BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	Docket No. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	Docket No. E-01933A-15-0239

PHASE 2 SURREBUTTAL TESTIMONY AND ATTACHMENTS

OF BRIANA KOBOR ON BEHALF OF VOTE SOLAR

September 29, 2017

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1 Introduction

Q. Please state your name and business address.

A. My name is Briana Kobor. My business address is 360 22nd Street, Suite 730, Oakland, CA, 94612.

Q. On whose behalf are you submitting this surrebuttal testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Did you submit direct testimony in Phase 2 of these proceedings?

A. Yes, I did.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to provide a response to the testimony filed by Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE") (collectively, "the Companies") and other intervenors on May 19, 2017, and the rebuttal testimony filed by the Companies on August 28, 2017. This testimony covers both the proposed Resource Comparison Proxy ("RCP") as well as rate design for customers who adopt distributed generation ("DG"). Following this brief summary, the second section of my testimony addresses the development of an appropriate export compensation rate in this proceeding. The third section addresses treatment of DG customers in the cost of service study ("COSS"). The fourth section addresses issues related to rate design. The fifth section discusses considerations in the evaluation of the proposals in this docket. The sixth section places the proposed rates in context alongside the rates the Commission has approved for Arizona Public Service Company ("APS"). The seventh section presents Vote Solar's recommendation for RCP and rate design. The eighth and final section provides a summary of my conclusions and recommendations.

Q. Please summarize your findings.

A. There are two main issues in front of the Commission in these proceedings: (1) development of an appropriate export compensation rate to implement the Commission's policy from the Value of DG docket, and (2) determination of appropriate rate design treatment for future DG customers. While Decision 75859 determined that retail rate net metering must be replaced with an export compensation rate, it left open the question of what an appropriate rate design should be for new DG customers. I find that implementation of the RCP in these proceedings will have a significant and negative impact on the Arizona solar market and will go a long way toward addressing the Companies' fixed cost recovery concerns. As a result, I recommend that the Commission implement the RCP as envisioned by Decision 75859 and exercise caution in implementing additional rate design changes for new DG customers.

Resource Comparison Proxy

Based on my review of the RCP-related testimony filed by the Companies and other intervenors, I find that many proposals put forth in this proceeding are an attempt to re-litigate issues that were clearly decided by this Commission in the Value of DG case with Decision 75859. These attempts to re-litigate fundamental aspects of Decision 75859 include: (1) attempts to characterize the RCP as a subsidy including the Residential Utility Consumer Office's ("RUCO's") proposal for a market-based trigger, (2) basing the first-year RCP on something other than the five years up to and including the utility's rate case test year, (3) the Companies' proposal for the initial export credit rate to be in effect for less than a year, and (4) exclusion of transmission and distribution adders from the RCP calculation. Each of these issues is described below.

First, the Companies have claimed the RCP represents a subsidy to DG customers. But Decision 75859 clearly indicated that the methodologies it adopted for valuing DG exports, including the RCP method, was intended to be a numerical representation of the value of DG and is therefore not a subsidy. I find a similar issue exists with RUCO's proposal for a market-based trigger, which would reduce the export compensation rate beyond the annual modifications set forth in Decision 75859. Not only did the Commission explicitly reject RUCO's proposal in Decision 75859, but the proposal appears to be based on the presumption that Staff's proposed RCP represents some level of subsidy. While the parties to this proceeding may disagree as to the appropriate level of compensation for DG exports, it is contrary to the Commission's decision for the Companies and RUCO to refuse to recognize that the RCP approved by this Commission and the value of DG are one and the same. As a result, I recommend that the Commission explicitly state that the RCP value adopted in this proceeding is by definition the value of DG and is not a subsidy. In addition, I recommend that the Commission reject any proposal that would trigger additional step-downs to the RCP based on market penetration rates.

Second, the Commission clearly ruled that the first-year RCP should be based on the five years up to and including the test year of each Company's rate case. The Companies, RUCO, the Arizona Investment Council ("AIC"), and Staff all propose to use more recent information. I recognize that the Commission may wish to revisit this aspect of the decision and can accept the Companies' proposal for a first-year RCP based on the period from 2012-2016.

Third, I find that the Companies' proposal to have the initial RCP rate expire on June 30, 2018 is unwarranted. Under the Companies' proposal, the initial RCP is likely to be in effect for less than 6 months rather than the one-year period outlined in Decision 75859. The Commission clearly decided this issue in the Value of DG docket and there has not been sufficient delay in the procedural schedule in this case to warrant such a substantial modification to the clear policy set forth by this Commission.

Fourth, I address the proposals by the Companies, AIC, and RUCO exclude adders for transmission and distribution. These proposals run counter to Decision 75859, and are yet another example of an attempt to re-litigate issues that were decided by the Commission in the Value of DG docket. I find the Companies' critique of my methodology to establish these adders is without merit. I have reviewed the proposal of the Alliance for Solar Choice ("TASC")/Energy Freedom Coalition of America ("EFCA") for marginal cost based adders and find this approach reasonable, though more complex, than my proposal in direct testimony. I continue to support the transmission and distribution adders I proposed on direct, and have made a small modification to my proposal for line losses to conform with other changes proposed in the RCP methodology.

I have additionally reviewed proposals from the Companies, RUCO, and AIC to develop a combined RCP value for TEP and UNSE. These parties point out the two Companies' shared attributes and express concern over the potential for a smaller utility like UNSE to experience gaps in available data for the RCP calculation. While the Commission has not ruled on this subject, I find that it may be reasonable to approve a combined RCP in these proceedings. However, approval of a combined RCP may prove problematic in future cases given other parameters that have been set by the Commission in Decision 75859. Moreover, while parties express concerns over gaps in UNSE data, this does not appear to be an immediate-term issue as Staff's RCP model identified solar projects and power purchase agreements ("PPAs") for UNSE in four out of six years examined. I believe that the parties' proposal to include industry data in the RCP calculation for a utility with single year gaps in data is both unnecessary and impractical. I recommend that the Commission find that industry data should be used only in the event that there is no utility-specific data for the five-year RCP period.

Next, I review the Companies' proposal to base the RCP calculation on expected production from utility-owned facilities, rather than actual production as proposed by Staff. While the Companies make this proposal based on concerns that curtailment of utility-owned resources may artificially inflate the per unit cost of energy from these facilities, I do not find evidence that curtailment has had a significant impact on the facilities in the RCP model. I am concerned with the use of expected, rather than actual, production data if a utility-owned solar facility does not produce as expected, similar to the recent experience with TEP's White Mountain facility. I recommend that the Commission adopt an RCP based on actual production data from utility-owned solar facilities.

I have reviewed and support the Companies' proposal to establish the year-two RCP in this proceeding for purposes of administrative efficiency and have included a year-two RCP proposal in my recommendations.

I reviewed the Companies' proposal for system eligibility requirements and support their proposal to maintain the current eligibility requirements defined by Commission rules and the current net metering tariffs. I recommend minor modification to the Companies' proposed language to accomplish this goal.

I additionally find RUCO's proposal to include Renewable Energy Credits ("RECs") in the purchase of exported energy to be reasonable and support its adoption. I find that customers should maintain all RECs associated with the DG that they produce and consume on-site and should have the choice to enroll on an optional rate rider that would allow them to retain RECs associated with their exports in exchange for a lower export compensation rate. This lower export compensation rate would initially be set at $0.01/kWh below RCP, to approximate the current value of RECs.

Next, I review the various proposals in this proceeding that would augment the basic RCP structure outlined in Decision 75859. These include: (1) Vote Solar's proposal for adoption of a 10% floor on annual export compensation rate decline after the 10-year lock-in period, (2) RUCO's proposal for an optional adjustment to the RCP based on time of day and season, and (3) RUCO's proposal to create adders based on inverter settings. I find that Vote Solar's proposal would alleviate consumer protection concerns raised by RUCO by allowing customers to forecast a worst-case scenario investment benchmark, while enabling the export credit rate to change annually based on the prevailing policy of the Commission. I additionally support RUCO's proposal for an optional adjustment to the RCP based on time of day and season. I recommend that this be accomplished via an optional rate rider available to customers regardless of their base tariff selection, and that the rider be designed to incent load management and technology adoption. Finally, I find that RUCO's proposal to create adders based on inverter settings has merit, but requires additional detail. I recommend that the Commission require the Companies to develop a proposal on this subject for evaluation in each Company's next rate case.

I present Vote Solar's revised recommendation for the RCP in this case. As a result of compromise on the base period definition, and the appropriateness of combining the RCP for TEP and UNSE in these proceedings, I am now recommending a first-year RCP for both utilities of $0.124/kWh and a second year RCP of $0.112/kWh. Both values include adders for avoided transmission, distribution, and line losses, as prescribed by the Commission in Decision 75859.

Finally, I present a comparison between the expected compensation from retail rate net metering and Vote Solar's proposed RCP, with the assumption that the Commission accepts Vote Solar's proposal for a 10% floor on annual export compensation rate decline after the 10-year lock-in period. Despite concerns expressed by the Companies and RUCO concerning RCP proposals that are above the retail rate, I find that when the structural changes being implemented in this docket are considered, it is expected that customers signing up for DG as soon as 2020 would receive compensation for their exports at <u>30-40% below</u> the compensation expected under retail rate net metering**.**

<u>Cost of Service Study Methodology</u>

Determination of the appropriate methodology for separation of DG customers in the COSS is an important issue of first impression for the Commission. I have reviewed the rebuttal testimony filed by the Companies on the COSS issues. I find that their critiques lack merit and that their proposals are flawed. In this testimony I highlight the three most important issues of disagreement over COSS methodology between the Companies and other intervenors, and explain why the methodology I put forth on direct is the appropriate method for the Commission to adopt. My recommendations on COSS methodology have not changed from the recommendations I offered on direct.

Rate Design

I find that the Companies and Vote Solar are in agreement that the appropriate Basic Service Charge ("BSC") for DG customers is the same level of BSC available to their non-DG counterparts.

I have reviewed the Companies' defense of their proposed meter fee and continue to find that the proposed fee is too high. The Companies' fee remains a measure of the full average embedded cost of the bidirectional meter, while the Commission clearly ruled in Decision 75975 that the meter fee should account for the incremental costs associated with the bidirectional meter. In response to new information provided by the Companies in discovery, I have updated my proposed meter fee. If the Commission chooses to continue the meter fee, it should be $2.23/month for TEP and UNSE residential customers with the option to avoid this charge via a one-time upfront payment of $155.55. For TEP and UNSE small commercial customers, I recommend a meter fee of $0.90/month with an optional one-time upfront charge of $62.78.

While the Companies have offered a reduced grid access charge proposal in their rebuttal testimony, I maintain my finding in direct testimony that DG customers recover more than their fair share of costs under current rates without the grid access charge and that such a charge is unnecessary.

I also find that the Companies continue to propose rates for DG customers that are separate, but after several revisions these rates are similar to rates offered to non-DG customers, with the exception of several additional charges such as the meter fee and the grid access charge. I find that adoption of DG under the new export compensation structure will already be a complex undertaking and the Companies have not provided sufficient evidence that the minor changes in their proposed tariffs are necessary. I recommend that the Commission allow DG customers to take service on all of the same tariffs that are currently available to them with the addition of a meter fee and/or grid access charge such as the Commission deems appropriate.

Evaluation of Proposals in this Docket

I have reviewed the tables put forth by the Companies in rebuttal purporting to show the offset, blended solar savings, and a measure of simple payback under the Companies' proposed rates. I have found that several key methodological flaws underlie these calculations that skew the results to look more favorable to solar customers than is accurate. After correcting for these issues, I find that the Companies' rebuttal position is too aggressive and would render solar uneconomic in Arizona. I also compare the Companies' proposal to the rates that were recently approved by this Commission for APS and find that the Companies' proposals would result in significantly lower rates than what is available to DG customers in the APS service territory.

I have additionally applied the same metrics used to evaluate the impact of the Companies' proposals to Vote Solar's proposals for RCP and rate design. I find that Vote Solar's proposal would result in blended solar savings lower than that approved by the Commission for APS, and that simple payback is expected to fall in the acceptable range articulated by intervenor Mr. Koch. In addition, I find that Vote Solar's proposal is expected to result in a gradual 7-14% decline in solar compensation relative to net metering. I recommend that Vote Solar's proposal be approved in this proceeding.

Q. Please summarize your recommendations for Phase 2.

A. The following recommendations are in addition to the recommendations I made in my Phase 2 direct testimony. Recommendations that have been revised from direct are noted.

Resource Comparison Proxy

- The Commission should include a finding in its decision stating that the RCP value adopted in this proceeding is by definition the value of DG and is not a subsidy.

- If the Commission departs from the Value of DG decision and approves a first-year RCP that is based on utility-scale resources beginning operations later than the five years up to and including the rate case test year, the Commission should maintain its focus on gradualism. This is a revised recommendation.

- The Commission should adopt Vote Solar's proposed transmission, distribution, and line loss adders.

- The Commission may desire to adopt a combined RCP for TEP and UNSE in these combined proceedings, but this issue should be revisited in each utility's next rate case. This is a revised recommendation.

- The Commission should find that in the event there are no utility-scale solar projects in any particular year of the five-year RCP period, the RCP will be calculated without a project for that particular year. Industry data will only be used in the event that there is no utility-specific data in the five-year period.

- The Commission should adopt an RCP based on actual production data from utility-owned solar facilities. To the extent significant curtailment occurs, the Companies should be required to provide evidence that may be incorporated into the RCP calculation to address the Companies' concerns.

- The Commission should adopt the second-year RCP in this proceeding for purposes of administrative efficiency.

- The Commission should adopt system eligibility requirements for the RCP consistent with the criteria defined by statute and included in the current net metering rate riders.

- The Commission should reject any proposal that would trigger additional step-downs to the RCP based on market penetration rates, consistent with what was decided in Decision 75859.

- The Commission should approve RUCO's request for RECs associated with exports to be included in the RCP transaction and should allow customers the option to maintain their RECs via an optional rate rider set at $0.01/kWh below the approved RCP.

- The Commission should adopt a fully optional rate rider that would allow for time-of-use ("TOU") adjustments to the RCP to incentivize customer load management and technology investment. The rider should be calibrated to result in the flat-rate RCP for the average customer without load management or technology.

- The Commission should require the Companies to develop an optional rate rider proposal that would provide additional credits to customers based on inverter settings beneficial to utility grid management, which could be presented and evaluated in each Company's next rate case.

- The Commission should approve a first-year RCP of $0.124/kWh and a second-year RCP of $0.112/kWh with a 10% floor on annual export compensation rate decline after the 10-year lock-in period. This is a revised recommendation.

Rate Design

- DG customers should be afforded access to all of the same tariff options as non-DG customers without exception.

- The Commission should not adopt a grid access charge for DG customers.

- If the Commission chooses to continue imposition of the meter fee, it should be $2.23/month for TEP and UNSE residential customers with the option to avoid this charge via a one-time upfront payment of $155.55. For TEP and

UNSE small commercial customers, the Commission should approve a meter fee of $0.90/month with an optional one-time upfront charge of $62.78. This is a revised recommendation.

2 Development of an appropriate export compensation rate

2.1 Compensating DG exports at the RCP rate is not a subsidy

Q. According to the Companies, would compensating DG exports at the RCP rate provide a subsidy to DG customers?

A. Yes, the Companies characterize the RCP as a subsidy. Specifically, TEP/UNSE witness Tilghman stated: "The initial RCP Rate determines what subsidy customers must pay for excess DG energy . . . ."[1]

Q. Did the Commission characterize the RCP methodology as a subsidy in Decision 75859?

A. No, the Commission stated the RCP methodology is one method intended to reflect the value of DG exports. It follows that if DG exports are compensated at a rate that is intended to reflect the value of those exports, the compensation rate is not providing a subsidy to DG customers. In the very first ordering paragraph of Decision 75859 the Commission states: "IT IS THEREFORE ORDERED that the Commission adopts . . . the methodologies for calculating the value of DG exports set forth and described herein for use in electric utility rate cases before the Commission."[2]

[1] Carmine Tilghman RCP Rebuttal Test. at 6:22–23 (May 19, 2017) (emphasis added) [hereinafter "Tilghman Phase 2 RCP Rebuttal"].
[2] Decision No. 75859 at 177:2–4 (Jan. 3, 2017).

It is clear that the Commission intended its approved methodologies to result in numerical representations of the value of DG that could be used to inform export rates going forward.[3] Indeed, the Commission stated:

> We agree with Staff that the purpose of this proceeding is to adopt methodologies to determine the value and cost of rooftop DG. The record in this proceeding is the culmination of years of argument and debate on this issue . . . . It is time to provide certainty and a path forward to resolve disputes surrounding the successful integration of DG with the utility's electrical systems in an economic and fair manner. We believe that the determinations we make in this proceeding provide that path.[4]

Q. Is the Companies' characterization of the RCP as a subsidy accurate or appropriate?

A. No, it is not. The methodologies set forth by Decision 75859, including the RCP methodology, are intended to result in a numerical assessment of the value of DG that will be approved by the Commission in this case. The Companies' characterization of the RCP as a subsidy that non-solar customers pay for excess energy is wholly inappropriate and undermines the stated purpose of the multi-year investigation undertaken by the Commission to arrive at the Value of DG decision. While the parties here may disagree as to the appropriate level of RCP the Commission should adopt, it is contrary to Decision 75859 for the Companies to refuse to recognize that the RCP approved by this Commission and the value of DG are one and the same.

Moreover, by claiming the RCP is a subsidy, the Companies fail to recognize <u>any</u> level of value that exported generation provides to the grid. Indeed, it appears the Companies' characterization of the RCP as a subsidy is premised on their opinion that the RCP proposed by Staff is too high. However, it is unclear what, if any, level of RCP value the Companies would accept as low enough to not represent a "subsidy." This entire assertion is premised on the Companies' underlying

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[3] *Id.* at 170:4–5.
[4] *Id.* at 143:6–12.

judgment of value, which clearly contravenes one of the Commission's stated methods for determining the value and compensation rates for solar exports in Arizona.

Q. Did the Commission caution against parties re-litigating the assumptions and methodologies in Decision 75859 in rates cases such as this?

A. Yes, the Commission admonished parties "that these initial evidentiary hearings will not be the forum to re-litigate any issue decided in this proceeding."[5] Despite this statement, the Companies continue to characterize an RCP-based export rate as a subsidy, which is contrary to a fundamental finding in Decision 75859.

Q. In your direct testimony, you recommended several modifications to Staff's proposed RCP export rate. Is Vote Solar attempting to re-litigate Decision 75859's fundamental assumptions and methodologies?

A. No. As I mentioned in my direct testimony, Vote Solar advocated for a different methodology for valuing DG exports in the Value of DG docket and continues to believe compensating DG exports based on utility-scale solar prices is flawed and inappropriate.[6] Nevertheless, I am not advocating for that methodology here. Instead, I have recommended modifications and improvements to the Companies' RCP proposal, consistent with Decision 75859.[7]

DG rate design has obviously been an ongoing and contentious issue in Arizona. While many aspects of the Value of DG decision were not Vote Solar's preferred outcome, the Commission has shown leadership in putting forward a method for valuing DG that can be used in rate cases to avoid the need for repeated litigation of these issues. While we may disagree with the adopted methodology, Vote Solar

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[5] *Id.* at 177:21–22.

[6] Briana Kobor Phase 2 Direct Test. at 17, n.24 (May 19, 2017) [hereinafter "Kobor Phase 2 Direct"].

[7] As I noted in direct, while I believe there may be legal barriers to implementation of an initial RCP below retail rates, I have nonetheless offered a proposal for an RCP to be implemented in this proceeding. *Id.* at 25:2–16.

appreciates the Commission's explicit recognition that by adopting methodologies for determining the value of DG, it "will reduce the risk of dramatic changes to customers and the solar industry and is consistent with our interest in rate gradualism."[8] As a result, I urge the Commission to include a finding in this proceeding that the RCP value adopted is by definition the value of DG and is not a subsidy.

