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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
TOM FORESE - CHAIRMAN
BOB BURNS
VACANT
ANDY TOBIN
BOYD W. DUNN

Arizona Corporation Commission
DOCKETED
OCT 13 2017
DOCKETED BY

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
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 **NOTICE OF FILING PHASE 2 REJOINDER TESTIMONY**

Tucson Electric Power Company ("TEP"), through undersigned counsel, hereby files the Phase 2 Rejoinder Testimony of Dallas J. Dukes, Susan Gray, Craig A. Jones, and Richard D. Bachmeier.

RESPECTFULLY SUBMITTED this 13th day of October, 2017.

TUCSON ELECTRIC POWER COMPANY

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REJOINDER TESTIMONY OF DALLAS J. DUKES

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.

OCTOBER 13, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct and/or Rebuttal Testimony in Phase 2 of this proceeding?

A. I filed Rebuttal Testimony on behalf of both Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric") in the Phase 2 proceedings.

Q. On whose behalf are you filing Phase 2 Rejoinder Testimony?

A. My Phase 2 Rejoinder Testimony is filed on behalf of TEP and UNS Electric, jointly referred to herein as the "Companies."

Q. What is the purpose of your testimony?

A. My Rejoinder Testimony responds to certain accusations made by Energy Freedom Coalition of America / The Alliance for Solar Choice (collectively "EFCA/TASC") and Vote Solar in the Rebuttal Testimonies. Specifically, the Companies are:

(i) not attempting to re-litigate issues from the VOS Order,[1]

(ii) proposing DG rate options that are consistent with the VOS Order, Staff and RUCO,

(iii) proposing DG rate options that are just and reasonable for **all** customers, and therefore in the public interest,

---

[1] Decision No. 75859 (January 3, 2017) in Docket No. E-00000J-14-0023, In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation ("VOS Order"), 170:6-8.

(iv) asking the Administrative Law Judge and Commission to recognize that the recent APS rate order and this current proceeding are vastly different and any such comparisons be appropriately weighted,

(v) not opposed to Staff's RCP of 10.7 cents per kWh provided that the RCP resets on July 1, 2018 to 9.63 cents per kWh for TEP and 9.20 cents per kWh for UNS Electric, and

(vi) opposing any T&D adder to the RCP since the proliferation of rooftop DG has not, and likely will not, result in identifiable avoided cost as it relates to any comparison to Utility Scale systems primarily interconnected to the distribution system and used in the Companies' proxy analysis. To the contrary, the cost to serve DG customers adds to system cost as compared to utility scale renewable systems.

II. SUMMARY

Q. Have you reviewed the Surrebuttal Testimony filed by the parties in this proceeding?

A. Yes, I have.

Q. Please summarize the Companies' response to the Surrebuttal Testimonies.

A. Much of the Surrebuttal Testimony from EFCA/TASC and Vote Solar has ignored the primary issue that the Companies' have worked diligently to mitigate, which is finding an equitable rate and value of export structure that fairly treats our entire customer base. We cannot lose sight of the fact that EFCA/TASC witness R. Thomas Beach, and Vote Solar witness Briana Kobor continue to advocate for positions that (i) are narrowly focused on protecting a business model, (ii) fail to follow the framework established by the Commission in the VOS Order; and (iii) increase the cost shift to non-DG customers. As a result, their positions fail to fairly and equitably treat ***all*** customers.

Q. Do EFCA/TASC or Vote Solar acknowledge the DG cost shift in their Rebuttal Testimonies?

A. No. Despite the findings by the Commission in the VOS Order and regardless of the evidentiary record in this proceeding, EFCA/TASC and Vote Solar apparently refuse to address the fact that Distributed Generation ("DG") customers, under current rates, are subsidized, as clearly found by the Commission.[2]

Below are two examples where Vote Solar witness Ms. Kobor ignores a very important finding by the Commission in the VOS Order.

VOS Order	Ms. Kobor's Surrebuttal
"...the Commission is committed to modifying residential rate design in a manner that mitigates the recognized cost shift caused by rooftop solar customers' self-consumption."[3]	"For all the discussion that has taken place in Arizona over the *alleged* (emphasis added) solar cost shift..."[4] "...my analysis demonstrates that DG customers cover more than their fair share of costs under *current* (emphasis added) rates."[5]

[2] See VOS Order, Finding of Fact 163.
[3] VOS Order, 176:1-2.
[4] Kobor Surrebuttal, 46:9-10.
[5] Kobor Surrebuttal, 64:10-11.

Q. Are the Companies attempting to re-litigate the VOS Order in this Phase 2 proceeding?

A. Absolutely not. Vote Solar's re-litigation claims[6] are disingenuous and a misplaced attempt to misrepresent the Companies' intent in this proceeding. The Companies are, in good faith, applying the key principles of the VOS Order to post-Phase 2 DG customers in a manner that is just, reasonable and in the public interest.

Q. Do you have any comments on the Rebuttal Testimony of EFCA/TASC witness Mr. Beach?

A. Yes, I do. Mr. Beach refers to the recent decision in the APS rate case[7] throughout his testimony. Comparing the APS order to the Companies' Phase 2 proceeding must be done with significant caution and in the proper context. Mr. Beach understates the differences between the two, although he does acknowledge that, "...there are differences between APS and TEP/UNS ELECTRIC; and the Commission is under no obligation to reach the same outcome here."[8] I will expand on this statement; the APS rate case and the Companies' Phase 2 proceeding are *vastly* different. I highlight a few of the key differences below.

- The APS rate case was a comprehensive settlement agreement that included, among other things, *all* rate design and revenue requirement issues. This provided the parties to that proceeding with multiple levers to pull in order to reach a compromise on numerous issues. While I was not privy to the APS settlement discussions, I am confident that if the APS case were bifurcated into two phases, a litigated outcome for DG rate design would likely have been much different than a comprehensive settlement.

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[6] Kobor Surrebuttal, 2:16-18.
[7] Decision No. 76295 (August 18, 2017).
[8] Beach Surrebuttal, 9:6-7.

- APS entered into a confidential "Joint Solar Parties Cooperation Agreement," in which certain solar entities agreed to refrain from participating in activities such as ballot initiatives and political advocacy.[9] This "cooperation agreement" certainly affected the negotiating posture of the relevant parties to the settlement agreement.

- APS' residential retail rates are significantly higher than those of TEP and UNS Electric. Proper weight must be given to Mr. Beach's various RCP, payback and bill comparisons between APS and the Companies. Companies' witness Rick Bachmeier provides a comprehensive analysis of the bill impacts and payback periods under our proposals.

Q. Are the Companies revising any of their Surrebuttal rate design positions?

A. Yes. The Companies, Staff, and RUCO followed the Commission's guidelines as set forth in the VOS Order to formulate positions that are just and reasonable for *all* customers, and thus in the public interest.

The Companies are prepared to reduce the DG meter charge for new DG customers even further below actual cost in order to match Staff's Surrebuttal proposal. With this change, the Companies, Staff, and RUCO agree on substantially *all* DG rate design issues as well as the structure of DG rates. The particulars are described in more detail in the Surrebuttal Testimony of Companies' witnesses Richard D. Bachmeier, and Craig A. Jones.

[9] Letter from Commissioner Andy Tobin, July 14, 2017 (Docket Nos. E-01345A-16-0036 and E-01345A-16-0123).

Q. Are the Companies revising their RCP recommendation?

A. The Companies still maintain their recommended combined RCP of 9.73 cents per kWh is the appropriate initial RCP rate for both Companies. However, the Companies would not oppose the following two options:

1. Adopt Staff's initial combined RCP of 10.7 cents for both Companies.
    - Reset the RCP on July 1, 2018 to 9.63 cents for TEP, which is 10% less than 10.7 cents.
    - Reset the RCP on July 1, 2018 to 9.20 cents for UNS Electric, which is equivalent to the weighted average retail rate of the Residential and Small General Service classes
2. Adopt the Companies' and RUCO's initial combined RCP of 9.73 cents
    - Reset the RCP 12 months after the decision date of Phase 2 to a combined rate of 8.76 cents.

Q. Why are you proposing to reduce the UNS Electric RCP more than 10% at the first reset in Option 1 above?

A. The 10.7 cent rate is far above UNS Electric's average retail rate. The purpose of the 10% reduction limit was to avoid decreasing the compensation for DG too quickly as compared to net metering and to allow solar providers time to adjust to reduced compensation. However, because the UNS Electric RCP rate is well above the retail offset enjoyed through net metering, there is no need to provide solar providers an adjustment period to get back to an RCP rate equal to the retail rate. Moreover, one of the goals of the VOS Order is to reduce the cost shift. Establishing an RCP rate well above the average retail rate does just the opposite and the RCP rate should be adjusted more rapidly to avoid that problem.

Q. Do the Companies support Vote Solar's recommendation to institute a 10% floor on the RCP after the 10-year lock-in period expires?[10]

A. No. The Value of Solar Order states the following:

> "IT IS FURTHER ORDERED that 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 interconnection for a period of ten years."[11]

In addition, the evidentiary record in this proceeding supports solar DG payback periods of less than 10 years, thus rendering certainty beyond 10 years unnecessary.

Q. Do the Companies support the transmission and distribution ("T&D") adders to the RCP proposed by Vote Solar and EFCA/TASC?

A. No, the Companies continue to oppose any T&D adders to the RCP. Companies' witness Susan Gray, who has 20 years of direct experience with TEP's and UNS Electric's T&D systems, proves that not only does solar DG impose a burden on the grid, it also results in higher utilization of the distribution system and imposes additional costs when compared directly with utility scale systems interconnected to our distribution system.[12]

Staff and RUCO also oppose T&D adders to the RCP. RUCO witness Mr. Huber provides a concise explanation in his Rebuttal Testimony.

> "Vote Solar is assuming that the Companies can somehow avoid embedded T&D capacity costs, which are fixed, by exporting solar. This argument falls into a logical fallacy because distribution capacity, which is already installed, is a precondition for DG solar to export power. The nail in the coffin to the argument of at least including the demand related portion of the transmission system as an

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[10] Kobor Surrebuttal, 37:7-8.
[11] VOS Order, 179:14-16.
[12] Gray Rebuttal, 3:17-22.

adder is, the fact, that most of the Companies' solar resources are actually located within the distribution system. So even if it was appropriate to add the cost of the transmission system to the RCP rate, which RUCO is not conceding at this point, it would largely not apply here given actual resource locations."[13]

III. JUST AND REASONABLE RATES

Q. Vote Solar[14] and EFCA/TASC[15] claim the Companies' DG rate proposals in this proceeding do not support gradualism and thus are unreasonable. Please comment.

A. The Companies believe that their initial Phase 1 proposals for DG rate design represented a gradual move away from net metering towards rates that would begin to gradually mitigate the DG cost shift and provide a higher level of fixed cost recovery. However, much has changed since UNS Electric and TEP filed their Phase 1 Direct Testimonies in 2015, including the bifurcation of the Companies' rate cases and the Commission's VOS Order. The charts below illustrate the significant movements the Companies have made throughout these proceedings in the spirit of compromise and gradualism.

Figure 1 below shows that the cost to provide service to a TEP residential DG customer is approximately $100 per month. While much time and effort has been spent debating the merits and assumptions of the Companies' cost of service studies, it is interesting to compare the fixed cost recovery under TEP's current rate proposal with Vote Solar's Surrebuttal position.[16] As shown below, TEP estimates that the DG TOU rate set forth in its Rejoinder Testimony will provide TEP with monthly fixed cost recovery of approximately $56 per month from an average sized customer, which is *less* than the DG

[13] Huber Surrebuttal, 17:15-21, 18:1-3.
[14] Kobor Surrebuttal, 81:10-11, 82:6-7.
[15] Beach Surrebuttal, 7:27-28.
[16] The Companies strongly disagree with Vote Solar's calculation of allocated cost as set forth in Mr. Jones' testimony.

customer cost allocation of approximately $58 set forth in Ms. Kobor's Testimony. Figure 1 also shows TEP's significant movement from Direct Testimony to Rejoinder Testimony – reducing its monthly fixed cost recovery from new residential DG customers by nearly 18%.

...

