations always involve comparing multiple resources and assessing which resource will procure the value in question in the most cost effective manner.[122] Attempting to use long-term valuations in the context of pricing exported energy ignores this critical part of the long-term valuation process. By comparing multiple resources, typical long-term valuations are designed to produce the ***best*** value. The Solar Interests propose misusing the concept of long-term valuations to create ***a*** value that perpetuates the subsidy inherent in net metering.

It is telling that despite introducing the written testimony of several witnesses, and engaging in three weeks of hearing, the Solar Interests could offer no example of rates actually being set using a long-term valuation of resources. Mr. Beach is not aware of any commission or other body that uses a long-term value of solar model to set rates.[123] Mr. Beach did testify that two jurisdictions—California and Nevada—use future forecasts in setting rates. But he admitted that even those forecasts are only for five years and, perhaps more importantly, the forecasts are only used "to some extent."[124] Indeed, a review of the Public Utility Commission of Nevada decision admitted as APS Exhibit 11 reveals what "to some extent" means.

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[121] Snook Rebuttal Testimony at 6.
[122] Albert Rebuttal Testimony at 4.
[123] Tr. 1932:14-19 (Beach).
[124] Tr. 1931:19 – 1932:4 (Beach).

The Public Utilities Commission of Nevada actually sets rates using an historical test year, and only uses forward-looking marginal cost of service studies (MCSS) as a guide:

> Rates are balanced in Nevada by using marginal cost pricing along with an historical test year and other rate-making considerations (e.g., understandability of rates). As a result of this balancing, the MCSS guides the development of each ratepayer class's total revenue requirement and rate design.[125]

Forward looking marginal cost studies that are recalculated each rate case are not, however, 20-30 year forecasts of hypothetical benefits. Indeed, the Nevada Commission has expressly rejected setting rates using the very long-term forecasting proposals advanced by the Solar Interests in this docket:

> Parties' proposals to weigh speculative, unquantified future benefits/values of NEM to offset current, known costs are rejected. These proposals conflate two separate and distinct regulatory processes: (1) the rate setting process, and (2) the resource planning process. When determining the rates that ratepayers pay for electric service, the revenue requirement is allocated to ratepayer classes ***based on the actual, measurable costs of providing service.*** Future benefits/values of NEM should be evaluated in the resource planning process.[126]

To the extent that the Nevada Commission does consider prospective events in the ratemaking process, that consideration does not resemble what the Solar Interests propose here in any way.

b. Grid-scale solar PPAs receive 20-year pricing because they enter into enforceable contracts.

Vote Solar's next criticism of the short-term avoided cost methodology is that grid-scale solar PPA developers receive 20-30 year fixed PPA prices, and that there is no economic reason to offer only short-term prices to rooftop solar.[127] But PPA developers receive 20-30 year prices because they offer enforceable guarantees in exchange. These guarantees protect customers from future uncertainties:

[125] Nevada Order at ¶ 83.
[126] Nevada Order at ¶ 85 (emphasis added).
[127] Kobor Rebuttal Testimony at 31.

> [T]he reason that you don't allow for assets to be valued on a long-term basis is whether or not the asset has an enforceable obligation. If it has an enforceable obligation, suppose you contract with me to provide me power for the next 20 years, but if you default, I own all your plant plus I have the right to sue you for any damages. That's the kind of protection that customers need for utilities to enter into that have long-term payment obligations.[128]

Moreover, utilities enter into long-term PPAs after a competitive selection process to ensure customers obtain the benefit of the resource at the least cost.[129] This is an additional layer of customer protection that the Solar Interests appear to ignore.

Vote Solar's insistence that rooftop solar should be treated comparably to grid-scale solar is curious. In criticizing APS's grid-scale adjusted methodology, Vote Solar insists that rooftop and grid-scale solar are so different that it is inappropriate to use grid-scale solar prices to set compensation for exported rooftop solar energy. Yet in criticizing the short-term avoided cost methodology, Vote Solar claims that exported energy shouldn't receive short-term prices because grid-scale solar PPAs extend for 20-30 years. This is an irreconcilable contradiction in Vote Solar's position, and suggests that its arguments are not reasoned policy positions that merit serious attention.

c. **The short-term avoided cost methodology captures the long-term value of DG as that future happens.**

Vote Solar's final criticism of using the short-term avoided cost method to establish the value of solar is that doing so will miss the long-term value of DG.[130] This isn't true. The short term avoided cost reflects the market value of exported energy to all customers. Under this methodology, exported energy would be purchased at this market value at the time the value is received. Exported energy that is purchased now would be paid at today's market value; exported energy that occurs in the future would be purchased when it occurs at the contemporaneous market rate.

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[128] Tr. 873:13-23 (Overcast).
[129] Albert Rebuttal at 4.
[130] Kobor Rebuttal Testimony at 32.

Vote Solar's true criticism is that the short-term avoided cost methodology does not administratively move future value into the present. It is only by moving future value forward through an administrative process that Vote Solar can avoid the reality of actual market or cost data. The fact is that Vote Solar's future values are entirely hypothetical. Customers should only be required to pay actual value when that value is received. Vote Solar's final criticism should be set aside.