2.2 Setting the RCP based on more recent utility-scale solar prices

Q. Does the Value of DG decision specify what data should be used to determine the initial, first-year RCP?

A. Yes, the Value of DG decision states that the first-year RCP should be "based on a utility's projects and PPAs with in-service dates within the five years up to and including the test year of the rate case."[9]

Q. Have the parties' proposals in this case complied with this directive in the Value of DG decision?

A. Generally no. My direct testimony and TASC/EFCA's direct testimony recommended that the first-year RCP be based on the five years up to and including the test year for each utility.[10] In contrast, the Companies, Staff, RUCO, and AIC have claimed the first-year RCP should be based on more recent utility-scale solar prices.[11]

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[8] Decision No. 75859 at 173:12–14.
[9] *Id.* at 153:14–16.
[10] Kobor Phase 2 Direct 15:27–16:8; R. Thomas Beach Phase 2 Direct Test. at 37:11–13 (May 19, 2017) [hereinafter "Beach Phase 2 Direct"].
[11] Tilghman Phase 2 RCP Rebuttal 2:9–12; Ralph Smith Phase 2 RCP Direct Test. at 28:20–25 (Apr. 20, 2017) [hereinafter "Smith Phase 2 RCP Direct"]; Lon Huber Phase 2 Rebuttal Test. at 5:11–12 (May 19, 2017) [hereinafter "Huber Phase 2 Direct"]; Gary Yaquinto Phase 2 RCP Direct Test. at 7:15–19 (May 19, 2017) [hereinafter "Yaquinto Phase 2 Direct"].

Q. Have you modified your proposal from direct?

A. I continue to believe that the Commission was very clear in its decision that the first-year RCP be based on the five years up to and including the test year. However, I recognize that the Commission may nonetheless wish to revisit this aspect of Decision 75859. If the Commission decides to modify the five-year time period used to calculate the initial RCP it should continue to maintain the principle of gradualism, as implementation of the RCP structure in place of retail rate net metering is expected to have serious negative impacts on solar economics in the state of Arizona.

In Decision 75958, the Commission adopted two methodologies for valuing DG going forward, stating "in the view of the Commission's desire to provide for a <u>gradual transition</u> to the DG export rate concept, the Resource Comparison Proxy methodology shall be implemented as a means to guide DG export rate compensation within currently pending electric utility rate cases."[12] It was widely expected that the Five-Year Avoided Cost methodology would result in a significantly lower rate, and thus the adoption of the RCP with a five-year rolling average for currently pending cases would result in a more gradual approach. Indeed, in the Value of DG Open Meeting, Staff stated: "[The RCP] is an excellent transitional model because where it will start – or result in a rate that is very close to the retail rate."[13] These statements were all made in accordance with the notion of an initial RCP based on the five years up to and including the test year for these two utilities. Any update that uses more recent and significantly lower costs must keep this in mind to maintain the principle of gradualism.

Vote Solar can accept a first-year RCP that is based on the period from 2012 to 2016, consistent with the Companies' recommendation. That said, Vote Solar

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[12] Decision No. 75859 at 148:13–15 (emphasis added).
[13] Docket No. E-00000J-14-0023, Open Meeting Tr. 338:20–23 (Dec. 20, 2016).

does not accept the Companies' proposal for zero adders for transmission and distribution and the low level estimate of avoided line losses, as discussed below.

2.3 The initial export credit rate must be in effect for one year

Q. Under the Companies' proposal, how long would the initial export credit rate remain in effect?

A. In direct testimony, the Companies had proposed that the initial export credit rate remain in effect for one calendar year, in accordance with Decision 75859. However, in rebuttal, the Companies have modified this proposal and are now requesting that the initial export credit rate remain in effect only until June 30, 2018.[14] It is unclear when the Commission will implement its decision in this proceeding. But given that the hearing in this case is currently scheduled for late October 2017, it is likely that if the Commission were to approve the Companies' proposal, the initial RCP would be in effect for substantially less than one year. Indeed, it is very likely the rate would be in effect for six months or less.

Q. What guidance does Decision 75859 provide on this topic?

A. Decision 75859 states: "[T]o allow the export rate developed using this methodology to change gradually, it will be updated annually after it is initially set in a rate case proceeding or separate rate design phase."[15] It appears this updated proposal from the Companies is yet another example of an attempt to re-litigate issues that were clearly decided in the Value of DG decision.

Q. What impact would the Companies' proposal have on customers who wish to adopt DG solar?

A. It is difficult to quantify any precise effects on potential solar customers. However, the Companies' proposal would certainly place additional and undue

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[14] Dallas Dukes Phase 2 Rebuttal Test. at 24:3–4 (Aug. 28, 2017) [hereinafter "Dukes Phase 2 Rebuttal"].

[15] Decision No. 75859 at 151:25–27.

strain on the families and small businesses considering a solar investment. With the implementation of Phase 2 of these proceedings, the Arizona solar market will be faced with a complete restructuring of the DG compensation model, from retail rate net metering to the purchase of instantaneous exports. This policy change will be complex for local installers who have built their businesses around the prior model, and it will take time for companies to adapt. If the Commission were to also force local installers to face even further decreased rates just six months later, it would exacerbate the challenges already experienced by the industry.

Q. Do you recommend that the Commission approve the Companies' proposal for the initial export credit rate to remain in effect until June 30, 2018?

A. I do not. While slightly delayed, the procedural schedule in this case has not changed in such a material way as to warrant substantial modification to the very clear policy set forth by the Commission in Decision 75859. In addition, Vote Solar's support of a more recent base period for the first-year RCP calculation makes this proposal unwarranted. The Commission should approve an initial export credit rate with an effective period of one year from the date of implementation.

2.4 Avoided transmission, distribution, and line losses must be considered for the RCP to be an accurate proxy

Q. Please summarize the other parties' positions on transmission, distribution, and line losses adders in the export credit rate.

A. The Companies take the position that it is not "appropriate to adjust the Companies' RCP to account for 'Avoided Distribution and Transmission Facilities.'"[16] This assertion is based on the claim that "integration of renewable resources is creating new operational challenges that require more grid

[16] Tilghman Phase 2 RCP Rebuttal 16:23–25.

flexibility,"[17] and that "there is simply no elimination of sunk costs associated with changes in load related to roof-top solar customers."[18] AIC expressed a similar position, stating simply that "avoided transmission and distribution costs should not be included in the RCP calculation."[19] RUCO additionally advocates for adoption of zero-value adders for transmission and distribution, stating: "It is important to note that nearly all the projects for both companies reside in the distribution system. Therefore, even if there was avoidance of transmission and distribution, the value would be nearly identical as rooftop solar."[20] Staff and RUCO support the 3.53% line loss adjustment originally proposed by the Companies.[21]

TASC/EFCA witness Mr. Beach has conducted a marginal cost analysis to determine the appropriate level of adders for transmission and distribution capacity costs and recommends adders of $0.0231/kWh for TEP and $0.0465/kWh for UNSE.[22] Mr. Beach additionally recommends a line loss adder based on losses of 7.83%.[23]

Q. Do you agree with the Companies, AIC, and RUCO that inclusion of adders for transmission and distribution would be inappropriate?

A. I do not. The Commission explicitly stated that adders for transmission and distribution are necessary in order for the RCP "to be an accurate proxy."[24] For the Companies, AIC, and RUCO to categorically claim such adders are not appropriate runs counter to Decision 75859, and is yet another example of an attempt to re-litigate issues that were decided in the Value of DG decision.

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17 *Id.* at 16:16–21.
18 Dukes Phase 2 Rebuttal 22:11–12.
19 Yaquinto Phase 2 Direct 7:19–21.
20 Huber Phase 2 Direct 9:3–6.
21 *Id.*; Smith Phase 2 RCP Direct 30:5–6.
22 Beach Phase 2 Direct 39:21–22.
23 *Id.* at 40:19–21.
24 Decision No. 75859 at 152:11.

While Mr. Tilghman and Mr. Dukes relate their position on inclusion of transmission and distribution adders to claims about renewable integration, any such costs are irrelevant to this discussion. The Commission indicated that transmission and distribution adders must be included for the RCP to be an accurate proxy for the price customers pay for utility-scale solar in comparison with rooftop solar exports. To that end, renewable integration costs are moot, as they would be borne on behalf of both utility-scale and distributed scale solar. Moreover, as discussed in my testimony in Phase 1 of the UNSE proceeding, the Companies have not shown that DG causes significant grid impacts and the claims made by the Companies on this topic are not based on any analyses of the Companies' own systems.[25] This conclusion is support by the testimony of Vote Solar witness Mr. Volkmann here in Phase 2.[26]

Finally, Mr. Huber's statement that nearly all projects for both Companies connect to the distribution system is not relevant, as the Commission has clearly ruled that "DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid."[27] Regardless of the location on the system of individual RCP-portfolio projects, utility-scale solar is bundled together with other system resources for delivery to end-use customers throughout the service territory. Transmission and distribution capacity are utilized in the delivery of system resources and are paid for by the utility's customers through their retail rates.

[25] Briana Kobor UNSE Phase 1 Direct Test. at 16–23 (Dec. 9, 2015); Briana Kobor UNSE Phase 1 Surrebuttal Test. at 21–24 (Feb. 23, 2016).
[26] *See, e.g.*, Curt Volkmann Phase 2 Direct Test. at 6:17–29 (May 19, 2017); Curt Volkmann Phase 2 Surrebuttal Test. at 5–12 (Sept. 29, 2017) [hereinafter "Volkmann Phase 2 Surrebuttal"].
[27] Decision No. 75859 at 152:11–13.

Q. Have the Companies expressed any concerns over Vote Solar's proposed adders?

A. Yes. In Mr. Dukes' rebuttal testimony, he takes issue with my proposal to use the average embedded cost for transmission and distribution as a conservative approximation for the costs of delivery of system resources during solar hours. But Mr. Dukes mischaracterizes the rationale behind my proposal. Mr. Dukes states:

> Witness Kobor essentially argues that the addition of a DG system somehow eliminates the embedded costs of the existing T&D system to which the DG customer is connected. However, it is clear that the DG customer utilizes and relies upon the same sunk cost T&D system as much as or even more than a full requirements customer.[28]

This is incorrect. As clearly explained my direct testimony, I have proposed to base the transmission and distribution adders in the RCP on average embedded costs, as a conservative approximation of the marginal costs related to system resource delivery. My proposal was not intended to be a precise measurement of marginal costs, but rather was offered for the Commission's consideration because of its conservatism and simplicity. These attributes make the methodology well-suited to formulaic annual updates. On behalf of TASC/EFCA, Mr. Beach has undertaken a more complex analysis of marginal cost-based adders. Mr. Beach's analysis produces results that are similar to, or higher than, the results derived from my conservative proxy methodology.

Q. Please describe Mr. Beach's recommendation for transmission and distribution adders.

A. Mr. Beach has assessed the level of marginal transmission and distribution costs avoided by rooftop DG.[29] His analysis results in recommended transmission and

[28] Dukes Phase 2 Rebuttal 22:14–17 (emphasis omitted).
[29] Beach Phase 2 Direct 38:3–15.

distribution adders for each utility. Mr. Beach's recommendations are presented below in Table 1, alongside my recommendations made in direct testimony.

Table 1: TASC/EFCA and Vote Solar Proposed Transmission and Distribution Adders ($/kWh)

	TASC/EFCA[30]	Vote Solar[31]
TEP	$0.023	$0.024
UNSE	$0.047	$0.021

Q. Why are TASC/EFCA's adders different than Vote Solar's adders?

A. As shown in Table 1, TASC/EFCA's adders are different from Vote Solar's, which is to be expected given the different methodology on which they were based. Vote Solar has recommended adders based on the average embedded cost for transmission and distribution identified in the Companies' COSS while TASC/EFCA has recommended adders based on an analysis of marginal costs. TASC/EFCA's marginal cost analysis results in transmission and distribution adders for TEP that total to within one tenth of one cent of Vote Solar's proposed TEP adders. For UNSE, the TASC/EFCA adders total to more than double Vote Solar's proposed adders.

Q. Do you have any modifications to your proposed line loss adjustment?

A. Yes. My original methodology was developed to be most consistent with the rest of the RCP calculation. I have my updated recommendation to: (1) base the RCP on more recent utility-scale solar data, as discussed in Section 2.2; and (2) use a single RCP value for both TEP and UNSE in this case, as discussed in Section 2.5. As a result, it is reasonable to update the line loss adjustment to be based on 2016 data combined for both utilities. This results in a line loss adjustment of 6.98%.

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[30] *Id.* at 41:4.
[31] Kobor Phase 2 Direct 19:13.

2.5 <u>Combined RCP for TEP and UNSE</u>

Q. Please summarize the parties' positions on whether the Commission should adopt a separate or a combined RCP value for TEP and UNSE.

A. In direct testimony, Staff recommended a separate RCP value for TEP and UNSE for the following reasons:

1. UNSE and TEP are separate companies.
2. They each have their own specifically identified PPAs and owned grid-scale solar facilities.
3. They each have separate rate cases.
4. They have different cost structures, cost of capital, and depreciation rates.
5. They have different service territories.
6. UNSE and TEP each have a different cost of service.
7. UNSE and TEP each have separate and distinct rates for the provision of utility service.[32]

Despite this recommendation, Staff states: "[I]f the Commission determines that these utilities should have a combined RCP, Staff would not object."[33]

The Companies, RUCO, and AIC all support a combined RCP.[34] In contrast, TASC recommends a separate RCP for TEP and UNSE.[35]

Q. What is the Companies' rationale for a combined RCP for TEP and UNSE?

A. The Companies indicate that they have advocated for a combined RCP in the Value of DG docket and that adoption of a combined RCP would be consistent with their position in that case.[36] They additionally point out that TEP and UNSE have access to the same market, operate as a single balancing authority, can take

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[32] Smith Phase 2 RCP Direct 29:19–29.
[33] *Id.* at 30:10–11.
[34] Tilghman Phase 2 RCP Rebuttal 11:13–15; Huber Phase 2 Direct 5:4; Yaquinto Phase 2 Direct 7:6.
[35] Beach Phase 2 Direct 41:4–5.
[36] Tilghman Phase 2 RCP Rebuttal 10:11–13.

advantage of shared facilities, and utilize shared personnel.[37] Finally, the Companies raise concern over the potential for a separate RCP for UNSE to result in years in which no new utility-scale solar is procured, resulting in gaps in RCP data from which to draw.[38]

Q. Do you have a response to the Companies' statement that a combined RCP would be consistent with their positions in the Value of DG docket?

A. Yes. While I agree that the Companies have consistently presented a combined RCP value for TEP and UNSE in the Value of DG docket, the Commission has not found that a combined RCP should be adopted for these two utilities. The Companies point to Staff's combined RCP calculations presented in the Value of DG docket as evidence that the Commission approved a combined RCP. However, the stated purpose of the Value of DG docket was not to adopt an RCP value for any utility, but rather to determine the appropriate methodology for calculating an RCP value in the rate cases. Specific numerical calculations were presented illustratively to assist parties in discussing the spreadsheet tool used to develop these calculations, not to advocate for specific values that would be implemented.

Q. Would a combined RCP be consistent with the Value of DG decision?

A. In Decision 75859, the Commission did not state whether it is best to adopt a combined or separate RCP for TEP and UNSE. But as I explained in my direct testimony, the adoption of a combined RCP could prove problematic given other parameters that have been set by Decision 75859. Namely, the Commission ordered that the first year RCP be based on the five years up to and including the utility's rate case test year, and TEP and UNSE have different test years.[39]

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[37] *Id.* at 8:1–10.
[38] *Id.* at 8:20–23.
[39] Decision No. 75859 at 172:1–4.

In addition, the Commission indicated that annual updates would be permitted to the RCP, but "[t]he formula should only be changed within a rate case to allow parties an opportunity to scrutinize the assumptions and weighting of the methodologies."[40] TEP and UNSE are separate utilities that file separate rate cases before the Commission. It is unclear how the Commission could approve a single combined RCP value for both TEP and UNSE when the issue would need to be explicitly addressed and approved in each separate rate case docket. In the present proceedings, the Commission has elected to combine the second phase of the rate cases for these two utilities. But in the future, I would expect the Companies to have separate proceedings with different test year periods. A combined RCP rate would thus make it difficult to comply with Decision 75859 in the future.

Q. Do you have a response to the Companies' argument that TEP and UNSE have access to the same market, operate as a single balancing authority, can take advantage of shared facilities, and utilize shared personnel?

A. A similar argument is made by RUCO and AIC.[41] However, I do not agree that these reasons support adoption of a combined RCP. While I do not disagree with any of the facts listed by the Companies describing the ways in which TEP and UNSE share operations and personnel, I find Mr. Smith's list of seven differences between the two utilities to be more relevant to the RCP methodology.[42] Mr. Smith points out that TEP and UNSE are separate companies with separate cost structures, separate utility-scale solar generation portfolios, and separate rates for their customers.[43] All of these differences are far more relevant to the utility's cost to deliver utility-scale solar generation to their customers than the fact that they may share some operations and personnel.

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[40] *Id.* at 173:9–11.
[41] Huber Phase 2 Direct 6:2–3; Yaquinto Phase 2 Direct 7:3–6.
[42] *See* Smith Phase 2 RCP Direct 29:19–29.
[43] *Id.*

Q. Do you have a response to the Companies' concern over the potential for a separate RCP for UNSE to result in years in which no new utility-scale solar is procured, resulting in gaps in RCP data from which to draw?

A. Yes. It appears that the Companies are concerned that UNSE has fewer utility-scale solar resources and PPAs on which to base an RCP calculation and, due to its relatively small size, may be less likely to contract for or build new resources with the same degree of regularity that one might expect from a larger utility like APS or TEP.[44] This does not appear to be an immediate-term issue, as Staff's RCP model identified solar projects and PPAs for UNSE in four out of six years examined.[45]

While UNSE may indeed be more prone to years in which fresh RCP data is unavailable, such a circumstance is already addressed by the Commission's direction in Decision 75859 without the need to combine the UNSE and TEP portfolios in a single RCP calculation. First, Decision 75859 states the RCP calculation should be updated annually based on the five year rolling average. This means that in the event an annual update for a utility's RCP does not include new projects for the most recent year, the oldest vintage projects will still roll out of the calculation to provide for more up-to-date information. Second, if there are no RCP portfolio resources for a utility over the five year RCP period, Decision 75859 states: "If projects of recent vintage are not available for the utility, Staff shall use pricing data from available industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available."[46] This would allow use of pricing data from other utilities for UNSE in the event no new PPAs were signed and all UNSE-specific data rolled out of the RCP calculation. Taken together, these two provisions eliminate any concern over what a smaller utility like UNSE may do in the event new RCP data is not available.

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[44] Tilghman Phase 2 RCP Rebuttal 8:20–23.
[45] Staff RCP model.
[46] Decision No. 75859 at 172:4–6.

Q. Is there a consensus among parties that the Commission intended industry data to apply only in the event that no RCP-eligible resources were available for a given utility?

A. It appears there is disagreement on this topic. The Companies argue that leaving "certain years 'blank' when calculating the RCP if no utility projects were placed in-service during the rolling five-year period is inconsistent with the VOS Order."[47] In addition, RUCO "strongly believes" that missing years should be filled in.[48]

Q. What does Decision 75859 state regarding this topic?

A. Decision 75859 only states that industry data should be used in the event that "projects of recent vintage are not available for the utility."[49] The key word in this sentence is the word "recent," which is not defined in the Commission's order.