Figure 1

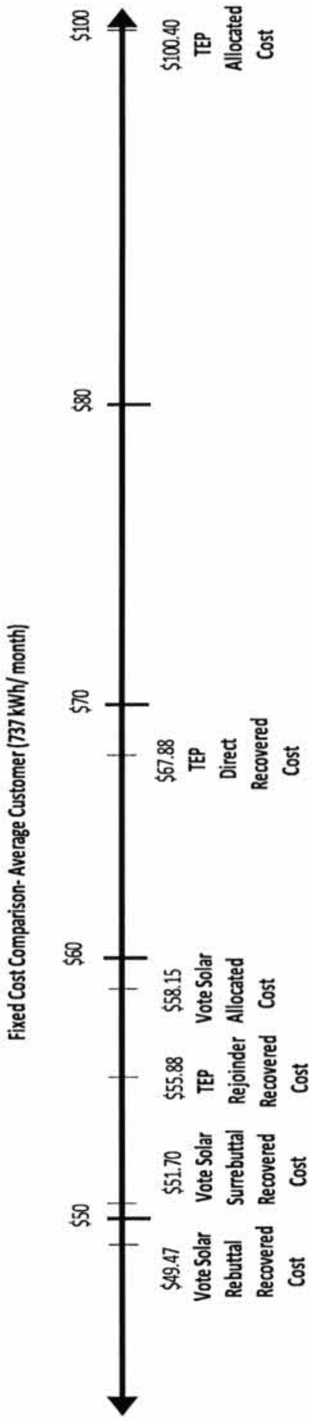
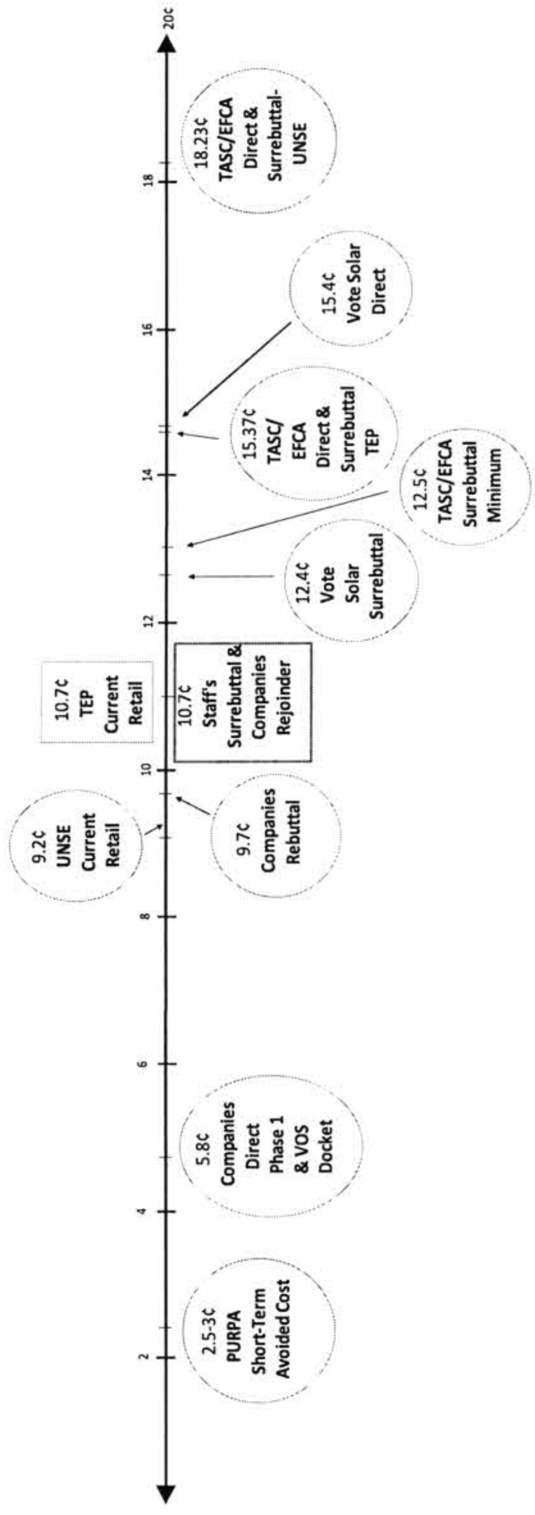

Fixed Cost Comparison- Average Customer (737 kWh/ month)
$100
$80
$70
$60
$50
$100.40 TEP Allocated Cost
$67.88 TEP Direct Recovered Cost
$58.15 Vote Solar Allocated Cost
$55.88 TEP Rejoinder Recovered Cost
$51.70 Vote Solar Surrebuttal Recovered Cost
$49.47 Vote Solar Rebuttal Recovered Cost

Figure 2 below shows how the Companies' proposed DG export rate has evolved in this docket to now supporting Staff's Surrebuttal recommendation of 10.7 cents per kWh. As Staff witness Smith points out, "...the Staff recommended initial RCP rates represent a reasonable recommendation and one that falls between the extreme low and high recommendations being presented by other parties."[17]

...

[17] Smith Surrebuttal, 11:7-8.

Figure 2



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20¢
2.5-3¢ PURPA Short-Term Avoided Cost
5.8¢ Companies Direct Phase 1 & VOS Docket
9.2¢ UNSE Current Retail
9.7¢ Companies Rebuttal
10.7¢ TEP Current Retail
10.7¢ Staff's Surrebuttal & Companies Rejoinder
12.4¢ Vote Solar Surrebuttal
12.5¢ TASC/EFCA Surrebuttal Minimum
15.37¢ TASC/ EFCA Direct & Surrebuttal TEP
15.4¢ Vote Solar Direct
18.23¢ TASC/EFCA Direct & Surrebuttal-UNSE

Q. Based on the charts above, do the Companies' rate design and RCP recommendations promote gradualism?

A. Absolutely. But remember that Phase 2 rates and the RCP will only affect **new** DG customers. Gradualism in rate-making typically focuses on minimizing or mitigating bill impacts for *existing* customers -- essentially, looking at a large bill impacts to existing customers associated with increased rates or new rate offerings. The Companies' proposal will have no impact on existing net metering customers, but will result in a reasonable reduction of the subsidies afforded to <u>new</u> DG customers. Let's also not lose sight of the fact that any under-recovered cost to serve these new DG customers will ultimately be paid by the other non-participating customers; and any overpayment for their exported renewable energy will be paid for by all customers as currently proposed.

Q. Do the Companies still believe there will be no undue negative impact on rooftop solar installations under your revised proposal?

A. Yes. The below "Payback" table incorporates the modeling changes described in the Surrebuttal testimonies of Vote Solar and Staff with all assumptions the same as before, with the exception that the Company (TEP) has accepted Staff's lowered DG meter fee for the 2-part TOU rate and has accepted a 10.7 initial RCP. The simple paybacks do not incorporate any utility rate escalation for the years 2017 and beyond and do not incorporate any projected DG system cost decreases or increases. Years prior to 2017 assume the same level of efficiency as years 2017 and beyond, which likely understates the historical paybacks.

	2014	2015	2016	2017	2017 proposed-Rejoinder	Period 2 RCP	Period 3 RCP
Simple Payback	11.75	9.00	8.33	7.08	8.92	9.58	10.17
Annual Residential Installs	2,009	3,192	3,388	3,194	N/A	N/A	N/A
% achieved of 2025 DG carve out target	36%	53%	72%	89%	N/A	N/A	N/A

As shown in my Rebuttal testimony, the projected simple pay backs over the next three projected RCP periods range from just under 9 years to just over 10 years. This payback period is equivalent to historical years where 2,000 – 3,000 DG systems were installed in the TEP service territory annually.

IV. DISTRIBUTION AND TRANSMISSION ADDER TO RCP

Q. Are T&D costs avoided as alleged in Vote Solar's witness Ms. Kobor's testimony?[18]

A. No. First and most importantly, we must understand what the T&D adder is meant to be in relation to comparing utility scale photovoltaic systems to distributed systems. As stated within the VOS Order:

> "In order to be an accurate proxy, however, we do believe that DG should receive credit for **costs that it avoids** that central station solar (and other central station generation) do not avoid. As a result, the Resource Comparison Proxy we adopt will require that **avoided** transmission, distribution capacity and line losses be considered in the analysis."[19]

[18] Kobor Surrebuttal, 18.
[19] VOS Order, 152:11-15.

The key point here is, **"costs that it avoids"**, not an assumption based upon a generalized scenario, but rather an evaluation of each utilities circumstances. Thus the reason that the establishment of the RCP formula was ordered to be established within a rate case and not a generic proceeding. TEP has proposed a 3.53% line loss factor in calculating RCP, with which both Staff and RUCO have agreed.

However, there are no appropriate "avoided" T&D costs that should be added to the RCP in this instance. To include avoided T&D costs, as proposed by Vote Solar and EFCA/TASC, would require non-DG customers to essentially pay for the facilities in two ways – once in their existing retail rates to allow solar generation to be delivered and then, if added to the RCP, again as an additional adder to the RCP that will be recovered in the PPFAC as a fuel cost or in the REST as subsidies paid for DG purchases in excess of MCCCG. The additional cost being proposed by Vote Solar and EFCA/TASC are not "avoided costs," they are proxy values assuming that cost can be avoided based upon current embedded cost recovery levels and/or cost to maintain or replace the current system, in today's dollars.

The VOS Order determined that the cost shift should be reduced[20] – not increased based on unsubstantiated adders.

Q. What additional support do you have for arriving at the conclusion that a T&D adder of zero is appropriate?

A. Vote Solar and EFCA/TASC attempt to support the T&D adder by using a historic marginal cost study. This cannot be used to support that any avoided T&D costs can be quantified as the result of solar DG because marginal costs for *added* load cannot equal the avoided cost for *reduced* load. The reasons are quite simple:

[20] VOS Order, 175-176 (Finding of Fact No. 163).

1. Sunk costs, such as distribution plant currently in service and its related revenue requirement at the margin, are in no way reduced by reductions in load.
2. The Companies have shown that to have a large enough peak load reduction to allow for a smaller set of delivery assets requires more installed DG capacity than the load carrying capability of the smaller assets.[21]
3. For "as available" DG resources, the only avoided cost that is permitted under <u>FERC regulations is the avoided cost at the time of delivery meaning that long-run marginal costs are not permitted to determine avoided costs</u>.

Q. EFCA witness Mr. Beach also uses a higher line loss adjustment than the Companies, Staff or RUCO. Do you believe his assumption is wrong?

A. Yes. Average losses exceed the losses avoided when DG output is delivered to the system. This conclusion is based on straight forward arithmetic. Average losses are equal to the sum of the hourly marginal losses (higher in high load periods and lower in low load periods) plus core losses that do not change with load. Since solar DG deliveries to the system occur in lower load periods (because that is when the DG customer's own load is less than the solar DG output), the avoided losses must be less than the average losses. The net result is that avoided losses are much less than the average losses. This supports the losses used by the Companies to inflate the RCP rate.

Q. EFCA witness Mr. Beach refers to PURPA requirements at various parts of his testimony. Do you wish to speak to PURPA requirements?

A. Yes. The Commission's VOS Order does mention some consideration should be given to include certain types of adders where costs are avoided. <u>But this does not mean a T&D adder is in any way appropriate if no costs are avoided</u>. To increase the already subsidized RCP (which is already well above the allowable "avoided cost" rate under PURPA) by

[21] Dukes Rebuttal, 21.

adding additional adjustments beyond actual avoided costs would potentially result in the Commission policy being in violation PURPA and the FERC Regulations. While the Commission may have substantial latitude in interpreting how it arrives at an avoided cost "proxy" (the RCP rate) in this case, it should still strive to follow FERC regulations as they relate to purchase of power from DG customers. DG customers have already been determined to be partial requirements customers and as such they are subject to FERC regulations relating to QFs and subject to the Commission's jurisdiction as delegated by FERC regulations. The T&D adder and actual line loss adjustment should only be assigned a positive value if there are actual avoided costs. The evidence shows that is not the case. This means a zero T&D adder is appropriate.

V. RUCO'S PROPOSED "ALL PRODUCTION TOU RCP"

Q. Do the Companies have any comments on RUCO's proposed "All Production RCP?"

A. Yes. The Companies do not oppose RUCO's All Production RCP as long as (i) the RCP rate only applies to energy exports from solar DG systems, (ii) the rates adjust commensurately with each change in the DG export rate and (iii) the proposal is established as a pilot program subject to evaluation and adjustment, if necessary, to address any unintended consequences or if its deemed to not be beneficial to the system or customer base.

VI. OTHER ISSUES

Q. Do the Companies have a position on AECC's proposal for recovery of payments for exported DG energy?

A. The Companies do not oppose AECC's proposal for above-market generation costs to be recovered through the REST surcharge. However, the Companies do not agree that the

REST caps could not or should not be adjusted by the Commission in future proceedings. The Companies also do not support the creation of any new special mechanism to recover these costs directly from the residential and small general service customers exclusively.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
TOM FORESE - CHAIRMAN
BOB BURNS
VACANT
ANDY TOBIN
BOYD W. DUNN

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
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 **PHASE 2**

REJOINDER TESTIMONY OF SUSAN GRAY

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.

OCTOBER 13, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Susan Gray. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct and/or Rebuttal Testimony in the Phase 2 proceedings in these dockets?

A. I filed Rebuttal Testimony on behalf of Tucson Electric Power ("TEP") and UNS Electric, Inc. ("UNSE") in the Phase 2 proceeding.

Q. On whose behalf are you filing Phase 2 Rejoinder Testimony?

A. My Phase 2 Rejoinder Testimony is filed on behalf of TEP and UNSE, jointly referred to herein as the "Companies."

Q. What is the purpose of your Phase 2 Rejoinder Testimony?

A. The purpose of my Rejoinder Testimony is to address the following areas discussed in the Surrebuttal testimonies of Mr. Volkmann and Mr. Beach.

In my testimony I address:

1. the burden caused by rooftop solar DG to the Companies' distribution systems;
2. the recommendations for advanced inverters and associated communication requirements;
3. rooftop solar DG has not resulted in the Companies being able to defer projects; and
4. the impracticality of storage customers providing grid services.