D. The Grid-Scale Adjusted Methodology Adjusts a Solar PPA Price to Produce an Apples-to-Apples Comparison with Rooftop Solar.

The grid-scale adjusted method begins with the recognition that both rooftop solar and grid-scale applications use the same basic technology—solar photovoltaic (PV) panels. APS's grid-scale methodology starts with a per kWh PPA price reported in recent, publicly available information.[131] The cost of grid-scale solar PV can be determined based on quotes that APS obtains from conducting RFPs, or from publicly-available costs of solar energy acquired by other utilities in the region having conditions similar to Arizona.[132] After obtaining a PPA price, this methodology then involves adjusting that price to reflect the very real operational differences between grid-scale and rooftop solar systems.

Significant operational differences exist between grid-scale and rooftop solar. Although they rely on the same basic technology, grid-scale and rooftop solar apply this technology in different ways. The first is related to scale. A typical grid-scale application for APS is in the 15-20 MW (15,000 to 20,000 kW) size range. By contrast, an average rooftop solar system is approximately 7 kW in size. The second main difference is that APS typically employs tracking technology on its grid-scale systems, permitting the panels to follow the sun all day and maximize the amount of energy produced. Rooftop solar systems, on the other hand, are mounted in a fixed position on a

[131] Albert Direct Testimony at 29.
[132] Tr. 424:23 – 425:2 (Albert).

customer's rooftop causing production to peak in the middle of the day and rapidly trail off as the sun begins to set. The third difference is that grid-scale applications are selected through competitive procurement processes to ensure that APS customers receive the best deal at the time the procurement decision is made. A fourth difference is that grid-scale solar PV systems can be curtailed at times when wholesale market prices are negative. This curtailability increases the value of grid-scale relative to rooftop solar.[133]

Based on these operational differences, and the different locations that grid-scale and rooftop systems are installed on the electrical grid, APS's grid-scale adjusted methodology adjusts the PPA price (i) upward to reflect energy losses that rooftop solar avoids; (ii) downward to reflect grid-scale solar's higher capacity values; (iii) downward to reflect that grid-scale solar produces solar later into the day when energy is more valuable; and (iv) downward because grid-scale solar can be curtailed to take advantage of negative energy prices in the market.[134] The total change to a grid-scale solar PPA price using these adjustments is to reduce the PPA price by 20%.[135] The adjusted PPA price is the final product of the grid-scale adjusted methodology, and results in a per kWh amount that utilities can use to purchase exported energy.

1. The grid-scale methodology incentivizes solar in an objective way and avoids the need to administratively quantify "value."

APS's grid-scale adjustment methodology offers a transparent and objective way to establish a value of solar. The PPA upon which the methodology is based is publicly available. And although the adjustments require judgment, they too are data driven. The 20% adjustment is not based on a forecast of future values, but is instead based on when grid-scale facilities produce power in relation to APS's peak; actual losses avoided with

[133] *See* Albert Direct Testimony at 27-28.
[134] *See* Albert Direct Testimony at 30-32.
[135] Tr. 2094:2 – 2095:3 (Albert).

rooftop solar; and recorded instances of negative market pricing. Notably, no party offered data contradicting APS's adjustments.

In addition, the grid-scale adjusted methodology sidesteps the need for the Commission to consider and quantify the intangible "value" of individual solar attributes. Grid-scale solar provides the same solar-related value that rooftop solar provides.[136] RUCO witness Lon Huber agreed, testifying that "nearly all of the benefits that DG solar could provide to utility customers can also be provided by utility-scale or community solar."[137] Even Vote Solar witness Briana Kobor agrees that "utility-scale solar provides many of the same attributes to the electric system, often at a lower unit price" as compared to rooftop solar.[138]

From the perspective of all customers, DG and non-DG alike, the grid-scale adjusted value represents the cost at which the utility could realize the same value attributes that rooftop solar systems supply.[139] Accepting the grid-scale adjusted methodology would strike a balance between the important value that solar offers and the very real financial impact of solar subsidies on non-DG customers.

2. Criticisms of the grid-scale methodology do not withstand scrutiny and would only entrench subsidies.

Vote Solar initially criticizes APS's grid-scale adjusted methodology because grid-scale prices are set in a market, whereas rooftop solar customers can only sell to the interconnecting utility.[140] Unfortunately for Vote Solar, this difference between rooftop and grid-scale solar proves the opposite of what Vote Solar intends. It is true that rooftop solar customers may only sell their exported energy to the interconnecting utility. But the interconnecting utility ***must purchase the energy*** under the net metering

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[136] Albert Direct Testimony at 29.
[137] Huber Direct Testimony at 4.
[138] Kobor Rebuttal Testimony at 34. Despite agreeing with this factual predicate, it should not be surprising that Ms. Kobor nonetheless disagrees with the notion that non-DG customers should only be required to pay grid-scale prices to obtain the value of solar.
[139] Albert Direct Testimony at 27-29; Tr. 362:1-21 (Albert); 401:3-10 (Albert).
[140] Kobor Rebuttal Testimony at 33-34.

rules and the utility's associated net metering tariff, regardless of resource need. Basic economics dictates that the presence of a guaranteed transaction should translate into a lower price. Instead of a lower price, however, rooftop solar customers actually receive four times the price of competitively-bid grid-scale solar.[141]

Vote Solar's only other criticism of the grid-scale adjusted methodology is that the methodology answers the wrong question. Instead of asking "why the utility should pay more for DG than they pay for utility-scale solar PPAs," Vote Solar would ask "what is the level of costs avoided by the non-participating customer as a result of the exported DG?"[142] As with Vote Solar's first criticism, however, this alternate question proves the opposite of what Vote Solar intends.