Q. What is your position on the inclusion of industry data in the RCP calculation?

A. I find that including industry data for individual year gaps in the RCP portfolio is not only unnecessary as indicated above, it is also impractical. Even if the Commission were to approve the use of industry data in the event of single-year gaps in the RCP portfolio data, it is unclear how that data would be weighted with the other data in the portfolio. Staff's RCP model weights each utility project and PPA by the energy supplied by that resource in its development of the weighted average RCP. This method allows for a blended price that represents the average per kWh cost of the utility-scale solar portfolio to the utility's customers. No party has taken issue with the concept of energy-based weighting.[50]

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[47] Tilghman Phase 2 RCP Rebuttal 20:10–12.
[48] Huber Phase 2 Direct 6:15.
[49] Decision No. 75859 at 172:4.
[50] There is some disagreement among parties regarding what data to use for the energy weighting, but all parties agree that resource pricing should be weighted by project energy.

If the Commission were to approve a method by which single-year gaps in utility RCP portfolios could be filled with pricing from other utilities, it is unclear how that data could be weighted against the other RCP data. A single large project from another utility, if weighted based on its energy delivered, could dwarf the remaining projects in the RCP portfolio of a smaller utility, even though the smaller utility's customers would receive no energy from that project. For example, TEP has recently contracted for a 100 MW solar project that is expected to be in service in 2019.[51] If this project were to be included in a UNSE RCP portfolio, its large size would outweigh the UNSE-specific data in the calculation.[52] Because the RCP is intended to be a proxy for what a utility's customers pay for utility-scale solar generation, it is not appropriate to flood the calculation with data from other utilities when data from the customers' own utility exists. To do so would break the link between the RCP and customer costs. Moreover, any decremental weighting to industry data in a smaller utility's RCP portfolio would likely be arbitrary, subject to lengthy debate, and too complex to implement in the formulaic annual updates. As a result, it is impractical to fill single-year gaps in a utility's RCP portfolio, and use of industry data should be limited to situations in which no data is available in the five-year RCP window.

While I understand the outcome of the APS settlement is not precedent setting on this issue, it is important to note that the settlement adopted this methodology. The APS settlement stated: "If there are no grid-scale solar photovoltaic projects in any particular year of the rolling five-year period described above, the rolling 5 year average will be calculated without a project for that particular year."[53]

[51] Elec. Light & Power/POWERGRID Int'l, *Tucson Electric Power to buy cheap solar power from solar-storage project* (May 22, 2017), https://goo.gl/Nyje5B.
[52] UNSE currently has only 66 MW of solar resources. UNSE, *Red Horse Expansion More Than Doubles Solar Capacity* (July 2016), https://goo.gl/FPAXwR.
[53] Docket No. E-01345A-16-0036, APS Plan of Admin., Resource Comparison Proxy at 5, http://docket.images.azcc.gov/0000178413.pdf.

Q. What recommendations do you have on this topic?

A. Because the Commission has combined the proceedings for TEP and UNSE in this case, I believe it may be appropriate to approve a combined RCP for the present proceedings only. I recommend that the Commission revisit this decision in the next rate cases for UNSE and TEP, where is it more appropriate to adopt a separate RCP rate for the reasons described above. In addition, I recommend the Commission find that in the event there are no utility-scale solar projects in any particular year of the five-year RCP period, the RCP will be calculated without a project for that particular year, and industry data will only be used in the event that there is no utility-specific data in the five-year period.

2.6 Actual production data should be used in the RCP calculation for utility-owned facilities

Q. What data sources have the Companies proposed to use for energy production from utility-owned facilities in the RCP model?

A. Mr. Tilghman states: "The Companies used expected production, provided by the vendor, rather than actual production as Staff used, to better represent and monetize the value to the Companies and their customers associated with being able to curtail a facility without regards to being 'penalized' in the RCP calculation."[54] The Companies express concerns that using actual data will not take into account the benefits provided by the ability to curtail utility-owned solar generation, resulting in an over-estimate of the price per kWh from these facilities.[55]

[54] Tilghman Phase 2 RCP Rebuttal 4:6–9.
[55] *Id.* at 14:18–15:2.

Q. Have the Companies provided any evidence to suggest that curtailment has had a significant impact on production for the utility-owned solar facilities in the RCP model?

A. No. The RCP model contains four utility-owned solar facilities: Prairie Fire and Ft. Huachaca I for TEP, and Rio Rico and La Senita for UNSE.[56] When asked in discovery to provide information on the number of hours and volume of energy not produced by these facilities due to curtailment and/or grid management services, the Companies stated they do not track this information.[57] I have examined the assumptions used for energy weighting in the Staff and Companies' models and do not find evidence that curtailment has had any impact on the energy from these four facilities. Indeed, Staff and the Companies assume the same production level for Rio Rico, and Staff's assessment of actual production is higher than the Companies' assessment of expected production for Prairie Fire and Ft. Huachaca I. La Senita is not included in the Companies' model, so data on this facility could not be compared.

Q. Do you have any concerns about using expected production levels rather than actual data?

A. Yes. I am concerned that using expected production data would not incorporate unexpected changes in circumstances that may lower the energy produced by a facility, thereby underestimating the per kWh costs of the utility-owned portfolio. In the Value of DG docket, Staff identified a TEP-owned solar facility (White Mountain) that was not performing as expected and asked the Company to provide updates to Staff on this facility to assist Staff in its determination of whether a plant adjustment may be warranted in future cases.[58] While White Mountain has been excluded from the current RCP portfolio, if a future utility-owned solar plant experienced similar production issues, it would not be captured

[56] Staff RCP model.
[57] TEP/UNSE Joint Resp. to VS P2 9.1(c), (d) (Attach. BK-SR-1 at 11–12).
[58] Letter from Thomas M. Broderick, Dir., Utils. Div., to Parties of TEP Rate Case (Sept. 23, 2016), http://docket.images.azcc.gov/0000173532.pdf.

by an RCP based on expected production and would result in an underestimate of per unit costs from that facility.

Q. What do you recommend for the Commission?

A. I recommend the Commission adopt an RCP based on actual production data from utility-owned solar facilities. To the extent significant curtailment occurs, the Companies should be required to provide evidence that may be incorporated into the RCP calculation to address the Companies' concerns.

2.7 Vote Solar supports the Companies' request to establish the year two RCP in this proceeding

Q. Please describe the Companies' proposals to establish the year two RCP in this proceeding.

A. In rebuttal testimony, Mr. Dukes calculates a second year RCP of $0.0817/kWh.[59] However, it appears that this calculation was based on a minor spreadsheet error that has been clarified through discovery.[60] Mr. Dukes has now offered revised work papers that depict a second year RCP of $0.0824/kWh.[61] Even with this update, the RCP would be subject to the 10% step down limitation, and the Companies' proposed first-year RCP of $0.0973/kWh results in a second year export rate of $0.0876/kWh.[62] Mr. Dukes states the Companies know which facilities will be in operation in 2017 and proposes setting the second year RCP in this proceeding to provide for administrative efficiency.[63]

[59] Dukes Phase 2 Rebuttal 24:4–10.
[60] TEP/UNSE Joint Resp. to VS P2 14.1 (Attach. BK-SR-1 at 16).
[61] RCP Model_TEP-UNSE-CompSen Confidential (092017).xlsx.
[62] Dukes Phase 2 Rebuttal 24:8–10.
[63] *Id.* at 25:23–26:6.

Q. Do you support the Companies' request to establish the year-two RCP in this proceeding?

A. I do. I agree with Mr. Dukes that setting the next year's RCP in this proceeding will improve administrative efficiency. Because the Companies are already aware of the full RCP portfolio that will be operational at the end of 2017, it is reasonable to set the rate today.

Q. While you support establishing the year-two RCP in this proceeding, do you agree with the Companies' proposed RCP for year two?

A. No, the Companies' year-two RCP proposal is too low. In Section 2.12 below, I discuss my recommendation for the first and second year RCP.

2.8 Vote Solar supports the Companies' proposed system eligibility requirements

Q. Please summarize the Companies' proposal for system eligibility requirements.

A. The current net metering riders for both Companies state that net metered systems must have "a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity."[64] This requirement is modeled after the Commission's net metering rules, which implement the same restriction on system sizing.[65] In its proposed Plan of Administration ("POA"), Staff included language modeled after the APS settlement, which would base eligible system capacity on 150% of the prior year's one-hour peak demand.[66]

[64] Current Rider R-4 TEP and UNSE.
[65] A.A.C. R14-2-2302(13)(d).
[66] Smith Phase 2 RCP Direct, Attach. RCS-8 at 4–5.

The Companies have opposed adoption of the APS settlement eligibility requirements and suggest the requirement "should either be deleted in its entirety, or made to be consistent with current size limitations."[67] The Companies have proposed the following wording for system eligibility in the POA: "A facility's expected annual production cannot exceed 125% of the customer's annual consumption over the prior twelve months. If a customer's previous twelve months of consumption is not available, then the customer's expected energy consumption shall be used."[68]

Q. Do you agree with the Companies on this issue?

A. Yes. I agree with Mr. Tilghman that revising system eligibility requirements is unnecessary. The Commission should direct the Companies to draft RCP Riders that include the same eligibility criteria as the current net metering riders, namely, that systems must have a generating capacity less than or equal to 125% of the customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the customer's electric service drop capacity. Doing so would obviate the need for additional system eligibility definitions in the RCP POA. However, if the Commission would like to place additional wording in the POA, Vote Solar suggests the following minor modification to the Companies' proposed wording to maintain consistency with the Commission's rules:

> In the event that load data does not exist for the prior twelve months, the customer's electric service drop capacity should be used, rather than the customer's expected energy consumption.

[67] Tilghman Phase 2 RCP Rebuttal 21:8–9.
[68] *Id.* at 21:13–16.

2.9 RUCO's proposal for a market trigger is counter to Decision 75859 and should be rejected

Q. Please describe RUCO's proposal for a market trigger.

A. Mr. Huber claims "RUCO is concerned about high market uptake of solar especially given a generous RCP."[69] Mr. Huber links this concern to the absence of "a policy like the RPS Credit Option."[70] This is presumably because that rate structure would periodically reduce the export compensation rate based on the level of solar adoption, rather than based on a predictable annual schedule as approved by Decision 75859. To address this concern, RUCO proposes the following:

> RUCO recommends that if TEP and UNSE hit 75% of the top historical peak quarter starting back to 2014 in terms of capacity, the Companies must file a report to the Commission noting the uptake and calculating the near and long-term costs of continuing at the current RCP rate. If the market hits 100% of the past peak quarter, RUCO recommends an automatic 10% decrease of the RCP be automatically applied early unless action is taken by the commission.[71]

Finally, in the event that the trigger was hit, RUCO proposes an additional annual adjustment be made to lower the RCP in addition to the 10% trigger adjustment.[72]

Q. How does this proposal align with what was decided in the Value of DG docket?

A. RUCO's proposal for a market trigger is directly counter to the findings of the Commission in Decision 75859 and should be rejected. In the Value of DG docket, RUCO proposed an RPS Credit Option proposal that would implement a compensation rate for DG that would step-down based on levels of solar

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69 Huber Phase 2 Direct 21:4–5.
70 *Id.* at 21:2–3.
71 *Id.* at 21:7–12.
72 *Id.* at 21:18–19.

adoption.[73] The Commission did not adopt that proposal. Instead, the Commission concluded: "A re-assessment of the value of DG formula in each electric utility rate case with annual updates to the formula inputs in order to inform compensation rates to be paid for DG exports precludes the need for the implementation of a separate step-down mechanism."[74] RUCO's proposal for a market trigger is an attempt to re-litigate an issue explicitly decided by Decision 75859, and it should therefore be rejected.[75]

Q. Even if RUCO's market trigger proposal complied with Decision 75859, are there flaws with this proposal?

A. Yes. Similar to the Companies' characterization of the RCP at any level as a "subsidy," RUCO's proposal for a market trigger seems to be premised on the idea that compensation for rooftop solar exports at the RCP value represents some level of subsidy. This premise undermines the Value of DG decision by placing some subjective level of value on DG that is different from the value defined by the RCP adopted in this proceeding. The Commission has clearly indicated the RCP method is intended to result in a numerical calculation of the Value of DG. To that end, the market should decide the optimal level of DG adoption that balances investment costs with that value. If the RCP rate reasonably values DG exports and there is significant new growth in DG during the year that export rate is in effect, this is an economically efficient result that will benefit the Companies, solar customers, and non-solar customers. RUCO's proposal to collar the market based on arbitrarily selected installation rates would unnecessarily interfere with and undermine a currently robust and competitive market.

Moreover, even if the Commission wished to limit the DG market based on some arbitrary installation rate, doing so would surely open future cases up to extensive litigation regarding what the "optimal" rate of DG deployment should be. This

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[73] Docket No. E-00000J-14-0023, RUCO Closing Br. at 8:6–10:17 (July 20, 2016), http://docket.images.azcc.gov/0000171988.pdf.
[74] Decision No. 75859 at 171:6–9.
[75] *Id.* at 177:21–22.

would require some parallel assessment of value, as the entire premise of an optimal install rate other than that set by the market undermines the definition of RCP as value. This approach would effectively render the multi-year process that resulted in the Value of DG decision obsolete.

Q. What do you recommend in regard to RUCO's proposal for a market trigger?

A. I recommend the Commission reject any proposal that would trigger additional step-downs to the RCP based on market penetration rates. The Commission has already decided that such a mechanism is unnecessary in Decision 75859, and it is not in the public interest to arbitrarily collar competitive markets and introduce additional and unnecessary complexity into the RCP process.

2.10 Vote Solar supports RUCO's proposal to include RECs in the purchase of exported energy

Q. Please describe RUCO's proposal to include RECs in the purchase of exported energy.

A. Under each of Mr. Huber's proposed rates, customers would be required to exchange RECs for the renewable energy that either received the RCP rate or the RPS Credit Option rate.[76] Mr. Huber explains:

> If the RCP is tied to utility scale solar, RUCO is wondering why rooftop solar adopters should not be required to exchange RECs in exchange for receiving a solar derived rate. Solar export payments come from every customer, including non-solar customers, through the fuel adjustor. As it stands today, when a solar customer installs solar but doesn't exchange RECs that energy cannot be counted as clean renewable solar energy for Renewable Portfolio Standard (RPS) purposes. If ratepayers are paying solar customers for their exports above a wholesale rate, solar customers should have to

[76] Huber Phase 2 Direct 10:3–11:5.

> exchange RECs. This would in turn allow the Companies to be able to count these RECs towards its RPS compliance.[77]

Q. Do you agree with RUCO on this issue?

A. Yes. Because the RCP is tied to the price of utility-scale solar energy for which the Companies obtain RECs, it is reasonable to require the exchange of RECs with the Companies' purchase of exported power at the RCP. However, the customer should be able to maintain the RECs associated with the solar energy they produce and consume onsite and have the option to maintain all RECs in exchange for a lower export credit rate.

Q. Do you agree with Mr. Huber's proposal for the lower purchase rate in the event that a customer chooses to maintain their RECs?

A. No. Mr. Huber has proposed to use the wholesale rate for such purchases.[78] I find that the wholesale rate would be significantly too low. The 2017 Market Cost of Comparable Conventional Generation ("MCCCG") is roughly $0.025/kWh for TEP and $0.027/kWh for UNSE.[79] Presuming the Companies' proposed RCP of $0.097/kWh for both TEP and UNSE is approved, such a proposal would imply a REC value of roughly $0.07/kWh. While there is not an active REC market in Arizona, RECs traded in the Western Electricity Coordinating Council ("WECC") trade below $0.01/kWh.[80] RUCO's proposal to charge customers $0.07/kWh to maintain their RECs is punitive. Customers should have the option to maintain RECs for a reasonable price. Vote Solar proposes that if a customer wishes to maintain their RECs, they be provided with a purchase rate that is $0.01/kWh below the RCP. This rate would more properly approximate the current value of RECs in the WECC. To avoid the need for a separate RCP rate, REC retention

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[77] *Id.* at 11:8–17.
[78] *Id.* at 10:3–5.
[79] 2017 TEP REST Appl. Ex. 2 at 20; 2017 UNSE REST Appl., Ex. 2 at 20.
[80] For example, Pacific Gas & Electric Company reports spending $0.008/kWh for RECs in 2015. Pac. Gas & Elec. Co., *August 8, 2016 Draft Renewable Energy Procurement Plan*, at D-2, D-6 (Aug. 8, 2016), https://goo.gl/Ah6MBb.

could be accomplished through a separate rate rider with a charge for each kWh exported.

2.11 Augmenting the basic RCP structure

Q. What proposals have parties presented to augment the basic RCP structure?

A. There are three proposals in this proceeding to augment the basic RCP structure laid out in Decision 75859.

1. Vote Solar's proposal for adoption of a 10% floor on annual export compensation rate decline after the 10-year lock-in period.[81]
2. RUCO's proposal for an optional adjustment to the RCP based on time of day and season.[82]
3. RUCO's proposal to create adders based on inverter settings.[83]

Each of these three proposals would build on the structure set forth by the Commission in the Value of DG decision to create price signals providing additional certainty for investment and incentives to unlock the potential for DG to be deployed in ways that are most beneficial to the grid.

Q. Have the Companies critiqued Vote Solar's proposal for a 10% floor on annual export compensation rate decline after the 10-year lock-in period?

A. No, the Companies' rebuttal testimony did not take issue with this proposal. In addition, Mr. Huber's expressed concerns over the basic structure of the RCP approved in Decision 75859 that could be eased by Vote Solar's proposal. Mr. Huber states:

> The RCP method cliffs at year 10: "A DG system that interconnects to a utility's distribution system after a DG export rate is set for that utility shall be placed on the DG export rate effective at the time of the interconnection for a period of ten years." This raises serious

[81] Kobor Phase 2 Direct 26:10–29:2.
[82] Huber Phase 2 Direct 18:2–11.
[83] *Id.* at 19:14–15.

> consumer protection issues if customers are not aware of this possible large change in the future compensation rate. RUCO strongly urges a revision to the current disclaimer to warn customers about this potential cliff.[84]

Vote Solar agrees that the basic structure of the RCP approved in Decision 75859 creates significant pricing uncertainty for new solar customers in Year 11 and beyond, which raises consumer protection issues. However, those issues are inherent in the structure of the export credit rate approved by the Commission and are not something that can be alleviated by a disclaimer. Without augmentation, the structure of the export compensation laid out in Decision 75859 makes it nearly impossible for customers to assess the viability of an investment in rooftop solar. Customers who install rooftop solar commit today to an investment with a large upfront expense that is expected to pay off over decades. If the investment goes underwater after 10 years, the customer will have no ability to recoup their costs.

This aspect is most troubling when one considers that the compensation rate for exports is being informed by the price the Companies pay for utility-scale solar. Yet utility-scale solar projects are routinely procured based on 20-year fixed or escalating price PPAs. In essence, the Commission is requiring that individual households and small businesses bear greater risk than sophisticated power project developers, while offering no additional financial benefits to compensate for that risk. If utility-scale solar developers are unable to finance solar projects without a 20-year PPA, it is unreasonable to expect households and small businesses to do the same.

Q. How would Vote Solar's proposal alleviate these concerns?

A. Vote Solar has proposed to build on the structure set forth in Decision 75859 to provide a floor on the price that the export credit rate would take after the 10-year lock-in expires. This proposal would allow customers to forecast a worst-case

[84] *Id.* at 22:2–8 (quoting Decision No. 75859 at 179:14–16).

scenario investment benchmark, while enabling the export credit rate to change annually based on the prevailing policy of the Commission.

Q. What is your position on RUCO's proposal for an optional adjustment to the RCP based on time of day and season?

A. Vote Solar supports RUCO's proposal in principle. However, this support is contingent on several key aspects to the design. Creating an avenue for time-varying price signals on the export credit rate would communicate to customers the benefits associated with increased solar output during the peak period and decreased solar output during the off-peak period. Such price signals may help to incentivize west-facing systems and adoption of battery storage technology.