II. RESPONSE TO SURREBUTTAL TESTIMONY OF VOTE SOLAR AND EFCA/TASC

Q. Is system capacity an issue as it relates to rooftop solar DG as discussed by Mr. Volkmann?

A. No. Mr. Volkmann continues to focus on system capacity to defend his claims that rooftop solar DG systems do not place a burden on the Companies' systems.[1] However, at this time, the Companies are not necessarily concerned with system capacity in terms of the burden that rooftop solar DG places on the Companies' systems. Evaluation of system capacity is one of the simplest assessments as it relates to rooftop solar DG. It is a simple addition calculation and is most frequently completed by administrative staff during the interconnection process. The existing interconnection process allows for the Companies to adequately evaluate requests from customers adding rooftop solar DG for system capacity. If capacity limitations arise during the interconnection review process, the customer is notified of the required upgrades and the customer pays for those upgrades up-front.

Q. Are there other types of burdens that rooftop solar DG places on the Companies' systems?

A. Yes. The Companies have provided evidence that an average rooftop solar DG customer utilizes the grid more than a full requirements customer. The COS Study analysis provided in my Rebuttal Testimony proves that rooftop solar DG customers utilize the Companies' systems more than a full requirements customer. Simply stated, a customer with an intermittent energy source, who exports excess energy using a distribution system that is not designed for two-way power flows, and imports energy when their DG system cannot meet their demand, uses the utility's facilities more than a standard, full-requirements customer.

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[1] Volkmann Surrebuttal (2:18-23).

Utilizing the system more shortens the life of utility assets, and increases the cost of operations and maintenance.

On page 11 of my Rebuttal I discussed the results from specific power flow studies showing that voltage deviations caused by a high-penetration of rooftop solar DG is possible on a number of existing distribution circuits and the issues will expand to other circuits as DG penetration increases.[2] Rooftop solar DG is reliant on the sun to produce power and when fast moving clouds reduce sunlight, the production from the rooftop solar DG system reduces abruptly. This sudden loss of generation requires the Companies system to respond and provide the necessary power instead of the rooftop solar DG system. As the study results show, this can result in voltage violations because traditional voltage control devices such as transformer load-tap changers, capacitor banks, and voltage regulators cannot respond quickly enough. Additional investment in new technologies is required to address this issue.

Unintentional "islanding" is another burden to the distribution system as PV penetration levels rise. Unintentional islanding is a condition created by distributed generation energizing a portion of the distribution grid when the utility energy source has been lost. The Companies are already approaching penetration levels on several circuits that could potentially create an island. This not only creates a voltage concern, but safety concerns as well. Unintentional islanding can produce voltage deviations outside industry standards as voltage regulation devices such as load tap changers ("LTCs") and regulators will be ineffective to control voltage on the circuit. Unintentional islanding also creates a safety hazard where distribution devices operate to isolate and de-energize sections of the grid but reverse power flow to the grid from distributed generation energizes the line.

[2] The Companies also provided information regarding this issue in response to Data Request VS P2 10.20 (see Exhibit SG-P2-RJ-1).

Q. Do you agree with Mr. Volkmann's assertions about transformer loading?

A. No. In his Surrebutal Testimony, Mr. Volkmann continues to use the same 'snapshot' example for proof that rooftop solar DG does not place a burden on the Companies' systems.[3] This is another example of his use of "cherry picking" particular data to pinpoint a specific timeframe that is most beneficial for proving his points. However, it does not accurately reflect the actual impact of rooftop solar DG over a period of time.

My analysis of the COS Study in my Rebuttal Testimony is a much more representative method of determining if rooftop solar DG places an increased burden on the Companies' systems. By using data for an average customer from the entire calendar year, and not a specific, opportune hour of the day as Mr. Volkmann has, I have proven that rooftop solar DG customers utilize the Companies' systems more than a full requirements customer. Increased burden and additional costs for the Company can be attributed to the increased utilization from rooftop solar DG customers.

Q. Please address how the unpredictable intermittency of solar and the associated ramping issues are not the same as normal variations in customer load.

A. Mr. Volkmann attempts to make a comparison of typical customer loads with typical rooftop solar DG to claim that a typical distribution system is "...designed to accommodate fluctuations in residential, commercial, and industrial load."[4] However, the impact of the ramping up and down of solar DG production on the distribution system is significantly different in both level and timing than the variations in customer load. Because Mr. Volkmann does not have any direct experience with the operation of a distribution system, he has to rely on studies and knowledge of what he considers 'typical' systems. Specific

[3] Volkmann Surrebuttal (3:15-23).
[4] Volkmann Surrebuttal (6:11-12).

knowledge and experience with the Companies' actual systems is essential to properly evaluate specific impacts.

Comparing typical loads such as a garage door opener or central air conditioner with a typical rooftop solar DG system is like comparing apples to oranges. Impacts caused by the loading of equipment is much different than the production or generation of electricity with intermittent inverter based technologies such as rooftop solar DG. Intermittent rooftop solar DG is highly dependent on irradiance or sunlight. Fast moving clouds can reduce the production from a rooftop solar DG system very quickly and faster than any equipment on the distribution system can respond. While the sudden loss of production from a single rooftop solar DG system may not impact the voltage on a distribution circuit, power flow study work has shown that the sudden loss of production from rooftop solar DG in a highly penetrated circuit can impact the voltage on a circuit. The Company has demonstrated that this potential exists on a number of its circuits today. Many of the Company's distribution circuits are relatively short in length and serve small areas of the service territory. Therefore, it is reasonable to consider that fast moving clouds could abruptly reduce the output from all of the rooftop solar DG systems connected to a single distribution circuit and cause voltage deviations.

Attempting to compare this type of intermittent operation with typical loads is inaccurate. As noted above, all of the rooftop solar DG systems will be impacted at nearly the same time by clouds and will abruptly reduce production. This is **not** what occurs with customer loads on a distribution circuit. Indeed, comparing this type of operation to typical loads would mean that a majority of the customers sourced on a common circuit simultaneously operated the same equipment at the same time. More simply put, every customer would need to be drying their hair at the same time and then turn off the hair dryer at the same time. This is an unlikely scenario. Loads are inherently diverse across the typical 1000-2000 customers that share a distribution circuit for a multitude of purposes, which limits sharp changes in circuit load and reduces the impact loads have on system voltage. On the other hand, there is only one sun that shines down to produce rooftop solar DG power, essentially eliminating any opportunity for diversity within a centralized distribution circuit as it relates to rooftop solar DG.

Q. Do Mr. Volkmann's claims of the IEEE Standard C57.91-2011 only represents loss of life on overloaded transformers stand true?[5]

A. No. Contrary to Mr. Volkmann's claims that the IEEE Standard C57.91-2011 is only used for determining the useful life on overloaded transformers, the Standard covers more. Section 4 of the standard addresses the effects of overloading transformers. Other sections of the IEEE Standard address aging equations that are directly linked to coil temperature. Coil temperature is affected by the utilization or loading of the transformer. In traditionally lower loading shoulder months, a transformer's coil temperature is lower due to loads being lower.

As identified in my Rebuttal Testimony, a rooftop solar DG customer actually increases the utilization on the transformer due to reverse power flow from rooftop solar DG production. This increase in utilization ages the transformer more than if no rooftop solar DG was installed. For aging coefficients see Table 1 Section 5 of the IEEE Standard C57.91-2011.

Q. Do the Companies support the installation of advanced inverters?

A. Yes, the Companies support the installation of smart or advanced inverters for all DER technologies. In fact, all Company-owned constructed and operated PV facilities have been specified with advanced inverter functionality since 2014. Advanced inverters have been installed as part of the Company's TEP-Owned Rooftop System ("TORS") program.

[5] Volkmann Surrebuttal (8:2-29).

Advanced inverter technology was required for the three larger-scale energy storage facilities presently in operation. I introduced the topic and justified the need for advanced inverters in my rebuttal testimony.

While not directly associated with this proceeding, the Companies have also supported the requirements for the installation of advanced inverters for customer-sided installations throughout the recent Distributed Generation Interconnection Requirements review initiated by the Commission several years ago.

Q. Do you agree with Mr. Volkmann that advanced inverters are needed?

A. Yes, As Mr. Volkmann has identified in his Surrebuttal Testimony, advanced inverter "capabilities will help significantly with grid stabilization and mitigation of any voltage or power quality issues as solar DG and energy storage penetrations increase."

As I have discussed several times throughout this proceeding, advanced inverter technology will be required to help manage the voltage fluctuations caused by the intermittent production of rooftop solar DG. In fact, results from specific power flow studies have shown that voltage violations are possible on a number of the Companies' distribution circuits due to the high penetration levels of rooftop solar DG.

However, even though advanced functions such as voltage and frequency ride-through do not necessarily require communications with the Utility, this is not the advanced functionality that will assist with managing the intermittent production of rooftop DG. Rather, advanced inverters with reactive power control are needed to help mitigate this issue. As previously discussed, traditional voltage control devices such as capacitor banks, voltage regulators, and transformer load-tap changers cannot operate fast enough to combat the voltage violations created by the intermittent production from rooftop solar DG. Advanced inverters can help more quickly adjust the voltage by consuming or producing reactive power. However, this cannot be accomplished with local settings in the inverter. Control of reactive power inverter settings must be coordinated with the other voltage control devices on the circuit to properly and more efficiently control the distribution system voltage.

Q. Why are direct communications with advanced inverters required?

A. In order to provide any material system benefits, inverter control needs to be integrated with other voltage control devices through a central management system that also controls other critical utility infrastructure. Therefore, the communications infrastructure must have high levels of security to prevent exposure to the Companies' network. This level of security requires direct communications with the inverters and cannot be accomplished with basic customer-owned wifi. As previously explained, the Companies will be investing significant capital to install the proper communications network and distribution management systems to properly coordinate, monitor, control and integrate additional voltage control devices due to the intermittent production of rooftop solar DG.

Q: Do the examples provided by Mr. Beach in Q25 of his Surrebuttal with examples from other utilities not affiliated with the Company have any relation to projects identified and constructed by the Company?

A. No. The first example credits both energy efficiency and distributed solar for T&D asset deferment, but does not provide any other detail. It is unknown from the information provided as to whether or not the benefits were derived more from energy efficiency or distributed solar. There is also no mention as to whether the distributed solar was behind the meter or utility-scale.

To date, the Company has not identified specific projects that can be deferred due to the installation of rooftop solar DG. In fact, as I have previously testified, intermittent production from rooftop solar DG is driving increased investment in new technologies such as a more robust communications network and an advanced distribution management system. Along with the installation of additional distribution system device controllers, the communication network and management system will allow the Companies to better manage system voltage and reduce the increasing voltage violations being caused by intermittent rooftop solar DG. The distribution system was designed for power plant generation to step down at different levels until it reached the customer, it was not designed for customer-sited generation. There are simply more costs when augmenting the distribution system to accommodate intermittent generation. It is telling that no solar advocate mentioned the additional costs identified in the Company's responses to data requests EFCA 4.3, 4.4, 4.5 and VS 10.10.

Q: Do you agree with Mr. Beach's testimony in Q36 where he introduces a number of *"other grid services that storage customers can provide?"*

A. No, the information provided by Mr. Beach in this question is wrong. He states that *"DERs with smart inverters can provide VARs to reduce voltage in areas with high voltage conditions".* This fundamentally flawed statement demonstrates Mr. Beach's lack of understanding of system operations. While the Company supports the installation and use of smart or advanced inverter technology, providing VARs will not reduce voltage. If a DER device provides VARs to the Companies system, the voltage will increase. The DER device would need to consume VARs to reduce voltage. The Companies are also concerned with the concept of having DER devices (which are creating high-voltage issues) attempting to consume VARs to solve the high-voltage problem they have created. If DER devices are programmed to consume VARs and are not integrated with other voltage control devices on the circuit, the system efficiency will decrease. VARs will have to be produced from other devices such as capacitor banks or from traditional generation facilities.

Mr. Beach also introduces the concept of Conservation Voltage Reduction ("CVR") in A36. The reference stated that utilizing DER devices with smart or advanced inverters can provide an average energy savings of 0.4%. Implementing system-wide, fully-functioning volt/var control comes with significant cost. Reliable and secure communication is required and must connect to more than the DER devices on the distribution circuit. Once communication and control of all voltage control devices on the system is integrated into an advanced distribution management system, the management system can then make automated decisions to make the most efficient adjustments of these devices. System voltage can then be lowered, if possible, to accomplish conservation voltage reduction.

Concerns arise for CVR on circuits that have a high penetration of rooftop solar DG. If the automated system reduces the system voltage and fast moving clouds abruptly reduce the production of the rooftop solar DG, significant voltage violations can arise. Substantial design and operational criteria must be set and implemented to ensure these types of initiatives do not create more system issues than they are attempting to solve.

"Situational Awareness" is also suggested as a benefit. However, outage data is already collected from every one of the Companies 400,000+ customers and the Companies see zero benefit from utilizing data from DER providers for outage notification. It is unclear to the Companies how DER providers with systems located behind a customer's meter could accurately provide system fault detection information similar to the inexpensive line sensors readily available on the market and easily installed directly on the Companies lines. Line sensors currently deployed by the company provide accurate information for circuit loading and fault detection. Additionally, it is unclear how a DER provider could provide similar functionality as *"communications with line equipment"*. DER devices connected behind a customer's meter would not be a reliable or secure means for communicating with line equipment such as capacitor banks, voltage regulators, line switches, and line regulators. As discussed, control of this equipment must be integrated with the Companies' central management system that also controls other critical utility infrastructure. The communications infrastructure must have high levels of security to ensure exposure to the Companies' network is not possible. This level of security cannot be accomplished with basic customer-owned wifi that is traditionally used by solar providers for communications with DER devices.