After analyzing actual data regarding all exported energy on APS's system in 2015, APS witness Albert testified that "a grid-scale solar system provides a higher value product than exported rooftop solar energy in terms of both energy value and generation capacity value."[143] In other words, grid-scale solar contributed more to APS's peak in 2015 than did exported rooftop solar energy. Indeed, APS's grid-scale adjusted methodology actually reflects this differential. Mr. Albert testified that a grid-scale solar price should be adjusted 20% ***downward*** to account for the fact that when compared to rooftop solar, grid-scale solar offers (i) a higher capacity value; (ii) energy later in the day when it is more valuable; and (iii) the ability to curtail production to take advantage of negative market prices.[144] Vote Solar's attempt to find solace in avoided cost is not just a dead end argument, but instead makes clear that using grid-scale PPA prices is actually a means to incentivize exported energy—solar PPA prices exceed the actual costs avoided by exported energy.

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[141] Tr. 365:21-366:8 (Albert).
[142] Kobor Rebuttal Testimony at 34-35.
[143] Albert Rebuttal Testimony at 20.
[144] *See* Albert Direct Testimony at 29-32.

TASC's single criticism of the grid-scale adjusted methodology does not fare any better. TASC claims that grid-scale and rooftop solar should not be compared because grid-scale provides a wholesale product to customers, whereas exported rooftop solar energy provides a retail product. According to TASC, exported energy is a retail product because it displaces another retail product provided by the utility.[145]

Curiously, TASC then contradicts itself by claiming that one can compare grid-scale and rooftop solar on an apples-to-apples basis by making appropriate adjustments.[146] TASC witness Beach even testified that creating this apples-to-apples comparison is "not particularly difficult. It takes a little bit of effort, but it's not particularly difficult."[147] If TASC's claimed wholesale/retail distinction truly rendered grid-scale and rooftop solar incomparable, it is not clear how an apples-to-apples comparison would be possible, much less "not particularly difficult."

Mr. Beach's subsequent testimony further undermined this asserted wholesale/retail distinction. Although unwilling to formally label exported rooftop solar energy as a wholesale product, he admitted all of the factual predicates to exported energy being just that—a wholesale product:

> Q. So when customers export power to the utility from a rooftop solar array, you testified earlier that title transfers to the utility, correct?
>
> A. Yes.
>
> Q. And that's the same as when a wholesale supplier of grid scale power exports power from their facility to the grid as well, correct?
>
> A. Yes.
>
> Q. In both instances title transfers to the utility?
>
> A. That's my understanding.
>
> Q. And then the utility resells that power to other customers, correct?

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[145] Beach Direct Testimony at 29.
[146] Beach Direct Testimony at 29-30; Tr. 1969:10-13 (Beach).
[147] Tr. 2001:19-22 (Beach).

A. Yes.[148]

After admitting these facts, it is not clear how TASC can maintain that exported energy is anything but a wholesale product. And after also testifying that an apples-to-apples comparison between grid-scale and rooftop solar is possible, it appears that TASC's sole criticism of the grid-scale methodology should be ignored.

IV. APS'S PERSPECTIVE ON OTHER PARTIES' POSITIONS

During the last day of the hearing on July 13, the Administrative Law Judge requested comment on the positions taken by other parties. Some parties offered positions regarding both a COSS and VOS methodologies, others only submitted evidence. This brief will first focus on positions and evidence regarding COSS methodologies.

A. COSS Positions

1. TASC's COSS methodology is largely consistent with, and confirms the findings of, APS's COSS methodology.

A detailed discussion regarding TASC's COSS appears earlier in this brief in the section responding to TASC's criticisms of APS's COSS methodology. TASC acknowledged that APS's initial consideration of total site load, and the subsequent credit for all energy and capacity, was theoretically sound.[149] TASC disagreed, however, with how APS calculated the capacity value of rooftop solar and how APS allocated demand costs.[150] As discussed above, TASC's criticisms of APS's COSS methodology lack merit. TASC's proposed modifications to APS's COSS methodology amount to no more than an unsurprising attempt to put the thumb on the scale and artificially enhance the benefits attributed to rooftop solar.