Q. For Vote Solar to support this proposal, how must the TOU adjustment to the RCP be designed?

A. First, a TOU adjustment to the RCP must be optional for all customers. RUCO has proposed to include the RCP TOU adjustment on their proposed volumetric TOU rate and provide customers the option to instead choose a three-part rate with a flat RCP. Mr. Huber states: "Since this rate is optional, RUCO sees no issue with this structure."[85] If the only available alternative to the TOU adjustment to the RCP is the three-part rate, I would not characterize the proposal as "optional." Demand charges are hugely unpopular and I expect few customers would enroll on the three-part rates being proposed. Vote Solar suggests that rather than require TOU adjustments to the RCP on some tariff options, the Commission approve a separate RCP-TOU rider that can be implemented at the customer's option on any available tariff. This rate rider would function similar to the REC rate rider discussed in Section 2.10 of this testimony. The rider would provide additional payments for energy exported during the peak period and charges for energy exported during the off-peak period. The rider would be

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[85] *Id.* at 18:4.

optional for all DG customers, regardless of the tariff on which they chose to take service.

Second, the TOU adjustment must be calibrated to result in the flat-rate RCP for the average customer without load management or technology. In Mr. Huber's proposal, he provides illustrative rates stating: "For instance, if the flat RCP rate is 10 cents/kWh and a TOU RCP rate is 5 cents/kWh for off peak and 15 cents/kWh for on peak, a customer through load management and technology can get to the 10 cent/kWh value and above."[86] It appears that under Mr. Huber's proposal, a customer may need to actively manage load and/or install technology to obtain an average export credit rate commensurate with the RCP rate adopted by the Commission. Such a design would penalize customers for selecting the RCP-TOU Rider, rather than provide a positive incentive to customers who are willing and able to engage in load management and adopt costly technologies, such as battery storage. Nowhere in Decision 75859 did the Commission state that customers must engage in load management and/or adopt costly technologies to receive the RCP-based export credit rate. As a result, the RCP-TOU Rider should be designed as an optional rider to incentivize customers, rather than penalize them.

Q. What is your position on RUCO's proposal to create adders based on inverter settings?

A. Vote Solar is open to this concept as an additional optional Rate Rider, but I would need to have more detail on the proposal before developing an official position. I recommend that the Commission require the Companies to develop a proposal for an optional rate rider that would provide additional credits to customers based on inverter settings beneficial to utility grid management that could be presented and evaluated in each Company's next rate case.

[86] *Id.* at 18:8–11.

2.12 Revised Vote Solar Recommended RCP

Q. Have you revised the proposal for the first-year RCP that you made in direct?

A. Yes. I have made several key modifications to the proposed RCP that I recommended on direct. While my original proposal is supported by the Value of DG decision, I recognize that the Commission may desire to adopt a first-year RCP for TEP and UNSE based on more recent information. This constitutes the primary change in my recommendation. In addition, I can accept the Companies' proposal to have a combined RCP for TEP and UNSE in this proceeding, but recommend that this issue be revisited in each Company's next rate case. Finally, I have made minor changes to my proposed adders for distribution, transmission, and line losses to be consistent with the concept of a joint RCP for the two utilities. My revised proposal is presented in Table 2 below.

Table 2: Vote Solar Proposed First-Year RCP ($/kWh)

	TEP/UNSE
Base RCP	$0.094
Transmission Adder	$0.011
Distribution Adder	$0.012
Line Loss Adder[87]	$0.007
Total RCP	**$0.124**

As shown in Table 2, Vote Solar is now recommending a first-year RCP of $0.124/kWh for both TEP and UNSE. While there has been some criticism in this proceeding over proposals for RCP values that are in excess of the retail rate,[88] I note that Staff has proposed an RCP as high as $0.128/kWh for UNSE, which exceeds the UNSE retail rate.[89] In addition, the Companies have indicated they are not opposed to adoption of an RCP that exceeds the retail rate:

[87] Adders derived by multiplying line loss adjustments of 6.98% by Base RCP value.
[88] *See, e.g.*, Huber Phase 2 Direct 8:9–13.
[89] Smith Phase 2 RCP Direct 29:14.

> [A]s evidenced by the Companies' proposed initial rate of $0.0973 per kWh exported, which is in excess of the average current retail rate for UNS Electric, the Companies believe many factors should be considered such as bill impacts, offset rates, payback periods, and continued cost shifting. The Companies believe they have struck an appropriate balance among these competing factors that allows customers to continue to have the choice to go solar and to begin mitigating the cost shift to non-solar customers.[90]

While Vote Solar disagrees that the Companies' proposal achieves an appropriate balance, we are in alignment that many factors should be considered in the Commission's evaluation of the proposed RCP.

The difference between Vote Solar's proposed RCP of $0.124/kWh and the Companies' proposed RCP of $0.0973 is the inclusion of transmission and distribution adders, as well as a more complete line loss adder in the Vote Solar proposal. In addition to the fact that Decision 75859 explicitly stated that these adders must be included in order for the RCP to be an "accurate proxy,"[91] inclusion of these adders is consistent with the Commission's adoption of a $0.129/kWh RCP for APS which was "inclusive of undifferentiated transmission, distribution, and loss components."[92]

Q. Have you developed a proposal for the second-year RCP?

A. I have. I recommend that the Commission accept Mr. Duke's revised calculation for the second-year RCP base value of $0.080/kWh[93] and maintain the transmission, distribution, and line loss adders developed for the first-year RCP. This calculation is summarized in Table 3 below.

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[90] TEP/UNSE Joint Resp. to STF P2 4.10 (Attach. BK-SR-1 at 18). Furthermore, the Companies' revised proposals with first-year RCPs below retail rates continue to violate the Commission's net metering regulations, which codify retail rate net metering. *See* Kobor Phase 2 Direct 25:2–16.
[91] Decision No. 75859 at 152:11–17.
[92] Decision No. 76295 at 25:8–9 (Aug. 18, 2017).
[93] Including a small adder for line losses, the Companies have proposed $0.0824/kWh.

Table 3: Vote Solar Proposed Second-Year RCP ($/kWh)

	TEP/UNSE
Base RCP	$0.080
Transmission Adder	$0.011
Distribution Adder	$0.012
Line Loss Adder[94]	$0.006
Total RCP	**$0.109**

As shown in Table 3, Vote Solar recommends a second-year RCP of $0.109/kWh. However, because this value is more than 10% lower than the first-year RCP, per Decision 75859 the adopted second-year export credit rate should be $0.112/kWh.

Q. Do you maintain your proposal for a 10% floor on export compensation rate decline after the 10-year lock-in period?

A. Yes. As I have explained in detail above and on direct, this proposal is critical for maintaining a sustainable market. Table 4 below provides a summary of proposed export compensation rates for the first 20 years under my proposal.

[94] Adders derived by multiplying line loss adjustments of 6.98% by Base RCP value.

Table 4: Vote Solar's Proposed RCP Years 1-20 ($/kWh)

	2017	2018
Year 1	$0.124	$0.112
Year 2	$0.124	$0.112
Year 3	$0.124	$0.112
Year 4	$0.124	$0.112
Year 5	$0.124	$0.112
Year 6	$0.124	$0.112
Year 7	$0.124	$0.112
Year 8	$0.124	$0.112
Year 9	$0.124	$0.112
Year 10	$0.124	$0.112
Year 11	$0.112	$0.100
Year 12	$0.100	$0.090
Year 13	$0.090	$0.081
Year 14	$0.081	$0.073
Year 15	$0.073	$0.066
Year 16	$0.066	$0.059
Year 17	$0.059	$0.053
Year 18	$0.053	$0.048
Year 19	$0.048	$0.043
Year 20	$0.043	$0.039

2.13 Comparison of RCP proposals to current compensation must take into account expected increases in retail rates

Q. How should the Commission evaluate the impact of parties' proposed RCP rates in comparison to compensation received under retail rate net metering?

A. Despite the fact that Vote Solar's proposed RCP remains above the retail rate, the proposal would still result in a significant reduction in the compensation paid for rooftop solar exports compared to retail rate net metering. This is because under retail rate net metering, exports are compensated at the retail rate and customers could reasonably expect the retail rate would increase over time. Given the fact that rooftop solar is a 20 to 30-year investment, rising retail rates have a significant impact on the value of the customer's investment. In contrast, under the export compensation structure set forth in Decision 75859, the price the customer receives for exports will not go up over time, but will be fixed for a period of 10 years. As I stated in direct testimony, this fundamental structural difference will result in significant decreases to compensation for rooftop solar exports over the life of a system compared to retail rate net metering.[95]

Even if the Commission approves Vote Solar's proposed RCP of $0.124/kWh and its proposal for a 10% floor on annual export compensation rate decline after the 10-year lock-in period, it is expected that customers signing up for DG as soon as 2020 would receive compensation for their exports 30-40% below the compensation expected under retail rate net metering. If the Commission approves Vote Solar's proposed RCP but rejects its proposal to augment the base RCP structure, it is difficult to reliably forecast the impact on customers, as the export credit rate after year 11 would be unknown. For purposes of comparison, Table 5 below compares export compensation under retail rate net metering with Vote Solar's proposed RCP rates, assuming Vote Solar's proposal for a 10% floor on annual export compensation rate decline after the 10-year lock-in period is approved.

Table 5: Comparison of Net Metering with Vote Solar RCP assuming Vote Solar Proposal for years 11+, 2020-vintage Customers

	Reduction in Export Compensation
TEP Residential	41%
UNSE Residential	33%
TEP Small Commercial	39%
UNSE Small Commercial	38%

As shown in Table 5, even if the Commission approves Vote Solar's proposal for a 10% floor on annual export compensation rate decline after the 10-year lock-in period, Vote Solar's proposed RCP rates are expected to result in significant

[95] Kobor Phase 2 Direct 11:1–15.

reductions in export rate compensation compared to retail rate net metering. Moreover, without Vote Solar's proposed 10% floor, Vote Solar's proposed RCP rates could result in even greater reductions, along with increased pricing uncertainty.

3 Determination of the appropriate method for isolating DG customers in the COSS

Q. Please describe the importance of determining the appropriate method for isolating DG customers in the COSS.

A. For all the discussion that has taken place in Arizona over the alleged rooftop solar cost shift and the appropriate rate treatment for DG customers, this case marks the first instance in which the Commission must consider a litigated cost of service study analysis that isolates DG customers as a separate class to analyze their relative costs and revenues. In the Value of DG docket, the Commission recognized the importance of this undertaking:

> It is important to determine these costs correctly. Once a utility's revenue requirement is determined, the actual costs to serve customers are a very important consideration when choosing an appropriate and fair rate design, based on principles of cost causation, that will result in just and reasonable rates for all customers.[96]

Due to proprietary issues with the COSS models, the Commission found that the record of the Value of DG docket did not support approval of a specific COSS methodology.[97]

In the wake of the APS rate case settlement, which avoided the need for litigation on these issues, Phase 2 of these proceedings brings an important issue in front of this Commission for the first time. Not only are these issues new for consideration

[96] Decision No. 75859 at 143:20–24.
[97] *Id.* at 143:25–144:22.

in Arizona, but this case marks one of the first instances in which a Commission must consider the appropriate method for separation of DG customers in a cost of service study nationwide. This means that while general cost of service study methods and principles are well established, the application of those principles and methods to the separation of DG customers is a novel undertaking and will necessitate important policy decisions by this Commission.

The Companies' rebuttal testimony obfuscates the fact that the Commission is faced with an important issue of first impression regarding how to separate DG customers in a cost of service study. Notably, the Companies have offered no credible reason why their methodological approach is better suited to this task than the methodological approach I, and other intervenors, recommend. Instead, the Companies simply assume their methodological approach is correct, and then claim the other parties' analysis is flawed and incorrect when it fails to conform to the Companies' preferred approach. But the critical question for the Commission is what methodology should be employed to allocate costs to rooftop solar customers, and the Companies' preferred approach is fundamentally flawed. In this section, I highlight the three most important methodological disagreements between Vote Solar and the Companies and explain the rationale for Vote Solar's recommendations in response to the Companies' criticisms. Failure to address a specific critique from the Companies does not imply that I am in agreement with their rebuttal position, rather I did not find merit in their criticisms and believe that it is important to focus on the most important issues at hand.

3.1 Cost allocation to DG customers based on Non-Coincident Peak

Q. Please describe the issue of disagreement over cost allocation to DG customers based on Non-Coincident Peak ("NCP").

A. Vote Solar, along with other intervenors, believes the cost of service study should allocate costs to DG customers based on the DG customer's usage at the time of the total residential or small commercial class NCP. In contrast, the Companies wish to allocate costs to DG customers based on the maximum hour of either DG customer usage or exports.

Q. Have other parties expressed a position on this issue?

A. Yes. Both TASC/EFCA witness Mr. Beach and RUCO witness Mr. Huber have conducted analyses using the same methodology proposed by Vote Solar. Mr. Beach explains:

> DG customers' cost-of-service should be based entirely and directly on their delivered loads, without TEP/UNSE's allocation to DG customers of the costs of delivering exported power. Accordingly, the NCP cost allocators used in the COSS should be based on the maximum DG Class NCP use of the distribution system for consumption (deliveries) alone, without considering export volumes.[98]

Similarly, Mr. Huber's examination of the cost of service studies performed by the Companies "displayed a significant drop in demand usage due to solar."[99] His subsequent analysis included an adjustment to each cost component "to account for the fact that solar customers seemed to significantly reduce peak related allocators."[100] Mr. Huber concludes that the fixed cost responsibility for a TEP residential customer with DG should be $57, in contrast to the $87 of fixed cost responsibility for a full requirements customer.[101] In support of this analysis, Mr. Huber measured cost allocation based on DG customer delivered load at the time of the residential class NCP, rather than based on the Companies' proposed use of DG exports.[102]

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[98] Beach Phase 2 Direct 10:19–23.
[99] Huber Phase 2 Direct 14:11.
[100] *Id.* at 14:20–21.
[101] *Id.* at 15:2–10.
[102] *See* Huber workpaper Solar Offset Rate breakdown UNSE-TEP.xlsx.

Q. Did APS allocate distribution costs based on the NCP related to DG customer exports in the cost of service study filed in support of its own rate case in Docket No. 16-0036?

A. No. APS did not base cost allocation on the DG customer export peak in its cost of service study. It appears that the Companies here are unique in their proposal to employ this cost allocation methodology.

Q. Why is the DG customer subclass usage at time of class NCP the preferred allocation method?

A. Allocation based on DG subclass usage at the time of class NCP is the preferred method because it most accurately approximates the design and operational criteria on which the distribution system is built and expanded. On this topic, the NARUC Electric Utility Cost Allocation Manual states the following:

> There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary – and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.[103]

In considering the appropriate methodology for development of a cost of service allocator, the analyst must consider the reason for which standard allocators are typically chosen. In the case of determining the appropriate means to allocate costs associated with the distribution system, the first step is to ensure understanding of the factors that drive distribution system investment and

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[103] Nat'l Assoc. of Regulatory Util. Comm'rs, *Electric Utility Cost Allocation Manual* 96–97 (1992), https://goo.gl/hAcjLR.

expansion. As the NARUC Manual clearly states, local loads are the major factors in sizing distribution equipment. Each portion of the distribution system is sized to meet the maximum local load expected for that equipment. It is as a consequence of this fact that the NARUC manual advises that customer class NCP and individual customer maximum demand are normally used to allocate the demand component of distribution facilities.

Rather than rely on the underlying logic behind employment of the class NCP allocator, the Companies' proposed method focuses entirely on their interpretation of the term of art "customer class." The Companies contend that DG customers were found to be a separate class of customers in Decision 75859, therefore their NCP should be measured separately from that of the overall residential and small commercial classes. Such a conclusion takes as dogma the use of "customer class" NCP, while failing to consider whether allocation of distribution costs based on DG exports occurring mid-day in April makes logical sense within the context of the cost of service study.

In general, because individuals within a customer class tend to be co-located on certain areas of the distribution system, customer class NCP is a reliable approximator of local area peak demand. While there are certainly exceptions, residential customers tend to be served by common feeders and likewise commercial and industrial customers may be served by different feeders than residential customers. This is to be expected, given how cities and towns are typically organized and the fundamentally different types of customers that comprise the residential and industrial classes. In contrast, DG customers are typically located throughout residential and small commercial areas, they do not take service on dedicated feeders, and they can be expected to contribute to the local area loads in conjunction with non-DG customers located on the same area of the distribution system.

In direct and rebuttal testimony, Mr. Volkmann has conducted illustrative transformer loading and loss analyses demonstrating that "solar DG exports are not imposing a 'burden,' do not result in significantly higher energy flows, and do not overload equipment."[104] Indeed, he concludes: "[P]eak DG exports occurring mid-day in April do not place a burden on the Companies' distribution systems. The distribution system is designed and upgraded to meet local peak load conditions, which for the Companies occurs primarily during the late afternoon in the summer, not mid-day in the spring."[105]

Q. Are there any additional reasons that the Commission should reject the Companies' proposal to allocate costs to DG customers based on their exported generation?

A. Yes. Not only have the Companies failed to demonstrate that DG customer exports are a cost driver, but cost allocation to DG customers based on exports would effectively charge the DG customer for use of the distribution system to deliver their exports to other customers. In this case, the Commission is implementing an export credit rate for DG exports that is benchmarked to the price paid for utility-scale solar. Utility scale solar contracts are priced for power at the point of delivery. Additional charges are not applied for the cost borne by the utility to bring power from the utility-scale generator over the transmission and distribution system to the end-use customer. Indeed, in Decision 75859, the Commission explicitly recognized that DG exports, which are generated and delivered to the utility at or near end-use customer load, will avoid use of the transmission and distribution system inherent in the delivery of power from utility-scale generators.[106] It is for this reason that the Commission directed that adders be included in the RCP for avoided transmission and distribution costs. For the Companies to advocate for additional costs to be paid by DG customers for delivery of these exports is inconsistent with the utility-scale contract pricing on

[104] Volkmann Phase 2 Surrebuttal 4:20–22.
[105] *Id.* at 16:3–7.
[106] Decision No. 75859 at 152:11–13.

which the RCP is based, and it is counter to the Commission's direction for the RCP in Decision 75859.

Q. The Companies also claim that if costs were to be allocated based on deliveries instead of exports, the correct NCP for DG customers is different than you assumed. Do you have a response?

A. While the Companies maintain their position that the NCP allocation factor for DG customers should be based on exports, they have additionally examined a scenario in which DG customers' NCP allocation is based on the maximum hour of delivered load specific to DG customers.[107] The Companies contend that if one were to assume a delivery-only scenario, the NCP should measure DG NCP at the later hour in which the group of DG customers reaches their collective peak, as opposed to the hour in which the residential and small commercial customer classes reach their peak. The change in hours between the Companies' definition of delivered DG NCP and Vote Solar's definition of delivered DG NCP is provided in Table 6 below.

Table 6: Hour of Defined DG Customer Class NCP

Customer Group	Company-Defined Hour of NCP[108]	Vote Solar-Defined Hour of NCP[109]
TEP Residential	June 19th at 5:00 p.m.	June 19th at 7:00 p.m.
UNSE Residential	July 24th at 5:00 p.m.	July 23rd at 8:00 p.m.
TEP Small Commercial	July 24th at 3:00 p.m.	July 24th at 8:00 p.m.
UNSE Small Commercial	July 24th at 3:00 p.m.	Sept. 2nd at 7:00 p.m.

As shown in Table 6, when separated from the residential class, it is clear that DG customers peak at a later time of day than their non-DG counterparts. This is because the residential and small commercial classes reach their NCPs during daylight hours at which time installed DG solar is contributing to local loads and

[107] Craig Jones Phase 2 Rebuttal Test. at 16:1–5 (Aug. 28, 2017) [hereinafter "Jones Phase 2 Rebuttal"].
[108] *Id.* at 15, n.16.
[109] *Id.* at 15, n.17.

reducing the usage of DG customers, as well as reducing congestion and capacity constraints at the time in which it is most needed. In my direct testimony, I pointed to one example of this from the Companies' analysis. I found that during the hour of class peak, UNSE DG customers were actually net exporters, rather than importers, of electricity.