Mr. Beach also references IEEE Standard C57.12.00-2000 to claim solar production reduces transformer loading which extends transformer life. IEEE C57.12.00-2000 is inactive and superseded according to IEEE. Also, this standard is a general requirements guide for transformer specifications and does not mention transformer loading's effect on transformer life or provide any calculations as claimed. Therefore, referencing this Standard to claim solar and battery storage benefits to transformer life extension is misleading.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit SG-P2-RJ-1

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 10.20

On page 11, lines 6-8 of Ms. Gray's rebuttal testimony, she states: "Distribution system power flow studies show that increased levels of rooftop solar DG penetration will cause distribution system voltage violations . . . ." Please provide a list of all circuits that will experience voltage violations due to increased penetrations of rooftop solar DG. For each circuit, please provide the circuit and substation name, voltage level, number of customers served by the circuit, current rooftop solar DG penetration, year in which the voltage violation will occur, forecasted rooftop solar DG penetration in the year the voltage violation will occur, the month and time-of-day of the voltage violation, number of hours each year the voltage violation will occur. Please provide this data in Excel format with all formulas and links intact.

RESPONSE:

This information is not available on a circuit-by-circuit basis due to the lack of real-time operational data from rooftop solar DG systems, including voltage and current.

A subset of the Companies' distribution circuits has been studied by a third-party consultant to determine the maximum level of rooftop solar DG penetration before voltage violations can be expected. The Companies have not received the final study from the third-party consultant, but have been provided results which show that under normal operating conditions, the Companies' systems can accommodate additional rooftop solar DG system installations. However, due to the intermittent production of rooftop solar DG systems, limitations arise during the sudden loss of rooftop solar DG system production. The tables attached in file **VS P2 10.20.xlsx** from the study results show that the Companies' systems have the potential to experience voltage violations on some circuits during minimum daytime loading conditions. Cells in the Excel file have been highlighted where study results show the sudden loss of rooftop solar DG production will cause a voltage violation. These violations occur because the loss of production occurs faster than the substation load-tap changer can respond and adjust the system voltage. The Companies will supplement this response with the final study, once available.

RESPONDENT:

Susan Gray

WITNESS:

Susan Gray

Case	Feeder Name	Customer Count	Length (Mi)	Load (MW)	PV Penetration (MW)	PV Penetration (%) on base case	Maximum PV Penetration allowed (%)		Maximum Voltage Fluctuation
							LTC Unlocked	LTC Locked	
Daytime Maximum Load	RO-4	1917	151	9.62	0.784	8.15	80	35	3
	RO-5	1338	139	10	1.19	11.90	75	30	1
	RO-6	1506	145	8.88	0.722	8.13	115	35	2
	RO-12	1218	71	7.5	0.346	4.61	190	35	2
	RO-13	878	118	5.4	0.686	12.70	145	25	3
	RO-14	1263	209	7.5	0.943	12.57	150	25	3
	RO-24	2344	86	8.5	0.593	6.98	200	35	1
	RO-25	844	111	4.3	0.609	14.16	210	30	3
	RO-26	2502	22	9.3	0.058	0.62	300	40	1
Daytime Minimum Load	RO-4	1917	151	1.92	0.784	40.83	300	30	3
	RO-5	1338	139	1.31	1.19	90.84	170	30	4
	RO-6	1506	145	1.53	0.722	47.19	300	40	1
	RO-12	1218	71	1.62	0.346	21.36	300	30	3
	RO-13	878	118	8.1	0.686	8.47	170	40	1
	RO-14	1263	209	1	0.943	94.30	250	35	4
	RO-24	2344	86	1.02	0.593	58.14	300	45	3
	RO-25	844	111	0.78	0.609	78.08	300	35	2
	RO-26	2502	22	1.4	0.058	4.14	300	40	2

Case	Feeder Name	Customer Count	Length (Mi)	Load (MW)	PV Penetration (MW)	PV Penetration (%) on base case	Maximum PV Penetration allowed (%)		Maximum Voltage Fluctuation
							LTC Unlocked	LTC Locked	
	LR-13	2598	118	10.5	1.832	17.45	150	35	3
	LR-14	1869	335	8.7	0.02016	0.23	90	30	2
	LR-15	1625	72	9.1	0.278	3.05	145	35	3
Daytime Maximum Load	LR-16	1871	133	7.7	1.294	16.81	85	35	4
	LR-13	2598	118	1.3	1.832	140.92	>300	25	4
	LR-14	1869	335	1.6	0.02016	1.26	75	20	2
	LR-15	1625	72	1.15	0.278	24.17	>300	40	2
Daytime Minimum Load	LR-16	1871	133	1.13	1.294	114.51	80	25	4

Case	Feeder Name	Customer Count	Length (Mi)	Load (MW)	PV Penetration (MW)	PV Penetration (%) on base case	Maximum PV Penetration allowed (%)		Maximum Voltage Fluctuation
							LTC Unlocked	LTC Locked	
Daytime Maximum Load	STZ-7	24	3	4	0.374	9.35	150	35	2
	STZ-8	2772	79	11.9	0.317	2.66	250	30	2
	STZ-10	12	2	3.7	0.37	10.00	150	35	1
	STZ-11	2666	32	10.4	0.081	0.78	90	35	3
	STZ-13	1683	35	7.4	0.311	4.20	95	30	3
Daytime Minimum Load	STZ-7	24	3	1.28	0.374	29.22	250	40	1
	STZ-8	2772	79	1.87	0.317	16.95	150	30	3
	STZ-10	12	2	1.06	0.37	34.91	200	35	2
	STZ-11	2666	32	0.54	0.081	15.00	110	25	3
	STZ-13	1683	35	1.65	0.311	18.85	200	35	3

Case	Feeder Name	Customer Count	Length (Mi)	Load (MW)	PV Penetration (MW)	PV Penetration (%) on base case	Maximum PV Penetration allowed (%)		Maximum Voltage Fluctuation
							LTC Unlocked	LTC Locked	
Daytime Maximum Load	GV-4	365	29	2.7	0.374	13.85	150	35	3
	GV-7	1819	57	7.8	0.317	4.06	250	30	1
	GV-9	1518	84	13.4	0.37	2.76	150	35	2
	GV-14	825	41	11.4	0.081	0.71	90	35	3
	GV-16	2783	107	6.8	0.311	4.57	95	30	3
	GV-19	3164	242	4.7	0.701	14.91	250	40	1
Daytime Minmum Load	GV-4	365	29	1.28	0.374	29.22	>300	30	3
	GV-7	1819	57	1.87	0.317	16.95	>300	30	1
	GV-9	1518	84	1.06	0.37	34.91	>300	40	3
	GV-14	825	41	0.54	0.081	15	250	45	1
	GV-16	2783	107	1.65	0.311	18.85	200	35	2
	GV-19	3164	242	1.44	0.701	48.68	>300	40	4

Case	Feeder Name	Customer Count	Length (Mi)	Load (MW)	PV Penetration (MW)	PV Penetration (%) on base case	Maximum PV Penetration allowed (%)		Maximum Voltage Fluctuation
							LTC Unlocked	LTC Locked	
Daytime Maximum Load	MDV-6	2083	57	12.32	0.512	4.16	140	35	2
	MDV-7	1458	40	6.33	0.252	3.98	115	30	2
	MDV-8	1095	37	5.64	0.903	16.01	155	35	3
	MDV-9	1608	56	10.19	0.381	3.74	220	35	3
	MDV-24	2556	88	11.16	0.315	2.82	90	30	1
	MDV-25	2237	66	11.94	1.926	16.13	70	40	1
	MDV-26	2843	89	10.76	0.378	3.51	175	25	2
Daytime Minmum Load	MDV-6	2083	57	2.4	0.512	21.33	180	30	3
	MDV-7	1458	40	1.6	0.252	15.75	160	35	3
	MDV-8	1095	37	1.5	0.903	60.2	200	20	4
	MDV-9	1608	56	2.3	0.381	16.57	250	35	1
	MDV-24	2556	88	1.5	0.315	21	150	30	3
	MDV-25	2237	66	3.5	1.926	55.03	120	20	4
	MDV-26	2843	89	1.9	0.378	19.89	200	40	2

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
TOM FORESE - CHAIRMAN
BOB BURNS
VACANT
ANDY TOBIN
BOYD W. DUNN

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
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 **PHASE 2**

REJOINDER TESTIMONY OF CRAIG A. JONES

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.

OCTOBER 13, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Craig A. Jones and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file testimony in Phase 2 of this proceeding?

A. Yes. I filed direct and rebuttal testimony on behalf of both Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric") on March 17 and August 28, 2017, respectively.

Q. On whose behalf are you filing Phase 2 Rejoinder Testimony?

A. My Phase 2 Rejoinder Testimony is filed on behalf of TEP and UNS Electric, jointly referred to herein as the "Companies."

Q. Please summarize the purpose of your Rejoinder Testimony.

A. This Rejoinder Testimony is designed to address certain areas of consistency between the Companies, Staff and Residential Utility Consumer Office ("RUCO"), a variety of misstatements and misinformation still alleged by Vote Solar and EFCA relating to Class Cost of Service Study ("CCOSS"), the Companies' use of class load shapes, and the Companies' allocation of distribution demand costs on non-coincident peak ("NCP"). Finally, I will provide additional support for the Companies proposed incremental DG meter charge and their position on storage rates.

II. SUMMARY

Q. How is your testimony organized?

A. My testimony consists of the following sections:

I. Introduction
II. Summary
III. Staff and RUCO
IV. CCOSS
V. Incremental DG meter charge
VI. Storage Rate

Q. Please summarize your testimony.

A. I will discuss certain issues where the Companies, Staff and RUCO are in agreement and I recommend that the Commission give greater weight to the proposals made by the Company, Staff and RUCO, who have similar interpretations of the policy determinations made in the Commission's decision in the Value and Cost of Distributed Generation Docket ("VOS Order"),[1] and have made proposals consistent with that Order and more in line with the interests of the majority of the Companies retail customers.

My testimony reiterates that the cost of service testimony of Vote Solar witness Ms. Kobor and EFCA witness Mr. Beach continue to be based on numerous errors and incorrect assumptions that render their positions on the cost to serve the solar class invalid not only empirically, but logically as well. I will discuss why the Companies will accept Staff's recommended incremental DG meter charges, but still fully oppose a subsidized, one-time, DG meter buy-out provision because it will result in additional costs being shifted to non-DG customers. I also explain why, counter to EFCA witnesses Mr. Warshay and Beach,

[1] Decision No. 75859 (January 3, 2017).

demand rates are beneficial to customers who use energy efficiently and are supported when creating a new battery storage rate if evaluated correctly. Additional issues are briefly discussed near the conclusion of my testimony. The omission of any rebuttal of a particular issue does not indicate the Companies are in agreement with the proposal.

III. COMPANIES' POSITION RELATING TO STAFF AND RUCO

Q. Please discuss any issues identified in Staff's Surrebuttal Testimony related to the areas discussed in your testimony.

A. Much of Staff's testimony provided on the topics discussed in my Direct and Rebuttal Testimony are consistent with the positions expressed by the Companies and/or in the VOS Order. First, it is important to again recognize that Staff expressed no concerns as it relates to the Companies' final CCOSSs. The few minor comments made by Staff in Phase 1 were incorporated into the Phase 2 CCOSS.

Second, the one area of disagreement between the Companies and Staff involves the incremental DG meter charges applicable to the residential customers. The Companies continue to believe that the record shows that the incremental DG meter charges originally proposed by the Companies are actually understated and do not fully recover the incremental costs of the bi-directional meter. However, the Companies are willing to accept the monthly DG meter charges proposed by Staff as a compromise. Staff did not specifically address the one-time upfront payment for the incremental DG meter costs in its Surrebuttal testimony, but the Companies still strongly oppose this option. This will be more fully discussed later in my testimony.

Third, Staff has indicated it would not object to the Fresh Produce proposal set forth in my Rebuttal proposal,[2] which included recovery of any revenue shortfalls through an Agricultural Adjustment in the PPFAC. The Fresh Produce issue was carried over from Phase 1 and was to be addressed in Phase 2 of UNS Electric's rate case. The Fresh Produce Group proposed an option that I discussed and indicated would be acceptable to UNS Electric with certain conditions in my Rebuttal testimony.[3] The Company has discussed this with the Fresh Produce Group and they have indicated that the option proposed in my Rebuttal Testimony is acceptable to them. Given the lack of opposition from Staff (or any other party), UNS Electric believes that the Fresh Produce issue has been resolved.

Q. Please address any issues in RUCO's Surrebuttal Testimony relating to your Rebuttal Testimony.

A. Much of RUCO's Surrebuttal Testimony that addresses the topics discussed in my Rebuttal Testimony is consistent with the positions expressed by the Companies. Like Staff, RUCO believes that new DG solar customers should be a separate rate class and should be identified as such in the CCOSS for the residential and SGS rate classes.[4] RUCO also recognizes that the Companies' Phase 2 rate design proposals should be designed in a manner that mitigates the recognized cost shift caused by rooftop solar customers' self-consumption.[5] RUCO further indicated that the incremental DG meter charges approved in Phase 1 should be revised for both residential and SGS DG customers and that the Companies' proposed incremental meter charges would be appropriate.[6] Finally, RUCO strongly supports the Companies' proposals relating to the RCS rate and the Bright Tucson program.[7]

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[2] *See* Smith Phase 2 Surrebuttal page 50, line 7.
[3] *See* Jones Phase 2 Rebuttal pages 42 through 44.
[4] *See* Huber Phase 2 Rebuttal page 9, line 11.
[5] *See* Huber Phase 2 Rebuttal page 15, line 2.
[6] *See* Huber Phase 2 Rebuttal page 21, line 22.
[7] *See* Huber Phase 2 Rebuttal page 20, line 6.