What is surprising, however, is the effect of TASC's modifications to APS's COSS methodology. APS's COSS methodology found that rooftop solar customers on

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[148] Tr. 1934:13-25 (Beach).
[149] Monsen Rebuttal Testimony at 4.
[150] *Id.*

an energy rate only contributed 37% of the cost to provide them service. Even after TASC's best efforts to tilt the COSS methodology in favor of rooftop solar, TASC witness Monsen could still only conclude that rooftop solar customers on energy rates contribute 42%-46% of the cost to provide them electric service, with that percentage rising to 58% if rooftop solar customers were only held to meeting 87% of the total cost to serve, instead of 100%.[151] That TASC's own COSS methodology concludes with rooftop solar customers falling far short of paying the cost to provide them service is strong corroboration that (i) the cost shift is significant; (ii) rooftop solar customers should be placed in their own separate subclass of customers; (iii) APS's COSS methodology is theoretically sound; (iv) a COSS methodology that accurately reflects the demonstrated costs and benefits of rooftop solar is needed.

2. Vote Solar did not offer its own COSS methodology and its concerns about transparency lack merit.

Vote Solar's testimony regarding the COSS methodology portion of this hearing was primarily focused on criticizing other parties' proposals. Vote Solar's criticisms of APS's COSS methodology are addressed above. Vote Solar's one remaining issue is that because it could not separately run its own scenarios using APS's COSS model, the Commission should reject APS's COSS model on its face.

This argument about transparency is inaccurate and a red herring. APS provided all parties with everything needed to assess APS's COSS methodology and run their own COSS. APS detailed its methodological assumptions, provided all of the COSS inputs, and shared the full output of APS's model. Any party could have taken this information and replicated the analysis using their own COSS tool.[152] Indeed, Vote Solar witness Kobor testified that she could, in fact, review the assumptions that APS made in its proposed COSS methodology.[153] Ms. Kobor also testified that she could, in

[151] Monsen Rebuttal Testimony at 33-34.
[152] Tr. 115:2-15 (Snook).
[153] Kobor Rebuttal Testimony at 3.

fact, rerun results using APS's model; Ms. Kobor's quibble is only that doing so would be a "tedious task."[154] In the end, Ms. Kobor admitted to the Administrative Law Judge that Vote Solar's concern about accessing APS's methodology was not significant enough to raise before filing its testimony.[155] With this admission, this alleged issue of transparency and access should be disregarded.

Perhaps more importantly, Vote Solar's assertions regarding transparency are irrelevant. This proceeding concerns the selection of an appropriate COSS ***methodology***, not the precise ***outcome*** of that methodology. Vote Solar witness Kobor herself testified that the purpose of this proceeding is "to focus on the methodology, not the results."[156] Vote Solar's inability to run its own COSS scenarios would not inform the discussion regarding whether APS's methodology itself was sound. Instead, the ability to run alternative scenarios would only permit Vote Solar to determine the ***effect*** of methodological changes. Yet, one does not need to know the effect of a methodology to assess whether the methodology itself is sound from a policy perspective. Vote Solar's insistence that it needs to test the outcome of methodological changes belies Ms. Kobor's testimony, and instead suggests that what Vote Solar really seeks to do is reverse engineer a methodology after first seeing the outcome it desires. At the point that Vote Solar could assess APS's assumptions and offer the detailed criticism reflected in Ms. Kobor's Rebuttal Testimony, Vote Solar did not need to run alternate scenarios and this issue of transparency became moot.

3. TEP/UNS's COSS methodology is a transparent and data-driven way to assess the cost to serve rooftop solar customers.

TEP/UNS propose a COSS methodology adopted by the Public Service Commission of Utah that involves comparing two cost of service studies. The first study looks at utility costs in the actual world; the second study looks at utility costs assuming

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[154] Tr. 1711:8-14 (Kobor).
[155] Tr. 1719:4-10 (Kobor).
[156] Tr. 1755:16-18 (Kobor).

that rooftop solar customers had not installed rooftop solar, but instead were full requirements customers.[157] This COSS methodology would create a clear picture of actual costs based on data. It would be transparent and produce verifiable results. APS considers the Utah COSS methodology to be a strong alternative to APS's proposed COSS methodology.

B. The Solar Interests' Long-Term Forecast Should be Rejected.

This brief first addresses the Solar Interests proposals to value solar using long-term forecasts. It then addresses the remaining value of solar methodologies.

1. Using long-term forecasts to establish a value of solar would entrench subsidies and result in inaccurate rates.

Instead of proposing a means to actually value exported rooftop solar energy, the Solar Interests instead use long-term forecasts to justify how exported energy is currently valued. Exported energy is currently valued at the full retail rate through net metering. Although the Solar Interests have carefully avoided claiming that utilities should purchase exported energy at the amount indicated by their long-term forecasts, TASC witness Beach did acknowledge that their long-term forecast proposal would determine the amount paid by utility customers:

> Q. If net metering is sustained as a result of your cost/benefit analysis, that will determine the amount to which non-DG customers pay for this retail rate credit, correct?
>
> A. Yeah, that would. Yes.[158]

In other words, the Solar Interests propose to set the amount customers pay for exported energy by using long-term forecasts of value.