Allocation of costs based on the DG customer NCP occurring after daylight hours is inappropriate for many of the same reasons why the DG customer export peak during mid-day in April is not appropriate. Namely, the distribution system is designed to meet local area peak loads that are occurring during the residential and small commercial class peaks in the late afternoon/early evening, not in the post-daylight hours in which DG customers reach their peak.

Q. What do you recommend for the Commission on this topic?

A. The method by which DG customers are allocated costs is an important issue of first impression for this Commission. While the Companies have devoted many pages of rebuttal to the argument that their proposed method is well-established, this is a mischaracterization that risks obfuscating the importance of this emerging topic and the need for a clear Commission policy. As demonstrated here, as well as in the testimony of Mr. Volkmann on behalf of Vote Solar, Mr. Beach on behalf of TASC/EFCA, and Mr. Huber on behalf of RUCO, the most appropriate method for allocation of DG customer costs is based on DG customer peak load at the time the residential and small commercial classes reach their respective NCPs. I recommend the Commission find DG customers should be allocated costs in the cost of service study based on delivered load coincident with the time of their parent class NCP.

3.2 Utilization of Load Research Data

Q. Please describe the issue of disagreement over the development of the load data used for DG customers in the cost of service studies.

A. The core of the issue lies in whether it is appropriate to scale hourly data from a sample of non-DG customers, based on monthly data from DG customers to approximate hourly DG customer load. In support of this method, Mr. Jones states:

> The Companies' analysis is not complex, hypothetical or out of the ordinary, and reflects common utility practices. It relies on actual customer data and applies standard analysis of load research data to develop hourly load curves. Load curves are prepared in exactly the same way for all other classes of service in the Companies' CCOSS with the exception of a few of the very large customers on the system. The hourly load curves become the source of the demand allocation factors in the same way and with the same statistical precision used for other classes modeled by load research data.[110]

Mr. Jones is correct that his method relies on "actual customer data," but he omits to mention the critical fact that some of the "actual customer data" used is from a different group of customers than the customers being analyzed. His method marries hourly customer data from the general residential and small commercial classes to monthly customer data from the DG classes to approximate DG customer hourly load. All customer groups analyzed in the cost of service studies, other than DG customers, were based on load research from their own group. In contrast, monthly load data for DG customers is scaled based on hourly load research from the general residential and small commercial classes, a distinct group in the cost of service studies.

DG customers have been separated out as a separate class in the cost of service studies for the express purpose of analyzing their unique cost of service in relation to the general residential and small commercial classes. Allocation of

[110] *Id.* at 12:12–18.

transmission, distribution, and production costs all rely in whole, or in part, on allocation factors that depend on the measure of customer class usage in a defined number of hours. For this reason, it is important that the method used to develop the hourly load shape be used consistently across all customer classes analyzed in the studies.

There are no other customer classes in the cost of service studies for whom the Companies have scaled hourly load research data from another class to approximate hourly load shapes of the class in question. The Companies' method is as if an analyst was seeking to understand the driving habits of pickup truck drivers. But rather than directly examining data on pickup truck drivers, the analyst chose to look at all customer driving habits then scaled the results based on the average size of the vehicle. While it may be a defensible method if no better information is available, it is most certainly an approximation.

Q. Is the data available for the Companies to treat DG customers in the same manner as all other types of customers in the cost of service study?

A. In rebuttal testimony Mr. Jones has clarified that "[t]here is no metered hourly data for solar DG customers' delivered loads contrary to Ms. Kobor's assertions that are based on an incorrect interpretation of the data available in the Companies' MDM system."[111] This is in response to the following statement in my direct testimony:

> In discovery, the Companies stated: "Hourly accumulation of instantaneous power deliveries by the Companies, to its customers, exists for all customers where the necessary metering technology was in place." In addition, the Companies confirmed that during the test year, all DG customers had meters capable of measuring hourly energy usage. As a result, it appears that the data exists to analyze DG customers in a manner consistent with the method used for all other groups of customers in the COSS.[112]

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[111] *Id.* at 12:24–27.
[112] Kobor Phase 2 Direct 39:15–21 (footnotes omitted).

While Mr. Jones certainly possesses the most knowledge about what data is and is not currently available and in what format, it appears the Companies have confirmed that the data exists. Regardless of the current availability, the Companies have not provided a credible reason why, after months to develop their original proposal, and now an additional three months to develop their rebuttal, they must use a method for DG customer load data that is inconsistent with their treatment of the other classes in the cost of service studies.

3.3 Accuracy of COSS using hourly net load when rates will apply without netting

Q. Please describe the issue of disagreement over the Companies' use of hourly net load in the COSS.

A. This is an example of one of several instances in which the Companies have taken statements from my direct testimony out of context in an attempt to mischaracterize my position and obfuscate the issue at hand. In this case, the Companies have attempted to attribute to my testimony conclusions that are not present: an assertion that customers are billed instantaneously.[113] There is no disagreement over the functioning of electric meters, nor accumulation of metered data for billing purposes. Rather, the issue is how the Companies have measured load for DG customers in their COSS in relation to how customers will be billed under proposed rates.

Decision 75859 ordered: "Once a DG customer is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will be no further netting or banking of exported DG kWh for that customer."[114] In discovery, Vote Solar clarified this issue:

> Question: Please provide the information requested below regarding the proposed tariffs filed as RDB-P2-1 . . . Would deliveries and

[113] Jones Phase 2 Rebuttal 32:17–20.
[114] Decision No. 75859 at 178:25–27.

> exports be netted hourly, measured instantaneously, or on some other basis?
>
> Answer: Instantaneously.[115]

It is clear that the Companies intend to comply with Decision 75859 and bill customer deliveries and exports without hourly netting. The discrepancy lies in examination of the load data for DG customers in the COSS in which the Companies have employed <u>hourly net</u> load in their assessment of DG customers.

Q. Does this issue pervade any other areas of the Companies critique of your direct testimony?

A. It does. Interestingly, the Companies devote a large section of rebuttal to a critique of my analysis in which I adopted their hourly net load shapes to provide an illustrative assessment of the costs and revenues under current and proposed rates.[116] As I stated in my direct testimony, there are major flaws with the use of this load information, including the presence of zero values for some key measures:

> Q. How should the Commission view your results in light of the load data on which it was based?
>
> A. While the zero value NCP allocator for UNSE small commercial customers is certainly not an accurate measure for cost allocation, I am unable to develop a more reasonable measure of UNSE small commercial customer demand during the class peak hour, as the Companies have not made instantaneous DG customer data available. I have elected to conduct an analysis based on this assumption, with the caveat that the results should only be used to analyze differences between the results of the COSS using the Base Case method and the DG Class method recommended by the Companies.[117]

[115] TEP/UNSE Joint Resp. to VS P2 2.07(b) (Attach. 1 to Kobor Phase 2 Direct at 22).
[116] Jones Phase 2 Rebuttal 17:23–18:16, Richard Bachmeier Phase 2 Rebuttal Test. at 36:1–40:15 (Aug. 28, 2017) [hereinafter "Bachmeier Phase 2 Rebuttal"].
[117] Kobor Phase 2 Direct 51:4–13.

It is as a direct result of the flawed load data that I repeatedly express throughout my direct testimony that the results presented are illustrative and that the Companies' COSSs and Proofs of Revenue should not be relied on for ratemaking. Mr. Bachmeier claims that adoption of their load data for measures of billing determinants constitutes an "egregious error."[118] But with the limited information available from the Companies, the most accurate measure could not be employed.

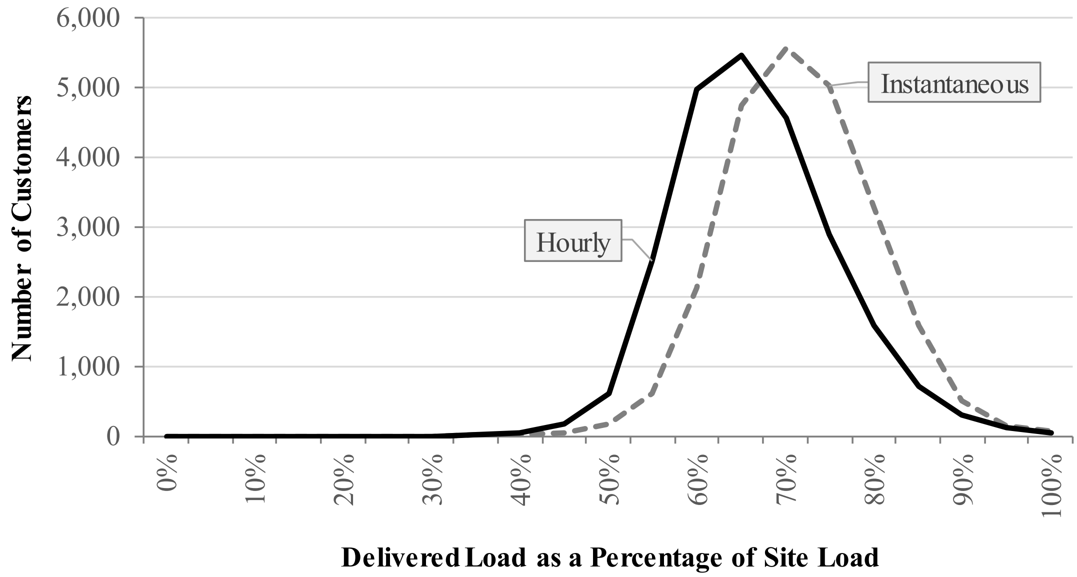
Q. In your direct testimony you discussed data from the APS case to illustrate the level of error the Companies' methodology may have on the analysis. Have you developed any further analysis on this topic?

A. Yes. In the APS rate case, the utility provided a robust dataset of instantaneously accumulated hourly load information for a sample of over 20,000 DG customers. I analyzed this data to determine the difference in measurement of delivered load as a percentage of site load under two scenarios: (1) delivered load is measured instantaneously, and (2) deliveries and exports are netted hourly. The first scenario is what is ordered under Decision 75859, and the second replicates the method used by the Companies in their COSS. Figure 1 below shows the results of that analysis for the sample of customers under each scenario.[119]

[118] Bachmeier Phase 2 Rebuttal 37:6.

[119] Attachment BK-SR-2 of this testimony additionally provides an assessment of the percentage of solar generation quantified as exports under the instantaneous and hourly netting scenarios.

Figure 1: Comparison between Instantaneous and Hourly Net Deliveries for APS Residential DG customers



As shown in Figure 1, there are salient differences in the percentage of customer site load that a customer is delivered from the utility in each scenario, while the magnitude varies across the population of customers in the sample. When deliveries are measured instantaneously, the average APS customer in the sample uses 69% of their load from the utility, with the other 31% being generated and consumed on-site from their own solar PV system. In contrast, when deliveries and exports are netted hourly, the average customer is found to use 64% of their load from the utility and gets the other 36% from their solar array.

Q. What do you conclude based on this analysis?

A. As I stated in direct, by netting hourly, instead of measuring instantaneously, the Companies likely underestimated all measures of delivered load. This results in two problems: (1) it underestimates the cost to serve DG customers, and (2) it underestimates the revenues received from DG customers under current and proposed rates. Taken together, these two factors form the basis of the Companies' conclusions regarding whether DG customers cover their cost of service under current and proposed rates. By introducing a potentially significant level of error to the analysis, the Companies have produced an unreliable result.

3.4 Summary of Findings

Q. Please summarize your findings regarding the appropriate method for isolating DG customers in the cost of service study.

A. While the Companies have devoted a large portion of their rebuttal testimony to critiquing my direct testimony, they have sidestepped the critical methodological issues before the Commission regarding a cost of service study that separates DG customers. As I have explained, while the Companies characterize their proposal to allocate costs to DG customers based on their peak exports as a standard cost of service methodology, they are unique in this position. Rather, the positions of Vote Solar, TASC/EFCA, and RUCO all align on this issue. Moreover, the testimony of Mr. Volkmann on behalf of Vote Solar clearly demonstrates that exports are not an appropriate measure for the driver of distribution system costs. In addition, the Companies have not addressed the core issues underlying their use of the load research data, nor their method which nets hourly load when rates will be applied to load that is not netted. After considering the Companies' rebuttal, my original conclusions on the cost of service study remain unchanged.

4 Rate Design

Q. Please summarize the rate design issues in this proceeding.

A. The Companies have proposed new tariffs for DG customers that resemble the tariffs available to non-DG customers, but with several key differences. For ease of discussion I will address each of the following tariff elements separately below: (1) Basic Service Charge, (2) Meter Fee, (3) Grid Access Charge, (4) Tariff structure and availability.

4.1 Basic Service Charge

Q. Please describe the Companies' position regarding DG customers' Basic Service Charge.

A. In the application, the Companies had advocated for implementing a Basic Service Charge in the DG TOU and demand charge tariffs that would be higher than the Basic Service Charge on the non-DG version of these tariffs. In rebuttal, the Companies have modified that proposal. Under the rebuttal proposal, DG customers on TOU and demand charge tariffs would be faced with the same level of Basic Customer charges as their non-DG counterparts. Vote Solar supports the Companies' rebuttal position on this issue.

4.2 Meter Fee

Q. Please describe the Companies' position on the Meter Fee.

A. In rebuttal testimony, the Companies maintain the same proposal for meter fees as they presented in their application. These fees are summarized in Table 7 below.

Table 7: Current and Proposed DG Meter Fees ($/month)

Customer Class	Current	Proposed
TEP Residential	$2.05	$4.32
TEP Small Commercial	$0.35	$5.62
UNSE Residential	$1.58	$3.92
UNSE Small Commercial	$1.58	$4.60

In support of this proposal, Mr. Jones states: "I have reviewed the costs associated with the bidirectional meter used to serve DG customers and have found it to be substantially more than a standard meter and requires an increase as anticipated by the Commission in its Order."[120]

[120] Jones Phase 2 Rebuttal 40:4–7.

Q. Do you agree with Mr. Jones' statement?

A. Yes. Mr. Jones is correct that costs associated with the bidirectional meter are indeed greater than standard metering costs. This is precisely why the current TEP meter fee was approved by the Commission in Phase 1 to recover those <u>incremental</u> costs. Unfortunately, Mr. Jones' proposal is not based on <u>incremental</u> bidirectional metering costs, but rather on the <u>full average embedded cost</u> of the bidirectional meter. DG customers are paying for the fully loaded costs associated with a standard meter through the existing customer charge, even though they no longer require use of a standard meter. Once the standard meter is replaced with the bidirectional meter, the DG meter fee should only cover the costs incurred by the utility that are above and beyond standard metering costs, as the Commission indicated in Decision 75975.[121]

Q. Did Mr. Jones raise any other critiques of your proposed meter fees?

Mr. Jones additionally states: "The referenced buy-out amounts were based on embedded cost data which blends in all vintage meters that have been depreciated for their entire in-service life."[122] This contradicts information provided in discovery, where the Companies stated: "UNS Electric's proposed DG meter charge is for <u>new meters and new meter installations</u> . . . ."[123] Interestingly, the information provided by the Company does reveal that for UNSE, the numbers used were for TOU meters, rather than bidirectional meters.[124] However, a comparison with the bidirectional meter costs for TEP does not reveal a significant difference between the two.[125]

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[121] Decision No. 75975 at 155:12–16 (Feb. 24, 2017).
[122] Jones Phase 2 Rebuttal 41:10–12.
[123] TEP/UNSE Joint Resp. to VS P2 4.3(a) (emphasis added) (Attach. BK-SR-1 at 9).
[124] *Id.*
[125] TEP bidirectional meter capital cost of $169.25 versus TOU meter capital cost of $166.00. TEP/UNSE Joint Resp. to VS 11.06 (Attach. BK-SR-1 at 1); TEP COSS.

In further discovery, the Companies have provided updated information for the installed costs of bidirectional meters in the TEP service territory.[126] Table 8 below compares these updated costs to the costs used to develop Vote Solar's proposed meter fees approved by the Commission in Phase 1 of the TEP case.

Table 8: TEP Bidirectional Meter Costs

Customer Class	TEP Res	TEP SGS
Phase 1 Capital and Labor Cost[127]	$212.78	$275.15
Revised Capital and Labor Cost[128]	$225.38	$314.19
Difference	$12.60	$39.04

In response to this updated information, Vote Solar proposes updating the TEP meter fees from those approved in Phase 1 of this proceeding.[129] With this additional information, the incremental capital and labor cost of the bidirectional meter is updated to $155.55 for residential customers, and the incremental cost is updated to $62.78 for small commercial customers. I continue to recommend that DG customers be given the option to pay these fees as a single upfront payment or to pay a monthly charge. Using the carrying charge employed by TEP in their marginal cost study, this results in a monthly charge of $2.23 for residential customers, and $0.90 for small commercial customers. The capital and labor costs used to derive these figures are provided in Attachment BK-SR-3, which is an update to Attachment 3 to my Phase 2 direct testimony. The Companies have not provided updated information on UNSE bidirectional meter capital and labor costs, but given the general similarities between the metering costs for the two utilities it is reasonable to adopt these revised meter fees, including the option for a single upfront payment, for UNSE as well.

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[126] TEP/UNSE Joint Resp. to VS P2 10.04 (Attach. BK-SR-1 at 13).
[127] TEP/UNSE Joint Resp. to VS 11.06 to 11.13 (Attach. BK-SR-1 at 1–8).
[128] TEP/UNSE Joint Resp. to VS P2 10.04 (Attach. BK-SR-1 at 13).
[129] While there may be some issues with inconsistency in tax treatment between the bidirectional meter and the standard meter in the updated calculation, the impact is expected to result in an overestimate in metering costs for DG customers relative to non-DG customers and is expected to be *de minimis*.

4.3 Grid Access Charge

Q. Please describe the Companies' position on the proposed Grid Access Charges.

A. While the Companies are continuing to propose grid access charges for DG customers taking service on two-part rates, their proposals have been revised downwards as summarized in Table 9 below.

Table 9: Company Proposed Grid Access Charges ($/kW-DC per month)

Customer Class	Application Proposal	Rebuttal Proposal
TEP Residential	$3.50	$2.50
TEP Small Commercial	$4.25	$2.50
UNSE Residential	$2.00	$1.00
UNSE Small Commercial	$2.45	$1.00

Q. Do you support the Companies' revised Grid Access Charge proposals?

A. I do not. As described in Section 3.4, my analysis demonstrates that DG customers cover more than their fair share of costs under current rates. It is therefore unnecessary to place additional fixed charges on DG customers at this time through the Grid Access Charge. In direct testimony, Mr. Koch stated:

> The Grid Access Charge is premature, and as currently designed would lead to the near complete cessation of customer owned solar adoption. There are already many changes being made to rates which will adversely affect solar adoption, and it would violate the spirit of gradualism to add this charge on top of the elimination of net metering and the reduction in grandfathering period to 10 years.[130]

While Mr. Koch's statement was made in response to the Companies' original proposals, I find the same holds true for the rebuttal proposals as further described in Section 5.5 below. Moreover, contrary to the Companies' claim that "[t]he

[130] Kevin Koch Phase 2 Direct Test. at 3 (May 19, 2017) [hereinafter "Koch Phase 2 Direct"].

export rate has no impact whatsoever on either the Companies' level or recovery of fixed costs,"[131] the replacement of net metering with compensation for exported generation will dramatically reduce the Companies' issues associated with fixed cost recovery from DG customers. Rather than allowing the customer to offset large proportions of their bill through net metering, future DG customers will pay for all deliveries received from the utility through their electric tariff. In addition, the Companies will be made whole for all exported generation purchased at export credit rates as set forth in the Commission's decision in the Value of DG docket. As a result, I find that implementation of the RCP in this proceeding will result in a fundamental change to cost recovery from DG customers and that further punitive rate design changes such as the proposed grid access charges are unnecessary.