IV. <u>CLASS COST OF SERVICE AND LOAD RESEARCH ISSUES</u>

Q. Vote witness Ms. Kobor[8] and EFCA witness Mr. Beach[9] both believe their modifications to the existing CCOSS modeling methods are appropriate for developing rates for the solar DG partial requirements rate class. Does the Company still believe they are wrong?

A. Absolutely. Parties with relevant rate case and cost of service experience, such as Staff and RUCO, have found that the CCOSS filed (including its methodology) is not only transparent but also reflects the correct application of cost of service principles.

Q. Are there other issues you would like to address relating to Ms. Kobor and Mr. Beach's positions as they relate to the CCOSS?

A. Yes. Both continue to press for CCOSS methodologies that improperly ignore:

- Standard cost allocation principles,
- That DG customers are more expensive to serve,
- That current rate design does not recover the costs associated with serving DG customers, and
- That the VOS Order specifically stated DG customers shall be a separate rate class.

By ignoring these critical elements, both Vote Solar and EFCA/TASC have calculated an understated level of costs for the newly created DG partial requirements rate classes. Existing methods of cost allocations have been used and reviewed by this Commission historically for the purpose of creating new rate classes, and neither of the referenced solar advocates have provided legal or precedential support for attempting to use different

[8] *See* Kobor Phase 2 Surrebuttal page 46, line 11.
[9] *See* Beach Phase 2 Surrebuttal page 4, line 28.

methods. The establishment of new rate classes has been considered many times by this Commission when determining appropriate cost allocations for rate classes such as lighting, MGS, water heating, water pumping, Agricultural rate classes, etc. The Companies are using cost allocation methods utilized and approved in the past (including Phase 1) and deemed reasonable by Staff and RUCO in this proceeding.

Q. Do you agree with Ms. Kobor's opposition to the use of a NCP to allocate distribution costs.[10]

A. No. Since distribution facilities are sized to meet load closer to the user, traditional CCOSS methods allocate the total system cost of the distribution facilities based on the NCP of each classes' individual peak. Ms. Kobor incorrectly assumes that since the distribution equipment is already in place, solar customers should not have to pay for it in proportion to the amount of capacity they utilize. However, the solar DG partial requirements class utilizes the distribution system the most when exporting and should have their cost allocations based on that level of capacity utilization.

Q. Do you agree with Ms. Kobor's statement that "...cost allocation to DG customers based on exports would *effectively* (emphasis added) charge the DG customer for use of the distribution system to deliver their exports to the other customers?"[11]

A. No. While costs are **allocated** to the solar DG partial requirements class based on their utilization of the distribution capacity, no charges are actually being applied to exports. Any charges are volumetrically applied to delivery kWh (or kW charges in the three-part rates), not exports. Her statement confuses the concepts of cost allocation and revenue recovery.

[10] *See* Kobor Phase 2 Surrebuttal page 48, line 1.
[11] *See* Kobor Phase 2 Surrebuttal page 51, line 11.

Q. The Vote Solar witnesses disagree with the Companies' treatment of DG customers as a separate class and attempt to justify keeping DG customers within the same class as non-DG customers. Please comment on this position.

A. First and foremost, Vote Solar's justification for keeping DG customers within the same class as non-DG customers is simply a distraction and goes against the Commission's directive. The VOS Order clearly stated that it was the service characteristics of DG customers (specifically that they exported to the grid) that determined that DG customers were a separate class. Additionally, the Company has referenced literature that indicates there are additional factors that should be taken into account when deciding separate class treatment as described in Mr. Bachmeier's Phase 2 Rebuttal Testimony page 32, lines 4-19.

Second, as shown in the Rebuttal and Rejoinder Testimonies of Companies' witness Susan Gray, the Vote Solar witnesses also rely on flawed analyses regarding circuit level DG penetration to justify their position that DG customers should not be in a separate class. Regardless, Companies' witness Susan Gray has shown that there are already additional costs associated with distributed solar and has shown Vote Solar's analysis stating otherwise to be incorrect. It is telling that in the Surrebuttal testimonies of witness Volkmann and Kobor, neither of them brought up the additional costs the Companies presented in responses to data requests EFCA 4.3, 4.4, 4.5 and VS 10.10.

Q. Ms. Kobor's indicates she still has three criticisms of the CCOSS in her Surrebuttal testimony. Do you wish to comment?

A. Yes. Ms. Kobor criticizes the Company's use of the export NCP to allocate distribution costs. She cites a section of the NARUC manual that describes what appears to be an agreement between Ms. Kobor and the Companies, the primary driver for distribution planning is the accommodation of maximum load, thus leading to the conclusion that distribution costs should typically be allocated on NCP. However, Ms. Kobor fails to recognize that for this solar DG partial requirements rate class, the maximum loading placed on the distribution system occurs during the export of energy.

Ms. Kobor's erroneous assumption seems to result from an oversimplification of the current distribution planning process. Instead of analyzing the load of the solar DG partial requirements rate class by itself as directed by the Commission in the VOS Order, she attempts to focus solely on peak load of the combined DG and non-DG classes. Distribution grid planning no longer is as simple as planning to meet the peak usage load of distribution feeders as it was when the NARUC manual Ms. Kobor cites was written. Bi-directional flow was not as prevalent in that era. As explained by Company witness Susan Gray, there are now additional distribution costs related to providing additional ancillary services that are specifically the result of DG intermittency and will continue to exist (and grow) as DG penetration increases. Thus, the rationale for the use of export NCP for customers is entirely reasonable.

The same manual cited by Ms. Kobor also states: "Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who **benefit** from these facilities are included in the allocator."[12] (emphasis added) Implicit in this language is the premise that those loads that benefit from the facilities should help determine the allocator. Simply ignoring the exported loads in determining the allocator is poor practice, particularly when these loads are causing additional costs.

Both Vote Solar and EFCA/TASC claim that the solar NCP should be calculated in a different manner than one consistent with cost of service principles. Class NCP for each individual rate class is, and has been, based on the time of the class peak that is the non-coincident peak of the class. Solar DG customers have their maximum non-coincident

[12] NARUC Electric Utility Cost Allocation Manual, page 97.

demand on system resources at the time of their maximum export deliveries to the system. As a result, the hour of the full requirements residential class maximum NCP is not the same as the solar DG partial requirement class maximum NCP.

Q. What are your thoughts on Ms. Kobor's "parent" class concept for solar DG customers?

A. There is no such thing as a "parent" class concept in cost of service. If so there would be only four non-homogeneous groups - Residential, commercial, industrial and lighting. Rate classes are separated because they have different load characteristics. Partial requirement customers, such as solar DG customers, are a separate class and should be treated as such.

Q. Ms. Kobor still objects to the results of the Companies load research results.[13] Are her concerns valid?

A. No. Again, as discussed at great length in my Rebuttal testimony, the Companies' utilization of the load research data and the resulting billing determinants are fully consistent with traditional load research principles, methods and Commission approved methods utilized to develop billing determinants for the Companies' other half-million retail customers, and they are appropriate to utilize for the solar DG partial requirement rate classes as well.

Q. Please comment on Ms. Kobor's issue regarding the utilization of load research data.

A. Witness Kobor errs when she claims that "...hourly customer data from the <u>general residential and small commercial classes</u> to monthly customer data from the <u>DG classes</u> to approximate DG customer hourly load."[14] The DG load is calculated by using residential full requirements load shape based on extensive load research data to model solar DG customers as full requirements customers-the counterfactual load. The data is available

[13] *See* Kobor Phase 2 Surrebuttal pages 54-60.
[14] *See* Kobor Phase 2 Surrebuttal page 54, lines 20-22.

monthly for solar production based on load research samples that when coupled with actual monthly consumption from the customers billing data base results in a total hourly consumption. Netting out hourly solar production leaves a solar DG hourly demand shape that differs from other customers because of the negative results in hours when generation exceeds load. The result of this hourly modeling is a statistically valid estimate of the class CP and NCP. Any claim to the contrary cannot be supported by any load research since those samples are valid and have been accepted by the Commission.

Additionally, the Company has not scaled data from another class as claimed by witness Kobor. The residential data was correctly applied to the solar DG customers as if they were full requirements customers consistent with the sampling of the residential class. The solar DG production load shapes are based on a statistically valid sample of solar production. Combining the two samples produces a solar DG load shape based on statistically valid sampling. There is nothing novel or different about estimating load shapes based on valid samples used for valid classes. It is not anymore an approximation than for any other sampled class except that there was a much larger sample of solar data than required for a homogeneous load class. A larger sample actually means more precision for the solar DG production data than for other samples used in the cost study except for those classes where the sample is the population.

Q. Please comment on Ms. Kobor's issue regarding hourly vs. instantaneous load.

A. This concern is pure fiction. Even for load research quality meters the loads are accumulated for an interval that is not instantaneous to produce kWhs. The measurement is instantaneous but accumulated over an interval and converted to kWh or kW based on the cost study requirements. The cost study relies consistently on hourly measures of kW and revenues rely consistently on measures of kWh for all customers and classes. If instantaneous measures had been used, the demand would have been higher and therefore allocated costs would have increased. That did not happen. Further the sum of the instantaneous readings over the billing cycle is the basis for the monthly kWh. There is no difference between the two calculations that impacts either revenue or costs so long as all customers are treated the same for determining allocation factors and revenues. That consistency results in accurate costs and revenues.

I recommend the Commission disregard any recommendation by Ms. Kobor on this topic.

Q. EFCA/TASC witness Mr. Beach asserts that a solar DG partial requirements customer is not taking service from the utility when they export energy to the distribution system and that the allocation of costs based on that assumption is a fundamental flaw in the Companies' CCOSS.[15] Is this statement true?

A. No. This statement can be disproven by asking the question, could a DG customer export energy if there were no distribution system? The answer is no! A solar DG partial requirements customer uses the system on at least three occasions, 1) to take power from the grid when their generator is not functioning or not meeting their load requirements (think nighttime), 2) to export energy back onto the utilities system and receive some "value" for that energy and 3) to receive ancillary services, especially those related to voltage regulation and quick start back-up generation. DG customers use the distribution system and are provided a service in both directions of their energy flow and there are costs associated with that export. In fact, the evidence in this docket shows that in some months the export NCP for the solar DG partial requirements rate class is 2 to 3 times the import NCP.[16] Both directions must be considered when determining the distribution system capacity needs of

[15] *See* Beach Phase 2 Surrebuttal page 22, line 23.
[16] *See* Jones Phase 2 Rebuttal page 14, Table 1.

these customers and appropriate cost allocation should be based on when they utilize it the most.

Q. It appears Mr. Beach still believes that allocating costs based on how the customer actually uses the system somehow results in "double-recovering" costs.[17] Do you agree with this statement?

A. No. As discussed thoroughly in my Rebuttal testimony, sound cost of service principles used in these proceedings and accepted by this Commission in Phase 1 for both utilities do not allow for that. Since solar DG customers utilize the system more when they export, the total cost allocated to them should be higher. Since the overall costs being recovered in rates does not change, all other rate payers will be allocated a slightly smaller portion of that cost. This is exactly what the Commission was referring to in the VOS Order when it specified that rates should be designed in Phase 2 to help reduce the cost shift currently being experienced in rates with historical "net-metering".

Q. Ms. Kobor and Mr. Beach both posit that the utility's use of DG exports allows it to avoid embedded grid infrastructure costs. Please comment.

A. This position is rooted in their erroneous belief that exported generation somehow reduces the utilities embedded cost to serve, and that a DG customer is still paying their fair share for utility services, including the use of the distribution system and ancillary services, even if their monthly bill is a net credit. When a NEM DG customer's bill nets to zero as discussed by Mr. Beach, they are contributing nothing to the recovery of fixed generation, transmission and distribution capacity costs. Mr. Beach's direct testimony from the Value of Solar docket is especially illuminating.[18]

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[17] *See* Beach Phase 2 Surrebuttal page 23, line 14.

[18] *See* Thomas Beach Direct [Value of Solar Docket, page 15]

> **"Q18: So if a NEM customer ends up with a small, zero, or even negative bill at the end of a month, does this mean that the NEM customer is not paying for the utility service the customer is receiving?**
> A18: Absolutely not. First, whenever the solar customer uses the utility system (by importing power and rolling the meter forward), the solar customer pays fully for the use of the utility system, at the same rate as any other customer. If the solar customer ends the month with a small or zero bill from the utility, this is the result of crediting the customer for the value of the power which the customer supplies to the utility (from exporting power and running the meter backwards). *These credits can offset the solar customer's costs of utility service when the customer imports power and the meter runs forward.* However, these credits are not the result of the solar customer's use of the utility system, instead, they are the means to account for the exported generation which the solar customer has provided to the utility at the meter. *Thus, the solar customer has paid fully for all actual use which the customer has made of the utility system,* even though the customer's net bill at the end of the year may be small or even zero…" (emphasis added.)