At least conceptually, TASC and Vote Solar propose to establish the long-term value of rooftop solar in very similar ways. Both propose establishing a levelized value of rooftop solar over the next 20-30 years based on how much energy rooftop solar will

[157] Overcast Direct Testimony at 23-24.
[158] Tr. 1943:13-17 (Beach).

export to the grid in relation to utility costs.[159] Doing so requires forecasting numerous variables over the next 20-30 years, including (i) the cost of natural gas; (ii) customer usage patterns; (iii) where customers might move; (iv) projected utility load growth; (v) the cost of capacity; (vi) future utility transmission plans; (vii) future utility distribution plans; (viii) future utility generation capacity plans; (ix) the efficiency of future capacity additions; (x) the technologies that will be available to utilities and customers over the next 20-30 years; (xi) rooftop solar penetration levels; (xii) the level of utility rates; and (xiii) a discount rate.[160] In total, Vote Solar witness Kobor identified 32 variables that need to be forecasted.[161]

The sheer number of variables alone makes inaccuracy almost certain. Staff witness Solganick testified that just a single variable—long term fuel forecasts—are notoriously inaccurate. When asked if he knew of a single long-term fuel forecast that had been correct, he responded "no."[162] And the Solar Interests seek to forecast over 30 variables! Layering assumption upon assumption and forecast upon forecast requires that each be correct, and that each be correct ***in relation to each other***, exponentially compounding the complexity and difficulty of making an accurate long-term forecast:

> Q. And we discussed the notion of forecasting fuel prices, and it was just one issue and relatively straightforward. In your mind, are the complications from using forecasts compounded the more buckets of data and analyses you layer on top? And by that I mean transmission capacity and distribution capacity and fuel forecasts and other elements of forecast.
>
> A. I think that's true, either because of algebra or calculus, that if you just have more variability and you keep doing it, you know, you could luck out and have them counterbalance each other. But, you know, one is one; 17 is a lot more than one.[163]

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[159] *See generally*, Kobor Direct Testimony at 17-36; Beach Direct Testimony at 18-28; The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update), attached as Exhibit 2 to Beach Direct Testimony.
[160] Brown Rebuttal Testimony at 2-5; Tr. 1762:2 – 1766:13 (Kobor); *see generally* Kobor Direct Testimony, Beach Direct Testimony, and Exhibit 2 to Beach Direct Testimony.
[161] Brown Rebuttal Testimony at 2-5.
[162] Tr. 1355:11-13 (Solganick).
[163] Tr. 1347:11-22 (Solganick).

TASC witness Beach admitted that at least some of these assumptions are "inherently unknowable."[164] In a similar vein, Staff witness Solganick testified that getting an accurate forecast simply relies on luck.[165] At a different point in the hearing, Mr. Solganick was even more blunt, testifying that "[a]s soon as you are finished forecasting you are wrong."[166]

Magnifying the insurmountable task of accurately forecasting so many variables is the timeframe of the forecast. It would be difficult to accurately forecast how this many variables might change over a single year. Yet the Solar Interests propose doing so over the next ***20-30 years***. Over this long of a timeframe, any number of circumstances can change that will render the forecast hopelessly inaccurate: "The danger is that things change out in the future, and what you perceived as a benefit and moved forward either doesn't occur or performance is changed such that it can't occur."[167] At the end of the hearing, even TASC witness Beach acknowledged that change was certain:

> You know, generally, I think that you know, this is a—this certainly is a dynamic market, and there are changes in solar costs; there are changes in utility rates; there are changes in avoided cost. And so, you know, this balance between participating and non-participating ratepayers will change over time, and so I do agree that it needs to be looked at periodically. I'm not sure I would do it every year, but every rate case, something like that.[168]

One need only think back over the last 20-30 years to the 1980s and 1990s, and contemplate the extraordinary technological changes that have taken place since, to perceive what it means to say that 20-30 year forecasts of over 30 variables can never be accurate.

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[164] Tr. 1938:1-21 (Beach).
[165] Tr. 1398:12-16 (Solganick).
[166] Tr. 1353:17-18 (Solganick); Tr. 811:7-9 (Tilghman).
[167] Tr. 1350:7-10 (Solganick).
[168] Tr. 2020:23 – 2021:6 (Beach).

The risks associated with inaccurately forecasting over 30 variables 20-30 years into the future directly falls on non-DG customers—the ones who pay the net metering subsidy. Relying on a perfect forecast of numerous, subject-to-change circumstances to set rates imposes risk on customers if those circumstances do change:

> Q. And so now we have discussed a number of different concerns with long-term forecasts. It is uncertain in the future. The utility plans are subject to change. Customer behavior might change. Circumstances might change. New technologies might come about. And all of these impose increasing risk if we were setting prices based on these long-term forecasts, is that correct?
>
> A. That's correct.
>
> Q. And the risk is entirely borne by customers without rooftop solar, is that correct?
>
> A. I am going to be careful here, because if someone were alleged lack of prudency, then the risk might be shared with another party. ***But generally the risk falls on customers.***[169]

Specifically, if a forecast is wrong, and utilities pay benefits that have been administratively moved forward, the customers who get harmed are the ones who paid the money: non-DG customers who subsidize rooftop solar.[170]

Moreover, if these long-term forecasts are wrong, customers will have been paying rates that are not just and reasonable. Simple things, like customers switching to an electric vehicle or using their air conditioner less, will render a forecast of levelized savings inaccurate.[171] And if the Commission establishes rates for exported energy that incorporate a levelized energy savings forecast, those rates would subsequently become inaccurate.[172] It is not clear how rates based on levelized savings of long-term forecasts can be just and reasonable, particularly when the evidence in this proceeding demonstrates that forecasts are wrong the moment they are complete.