4.4 Tariff Structure and Availability

Q. Please describe the Companies' position regarding tariff structure and availability.

A. While the Companies continue to propose entirely separate rates for DG customers, in rebuttal testimony they have proposed several revisions that result in DG tariffs that are similar to the non-DG tariffs currently in effect. For instance, the Companies have now proposed identical Basic Service Charges, and have modified delivery charges accordingly. Apart from the proposed Meter Fees and the Grid Access charges on the TOU rates, the only differences that remain between the Companies' proposed tariffs for DG customers and the tariffs that are currently in effect are the following:

- Two-part TOU rates for non-DG customers have a three-tiered delivery charge, while the corresponding DG customer tariffs have a flat delivery charge.

[131] Bachmeier Phase 2 Rebuttal 49:6–7.

- Three-part TOU rates for non-DG customers have a demand tier threshold of 7 kW, while the corresponding DG customer tariffs have a demand tier threshold of 5 kW. The proposed demand charges in the first and second tier are the same.[132]

Q. Do you find that these differences are necessary?

A. No. Adoption of DG under the new export compensation rate structure will be a complex undertaking. Under the Companies' proposed tariffs, estimated bill savings will become even more difficult for customers to calculate due to these minor differences between the DG and non-DG tariffs. Given the convergence of the Companies' rebuttal positions to the current tariffs, it is reasonable to allow DG customers to take service on the same two-part TOU and three-part TOU tariffs as non-DG customers with the addition of a meter fee and/or grid access charge if the Commission chooses to adopt either of these rate structures. This would simplify a customer's choice to adopt DG, as their tariff with DG would look the same as tariffs available to them prior to their DG investment, but for the meter fee and/or grid access charge should the Commission choose to adopt either of these rate components. In addition, this approach would be consistent with the rates approved by this Commission for APS in Decision 76295.

Q. Do you have any additional comments on tariff availability?

A. Yes. The Companies currently have four tariff options available to residential and small commercial customers, but they have proposed to remove two of those options for their DG customers. The Companies have proposed that DG customers be ineligible for two-part non-TOU rates and three-part non-TOU rates, even though these options are available to non-DG customers. As I have demonstrated in my direct testimony, as well as discussed in Section 3.4 of this

[132] Mr. Bachmeier's Phase 2 rebuttal testimony indicates that the first tier UNSE SGS demand charge would be $8.85. But this appears to be a typo, as the proposed tariff provided in RDB-P2-R1, as well as Mr. Bachmeier's workpapers, reflect a value of $8.25, which is consistent with the non-DG UNSE SGS tier one demand charge.

surrebuttal, DG customers are already paying their fair share of costs under current rates and therefore should continue to be eligible to take service on all tariff options currently available to them.

5 Evaluation of Proposals in this Docket

Q. What metrics have the Companies provided to evaluate their proposals?

A. In rebuttal testimony, the Companies present an evaluation of their proposals based on several different metrics: average monthly bill savings, offset rate, blended solar value, and simple payback period. These metrics are provided for four monthly customer usage amounts: Mean, Medium (75th percentile), Large (90th percentile) and Extra Large (95th percentile), in Tables 3-8 of Mr. Bachmeier's rebuttal testimony.

Q. Do you think that it is useful to look at the four different customer sizes presented in the Companies' rebuttal testimony?

A. Yes. Customers of different sizes install solar, and it's crucial to understand the full range of impacts of the Companies' proposal. However, the four sizes presented by the Companies paint an incomplete picture because they are weighted toward very high-usage customers and exclude any customer whose energy requirements fall below the mean. It is helpful to know the impact on the 75^{th} (Medium) and 90^{th} (Large) percentile customers, but one must also consider that these customers represent less than 25% of the Companies' overall customer base, and that the economics of adopting solar will be reduced for smaller-sized customers. In this testimony, I focus on the Medium (75^{th} percentile) customer as a reasonable and representative size for a new solar customer. This is also consistent with Mr. Huber's analysis.[133] As a reference, I have provided tables with results for larger and smaller usage customers in Attachment BK-SR-4.

[133] Huber Phase 2 Direct 14:15–18.

Q. Please clarify the relationship between the offset rate, export credit rate, blended solar value, and payback period.

A. The offset rate quantifies the value of any solar production that the customer generates and uses onsite, and is often called the self-consumption offset. As used by Mr. Bachmeier and Mr. Huber, the offset rate represents only base rate savings and is exclusive of rate adjustors and taxes. The export credit rate, which in this case is being set based on the RCP, is the rate at which the solar customer is compensated for the proportion of their solar generation that is exported to the grid. When you combine these two numbers based on the proportion of solar energy that is consumed on-site and exported to the grid, and include taxes and adjustors, you arrive at the blended solar value. Finally, the customer's estimated bill savings are placed in a financial projection model to estimate the payback period expected for a given set of cost and production assumptions.

Q. Which of these metrics do you suggest the Commission consider as it evaluates the parties' proposals?

A. Because the Commission is setting rates in this proceeding, I recommend the focus remain on the rate metrics: offset rate, export credit rate, and blended solar savings, rather than on the payback periods presented. Assessment of payback periods is an excellent tool for individual customers to evaluate whether a particular solar quote is a sound investment for their unique circumstances. However, there is a large weight given to the assumed installation cost in the payback period calculation, when in reality installation prices may vary. In addition, a discounted payback period that incorporates the time value of money is a more accurate measure of financial value to the customer than the nominal approach taken by simple payback methodology.

Moreover, recent developments have led to significant uncertainty about the future cost to install DG solar. In April 2017, a bankrupt domestic solar cell manufacturer, Suniva, filed a petition with the U.S. International Trade Commission ("ITC") requesting new tariffs on solar cells and minimum prices on solar modules that are imported into the United States. While the outcome of the case is uncertain, on September 22, 2017, the ITC reached a finding of injury in the case, which means that Suniva's request will be considered. If approved as requested, the proposed tariff would increase imported module costs by $0.41/W.[134] For context, Mr. Koch assumes an install cost of $2.51/W for the Medium customer, thus a $0.41/W adder would increase the upfront price by 16%. Even though the ruling is not yet final, the industry is already seeing the impact of this case. Recent news reports have stated:

> Prices for solar panels and their components have risen sharply since the ITC took the case in May. Project managers have snapped up available supply amid fears that tariffs would drive prices higher, and those prices climbed another 5 cents a watt in the hours following the ITC's Friday ruling.[135]

Placing too much weight on payback analysis that is highly sensitive to the system price assumed, especially in the face of such significant uncertainty, could put the Arizona solar industry at risk.

For these reasons, I discourage the Commission from deciding this docket on the basis of payback period, and encourage a focus on the rate metrics as the most straightforward measure of proposed changes. However, to aid discussion, I will additionally present my result adopting the simple payback approach consistent with the Companies' presentation that adopts Mr. Koch's assumption for installed solar costs.

Q. Regarding the analysis in Mr. Bachmeier's rebuttal testimony, have you identified any issues with the values presented in Tables 3-8?

A. Yes. I have identified four distinct issues in the impact analysis presented in Mr. Bachmeier's testimony. The effect of these methodological issues is to inflate the

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[134] Eric Wesoff & Stephen Lacey, *Solar Costs Are Hitting Jaw-Dropping Lows in Every Region of the World*, Greentech Media (June 27, 2017), https://goo.gl/riWWkh.
[135] David Ferris, *Who's winning and losing the tariff battle*, EnergyWire (Sept. 25, 2017), https://goo.gl/JvGanj.

presentation of blended solar savings and decrease the presentation of payback periods. These issues include: (1) inaccurate tax treatment of the RCP, (2) an inconsistent and inflated production factor for TEP, (3) a simple error in the application of TOU periods in the model, and (4) conflation of customer savings from switching tariff options with customer savings from adopting solar. Each of these issues is described in detail below.

5.1 The RCP should be applied to a customer's bill after taxes

Q. Please describe the issue over tax treatment of the RCP.

A. In the tables presented in rebuttal testimony, the Companies calculated taxes on the customer's bill after RCP credits had been applied. This increased the presentation of blended solar savings, because each kWh of exports decreased the bill on which the customer would be taxed. However, in discovery the Companies stated: "[A]fter further discussions with the Companies' tax experts, taxes will be calculated on a new solar customer's bill ***before*** the RCP credits are applied."[136]

Mr. Bachmeier provided updated workpapers incorporating this change on September 20, 2017. The revision impacts the payback periods presented in the Companies' rebuttal testimony. The updated results presented in Section 5.5 reflect application of the RCP after taxes.[137]

[136] TEP/UNSE Joint Resp. to VS P2 15.1 (Attach. BK-SR-1 at 17).

[137] The revised work papers also contain a small error in which the RCP for TEP SGS customers under the Companies proposal is incorrect. For purposes of this analysis, I have corrected this error.

5.2 The Companies have adopted a significantly higher production factor for TEP than in their Application

Q. What is the production factor and how does it affect the Companies' bill impact analysis?

A. The production factor is the measure of the energy (kWh) a solar system will produce annually per unit of capacity (kW) installed. This factor varies by region, based on the unique insolation and weather patterns present in an area. It also varies by each specific installation when system orientation, tilt, and potential shading are taken into account.

The Companies' analysis relies on the assumed production factor to calculate the size of a solar array required based on their assumption that a solar customer will supply 100% of total usage with solar. The system size then affects the relationship between magnitude of the grid access charge that will be levied on the customer and the customer's energy requirements. It additionally impacts the assessment of simple payback by reducing the upfront cost the customer pays for their solar system.

Q. What production factor did the Companies assume in their application for TEP?

A. In the application, the Companies assumed a production factor of 1,687 kWh/kW-year for TEP customers. This value was generated using the National Renewable Energy Laboratory's ("NREL") System Advisor Model ("SAM Model"), version 2016.3.14.[138] The SAM Model is the industry standard tool for assessment of insolation and production factors nationwide. In developing the TEP solar load profile and production factor assumptions employed in their application, the

[138] TEP/UNSE Joint Resp. to VS P2 11.2(a) (Attach. BK-SR-1 at 15).

Companies calibrated the SAM model for a location at the Tucson International Airport.

Q. Is this approach consistent with what the Companies did in rebuttal?

A. No. While the Companies continued to use the same SAM-derived solar production profile, the profile was scaled to account for a modified assumption for the production factor. In place of the assumption that a TEP solar array will produce 1,687 kWh/kW-year, the Companies assumed that the production factor would be 1,835 kWh/kW-year, an increase of nine percent.

When asked about this change in discovery, the Companies stated: "After discussions with experts both inside and outside of TEP, it was concluded that the 1,687 kWh/kW-DC/year from the NREL SAM simulation for Tucson was too low and that 1,835 kWh/kW-DC/year is a more reasonable value."[139]

Q. Do you find the Companies' updated production factor to be reasonable?

A. No. While I appreciate there may be a variety of different statistics on specific solar production factors in a given area, the NREL SAM model is an industry standard tool and the Companies have not provided sufficient rationale to depart from this approach. Moreover, the Companies continue to employ the SAM model for the TEP solar production profile, and continue to employ it for the UNSE production factor, as well as the production profile. The differing opinion of unidentified experts is not a sufficient reason to forgo consistency in their approach.

Q. What effect does increasing the production factor in TEP have on the Companies' analysis?

A. By increasing the TEP production factor, the Companies reduce the size of solar systems modeled – thereby reducing the impact of the grid access charge and

[139] *Id.*

inflating solar savings. The reduced system size also has a significant impact on the assumed solar purchase price used to derive the simple payback calculation. The updated results shown in Section 5.5 below reflect an assumed production factor of 1,687 kWh/kW-year for TEP.

5.3 TOU periods are defined incorrectly in the Companies' model

Q. Please describe the issue with the TOU period definition in the Companies' model.

A. There is a simple spreadsheet error in the Companies' work papers regarding how TOU periods are defined. It appears the Companies inadvertently employed a formula error that results in incorrect hours being defined as on-peak and off-peak across the analyses for all four types of customers: TEP residential, TEP SGS, UNSE Residential, and UNSE SGS.

While correction of this minor error does not have a significant impact on estimates of solar savings, it does reduce the results for blended solar savings, as well as increase the results for payback period under the Companies' proposal. This change is incorporated into the updated results shown in Section 5.5 below.

5.4 The Companies' analysis conflates customer savings from switching tariff options with customer savings from adopting solar

Q. Please describe the issue with customer savings under the various tariff options available.

A. Under the Companies' analyses, bill savings are calculated by comparing the customer's bill prior to adoption of solar and after adoption of solar. In the pre-solar assessment, the Companies assume that the customer takes service on the standard tiered rate, and after adoption of solar, the Companies assume that the customer adopts either the DG TOU rate or the DG Demand rate as proposed.

While this appears reasonable, analysis reveals that the medium sized customer modeled for three of the four customer classes could save money by taking service on the optional TOU or demand rates available prior to adoption of solar. Namely, the demand charge rate saves a TEP residential customer $4.39 per month. Likewise, the TEP SGS customer would save $7.16 per month on the TOU rate and the UNSE residential customer would save $5.76 per month on the demand charge rate. The one exception is the UNSE SGS customer who sees the lowest bill on the standard rate. The results are even more pronounced for the larger customers. For example, Extra Large TEP residential customers could save as much as $59.70 per month by switching to the optional demand charge rate. These potential savings are solely a function of rate design, irrespective of the decision to install solar.

Q. What effect does this assumption have on the analysis?

A. While the Companies present their results as solar savings, their calculations conflate the natural savings a customer could achieve on the optional rate tariffs with the savings they could achieve from adoption of solar. As a result, a portion of the "savings" attributed to solar are in fact a result of changing tariffs, which the customer would receive regardless of any solar production.

Q. Is there an alternate method that you recommend?

A. My recommendation is to assume the customer is a rational actor – i.e., the customer has taken advantage of the potential savings offered by the opt-in rates, and is on the lowest cost tariff prior to going solar. This choice ensures the savings calculated are only attributable to the DG solar system, and not the move on to an alternate tariff type.

5.5 When combined, these four issues overstate expected solar savings under the Companies' proposal

Q. Have you analyzed the offset, blended solar savings, and simple payback periods after correcting for the four issues described above?

A. Yes. Table 10 through Table 12 provide updated values for the offset rate, blended solar value, and payback period for the Medium Residential and SGS customer in TEP and UNSE service territories on the proposed TOU rates.[140]

Table 10: Comparison of Offset in Companies' Testimony and Vote Solar Assessment ($/kWh)

Customer Class	Company Testimony	Vote Solar Assessment	Difference
TEP Residential	$0.0734	$0.0597	-19%
TEP SGS	$0.0830	$0.0658	-21%
UNSE Residential	$0.0818	$0.0685	-16%
UNSE SGS	$0.0732	$0.0711	-3%

Table 10 demonstrates that the offset rates decrease by 15-20% for the Medium TEP Residential, TEP SGS, and UNSE Residential customer relative to the Companies' assessment. While the UNSE SGS offset also decreases, it decreases by only 3%. When the Companies' assessment is corrected for the issues identified, the offset rates no longer achieve the targets stated by Mr. Huber. Mr. Huber articulates a desired offset of $0.0700/kWh for TEP Residential and $0.0800/kWh for UNSE Residential.[141] As shown in Table 10, an accurate assessment of the Companies' proposals reveals the Medium TEP Residential customer would achieve a $0.0597/kWh offset and the UNSE residential

[140] Consistent with the Companies' methodology, the offset metric excludes surcharges and taxes; the blended solar value includes surcharges, but excludes taxes; and the payback period assumes bill savings inclusive of both surcharges and taxes.
[141] Huber Phase 2 Direct 9:20–22.

customer $0.0685/kWh. Both of these results are more than $0.01/kWh short of Mr. Huber's stated criteria.

Table 11: Comparison of Blended Solar Value in Companies' Testimony and Vote Solar Assessment ($/kWh)

Customer Class	Company Testimony	Vote Solar Assessment	Difference
TEP Residential	$0.0889	$0.0827	-7%
TEP SGS	$0.0781	$0.0706	-10%
UNSE Residential	$0.0919	$0.0859	-7%
UNSE SGS	$0.0873	$0.0862	-1%

Table 8 illustrates that the blended value of solar decreases by 7-10% for TEP Residential, TEP SGS, and UNSE Residential on the proposed TOU rates when corrections are incorporated. As with the offset, the impact of the updated analysis is not as large for UNSE SGS, which decreases by 1% relative to the Companies' analysis. Note that Table 11 only shows first year savings; over time, blended solar value will decrease for future customers as the RCP steps down.

Table 12: Comparison of Payback Periods in Companies' Testimony and Vote Solar Assessment (years)

Customer Class	Company Testimony	Vote Solar Assessment	Difference
TEP Residential	8.8	11.3	30%
TEP SGS	10.1	13.8	36%
UNSE Residential	8.7	10.4	20%
UNSE SGS	9.3	10.7	15%

The adjusted simple payback periods shown in Table 12 are 1-4 years higher than presented in the Companies' testimony. When the identified issues are corrected for, all customer groups are expected to see payback periods above 10 years, and no class reaches the 8-9 year payback period advocated for by Mr. Koch.[142] At the

[142] Koch Phase 2 Direct 2.

high end, under the Companies' proposal, the Medium TEP Residential customer would see a payback of nearly 14 years.

In the Companies' rebuttal testimony, they highlight that payback periods under their analysis are shorter for the larger customers analyzed.[143] However, as shown in Attachment BK-SR-4, after correcting for the substantial tariff savings that larger customers reap from selecting the optional rates, these impacts largely disappear and larger customers are faced with similar payback periods as the 75th percentile "Medium" customer. In addition, while not reflected in the Companies' testimony, the Companies' own assessment of the payback period for the 50th percentile of TEP SGS customers reflects a payback period of 53.6 years, a period substantially longer than the expected life of the DG system itself. When updated to correct for the four issues identified, the 50th percentile TEP SGS customer will never pay off their system as system degredation chips away at the small level of saving they'd reap from their system under the Companies' proposed rates. While this size of customer is called "Small" in the Companies' analysis, this extreme result would hold true for 50% of TEP SGS customers.

Q. What is the significance of the increase in payback periods?

A. The Companies consistently benchmark their rebuttal proposals on the ability of solar customers to payback their investment within 8-9 years, based on the minimum criteria articulated by Mr. Koch. For example, Mr. Bachmeier states:

> New Residential DG customers who install DG systems during the period that the Companies' proposed initial Resource Comparison Proxy ("RCP") rate is effective, and take service on any of the Companies' proposed DG rate options, will see simple payback periods within the 8 to 9-year payback period recommended by Intervenor Kevin Koch, a Tucson-based solar installer.[144]

However, my analysis shows that these payback periods were driven by faulty assumptions. After correcting for these issues, the Medium customer in all studied

[143] Bachmeier Phase 2 Rebuttal 48:15–16.
[144] *Id.* at 3:8–12.

customer classes would see simple payback periods longer than 10 years. Moreover, as payback periods lengthen to exceed 10 years, the Companies' model further underestimates expected payback because it holds the RCP constant for the entire 20-year period when the RCP is expected to decline annually in year 11 onward. It additionally excludes potential future capital expenditures the customer may incur to replace their inverter, which is typically warrantied only for ten years. Inclusion of both of these factors would further increase the payback periods under the Companies' proposal.

Q. Earlier in your testimony you mentioned potential uncertainty with the ITC case. Have you also analyzed the impact that case may have on payback periods if approved?

A. Yes. Table 13 modifies Table 12 to show the effect of increasing the upfront system price by $0.41/W – the potential price increase if a tariff is approved as proposed. It shows that increasing the price of solar would extend payback periods by 2 to 3 years.