Unfortunately, this logic only holds water if one focuses solely on the end use (net kWh delivered) while ignoring all of the other ancillary services the grid was designed to provide and whose costs have increased due to the presence of DG.

Additionally, Mr. Beach's statement refers to utility service "as available energy". However, that service can only be provided if the delivery capacity is available to accept that power. For example, if the utility designed the service line to deliver a peak consumption of 5 kW to the customer, then the customer could not deliver 7 kW of export energy to the utility.

V. INCREMENTAL DG METER CHARGE

Q. With a small reduction to the residential incremental DG meter charge, Staff[19] has submitted testimony generally agreeing with the Companies' proposed incremental DG meter charges, while the solar advocates recommend much smaller charges? Do you wish to discuss these recommended changes?

A. Yes. The Commission's Order in the Phase 1 TEP rate case specifically stated this charge "...will be reviewed, and may be subject to modification, in Phase 2 of this proceeding."[20] I have reviewed the costs associated with the bi-directional meter used to serve DG customers and have found it to be substantially more than a standard meter and requires an adjustment as anticipated by the Commission. The proposed charges do not include any allowance for the cost of:

- the production meter (shifted to non-DG customers through the REST),
- the connectors (shifted to non-DG customers through the REST),
- meter rings (shifted to non-DG customers through the REST),
- upgrades to the billing system (shifted to non-DG customers through the base rate adjustments),
- the cost to format the bill for DG billing processes (shifted to non-DG customers through the base rate adjustments),
- meter testing (shifted to non-DG customers through the base rate adjustments),
- O&M associated with the meter or any of the above equipment (shifted to non-DG customers through the base rate adjustments), and
- repairs if needed (shifted to non-DG customers through the base rate adjustments) or

[19] See Smith Phase 2 Surrebuttal testimony, page 34. Staff is recommending a slightly lower incremental DG meter charge. All other rate components are consistent with the Companies recommended numbers.
[20] Decision No. 75975 (February 24, 2017), page 195, line 14.

- replacement if needed (shifted to non-DG customers through the base rate adjustments).

One must also recognize this charge should be based on the incremental difference between the historical embedded cost used to create the standard basic service charge and the marginal cost of a new bi-directional meter. The Companies' proposed incremental DG meter charge does not include all of these costs in order to more gradually move to a cost based rate. The proposed incremental DG meter charge is a bare-bones, understated amount that the Companies have proposed to simply move in the right direction and reduce subsidies from non-DG customers to DG customers.

With a small reduction to the residential incremental DG meter charge, Staff has accepted the Companies' proposed charges. The Companies are willing to accept Staff's recommended charges as reasonable movement in the direction of cost recovery. This helps mitigate the recognized cost shift caused by rooftop solar customer's self-consumption.[21]

Q. Do the Companies still oppose the one-time upfront payment for this incremental meter charge?

A. Yes. Not only does this continue to result in DG customers being subsidized by full requirements customers, it is inconsistent with ratemaking theory. The original upfront amounts adopted in Phase 1 were based on embedded cost data which blends in all vintage meters that have been depreciated for their entire in-service life. The one-time upfront fee makes no allowance for:

- costs associated with meter testing,
- the additional trip fee,

[21] Decision No. 75859 page 176, line 2.

- potential monthly cellular fees,
- fixed network upgrades,
- meter repairs or
- meter replacements when needed.

A one-time upfront payment would create a situation where a subsidy by full requirements customers would continue, therefore if the Commission insists on allowing a one-time upfront payment, the charge should be based on actual incremental costs or at a minimum, be calculated at fully loaded marginal costs instead of the artificially low charge proposed by Ms. Kobor. The incremental costs reflected in TEP's recent REST filing reflect incremental charges for the bi-directional meter of approximately $170 and $210 for residential and SGS, respectively, without accounting for any related costs such as installation, maintenance or repair. Those adders would be substantial to arrive at a fully cost-based recovery amount to pay up front.

If the reduction of subsidization is the goal of this proceeding the one-time buy-out option should not be allowed. The Companies strongly oppose it.

While Staff did not specifically respond to my concerns in its Surrebuttal testimony or offer a change in their rebuttal position, the Companies still believe the one-time upfront payment of the incremental bi-directional meter costs is not sound rate making policy and will create additional cost shifts relating to operating and maintenance costs and replacement costs. If the Commission believes it should be continued as an option, those costs should be adjusted to more accurate numbers. Based on the incremental costs filed in the REST filing plus loadings appropriate for these charges, any incremental meter charge assessed as a one-time upfront payment should be adjusted to a number no less than the following which will still under recover the cost of the meter over its life and ultimately require non-DG customers to pay for ongoing maintenance, testing or replacement costs associated with that meter:

Residential	\$225
SGS	\$315

Q. Vote Solar witness, Ms. Kobor does not agree with your incremental DG meter fees.[22] Do you wish to reply?

A. Yes. As discussed at great length in both my Direct and Rebuttal testimony, any incremental DG meter fee should be substantially more than what the Companies have been proposing and the amounts ultimately accepted by both Staff and RUCO. None of the amounts being discussed by the parties include all incremental costs associated with the bi-directional meter. To prevent additional cost shifts those charges should be based on marginal costs associated with installing new meters and all loadings and other grossed up adjustments designed to recover operating and maintenance expenses and some level of replacement costs. In fact, some DG systems, depending on location may require even more expensive meters and a cellular system to provide the data necessary for accurate billing. None of the charges discussed to date include the \$1.00 to \$2.00 monthly cellular fee associated with these metering systems.

Staff has submitted revised values in its Surrebuttal testimony (charges for the residential charge were reduced from Staff's Rebuttal position). In the interest of gradualism, the Companies are willing to accept Staff's recommended incremental meter charges. Costs will still be shifted to the other customers, but this is a move in the right direction and further adjustments can be considered in subsequent rate case proceedings.

[22] *See* Kobor Phase 2 Surrebuttal page 61.

VI. STORAGE RATE

Q. There has been significant attention given to ratchets and energy storage from TASC/EFCA and Vote Solar in these proceedings, can you give an example of how ratchets work and how they influence energy storage?

A. Yes. Consider a steady use customer like a 24-hour convenience store and an intermittent "spikey demand" customer, such as a seasonal large water pumping facility. Suppose the convenience store and the water pumping facility have identical peak loads of 100 kW. The convenience store has a load profile that sees small diurnal movements through the day and small load changes through the year. This makes not only their daily consumption steady but also their overall consumption steady throughout the year. The water pumping facility is used only from May through September as a supplemental facility to cope with increased demand during the warm months where people are using evaporative cooling. On the other hand, the water pumping facility only operates during peak consumption hours when water demand is highest. The infrastructure costs: conductors, transformers, generation facilities, etc. are the same to serve both customers, indeed identical. Thus, it makes perfect sense that both customers should pay equivalent amounts to support the cost of these facilities. Suppose in a given year that the infrastructure costs to serve these customers are $20,000 for each customer, the convenience store's annual kWh is 660,000, and the water pumping facility's annual kWh is 70,000. If the infrastructure costs were recovered strictly on a kWh basis, the rate would be $0.05479/kWh. The convenience store would pay an annual amount of $36,164.38 towards infrastructure costs and the water pumping facility would pay an annual amount of $3,835.62. The convenience store would be subsidizing the water pumping facility to the tune of $16,164.38 per year due to the poor rate design. Suppose now you recover the infrastructure costs through a kW charge without a ratchet, the convenience has a total 1,045 kW units in a year, and the water pumping facility has a total 500 kW units in a year making for a rate of $25.89/kW. The convenience store would pay $27,055.02 per year and the water pumping facility $12,944.98 per year towards the infrastructure costs. In the non-ratcheted kW case, the convenience store would be subsidizing the water pumping facility $7,055.02 per year. Suppose now, the costs were recovered through ratcheted demand charge at 75%. The convenience store would maintain 1,045 kW units in a year but now the water pumping facility would have 1,025 kW units in the year. This change would reduce the kW rate to $19.32/kW and now the charges would be $20,193.24 and $19,806.76 for the convenience store and water pumping facility respectively. The 75% ratchet reduced the subsidy between these customers to $193.24 per year. To fully reduce the subsidy to zero, the ratchet could be raised to 100%. It is clear from this example that ratchets reduce subsidies between efficient and non-efficient users of the grid.

Q. How do demand ratchets actually affect the economics of energy storage?

A. Demand ratchets incentivize energy storage, particularly when that energy storage can reduce the customer's peak demand. As was made explicit in the previous examples, as a customer's average usage compared to their peak usage approaches parity (increased annual load factor), the unit cost to serve them is greatly reduced. Ratchets are a mechanism that incents a customer to reduce their annual peak demand. They do this by sending a very clear price signal that a customer's annual peak demand is the single largest indicator of the cost of infrastructure to serve that customer. A battery is a mechanism that allows a customer to increase their annual load factor by taking power from high use periods and shifting it to low use periods to lower their annual peak usage while maintaining the same average usage. This means that a battery attempts to achieve the same effect that a ratchet incents. Thus, ratchets are a well aligned incentive to storage facilities for low load factor customers.

Q. How would storage influence the previous pump and convenience store example?

A. The convenience store is a customer that is unlikely to use energy storage. They already have a very steady usage (and a high load factor) and the benefit they could achieve from time-of-use price arbitrage is not likely to pay for the cost of the battery. The water pumping facility on the other hand uses the system very inefficiently and is a perfect candidate for energy storage. Suppose the water pumping facility was to install a water tower (a mechanical equivalent of a battery). With a water tower, the customer could install a much smaller motor which would use the same amount of energy as the larger motor but it would spread the consumption over the day while it filled the water tower. During periods of high water demand, the water tower would be discharged. This would allow the water pumping facility to reduce their peak demand to 22 kW from 100 kW. In the case where the cost of infrastructure was recovered through kWh charges there would be no incentive to install the water tower as their bill at $3,835.62 remains the same as they reduced kW and not kWh. In the case where the cost of infrastructure was recovered through non-ratcheted kW charges, the water pumping facility would have an incentive of $10,097.09/year. In the case of the 75% ratchet, the incentive is significantly higher at $15,449.28 in annual savings. This example makes clear that because ratchets align costs with exactly what a battery is intended to do, ratchets provide a much stronger incentive to storage than non-ratcheted rates.

Q. How do ratchets affect when a customer realizes savings after installing a storage technology?

A. Looking to the water tower, suppose the customer had the worst case and could only save 25% of the annual $15,449.28 or $3,862. The 25% savings is still almost half of the $10,097.09 savings on the non-ratcheted rate. This short term view is however ignorant of storage and energy efficiency project lifetimes. In the water tower case, the water tower could feasibly last decades. In the first decade of savings, without a ratchet, the customer could save $100,971. This is not an insignificant amount of savings. However, had a ratchet been in place and the customer had the worst possible case of forgoing 75% of first year savings, the customer instead would have saved $142,906, an increase savings of $41,935 over the non-ratcheted rate. The water tower is perhaps an extreme case in that its life would be significantly longer than a battery system which might have a useful life of 10 years. Clearly any minor forgoing of first year savings is more than offset by the long term savings. Further, the customers who are looking to install these facilities, or the vendors wishing to sell them, are the ones that are highly sophisticated and will understand that the savings of a project is not wholly dependent on the first few months.

Q. How do the arguments of those against having ratchet compare to the example set forth above?

A. The primary arguments against ratchets are easily exposed as misleading and false when contrasted with the example above.

Q. Can you give some examples?

A. Yes. A common argument is that ratchets limit or entirely remove a customer's savings in the first year a storage system is installed[23]. It is possible that the storage installing customer may not maximize first year savings if the system is installed at an inopportune time, but if a storage installer works in the customer's best interest, then first year savings can be the same as the remaining years. In cases where the system is installed at an inopportune time, the example above illustrates that even when a significant portion of first year savings is foregone, the overall savings over the life of the storage system is significantly higher with a ratchet.

Another argument is that ratchets are somehow punitive to customers. Far from being punitive, the discussion above illustrates that ratchets actually align costs to cost recovery and that they prevent high load factor customers from being penalized by subsidizing low load factor customers. This fact is ignored by storage promoters who claim that a ratchet makes storage a risky proposition or that the 75% ratchet is somehow overly punitive. In the

[23] *See* Beach Phase 2 Surrebuttal page 28, lines 1-5; Warshay Surrebuttal page 9, lines 9-12

example above, with the installation of storage, the water pumping facility was able to permanently reduce peak demand and has no risk of resetting their ratchet. By permanently reducing their peak demand, capacity has been freed on that line which can be used to serve additional customers. In the case where a customer's system cannot permanently reduce peak demand and the customer were to require a large amount of power from the grid, then no grid infrastructure costs could be reduced. Further, no additional customers could be added to the line as no capacity was freed. In this case, it would be inappropriate to push the infrastructure costs the customer required onto other customers. This is a point ignored by both Beach and Warshay when they criticize the ratchet mechanism.

Warshay claims that the only way to offset the risk of setting a high demand is to have perfect foresight[24]. In the case above for the water pumping customer, no foresight is required for the customer to continue to keep their demand low making it clear that the risk is not caused by a lack of foresight but by mal-functioning equipment that is unable to lower infrastructure costs.

Q. Does EFCA/TASC Witness Warshay make a compelling argument that daily cycling does not increase costs to a battery storage customer?