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[169] Tr. 1355:14 – 1356:3 (emphasis added) (Solganick).
[170] Tr. 1345:10-14 (Solganick); 1348:2-5 (Solganick).
[171] Tr. 1350:13 – 1351:8 (Solganick).
[172] Tr. 1351:3-8 (Solganick).

Using long-term forecasts to establish the amount customers pay for exported energy introduces an unacceptable amount of customer risk in the rate setting process. Absent luck, it is impossible to create accurate rates that incorporate a forecast of over 30 variables over a 20-30 year time period. Because the Solar Interests' value of solar methodology cannot result in an accurate basis for rates, any resulting rates are incapable of being just or reasonable. The Solar Interests' proposal to use long-term forecasts to establish the value of solar should be rejected by the Commission.

2. TASC concluded that south-facing rooftop solar is a net cost to customers even before studying less valuable exported energy.

TASC's position in this proceeding is that if the long-term benefits of exported rooftop solar energy exceed the costs, the full retail rate credit embedded in net metering should continue as the price paid for exported energy. TASC's own study, however, predicts that south-facing rooftop solar will cost APS non-DG customers 17.9 cents per kWh over the next 20 years, but only provide 15.5 cents per kWh in direct benefits.[173] Mr. Beach did attempt to inflate the predicted benefits by quantifying the value of predicted societal benefits. During cross examination, however, he also admitted that these types of externalities are not included in a cost of service[174] and that, in any event, grid-scale and rooftop solar have the same effect on reducing carbon.[175] In other words, in terms of actual money that non-DG customers must contribute to purchase exported energy at the full retail rate, net metering should be discontinued for south-facing rooftop solar using TASC's own test.

Moreover, the net cost of south-facing solar would have only grown in size had TASC actually valued what it claimed to value: exported energy. TASC claims that its VOS methodology establishes the value of exported energy. Yet TASC witness Beach admitted that ***he did not evaluate exported energy***. Instead, he evaluated total rooftop

[173] *See* Exhibit 2 to Beach Direct Testimony at 22-23; Tr. 1971:13-18 (Beach).
[174] Tr. 1966:20 – 1967:1 (Beach).
[175] Tr. 1967:19 – 1968:11 (Beach).

solar output, stating that "the analysis is considerably easier if you look at the, at all output rather than just looking at exports."[176] Although data concerning export energy are available, he just simply did not attempt an export energy analysis.[177]

APS did do an export energy analysis, and provided the results in Brad Albert's Rebuttal Testimony. There, Mr. Albert explained the results, testifying that (i) at the time of 2015 peak APS customer consumption of approximately 7,000 MWs, only 5% of rooftop solar energy, or 8.8 MWs, was being exported to the grid;[178] (ii) during the top 90 peak hours on APS's system in 2015, only 7% of rooftop solar energy, or an average of 11.9 MWs, was being exported;[179] (iii) rooftop solar customers export more energy over the course of the year than they use for self-consumption;[180] and (iv) the large majority of exported energy occurs during mild-weather months, when energy is much less valuable because of lower customer demand.[181]

The data confirm that exported energy is less valuable because it occurs in abundance when APS does not need it (off-peak months), and occurs in only nominal amounts when APS does need it (on-peak months). At APS's 2015 peak of 7,000 MWs, exported energy only accounted for 8.8 MWs—or 00.12%—of supply. Had Mr. Beach actually reviewed exported energy, he would have discovered this fact. And had he run his own cost/benefit test for exported energy only, he would have discovered that exported energy fails any cost/benefit measure for non-DG customers by a very wide margin.[182] And that is before Mr. Beach's existing conclusion that south-facing rooftop solar is a long-term losing proposition for customers.

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[176] Tr. 1945:16-22 (Beach).
[177] Tr. 1945:23 – 1945:6 (Beach).
[178] Albert Rebuttal Testimony at 12-14.
[179] Albert Rebuttal Testimony at 12-14.
[180] Albert Rebuttal Testimony at 14.
[181] Albert Rebuttal Testimony at 16-18.
[182] Albert Rebuttal Testimony at 19.