Table 13: Comparison of Payback Periods at Different System Prices (years)

Customer Class	Company Testimony ($2.51/W)	Vote Solar Assessment ($2.51/W)	Vote Solar Assessment at ($2.91/W)
TEP Residential	8.8	11.3	13.4
TEP SGS	10.1	13.8	16.4
UNSE Residential	8.7	10.4	12.3
UNSE SGS	9.3	10.7	12.5

Q. What conclusions do you draw from this analysis?

A. It is imperative for the Commission to approach longer payback periods with caution. For the purposes of discussion, the simplified approach utilized by the Companies is useful, but there is little certainty that the payback periods referenced are what customers will actually achieve throughout TEP and UNSE territories as a function of the Companies' proposed changes.

Q. What are your overall conclusions regarding the above results?

A. The proposals presented in the Companies' rebuttal testimony are an improvement over those in direct. However, the value provided to solar customers is still too low to facilitate a sustainable industry. If the Commission were to approve the Companies' proposals, many Arizona families and small businesses would lose the economic choice to go solar.

6 Illustrative comparison to rates approved in Decision 76295

Q. How does the Commission's decision in the APS rate case relate to the proposals put forth by the Companies in this case?

A. While the Commission decided the APS case based on a separate set of facts and Decision 76295 is not precedent-setting for this proceeding, it is useful to compare the rates approved by the Commission for APS with the rates the Companies have proposed here. While the rates adopted in this case may vary from the rates adopted in the APS service territory, one of the goals of the Value of DG docket was to provide a consistent policy framework to employ throughout the state of Arizona. To that end, the economics and value of rooftop solar should not be significantly lower in TEP's and UNSE's service territories than in APS's territory. Such inconsistency from utility to utility would not be in the public interest, as families and small businesses in Tucson or Kingman who wish to install solar should not be worse off than similar families and small businesses in Phoenix or Flagstaff.

Q. How do the rates approved in the APS case compare to the rates proposed by the Companies in this case?

A. Decision 76295 only approved DG-specific rate design for APS residential customers. APS small commercial customers remain on retail rate net metering and have available to them all of the tariffs that are available to non-DG customers without any additional charges. The Commission approved a self-consumption offset for APS residential DG customers on the two-part TOU rate of $0.105/kWh, exclusive of taxes and adjustors, and a first-year RCP of $0.129/kWh inclusive of undifferentiated transmission, distribution, and loss components.[145]

I estimate that these rates produce blended solar savings of $0.124/kWh, including adjustors and excluding taxes. In contrast, the Companies in this case have proposed blended solar savings of only $0.071 to $0.086 per kWh for their DG customers.[146]

Making a direct comparison with the rates approved for APS is complicated by the fact that the standard retail rate varies for each utility. For example, APS residential volumetric rates are roughly 15% higher than TEP residential volumetric rates and are roughly 35% higher than UNSE residential volumetric rates.[147] These differences create a challenge in estimating DG rates for TEP and UNSE that are comparable to that approved by the Commission for APS. In drawing this comparison, I recommend the Commission evaluate both the proposed solar rates in relation to the current volumetric retail rate, as well as the absolute value of the solar rates and the implications that approval of such rates would have on solar choice in TEP and UNSE service territories. In Table 14 below, I demonstrate the relationship between retail rates and the approved solar rates for APS and proposed solar TOU rates for TEP and UNSE.

[145] Decision No. 76295 at 25:3–10.
[146] *See supra* p. 76, Table 11.
[147] Calculated inclusive of adjustors.

Table 14: Comparison of Retail Rates with Approved/Proposed Blended Solar Savings ($/kWh)[148]

Customer Class	Retail Rate	Blended Solar Savings	Difference
APS Residential	0.1303	0.1236	-5%
TEP Residential	0.1107	0.0827	-25%
TEP Small Commercial	0.1070	0.0706	-34%
UNSE Residential	0.0969	0.0859	-11%
UNSE Small Commercial	0.1046	0.0862	-18%

As shown in Table 14, the Commission approved rates with blended solar savings for APS that are roughly 5% below the retail rate, while the Companies have proposed rates that would reduce solar savings from 25-34% below retail in TEP's service territory and 11-18% below retail in UNSE's service territory. In addition, the actual blended solar savings are much lower than approved for APS – roughly 7.0-8.6 cents for TEP and UNSE, as opposed to 12.4 cents for APS. It is clear from this table that the proposal for TEP is not gradual by any means. And while the UNSE proposal is somewhat closer to retail, as shown in Table 14, the UNSE savings rates are too low to allow the market to continue.

In considering the results shown in Table 14, it is important to consider that, unlike retail rate net metering, under which solar savings would be reasonably expected to rise as the underlying rates increase, compensation for roughly half of the customers' solar production will be set at the RCP which is fixed for ten years and then is expected to decline. Table 15 below compares the levelized value of expected compensation under retail rate net metering to blended solar savings under the Companies' proposals assuming the Commission approves Vote Solar's proposal for a 10% floor on annual export compensation rate decline after the 10-year lock-in period.

[148] Retail rate based on volumetric charges on each Company's current TOU rate inclusive of volumetric charges and adjustors and exclusive of taxes, blended solar savings inclusive of adjustors and exclusive of taxes.

Table 15: Comparison of Levelized Blended Solar Savings under NEM and Company Proposal ($/kWh)

Customer Class	NEM Rate[149]	Proposed Blended Solar Savings	Difference
TEP Residential	0.1339	0.0818	-39%
TEP Small Commercial	0.1294	0.0665	-49%
UNSE Residential	0.1172	0.0858	-27%
UNSE Small Commercial	0.1265	0.0878	-31%

As shown in Table 15, when compared with the value expected under retail rate net metering, the Companies' proposal would result in 30-50% reduction in savings available to DG adopters. Such an extreme change in a single rate case is not gradual.

7 Vote Solar Proposal

Q. Please summarize Vote Solar's proposed RCP and DG rate design.

A. Vote Solar proposes a first-year RCP of $0.124/kWh and a second year RCP of $0.112/kWh. In addition, Vote Solar proposes that DG customers who apply for interconnection after the effective date of the decision in these proceedings be afforded the same rate options as non-DG customers with the addition of meter fees covering the incremental capital cost associated with the bidirectional meter that is installed when a customer adopts DG. For residential customers, I recommend a meter fee of $2.23/month, with the option to avoid this charge via a one-time upfront payment of $155.55. For small commercial customers, I recommend a meter fee of $0.90/month, with an optional one-time upfront charge of $62.78. I recommend that DG customers be afforded access to all current tariff options including: (1) the standard tiered rate, (2) the two-part TOU rate, (3) the non-TOU demand charge rate, and (4) the TOU demand charge rate.

[149] Retail rates under NEM are based on volumetric charges on each Company's current TOU rate and are inclusive of adjustors.

Results for blended solar savings and simple payback on each available rate are summarized in Table 16 and Table 17 below.

Table 16: Blended Solar Savings under Vote Solar Proposal ($/kWh)

Customer Class	Tiered Rate	Two-Part TOU Rate	Three-Part Non-TOU Rate	Three-Part TOU Rate
TEP Residential	0.1157	0.1182	0.0967	0.0989
TEP Small Commercial	0.1071	0.1119	0.0875	0.0896
UNSE Residential	0.1077	0.1095	0.0965	0.0981
UNSE Small Commercial	0.1116	0.1120	0.0975	0.0946

Table 17: Simple Payback under Vote Solar Proposal (years)

Customer Class	Tiered Rate	Two-Part TOU Rate	Three-Part Non-TOU Rate	Three-Part TOU Rate
TEP Residential	8.1	8.0	9.7	9.5
TEP Small Commercial	8.8	8.4	11.1	10.8
UNSE Residential	8.8	8.8	9.0	8.9
UNSE Small Commercial	8.2	8.2	9.5	9.8

As shown in Table 16 and Table 17, under the Vote Solar proposal, DG customers will have comparable solar savings on the tiered rate as on the two-part TOU rate, although for all customer classes, the DG customer will be better off on the TOU rate. For all customer classes, solar savings will be reduced on the demand charge tariffs. Given the lengthy payback periods on the demand-charge rates, I expect it will be difficult for customers to make an investment pencil out on these tariffs, and that most customers will adopt the two-part rates.

As shown in Table 16, Vote Solar's proposal would result in blended solar savings that are 4-11% lower than the $0.124/kWh blended solar savings approved for APS customers in Decision 76295. In addition, Vote Solar's proposal would result in payback periods on the two-part rates that are consistent with Mr. Koch's recommendation for 8-9 year simple payback.[150]

Finally, in Table 18 I have provided a comparison between the levelized solar savings expected under net metering and the levelized blended solar savings under Vote Solar's proposed rates. As shown below, Vote Solar's proposal would result in a 7-14% reduction in solar savings compared with savings expected under net metering. Savings would further decline in future years as the RCP rate declines. Vote Solar's proposal provides a reasonable balance between the desire for a gradual transition away from net metering and the preservation of the choice for Arizona families and small businesses to invest in local clean energy.

Table 18: Comparison of Levelized Blended Solar Savings under NEM and Vote Solar Proposal ($/kWh)

Customer Class	NEM Rate[151]	Proposed Blended Solar Savings	Difference
TEP Residential	0.1339	0.1198	-11%
TEP Small Commercial	0.1294	0.1112	-14%
UNSE Residential	0.1172	0.1094	-7%
UNSE Small Commercial	0.1265	0.1144	-10%

8 Conclusions and Recommendations

Q. Please summarize your conclusions.

A. Based on my review of the evidence presented thus far in this proceeding and the Commission's findings in the Value of DG docket, I conclude that many of the

[150] As commonly used, an 8-9 year payback period refers to an investment that pays back in the 8th or 9th year of investment, which as presented in the simple payback calculations in this testimony, would refer to a simple payback of less than 8.0 to less than 9.0 years. A payback of 9.5, for example, would pay back after 9 years and 6 months, or the 10th year of investment.

[151] Retail rates under NEM are based on volumetric charges on each Company's current TOU rate and are inclusive of adjustors.

proposals by parties to the proceeding are attempts to re-litigate issues expressly resolved by the Commission in Decision 75859. While many aspects of the Value of DG decision were not Vote Solar's preferred outcome, the Commission has shown leadership in implementing a method for valuing DG that can be used in rate cases to avoid the need for repeated litigation of these issues.

I find that the Commission thoughtfully considered several issues that parties are attempting to re-litigate here, and that the Commission developed a reasonable methodology that "will reduce the risk of dramatic changes to customers and the solar industry and is consistent with [the Commission's] interest in rate gradualism."[152] The RCP was intended to be a gradual stepping stone away from retail rate net metering, and not a sudden cliff in compensation rates. While many parties express the view that some proposals in this proceeding do not go far enough, the Commission has clearly outlined a future compensation mechanism that will gradually and predictably lower the rates paid for exported DG. As presented in this testimony, and in my direct testimony, implementation of the RCP and elimination of net metering is expected to significantly reduce export compensation, even at relatively high rates. Moreover, the RCP will continue to decline annually for new DG customers.

The Commission should not be swayed by attempts to undermine the reasonable and gradual path set forward by Decision 75859, but should adopt an RCP rate that will allow individual households and small businesses to invest in local clean energy. Paramount to this goal is approval of Vote Solar's proposal to augment the basic RCP structure and adopt a 10% floor on annual export compensation rate decline after the 10-year lock-in period. This proposal balances the desire among parties for continual decline in export compensation with vital certainty required by the individuals making these investments.

In addition, I find that the Companies have not provided a credible cost of service study to support their proposed rate design changes. With the implementation of

[152] Decision No. 75859 at 173:12–14.

the RCP, new DG customers will recover more than their fair share of costs under current rates and should not be restricted in their rate options or subject to punitive grid access charges. If the Commission desires to continue imposition of a meter fee, the fee should be modest and should account only for the incremental costs associated with installation of the bidirectional meter required for a DG customer to take service. Vote Solar's proposed RCP and rate design achieves an appropriate balance between allowing for greater fixed cost recovery for the Companies and maintaining the option for Arizona families and small businesses to supply a portion of their own energy needs through distributed solar generation.

Q. What are your recommendations for the Commission?

A. The following recommendations are in addition to the recommendations I made in my Phase 2 direct testimony. Recommendations that have been revised from direct are noted.

Resource Comparison Proxy

- The Commission should include a finding in its decision that states the RCP value adopted in this proceeding is by definition the value of DG and is not a subsidy.

- If the Commission departs from the Value of DG decision and approves a first-year RCP that is based on utility-scale resources beginning operations later than the five years up to and including the rate case test year, the Commission should maintain its focus on gradualism. This is a revised recommendation.

- The Commission should adopt Vote Solar's proposed transmission, distribution, and line loss adders.

- The Commission may desire to adopt a combined RCP for TEP and UNSE in these combined proceedings, but this issue should be revisited in each utility's next rate case. This is a revised recommendation.

- The Commission should find that in the event there are no utility-scale solar projects in any particular year of the five-year RCP period, the RCP will be calculated without a project for that particular year. Industry data will only be used in the event that there is no utility-specific data in the five-year period.

- The Commission should adopt an RCP based on actual production data from utility-owned solar facilities. To the extent significant curtailment occurs, the Companies should be required to provide evidence that may be incorporated into the RCP calculation to address the Companies' concerns.

- The Commission should adopt the second-year RCP in this proceeding for purposes of administrative efficiency.

- The Commission should adopt system eligibility requirements for the RCP consistent with the criteria defined by statute and included in the current net metering rate riders.

- The Commission should reject any proposal that would trigger additional step-downs to the RCP based on market penetration rates, consistent with what was decided in Decision 75859.

- The Commission should approve RUCO's request for RECs associated with exports to be included in the RCP transaction and should allow customers the option to maintain their RECs via an optional rate rider set at $0.01/kWh below the approved RCP.

- The Commission should adopt a fully optional rate rider that would allow for TOU adjustments to the RCP to incentivize customer load management and technology investment. The rider should be calibrated to result in the flat-rate RCP for the average customer without load management or technology.

- The Commission should require the Companies to develop an optional rate rider proposal that would provide additional credits to customers based on inverter settings beneficial to utility grid management, which could be presented and evaluated in each Company's next rate case.

- The Commission should approve a first-year RCP of $0.124/kWh and a second-year RCP of $0.112/kWh, with a 10% floor on annual export compensation rate decline after the 10-year lock-in period. This is a revised recommendation.

Rate Design

- DG customers should be afforded access to all of the same tariff options as non-DG customers without exception.

- The Commission should not adopt a grid access charge for DG customers.

- If the Commission chooses to continue imposition of the meter fee it should be $2.23/month for TEP and UNSE residential customers, with the option to avoid this charge via a one-time upfront payment of $155.55. For TEP and UNSE small commercial customers, the Commission should approve a meter fee of $0.90/month, with an optional one-time upfront charge of $62.78. This is a revised recommendation.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment BK-SR-1

Discovery Responses Referenced in Testimony

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
September 13, 2016

VS 11.06

Please provide the total per meter capital cost associated with the bi-directional meter installed for TEP's residential Net Metering customers.

RESPONSE:

The total cost for a bi-directional Net Meter is $169.25.*

**This cost consists of a bi-directional residential Net Meter $154.40, Locking Ring $14.60, and Meter Seal $.25.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 September 13, 2016

VS 11.07

Please provide the total per meter capital cost associated with the standard meter installed for TEP's residential customers.

RESPONSE:

The total cost for a standard meter for TEP's residential customers is $41.06.*

**This cost consists of a standard residential Meter $35.00, Locking Ring $5.91, and Meter Seal $.15.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
September 13, 2016

VS 11.08

Please provide the total per meter capital cost associated with the bi-directional meter installed for TEP's SGS Net Metering customers.

RESPONSE:

The total cost for a bi-directional SGS Net Meter is $202.85*

**This cost consists of a bi-directional SGS Net Meter $188.00, Locking Ring $14.60, and Meter Seal $.25.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
September 13, 2016

VS 11.09

Please provide the total per meter capital cost associated with the standard meter installed for TEP's SGS customers.

RESPONSE:

The total cost for a standard SGS meter is $194.06

**This cost consists of a standard SGS Meter $188.00, Locking Ring $5.91, and Meter Seal $.15.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
September 13, 2016

VS 11.10

Please provide the total per meter labor cost associated with installing the bi-directional meter for TEP's residential Net Metering customers.

RESPONSE:

The total labor cost for installing a residential Net Meter is $43.53*.

** This cost consists of the loaded hourly rate for a Single Phase Technician drive/wrench time and the loaded hourly rate for a Communication Specialist scheduling/order completion time.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 September 13, 2016

VS 11.11

Please provide the total per meter labor cost associated with installing the standard meter for TEP's residential customers.

RESPONSE:

The total labor cost for installing a standard residential meter is $28.77*.

**This cost consists of the loaded hourly rate for a Single Phase Technician drive/wrench time and the loaded hourly rate for a Communication Specialist scheduling/order completion time.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 September 13, 2016

VS 11.12

Please provide the total labor cost associated with installing the bi-directional meter for TEP's SGS Net Metering customers.

RESPONSE:

The total labor cost for installing a SGS Net Meter is $72.30*.

**This cost consists of the loaded hourly rate for a Metering Journeyman drive/wrench time and the loaded hourly rate for a Communication Specialist scheduling/order completion time.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 September 13, 2016

VS 11.13

Please provide the total per meter labor cost associated with installing the standard meter for TEP's SGS customers.

RESPONSE:

The total labor cost for installing a standard SGS meter is $57.35*.

**This cost consists of the loaded hourly rate for a Metering Journeyman drive/wrench time and the loaded hourly rate Communication Specialist scheduling/order completion time.*

RESPONDENT:

Nicole SantaCruz

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FOURTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 April 14, 2017

VS P2 4.3

Please provide the information requested below regarding UNSE's residential meters.

a. The UNSE COSS states the Company has a residential TOU meter inventory of 257 in cell N9 on the tab entitled "Meter Cost," but in cell K40 on the tab entitled "G-6-1 Unit Cost Proposed" UNSE indicates it has 1,243 residential DG customers. Please explain the discrepancy in these figures.

b. Please provide the specifications, model name, brand, and product type for the residential meter types identified on the tab entitled "Meter Cost" in the COSS. For each residential meter type, please provide an inventory of meters in service for UNSE during the test year, separated by customers with and without DG.

c. If the residential meter types identified on the tab entitled "Meter Cost" in the COSS are intended to be representative of a larger group of meter types, please provide a full list, per unit installed cost, and associated inventory of all residential meter types in service for UNSE, separated by customers with and without DG.

d. Please indicate whether the meter type identified on line 9 on the tab entitled "Meter Cost" in the COSS is the same meter type as that identified in the Marginal Cost study attached to Mr. Jones' Phase 2 direct testimony. If any differences exist, please explain.

RESPONSE:

a. The 257 count in cell N9 on the Meter Cost tab is a count for time-of-use customers, not DG customers. UNS Electric chose to take the conservative route and maintain the information reviewed and approved in Phase 1 of the proceeding as the starting point to develop the separate DG rate class. Since the cost of an installed meter will be at least as much for a DG customer as it is for a TOU customer, UNS Electric chose to use that number to determine the unit cost associated with a DG customer. Since the DG class is a separate rate class in Phase 2, this is the cost used to develop the unit cost associated with a DG customer. UNS Electric's proposed DG meter charge is for new meters and new meter installations and, while understating the actual cost, it is the starting point for recovering a portion of the incrementally higher cost of serving a DG customer that UNS Electric proposed for Phase 2 rates.

b. UNS Electric objects to the question to the extent it is asking for information relating to non-DG-related meter costs which is not relevant to the Phase 2 issues. Moreover, UNS Electric does not track or keep the information in the form requested and it would therefore be overly burdensome to gather and produce such information as requested. However, without waiver of objection, UNS Electric is in the process of gathering whatever information it can to be as responsive as possible and will provide such information as expeditiously as possible.

c.. UNS Electric is not sure that it fully understands this question. If the question is asking if the meter types and costs reflected on the tab, "Meter Cost", represent an average cost for the population shown, then the answer is yes. Please see the response to VS P2 4.3b.

d. The meter cost identified on the "Meter Cost" tab are also represented in the Marginal Cost study.