A. No. Mr. Warshay attempts to misdirect and confuse the issue by conflating warranty information to costs to the consumer. He attempts to show that because a warranty covers a battery for 10 years or 10,000 cycles,[25] that no additional savings can be made by installing a battery equipped to cycle fewer times. In arriving at this conclusion, Mr. Warshay ignores the second law of thermodynamics and his own testimony when he states unequivocally "Increased throughput does decrease energy retention but this is just how batteries work."[26] To make a battery system last through the high number of cycles suggested by the warranties,

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[24] *See* Warshay Surrebuttal page 5, lines 12-14.
[25] *See* Warshay Surrebuttal page 3, line 30 – page 4, line 10.
[26] *See* Warshay Surrebuttal page 3, lines 21-22.

the battery must be over-built when compared to a more limited cycling schedule. Overbuilding the battery increases the costs to the customer because a battery designed to cycle less frequently could be built at a lower initial cost.

Q. Does Mr. Warshay make a compelling argument that the use of a demand ratchet does not limit the need for daily cycling?

A. No. To come to his conclusion, Mr. Warshay relies heavily on two false suppositions about ratcheted demand and battery storage:

1. to maximize the benefit from battery storage on a ratcheted rate, a customer needs to use a battery daily to account for uncertainty of future load; and[27]
2. avoided cycling does not decrease battery storage costs.[28]

The example of the water pumping facility clearly shows a customer does not need to operate a storage facility on a daily basis to achieve maximum savings with a ratchet negating the first supposition. For the reasons discussed above related to cost increases related to increased cycling, Warshay failed to show that daily cycling doesn't increase costs and his testimony suggests the opposite.

Q. Are there problems with Mr. Warshay's claims that the Companies analysis shows that the LGST and LGSTB tariffs incentivize the same amount of battery use?

A. Yes. Mr. Warshay states "After analyzing how the Companies cycle the batteries in their analysis, I actually found that the simulated batteries cycle just as much on the ratcheted LGST as they did on the non-ratcheted LGSTB."[29] and "This analysis reveals that the

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[27] *See* Warshay Surrebuttal page 5, lines 12-14.
[28] *See* Warshay Surrebuttal page 5, lines 14-17.
[29] *See* Warshay Surrebuttal page 6, lines 11-13.

batteries modeled on both rates cycle roughly the same, 68 and 67 full cycles over the 24 month period for LGST and LGSTB, respectively."[30] This statement continues the misstatements by Warshay or shows that he either cannot or has chosen not to conduct the analysis to count the cycles of the batteries for each of the load profiles. The Companies' file actually shows that the average number of cycles (where the battery goes from either charging to discharging or charged to discharging) is 145 and 160 cycles per annum for the LGST and LGSTB rate respectively. Given the vastness of the spread between the most frequent and least frequent cyclers, median is a better metric at 109 and 170 cycles per annum for LGST and LGSTB. Further, the analysis for the LGSTB rate significantly understates the number of cycles required for economic battery dispatch (ignoring the additional costs from increased cycling) where a customer will have to focus on every higher than normal use hour per month. By moving to the daily charge proposed by Beach, this would further complicate battery dispatch for customers by making them focus on every day of the year.

Q. Mr. Warshay claims the battery configuration used in the Companies model do not exist in the market. [31] Do you agree?

A. No. This again is another misunderstanding by Mr. Warshay of the Companies' model. The model took a simple battery spec sheet from Tesla with either a max energy storage of 7kWh or peak power production of 3.3kW[32]. It then found either the maximum energy stored or peak power production necessary to meet a 25% peak demand reduction and applied that to the battery specification. Every battery in the sample thus has an energy to power ratio of 3.0kW/kWh which is perfectly in line with the range given by Mr. Warshay of 0.5 to 6.0 kWh/kW.[33]

[30] *See* Warshay Surrebuttal page 6, lines 20-23.
[31] *See* Warshay Surrebuttal page 9, line 19.
[32] *See* Warshay Surrebuttal BW-5.
[33] *See* Warshay Surrebuttal page 9, lines 24-27.

Q. How has Mr. Warshay misunderstood the Companies' models when he claims it is not an "apples-to-apples" comparison.

A. Mr. Warshay's final critique, that the LGST and LGSTB analyses show different sized batteries, again shows he failed to understand the Companies model. The minimum sized battery required to offset 25% of the customer's peak load on the LGST and LGSTB tariff determines the battery sizes. Because these are different tariffs, it is perfectly logical that the resulting battery sizes would be different and this is not an error but a correct accounting for the separate tariffs. Further, when he concludes "This makes it difficult to compare the results of this analysis on an apples-to-apples basis" shows he doesn't understand that the model is finding the minimum sized battery necessary to meet the customer's needs and pricing a rough cost estimate to said battery.

Q. Please explain why you do not agree with Mr. Beach's proposed storage rate design?

A. First, he advocates for an all-volumetric TOU rate. However, for the reasons listed in my Rebuttal Testimony, there is no cost based support for increasing the TOU differential and, without a demand charge, this rate could not be cost based and encourage storage. Second, he continues to advocate for daily demand charges, which he calls cost based, but the reality is they are not and could never be cost based no matter how often he makes claims to the contrary. The market fluctuations in price on a daily basis that Mr. Beach uses to justify the daily demand charge are largely fuel based. Capacity costs recovered in demand charges are mostly fixed and do not vary with fuel costs or volumetric variations in consumption. To suddenly collect these fixed capacity charges through volatile rates misaligns costs making a daily demand rate not cost based.

Q. Are there any elements of Mr. Beach's rate design proposals that are correct?

A. Mr. Beach's continued insistence on cost-based rates is correct, as much as practicable, rates should be cost based. It is also encouraging when Mr. Beach says "Most of the demand-related costs should be allocated to the summer on-peak period, when the TEP system peaks, to signal that storage capacity should be used when the stored power provides the greatest system benefit."[34] What Mr. Beach fails to realize in advocating for this position is he is clearly advocating for ratcheted demand charges.

Q. When Mr. Beach concludes that recent Commission decisions have reviewed and decided that storage-friendly rates should not include demand ratchets, does that reconcile with the record?

A. The decision from those cases state "Ratchets **can** send incorrect pricing signals" and "however the demand ratchet mechanism featured in this rate design **may** be incompatible with battery storage technology." (emphasis added).[35]. The decisions do not say that ratchets send incorrect price signals or that they are incompatible with battery storage, they say that they might be. The second phase of these cases are the first time ratchets and energy storage has actually been examined in any real way in relation to specifically designed storage rates[36]. As is clear from the evidence presented here, ratchets send correct pricing signals and ratchets are not only compatible, they actually provide a strong incentive for battery storage.

Q. What are your final recommendation regarding Mr. Beach's and Mr. Warshay's testimony as it relates to storage and rate design to incentivize it.

A. Given the problems with their assertions, the recommendations in my Rebuttal Testimony stand. Specifically, if the Commission wants to incentivize different technologies that result in more efficient use of the utility system, then rates that encourage peak demand reductions, such as three-part rates and especially ratcheted three-part rates should be approved. Further,

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[34] *See* Beach Phase 2 Surrebuttal page 26, lines 20-22.

[35] Decision No. 75697 page 83, line 9; Decision No. 75975 page 188, Finding of Fact No. 60.

[36] TEP's storage rate was borne not out of litigated testimony or facts in evidence, but out of an amendment at the open meeting for its rate case. Comments submitted by the solar industry in APS' rate case falsely suggested that the storage rate was discussed at length in the TEP rate case.

custom fit non-cost-based rates designed for a specific technology will be inherently unfair and rendered obsolete as newer technologies are adopted. Thus, at this juncture, no additional storage specific rates should be created. If it is deemed necessary to create additional storage specific rates then they should be modeled after the current large general service time-of-use tariff rate design which includes seasonal and time differentiated demand charges that recover most of the transmission and delivery costs, time-of-use volumetric charges to recover fuel costs, and a 75% ratchet applied to the on-peak demand.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
TOM FORESE - CHAIRMAN
BOB BURNS
VACANT
ANDY TOBIN
BOYD W. DUNN

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
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 **PHASE 2**

REJOINDER TESTIMONY OF RICHARD D. BACHMEIER

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY AND UNS ELECTRIC, INC.

OCTOBER 13, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard D. Bachmeier and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file direct and/or rebuttal testimony in Phase 2 of this proceeding?

A. Yes. I filed both direct and rebuttal testimony on behalf of both Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric").

Q. On whose behalf are you filing Phase 2 rejoinder testimony?

A. My Phase 2 Rejoinder Testimony is filed on behalf of TEP and UNS Electric, jointly referred to herein as the "Companies."

II. SUMMARY

Q. Please summarize your testimony.

A. My Testimony will cover the following issues:

1. I present the Companies' Rejoinder positions on rate design for TEP and UNS Electric Residential and Small General Service ("SGS") customers who apply for interconnection of on-site rooftop solar Distributed Generation ("DG") facilities after the date of the decision in Phase 2 ("new DG customers"). I also present monthly bill comparisons and other metrics for new DG customers who take service on the Companies' proposed DG rate options.
2. I address certain issues raised by Staff and Intervenor witnesses in Surrebuttal Testimony, specifically those raised by Staff witness Ralph C. Smith, Residential Utility Consumer Office ("RUCO") witness Lon Huber, Vote Solar witness

Briana Kobor, The Alliance for Solar Choice/Energy Freedom Coalition of America (collectively "TASC/EFCA") witness R. Thomas Beach, witness Louis Woofenden on behalf of Intervenor Bruce Plenk, and Intervenor Kevin Koch.

Q. Please summarize your findings and recommendations.

A. My findings and recommendations are summarized as follows:

1. As envisioned in the Commission's Value of Solar Order ("VOS Order")[1], the Companies' Rejoinder DG rate design proposals exhibit a gradual transition away from the net metering model and a gradual reduction in subsidies paid by non-DG customers. These proposals should therefore be approved.
2. The Companies' Rejoinder rate design proposals for new Residential and SGS DG customers mirror those presented by Staff in Surrebuttal Testimony. These proposals are in the public interest and strike the proper balance between adequate cost recovery for the Companies and ample monthly bill savings and return on rooftop photovoltaic ("PV") system investments for new DG customers. This balance is struck while at the same time gradually reducing, but not eliminating, the subsidies from non-DG customers to DG customers.
3. The Companies' Rejoinder DG rate design proposals result in self-consumption PV value ("offset rates") for new Residential DG customers consistent with offset rates recommended by RUCO.

Q. Will you be providing tariffs for the Companies' proposed rate options for new Residential and SGS DG customers?

A. No. The Companies' proposed Residential and SGS DG rate tariffs are unchanged from those submitted with the Companies' Rebuttal Testimony.

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[1] Arizona Corporation Commission Decision No. 75859 (January 3, 2017) in Docket No. E-00000J-14-0023, *In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation,* 170:6-8.

III. RATE DESIGN ISSUES COMMON TO BOTH TEP AND UNS ELECTRIC RESIDENTIAL AND SGS DG CUSTOMERS

Q. Are the Companies proposing the same DG rate options in Rejoinder as were proposed in Direct and Rebuttal Testimony?

A. Yes. The Companies are proposing the same two rate options for new Residential and SGS DG customers that were proposed in Direct Testimony:

1. Two-part Time-of-Use ("TOU") DG Rate with a Grid Access Charge.
2. Three-part TOU DG Rate with a Demand Charge ("Demand TOU").

In my Direct and Rebuttal Testimonies, I described the Companies' rate design proposals in detail and provided draft rate tariffs for the proposed options.

Q. Are the Companies proposing the same rate design and charges for the DG rate options as proposed in Rebuttal Testimony?

A. Yes, with two minor changes. Consistent with Staff recommendations presented in Surrebuttal Testimony, the Companies are proposing lower DG Meter Charges for the TEP and UNS Electric residential DG rate options than those proposed in Rebuttal. The Companies are now recommending incremental DG Meter Charges of $3.50/month for new TEP residential DG customers and $3.00/month for new UNS Electric residential DG customers. These charges are reduced from the $4.32/month for TEP and $3.92/month for UNS Electric that the Companies proposed in Rebuttal Testimony. With these changes, the Companies' rate design proposals for new residential and SGS DG customers are essentially identical to those proposed by Staff in Surrebuttal Testimony.

Q. Do you have any final comments before presenting the Companies' proposed DG rate options for TEP and UNS Electric?

A. Yes. First, both Staff witness Smith[2] and Vote Solar witness Kobor[3] have noted in Surrebuttal Testimony that the Companies' models used for calculating bill comparisons were using the incorrect time-of-use hours. Upon inspection of the models, an Excel formula error was found that caused the on-peak periods to begin and end one hour too early. This error has been corrected and the corrections are reflected in the bill calculations and comparisons presented below.