3. That IRP processes use long-term forecasts is unavailing—IRPs don't establish how much customers pay.

Throughout the proceeding, the Solar Interests have insisted that it is appropriate to establish the rate paid for exported energy using long-term forecasts because long-term forecasts are used in utilities' integrated resource planning (IRP) processes. IRP processes, however, are significantly different than ratemaking. It is true that IRP processes involve forecasting benefits over the long term. But rates are not based on these IRP forecasts; rates are based on actual cost.[183]

Aside from the fact that IRP forecasts do not produce rates, IRP processes involve a number of other critical differences that make any comparison inappropriate. In IRP forecasts, utilities use different scenarios, with high and low cases, and get input from stakeholders and the Commission.[184] To "keep pace with ever-changing assumptions," IRP forecasts are updated every two years.[185] Once an IRP forecast identifies a resource need, utilities make a decision on the best available information at the time.[186] To meet that resource need, utilities conduct RFPs and procure the least cost resource that also best fits the need.[187] And once the utility acquires the resource, the acquisition is carefully scrutinized for prudency during the utility's next rate case.[188]

The Solar Interests' long-term forecast proposal includes none of these protections. They do not propose using actual costs; they do not offer alternate scenarios; they do not acknowledge high and low cases; they do not propose to update forecasts every two years; they do not propose RFPs; they do not propose considering different resources to fit an identified need; they do not propose pursuing least cost resources; nor do they propose a prudency review by the Commission. Setting aside that

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[183] Snook Rebuttal Testimony at 6.
[184] Tr. 1343:14 – 1344:7 (Solganick).
[185] Snook Rebuttal Testimony at 6.
[186] Snook Rebuttal Testimony at 6.
[187] Albert Rebuttal Testimony at 4-5.
[188] *See generally,* Ariz. Admin. Code R14-2-103.

the IRP process does not directly translate into customer rates in the first place, the IRP process contains a significant number of strong protections that the Solar Interests appear to ignore. It is inappropriate to rely on the IRP process of long-term forecasting for support in using long-term forecasts to establish a value of solar.

4. The Solar Interests ignore that customers are better off by obtaining a higher value of solar at a quarter of the cost.

APS witness Albert testified that the value of solar can be obtained for 4 cents per kWh, as compared to the 14-16 cents per kWh that APS customers currently pay for exported energy through net metering.[189] If customers can have lower bills and obtain the same value of solar, how can it be reasonable to insist that customers should continue paying the higher price? When pressed to answer why customer bills should increase to subsidize rooftop solar, TASC witness Beach's rationale collapses to providing rooftop solar to the segment of customers who have average credit scores of 760:

> Q. I understand that. My question is focused on cost and actual customer bills. These are real families who have to decide where they are going to spend what they make. And they are going to buy food and clothing for their children and school and energy costs.
> And so when the Commission is assessing what is the most cost effective way to increase the amount of rooftop solar penetration, if we gross up the costs or the benefits of rooftop solar to account for T&D, and grid scale is still better, wouldn't that be the better policy option for the Commission?
>
> A. Well, you also—there is also a demand among customers to increase, to be able to be served by a higher penetration of renewables. And you just can't meet that with utility scale solar unless you are going to, you know, do a program where you directly allocate the utility scale solar power to the customer.
>
> Q. ***Demand by customers who have average credit of 760?***
>
> A. ***You know, whatever.*** But you can't meet the demand of customers to be served by a higher penetration of renewables with utility scale solar unless you have some kind of community solar or program.[190]

[189] Tr. 365:21 – 366:8 (Albert).
[190] Tr. 1970:6 – 1971:3 (emphasis added) (Beach).

Minutes later, Mr. Beach also admitted that the rooftop solar industry's objective is to simply market its product and grow.[191] APS submits that increasing customer bills to subsidize rooftop solar for customers with high credit scores and permit rooftop solar companies to continue growing their profits is not in the public interest.

C. Other Parties' VOS Positions

1. TEP/UNS

TEP/UNS propose establishing the price paid for exported energy by using a grid-scale PPA.[192] Exported energy is a wholesale product, and TEP/UNS's proposal is an objective and transparent way to derive a wholesale value. APS largely agrees with TEP/UNS's proposal, but believes that any grid-scale PPA rate should be adjusted downward by 20% to reflect the very real operational differences between grid-scale and rooftop solar. This adjustment is needed to keep non-DG customers financially indifferent to the source of wholesale solar energy on the electrical grid.

2. Commission Staff

Staff offered two proposals. The first focused on compensating exported energy at avoided cost. That cost begins with an avoided energy cost, is increased by appropriate losses, and further increased if generation, transmission, or distribution capacity value can be demonstrated or is forecasted.[193] Staff also proposes resetting the price of exported energy in every rate case.[194]

APS largely agrees with Staff's avoided cost methodology. This methodology would establish a price for exported energy based on actual data regarding energy savings and losses. The capacity savings were also based on an equivalent load carrying capability (ELCC) assessment, which is APS's method for deriving capacity value in the resource planning process. One concern, however, involves Staff's suggestion that

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[191] Tr. 2019:21 – 2020:3 (Beach).
[192] Carmine Tilghman Direct Testimony at 4-5.
[193] Solganick Direct Testimony at 19-20; *see* Exhibit HS-3 to Solganick Direct Testimony.
[194] Soglanick Direct Testimony at 20.

forecasted capacity could be used in determining avoided cost. Staff witness Solganick testified that by forecasted capacity savings, he meant something similar to a statistical analysis of generation outage rates.[195] He also testified that any forecast would need to be trued up, or otherwise folded into a rolling average over a limited period of time that is no longer than the period between rate cases.[196] To the extent that the forecasted capacity savings contemplated in Staff's avoided cost methodology are constrained to the limited time period indicated, and the magnitude of capacity savings is based on actual data derived from an ELCC analysis, Staff's first proposal would protect customers and be a transparent, verifiable, and fair way to value exported energy.