RESPONDENT:

Brenda Pries

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S NINTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
June 2, 2017

VS P2 9.1

Please provide the information requested below regarding the following statement by Mr. Tilghman on page 4, lines 6 through 9 of his Phase 2 Rebuttal Testimony: "The Companies used expected production, provided by the vendor, rather than actual production as Staff used, to better represent and monetize the value to the Companies and their customers associated with being able to curtail a facility without regards to being 'penalized' in the RCP calculation."

a. Please indicate whether this statement refers only to the utility-owned facilities or whether it refers to both utility-owned facilities and facilities with a PPA.

b. For each resource in the RCP portfolio, please indicate the difference between actual production and expected production as provided by the vendor.

c. For each resource in the RCP portfolio for which there is a difference between actual production and expected production, please indicate (1) the number of hours in which that resource was curtailed during its first year of production; and (2) the total MWh curtailed during its first year of production.

d. For each resource in the RCP portfolio for which there is a difference between actual production and expected production, please indicate (1) the number of hours in which that resource was used for grid management (e.g., voltage regulation); and (2) the total MWh of energy production forgone as a direct result of this grid management usage during its first year of production.

e. It appears the Companies' model employs a different assumption for first year energy for all RCP resources, with the exception of Avalon II and La Senita. To the extent not already addressed in response to the above questions, please explain any and all differences in the assumption for first year energy between the Staff model and the Companies' model for each resource in the RCP model.

RESPONSE:

a. Utility-owned only, as the only projects in the Companies' portfolio whose calculated "cost per kWh" can be altered by changing production values.

b. **THE FILES LISTED BELOW CONTAIN COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

Since the Companies used the expected annualized value for the first year, the difference will not only be associated with curtailments, but with the partial versus full year. Actual production, as provided by the Companies and verified by Staff Witness Smith through invoices, is contained Witness Ralph Smith's Attachment RCS-5-CompSenCONFIDENTIAL. Expected annual production is shown for the first year of each facility in Mr. Tilghman's confidential work papers within the file named Revised Staff-CONFIDENTIAL RCP Model_TEP-UNSE_FINAL.xlsm that are available in the

Companies' electronic data room in the work space Phase 2 TEP/UNSE Rate Case. Please refer to the energy tab for estimated annual production values.

c. The Companies have not tracked hours of curtailment from full load for renewable facilities, as it provides no meaningful data from a balancing authority perspective. Additionally, even if the Companies did track the number of hours where a manual curtailment was initiated, it would be purely speculative to estimate the amount of lost production, since there is no basis for what the actual full load capability of the solar facility would have been at that moment. Moreover, it is not appropriate to convert a Company-owned asset into a "per kWh" price for use in a market-based proxy.

d. Please see response for part C of this question.

e. See response in part B of this question.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT SUPPLEMENTAL RESPONSE TO VOTE SOLAR'S TENTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142

Original: September 8, 2017

Supplement: September 21, 2017

VS P2 10.04

Please provide the information requested below regarding the following statement on page 41, lines 20-23 of Mr. Jones' rebuttal testimony: "The incremental costs reflected in TEP's recent REST filing reflected an incremental meter charges of approximately $170 and $210 for residential and SGS, respectively, without any loading adders or the recovery of other costs such as maintenance or repair."

a. Please provide a specific citation to the REST filing from which these figures were derived.

b. If these figures are not present in the filing, please provide a workpaper and thorough explanation of how these figures were calculated.

RESPONSE:

a. Please refer to page 14, section C, of TEP's 2018 proposed REST Implementation Plan filed in Docket No. E-01933A-17-0226. This references a total cost of $294.55 and $206.20 for the incremental cost of a net meter installation for residential and SGS DG customers, respectively.

The Production Meter and Solar DG kits were included in the original residential number of $294.55, but were removed to obtain the $170 figure referenced in Mr. Jones' rebuttal testimony. Incremental meter installation costs were estimated to arrive at the final number for the residential customer of $170 ($129.87 plus approximately $40 of labor). As mentioned in Mr. Jones' rebuttal testimony, the estimated labor associated with the installation of a bi-directional meter would be substantially higher due to the addition of loadings (assuming an average of one-hour per installation at the average hourly rate for a more skilled journeyman installer, plus loading for P&B, paid absences, FICA, sales tax on the meter and loading on the meter cost for procurement and warehousing cost). This would put the estimated incremental cost of the residential meter at approximately $225.00 ($129.87 * (8.1% + 8.25%) = $151.10 plus $74.28 average hourly rate - loaded = $225.38); still doesn't recover cost associated with maintenance, repairs, testing or replacement of the meter if needed.

All labor costs were inadvertently omitted from the non-residential incremental cost reflected in Mr. Jones' rebuttal testimony. Incremental meter costs of $206.20 when loaded would be $314 ($206.20 * (8.1% + 8.25%) = $239.91 plus $74.28 average hourly rate - loaded = $314.19) for the small non-residential customer without adding to the installation time for any added complexities or the cost associated with maintenance, repairs, testing or replacement of the meter if needed.

Any one-time incremental meter charge below $225 and $314 for the residential and small non-residential DG customer, respectively, will cause additional cost shifts to the remaining non-DG customers. Non-DG customers will still be paying for maintenance, repairs, testing or replacement of the meter, if needed, unless the one-time option is eliminated.

b. See the response to VS P2 10.04 a.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S ELEVENTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
September 8, 2017

Regarding Richard Bachmeier's Rebuttal Testimony

VS P2 11.2

Please provide the information requested below regarding the following statement by Mr. Bachmeier on page 10, lines 6-8 of his rebuttal testimony: "The Tucson PV profile simulates the output of a system that generates 1,835 kWh/year per kW-DC installed and the Kingman PV profile a system that generates 1,800 kWh/year per kW-DC installed."

a. In Mr. Bachmeier's workpaper entitled "2015 TEP RES DG-PH2_FINAL_REV1.xlsx," he uses a kWh/year per kW-DC installed figure of 1,687. Please explain why this figure was updated for the rebuttal testimony.

b. Please provide the source that was used to derive the 1,687 value used in direct testimony and the source that was used to derive the 1,835 value used in rebuttal testimony. If applicable, please provide the source in Excel format with formulas and links intact.

RESPONSE:

a. The figure of 1,687 kWh/kW-DC/year was derived from a simulation using the National Renewable Energy Laboratory System Advisor Model ("NREL SAM"), version 2016.3.14. After discussions with experts both inside and outside of TEP, it was concluded that the 1,687 kWh/kW-DC/year from the NREL SAM simulation for Tucson was too low and that 1,835 kWh/kW-DC/year is a more reasonable value.

b. See Excel file **VS P2 11.2 NREL SAM DATA.xlsx** submitted with this response for derivation of 1,687 value. See response to VS P2 11.2(a) for derivation of 1,835 value.

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FOURTEENTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142
September 25, 2017

VS P2 14.1

Mr. Tilghman's RCP workpaper for his direct testimony entitled "RCP Model_TEP-UNSE-CompSen Confidential.xlsx" contains data in the Summary tab regarding the Cost per MWh for Rio Rico and Ft. Huachaca. This data appears to be inconsistent with the corresponding cost per MWh listed for these two facilities in Mr. Dukes' rebuttal workpaper entitled "RCP Model_TEP-UNSE-CompSen Confidential (082517).xlsx." Please fully explain this discrepancy and provide updated work papers as applicable.

RESPONSE:

THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

The discrepancy occurred due to errors in hard coded values and broken links in Mr. Tilghman's RCP workpaper that did not get properly updated in Mr. Dukes' workpaper dated 8/25/2017. Please see Mr. Dukes' workpaper **RCP Model_TEP-UNSE-CompSen Confidential (092017).xlsx** updated on September 25, 2017 for the updated values.

RESPONDENT:

Ted Burhans

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT RESPONSE TO VOTE SOLAR'S FIFTEENTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NOS. E-01933A-15-0322 AND E-04204A-15-0142 September 25, 2017

VS P2 15.1

Please confirm whether the Companies intend for taxes to apply to a new solar customer's bill after the RCP credits have been applied, as assumed in Mr. Bachmeier's work papers and rebuttal testimony. Please provide any updated work papers as applicable.

RESPONSE:

Mr. Bachmeier's rebuttal testimony and workpapers originally assumed that taxes would be calculated on a new DG customer's monthly bill after RCP credits are applied. However, after further discussions with the Companies' tax experts, taxes will be calculated on a new solar customer's bill ***before*** the RCP credits are applied. Please see Mr. Bachmeier's revised rebuttal workpapers in the Companies' electronic data room, updated September 20, 2017. The updated files are listed below:

Updated	File Name	Bates Numbers
9/20/2017	2015 TEP RES DG-P2_COMPS_RB1-rev1.xlsx	N/A
9/20/2017	2015 TEP RES DG-PH2_SUMMARY_RB1-rev1.xlsx	N/A
9/20/2017	2015 TEP SGS DG-P2_COMPS_RB1-rev1.xlsx	N/A
9/20/2017	2015 UNSE RES DG-P2_COMPS_RB1-rev1.xlsx	N/A
9/20/2017	2015 UNSE RES DG-PH2_SUMMARY_RB1-rev1.xlsx	N/A
9/20/2017	2015 UNSE SGS DG-P2_COMPS_RB1-rev1.xlsx	N/A

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

TUCSON ELECTRIC POWER COMPANY'S AND UNS ELECTRIC, INC.'S JOINT SUPPLEMENTAL RESPONSE TO STAFF'S FOURTH SET OF DATA REQUESTS REGARDING PHASE 2 OF THE 2015 TEP RATE CASE AND THE 2015 UNSE RATE CASE DOCKET NO. E-01933A-15-0322 AND E-04204A-15-0142
Originally Submitted: September 5, 2017
Revised: September 7, 2017

STF P2 4.10

Refer to the Rebuttal Testimony of Carmine Tilghman filed May 19, 2017 (adopted by Dallas Dukes in his August 28, 2017 Rebuttal Testimony, at page 10, lines 7-8) at page 12, lines 1-4, and to the Rebuttal Testimony of Richard Bachmeier filed August 28, 2017 at page 27, lines 1-4 and 19-20. Is it the Companies' position that the current average residential rate per kWh should be utilized as a ceiling on the RCP rate? If not, explain fully why not. If so, explain fully.

RESPONSE: September 5, 2017

The Companies are in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Dallas Dukes / Richard Bachmeier

WITNESS:

Dallas Dukes / Richard Bachmeier

SUPPLEMENTAL RESPONSE: September 7, 2017

The Companies are supportive of using the average residential rate for each Company as a ceiling for the RCP rate. The Companies believe that the clear intent of the Commission, as reflected within the Value of Solar Order, was to reduce the cost shift associated with net metering. Therefore, it would be appropriate and consistent with the Commission's directive to limit the RCP rate to the average retail rate of each company.

However, as evidenced by the Companies' proposed initial rate of $0.0973 per kWh exported, which is in excess of the average current retail rate for UNS Electric, the Companies believe many factors should be considered such as bill impacts, offset rates, payback periods, and continued cost shifting. The Companies believe they have struck an appropriate balance among these competing factors that allows customers to continue to have the choice to go solar and to begin mitigating the cost shift to non-solar customers.

RESPONDENT:

Dallas Dukes / Richard Bachmeier

WITNESS:

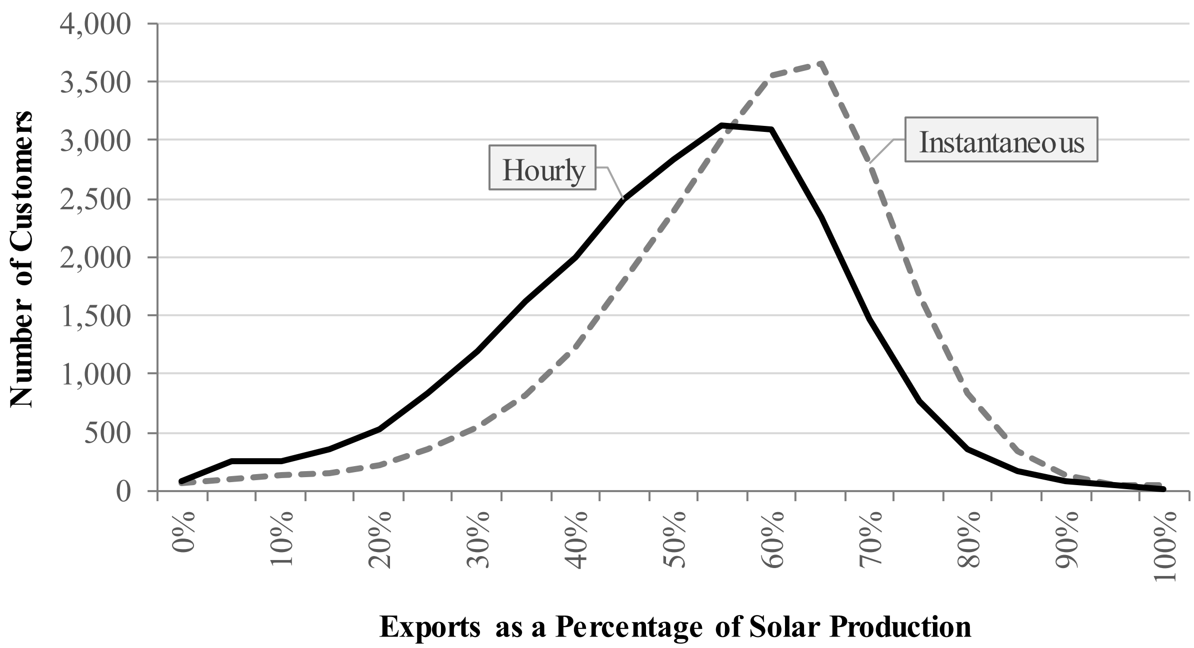
Dallas Dukes / Richard Bachmeier

Attachment BK-SR-2

Comparison of Customer Exports as a Percentage of Solar Production

Attachment BK-SR-2: Comparison of Customer Exports as a Percentage of Solar Production

The following figure compares solar exports as a percentage of solar production when measured on two different intervals: (1) net hourly, and (2) measured instantaneously without netting. Data used to derive this figure is from a sample of over 20,000 solar customers in Arizona Public Service Company territory during calendar year 2015.



- Summary statistics: Average Hourly = 47%, Average Instantaneous = 55%
- Based on the analysis, the average customer would export 8% more solar production under instantaneous netting versus hourly.

Attachment BK-SR-3

Updated TEP Meters – Capital and Labor Costs

Capital and Labor Costs Associated with TEP Meters
VS 11.06-11.13, VS P2 10.04

Line No.		(A) Residential Bidirectional	(B) Residential Standard	(C) SGS Bidirectional	(D) SGS Standard
1	Meter		$ 35.00		$ 188.00
2	Locking Ring		$ 5.91		$ 5.91
3	Meter Seal		$ 0.15		$ 0.15
4	**Total Capital (sum lines 1,2,3)**	**$ 151.10**	**$ 41.06**	**$ 239.91**	**$ 194.06**
5	Labor	$ 74.28	$ 28.77	$ 74.28	$ 57.35
6	**Total Capital and Labor (sum lines 4,5)**	**$ 225.38**	**$ 69.83**	**$ 314.19**	**$ 251.41**
7	**Incremental Cost (A-B and C-D)**		**$ 155.55**		**$ 62.78**
8					
9	**Meter ECCR per CAJ-1**	**17.22%**			
10					
11		**Annual**	**Monthly**		
12	**Incremental Bidirectional Residential**	$ 26.79	$ 2.23		
13	**Incremental Bidirectonal SGS**	$ 10.81	$ 0.90		

Attachment BK-SR-4

Evaluation of Company and Vote Solar Proposed Two-Part TOU Rates

Attachment BK-SR-4: Evaluation of Company and Vote Solar Proposed Two-Part TOU Rates

TEP Residential:

Monthly Usage	Company Testimony			Vote Solar Assessment of Company Proposal			Vote Solar Proposal		
	Offset	Blended Value	Payback Period	Offset	Blended Value	Payback Period	Offset	Blended Value	Payback Period
Small: 50th Percentile	$0.0606	$0.0842	10.1	$0.0456	$0.0777	13.4	$0.0982	$0.1158	8.8
Mean	$0.0656	$0.0856	9.6	$0.0516	$0.0792	12.6	$0.1005	$0.1162	8.4
Medium: 75th Percentile	$0.0734	$0.0889	8.8	$0.0597	$0.0827	11.3	$0.1054	$0.1182	8.0
Large: 90th Percentile	$0.0818	$0.0923	8.5	$0.0536	$0.0792	11.9	$0.0948	$0.1128	8.3
Extra Large: 95th Percentile	$0.0859	$0.0942	8.2	$0.0156	$0.0609	12.0	$0.0549	$0.0937	8.3

TEP Small Commercial:

Monthly Usage	Company Testimony			Vote Solar Assessment of Company Proposal			Vote Solar Proposal		
	Offset	Blended Value	Payback Period	Offset	Blended Value	Payback Period	Offset	Blended Value	Payback Period
Small: 50th Percentile	$0.0354	$0.0173	53.6	$0.0013	$0.0048	n/a	$0.1009	$0.0585	19.7
Mean	$0.0801	$0.0731	11.0	$0.0624	$0.0652	15.4	$0.1244	$0.1081	8.8
Medium: 75th Percentile	$0.0830	$0.0781	10.1	$0.0658	$0.0706	13.8	$0.1247	$0.1119	8.4
Large: 90th Percentile	$0.0977	$0.1004	7.8	$0.0805	$0.0925	10.1	$0.1215	$0.1262	7.3
Extra Large: 95th Percentile	$0.1013	$0.1064	7.5	$0.0776	$0.0953	9.8	$0.1138	$0.1269	7.4

UNSE Residential:

Monthly Usage	Company Testimony			Vote Solar Assessment of Company Proposal			Vote Solar Proposal		
	Offset	**Blended Value**	**Payback Period**	**Offset**	**Blended Value**	**Payback Period**	**Offset**	**Blended Value**	**Payback Period**
Small: 50th Percentile	$0.0730	$0.0888	9.5	$0.0613	$0.0838	11.3	$0.0868	$0.1101	8.7
Mean	$0.0778	$0.0903	9.3	$0.0658	$0.0849	10.9	$0.0887	$0.1100	8.5
Medium: 75th Percentile	$0.0818	$0.0919	8.7	$0.0685	$0.0859	10.4	$0.0881	$0.1095	8.8
Large: 90th Percentile	$0.0858	$0.0935	8.4	$0.0650	$0.0838	10.3	$0.0816	$0.1059	8.6
Extra Large: 95th Percentile	$0.0876	$0.0943	8.4	$0.0619	$0.0823	10.6	$0.0775	$0.1040	8.7

UNSE Small Commercial:

Monthly Usage	Company Testimony			Vote Solar Assessment of Company Proposal			Vote Solar Proposal		
	Offset	**Blended Value**	**Payback Period**	**Offset**	**Blended Value**	**Payback Period**	**Offset**	**Blended Value**	**Payback Period**
Small: 50th Percentile	$0.0627	$0.0814	10.5	$0.0536	$0.0771	12.4	$0.0918	$0.1095	8.6
Mean	$0.0708	$0.0863	9.8	$0.0680	$0.0849	10.9	$0.0950	$0.1120	8.3
Medium: 75th Percentile	$0.0732	$0.0873	9.3	$0.0711	$0.0862	10.7	$0.0957	$0.1120	8.2
Large: 90th Percentile	$0.0787	$0.0889	8.8	$0.0767	$0.0878	9.7	$0.0930	$0.1090	7.8
Extra Large: 95th Percentile	$0.0801	$0.0895	8.9	$0.0780	$0.0883	9.7	$0.0921	$0.1082	7.9