Commission Staff's second proposal involved creating a per kWh price based on a weighted blending of all grid-scale solar facilities on a utility's system, both utility-owned and PPAs, over a particular time period. Although Staff appears to have conducted a large amount of work on the methodology, Staff witness Thomas Broderick testified that Staff's second blended grid-scale methodology was still a work in progress.[197]

APS's perspective on this methodology is that it could produce an objective and transparent valuation for exported energy. APS's primary comments are those that APS provided initially in response to Staff Data Request 3.6, which became Staff Exhibit 5. There, APS stated that to be comprehensive, a methodology that blended the effective per kWh price of all grid-scale solar facilities should include several factors, including:

> (i) a graduated weighting system that places a greater emphasis on more recent announced or executed grid- scale solar prices;
>
> (ii) a rolling blended average of no more than five years, where in each subsequent year, the oldest year of data in that period would roll out of the calculation;

[195] Tr. 1356:19 – 1358:6 (Solganick).
[196] Tr. 1358:7-23 (Solganick).
[197] Tr. 2330:8-18 (Broderick).

(iii) refreshing the analysis each year to capture the most current available data and ensure that the price used in the calculation reflects current market conditions;

(iv) utilizing data and pricing for photovoltaic solar panels, and excludes other types of solar technologies (e.g., concentrated solar or solar thermal projects),

(v) in the event that the utility does not have any projects of recent vintage (for example - within the previous year), the methodology could consider utilizing pricing data from available industry sources for grid-scale solar PV projects with priority placed on projects within the state of Arizona to the extent available; and

(vi) adjusting to recognize the value differences between grid-scale and the export portion of rooftop solar. This adjustment to recognize valuation differences such as generation capacity value and energy losses is more fully discussed in the direct testimony of Mr. Albert.[198]

The latest version of Staff's methodology presented by Staff witness Liu appeared to largely reflect these factors. Because Staff's blended grid-scale methodology does not rely on long-term forecasts, but instead derives a value of solar based on actual data that is verifiable and transparent, APS could support Staff's second methodology.

3. RUCO's proposal would impose risk on non-DG customers for similar reasons as the Solar Interests' proposals.

RUCO proposes to establish a value of rooftop solar using a long-term forecast of predicted benefits.[199] RUCO believes that the total production of rooftop solar systems should be used to establish those benefits, not just exported energy.[200] Similar to the Solar Interests, RUCO believes that the time period for the forecasted benefits should be 20 years.[201]

RUCO's proposal offers an interesting contrast to the long-term forecasts urged by the Solar Interests. RUCO does not advocate a continuation of net metering, but instead proposes actually valuing rooftop solar production at the calculated long-term

[198] Staff Exhibit 5, Response to Data Request 3.6.
[199] *See* Huber Direct Testimony at 17-23.
[200] Huber Direct Testimony at 13.
[201] Huber Direct Testimony at 13.

value.[202] RUCO does not support quantifying intangible benefits.[203] And RUCO believes that the value of solar should exclusively be viewed from the perspective of customers without rooftop solar, and that the primary cost to those non-participants is the lost utility revenues that they must pay, i.e., the costs shifted to utility customers due to rooftop solar.[204]

A primary flaw in RUCO's proposal, however, is that it relies on a long-term forecast to determine how much non-DG customers pay for rooftop solar. As made clear throughout this proceeding by multiple parties and witnesses, the only thing we know about forecasting is that once you are done, you are wrong.[205] Getting a correct forecast of long-term benefits requires luck,[206] and based on the evidence presented in this proceeding, APS cannot see how rates set using a long-term forecast could be just or reasonable. Accordingly, APS cannot support RUCO's proposed VOS methodology.

VI. CONCLUSION

After years of requesting that the Commission conduct a docket to analyze the cost and value of rooftop solar energy, this proceeding provided the Solar Interests <u>the</u> forum to put forth their best case for abandoning cost-based ratemaking in favor of value-based ratemaking. Frankly, they failed. The overwhelming evidence in this proceeding underscores that cost-based ratemaking is in the public interest and should not be diluted with the introduction of assumptions and projections of aspirational benefits. APS's cost of service methodology is transparent, proven, quantifiable and verifiable and should be adopted by the Commission as the methodology for use in rate cases. Also, the Commission should decide how it will determine the rates to charge for exported energy by rooftop solar customers. Again, the record supports the APS

[202] Huber Direct Testimony at 13.
[203] Huber Direct Testimony at 5, 13.
[204] Huber Direct Testimony at 13-14.
[205] Tr. 1353:17-18 (Solganick).
[206] Tr. 1398:12-16 (Solganick).

methodologies as being reasonable and appropriate for integrated resource planning, determining the value of exported energy, and for other incentives, if needed. The weight of the evidence in the record reveals that other methodologies that depend on many assumptions and long range forecasts are unproven, unreliable, and not in the public interest and should be rejected by the Commission.

RESPECTFULLY SUBMITTED this 20th day of July 2016.

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