Second, a question was raised about the proper application of revenue-based taxes in the calculation of DG customer bills with RCP credits. Initially, the Companies assumed a 15% multiplier for revenue-based taxes and calculated them as a percentage of the monthly bills ***after*** netting RCP credits for PV exports from the bills. However, after consulting further with the Companies' internal tax experts, the Companies believe that revenue-based taxes should be calculated as a percentage of the monthly bill subtotal ***before*** netting RCP credits. Once the decision was made to change the revenue-based tax calculation method, the Companies submitted updated Phase 2 Rebuttal workpapers with the appropriate changes. All bill calculations in this testimony use the revised method whereby revenue-based taxes are calculated as a percentage of the monthly bill subtotal before netting RCP credits. This change has the effect of increasing revenue-based taxes and after-tax monthly bills for new DG customers. The resulting decrease in monthly bill savings calculated for new DG customers, all else equal, yields slightly longer simple payback periods. However, because all monthly bill comparisons presented by the Companies in Direct, Rebuttal, and Rejoinder Testimony are pre-tax, this change in the calculation of revenue-based taxes only impacts estimated simple payback periods and

[2] Staff Phase 2 Surrebuttal Testimony of Ralph C. Smith ("Smith"), 15:20-21.
[3] Vote Solar Phase 2 Surrebuttal Testimony of Briana Kobor ("Kobor"), 73:9-13.

has no impact on any monthly bill comparisons presented.

Third, Vote Solar witness Kobor[4] notes that in my Rebuttal Testimony I reported the first tier demand charge for the UNS Electric SGS Demand TOU DG rate option as $8.85/kW, but the current full-requirements UNS Electric SGS Demand TOU tariff has the first tier charge as $8.25/kW. The $8.85/kW in my Rebuttal Testimony is a typo and the correct charge should be $8.25/kW consistent with the current full-requirements UNS Electric SGS Demand TOU tariff. This typo appeared only in my written Rebuttal Testimony and the correct charge of $8.25 was used in all Rebuttal workpapers.

Fourth, the simple payback periods presented below assume no financing costs, no future electric rate increases, and no changes in future incremental DG Meter Charges simply because those variables are not knowable with any certainty. The simple payback periods presented are calculated only for the period that the initial RCP rate is in effect and not for any future periods. A 0.5% per year PV panel degradation rate is assumed, but no changes in future PV installation costs or efficiencies. For these reasons, I refer to the payback periods presented in the tables below as "simple" payback. I will have more to say about the use of payback analysis to evaluate DG rate options later in my testimony.

Finally, the bill comparisons and calculations presented in the next two sections of my testimony use an RCP rate for PV exports of $0.1070/kWh for both TEP and UNS Electric, which is the RCP rate proposed by Staff in Surrebuttal[5] and the Companies do not oppose as long as the next reset date for the RCP is July 1, 2018. Companies' witness Dallas Dukes is sponsoring the proposed RCP rate in his Rejoinder Testimony.

[4] Kobor Phase 2 Surrebuttal Testimony, 66:fn 132.
[5] Smith Phase 2 Surrebuttal Testimony, 13:14-17.

IV. TUCSON ELECTRIC POWER

A. TEP Residential DG Rate Design

Q. Please summarize the rates and charges TEP is now proposing for the Residential two-part TOU DG Rate.

A. TEP is proposing a Residential two-part TOU DG Rate option with the following elements (all changes from rates proposed previously in Rebuttal Testimony are noted):

- A monthly Basic Service Charge of $10.00.
- A monthly DG Meter Charge of $3.50 (previously $4.32).
- An Energy Delivery Charge of $0.07435/kWh for all billing kWh.
- A Grid Access Charge of $2.50/kW-DC based on the DC-rated installed capacity of the customer's DG system.
- Base Power Charges ($/kWh):
  - Summer On-Peak $0.066567
  - Summer Off-Peak $0.026332
  - Winter On-Peak $0.032565
  - Winter Off-Peak $0.025651
- Summer months are May through September; the Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are October through April; the Winter On-Peak periods are 6:00 a.m. to 9:00 a.m. and 6:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has TEP calculated bill impacts for the proposed Residential two-part TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 1 below.

Table 1: TEP Residential Two-Part TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	TEP RES Basic: Full Require-ments	TEP Residential DG Option 1: Two-Part TOU Rate				
		RES-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 737 kWh	$97.39	$30.10	($67.29)	$0.0664	$0.0913	9.8
Medium: 964 kWh	$124.95	$34.01	($90.94)	$0.0736	$0.0943	8.9
Large: 1,366 kWh	$173.41	$40.24	($133.17)	$0.0816	$0.0975	8.7
Extra Large: 1,667 kWh	$210.28	$44.79	($165.49)	$0.0857	$0.0993	8.4

The results in Table 1 show that a typical medium usage TEP residential DG customer taking service on the proposed two-part TOU DG rate would save $90.94 per month, or about 73 percent of the average monthly bill, compared to a customer with the same usage profile taking full-requirements service under TEP's Residential basic two-part rate. Moreover, medium usage DG customers who take service on this rate option and install PV systems during the period that the Companies' proposed initial RCP is effective, and assuming no increase in TEP's volumetric rates, would face a simple payback period for their PV system investment of 8.9 years, which is a significant reduction from the 10.8-year simple payback period that resulted from TEP's corresponding DG rate proposal in Direct Testimony.[6] Also, the proposed TEP Residential TOU DG rate option would result in a self-consumption offset rate of $0.0736/kWh, which meets the offset rate criteria put forth by RUCO witness Lon Huber.[7] Finally, this DG rate option yields a class rate of return of ***negative*** 1.12 percent, compared to a return of positive 3.13 percent for the TEP Residential class as a whole.

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[6] See Table 11 below.

[7] RUCO Phase 2 Surrebuttal Testimony of Lon Huber ("Huber"), 21:12-20 and Huber Phase 2 Direct Testimony, 14:5-6.

Q. Please summarize the rates and charges TEP is proposing for the Residential three-part TOU DG Rate with a Demand Charge.

A. TEP is proposing a Residential three-part TOU DG Rate option with the following elements (all changes from rates proposed previously in Rebuttal Testimony are noted):

- A monthly Basic Service Charge of $10.00.
- A monthly DG Meter Charge of $3.50 (previously $4.32).
- An Energy Delivery Charge of $0.033988/kWh for all billing kWh.
- Demand charges of $8.85/kW for the first 5 kW of billing demand and $12.85/kW for all billing demand greater than 5 kW with billing demand defined as the maximum one-hour average kW during on-peak periods in the billing month.
- Base Power Charges ($/kWh):
    - Summer On-Peak $0.066567
    - Summer Off-Peak $0.026332
    - Winter On-Peak $0.032565
    - Winter Off-Peak $0.025651
- Summer months are May through September; the Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are October through April; the Winter On-Peak periods are 6:00 a.m. to 9:00 a.m. and 6:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has TEP calculated bill impacts for the proposed Residential Demand TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 2 below.

Table 2: TEP Residential Demand TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	TEP RES Basic: Full Require-ments	TEP Residential DG Option 2: Demand TOU Rate				
		RES-DEM-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 737 kWh	$97.39	$34.72	($62.67)	$0.0526	$0.0850	10.7
Medium: 964 kWh	$124.95	$36.12	($88.83)	$0.0688	$0.0921	9.3
Large: 1,366 kWh	$173.41	$39.83	($133.58)	$0.0822	$0.0978	8.7
Extra Large: 1,667 kWh	$210.28	$42.03	($168.25)	$0.0892	$0.1009	8.3

The results in Table 2 show that a typical medium usage TEP residential DG customer taking service on the proposed Demand TOU DG rate would save $88.83 per month, or about 71 percent of the average monthly bill, when compared to a customer with the same usage profile taking full-requirements service under TEP's Residential basic two-part rate.

B. <u>TEP SGS DG Rate Design</u>

Q. Please summarize the rates and charges TEP is proposing for the SGS two-part TOU DG Rate.

A. TEP is proposing a SGS two-part TOU DG Rate option with the following:

- A monthly Basic Service Charge of $22.00.
- A monthly DG Meter Charge of $5.62.
- Energy Delivery Charges of $0.09191/kWh for all Summer billing kWh and $0.08130/kWh for all Winter billing kWh.
- A Grid Access Charge of $2.50/kW-DC based on the DC-rated installed capacity of the customer's DG system.
- Base Power Charges ($/kWh):
  - Summer On-Peak $0.071322
  - Summer Off-Peak $0.025609
  - Winter On-Peak $0.038010

- Winter Off-Peak $0.025651

- Summer months are May through September; the Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are October through April; the Winter On-Peak periods are 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day)

Q. Has TEP calculated bill impacts for the proposed SGS two-part TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 3 below.

Table 3: TEP SGS Two-Part TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	TEP SGS Basic: Full Require-ments	TEP SGS DG Option 1: Two-Part TOU Rate				
		SGS-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 1,040 kWh	$166.63	$85.70	($80.93)	$0.0783	$0.0778	11.5
Medium: 1,178 kWh	$186.65	$89.02	($97.63)	$0.0811	$0.0829	10.5
Large: 2,753 kWh	$415.57	$126.43	($289.14)	$0.0960	$0.1050	8.1
Extra Large: 4,324 kWh	$643.27	$163.30	($479.97)	$0.0997	$0.1110	7.7

The results in Table 3 show that a typical medium usage TEP SGS DG customer would save $97.63 per month and a large usage customer $289.14 per month under the proposed two-part TOU DG rate when compared to customers with the same usage profiles taking full-requirements service under TEP's SGS basic two-part rate. These correspond to monthly bill savings of 52 percent and 70 percent, respectively. Finally, this DG rate option yields a class rate of return of 3.14 percent, compared to a return of 16.12 percent for the TEP SGS class as a whole.

Q. Please summarize the rates and charges TEP is proposing for the SGS three-part TOU DG Rate with a Demand Charge.

A. TEP is proposing a SGS three-part TOU DG Rate option with the following:

- A monthly Basic Service Charge of $22.00.
- A monthly DG Meter Charge of $5.62.
- Energy Delivery Charges of $0.062483/kWh for all Summer billing kWh and $0.052483/kWh for all Winter billing kWh.
- Demand charges of $9.95/kW for the first 5 kW of billing demand and $13.95/kW for all billing demand greater than 5 kW with billing demand defined as the maximum one-hour average kW during on-peak periods in the billing month.
- Base Power Charges ($/kWh):
  - Summer On-Peak $0.071322
  - Summer Off-Peak $0.025609
  - Winter On-Peak $0.038010
  - Winter Off-Peak $0.025651
- Summer months are May through September; the Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are October through April; the Winter On-Peak periods are 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has TEP calculated bill impacts for the proposed SGS Demand TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 4 below.

Table 4: TEP SGS Demand TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	TEP SGS Basic: Full Require-ments	TEP SGS DG Option 2: Demand TOU Rate				
		SGS-DEM-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 1,040 kWh	$166.63	$88.20	($78.43)	$0.0603	$0.0754	11.9
Medium: 1,178 kWh	$186.65	$91.31	($95.34)	$0.0647	$0.0809	10.8
Large: 2,753 kWh	$415.57	$121.77	($293.80)	$0.0918	$0.1067	7.9
Extra Large: 4,324 kWh	$643.27	$147.69	($495.58)	$0.1003	$0.1146	7.5

The results in Table 4 show that a typical medium usage TEP SGS DG customer would save $95.34 per month and a large usage customer $293.80 per month under the proposed Demand TOU DG rate when compared to customers with the same usage profiles taking full-requirements service under TEP's SGS basic two-part rate. These correspond to monthly bill savings of 51 percent and 71 percent, respectively.

V. UNS ELECTRIC

A. UNS Electric Residential DG Rate Design.

Q. Please summarize the rates and charges UNS Electric is proposing for the Residential two-part TOU DG Rate option.

A. UNS Electric is proposing a Residential two-part TOU DG Rate option with the following elements (all changes from rates proposed previously in Rebuttal Testimony are noted):

- A monthly Basic Service Charge of $12.00.
- A monthly DG Meter Charge of $3.00 (previously $3.92).
- An Energy Delivery Charge of $0.03984/kWh for all billing kWh.
- A Grid Access Charge of $1.00/kW-DC based on the DC-rated installed capacity of the customer's DG system.
- Base Power Charges ($/kWh):
  - Summer On-Peak $0.111000
  - Summer Off-Peak $0.042500
  - Winter On-Peak $0.091550
  - Winter Off-Peak $0.038570
- Summer months are May through October; the Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are November through April; the Winter On-Peak periods are 6:00 a.m. to 9:00 a.m. and 6:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has UNS Electric calculated bill impacts for the proposed Residential two-part TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 5 below.

Table 5: UNSE Residential Two-Part TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	UNSE RES Basic: Full Require-ments	UNSE Residential DG Option 1: Two-Part TOU Rate				
		RES-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 797 kWh	$94.58	$18.52	($76.06)	$0.0772	$0.0954	9.5
Medium: 1,112 kWh	$126.46	$19.07	($107.39)	$0.0803	$0.0966	8.9
Large: 1,615 kWh	$177.41	$19.07	($158.34)	$0.0844	$0.0980	8.7
Extra Large: 1,992 kWh	$215.70	$18.77	($196.93)	$0.0861	$0.0988	8.7

The results in Table 5 show that a typical medium usage UNS Electric residential DG customer taking service on the proposed Residential TOU DG rate would save $107.39 per month, or about 85 percent, when compared to a customer with the same usage profile taking full-requirements service under UNS Electric's Residential basic two-part rate. Also, the proposed UNS Electric Residential TOU DG rate option would result in a self-consumption offset rate of $0.0803/kWh, which meets the offset rate criteria put forth by RUCO witness Lon Huber.[8] Finally, this DG rate option yields a class rate of return of negative 3.65 percent, compared to a return of positive 2.20 percent for the UNS Electric Residential class as a whole.

Q. Please summarize the rates and charges UNS Electric is proposing for the Residential three-part TOU DG Rate option with a Demand Charge.

A. UNS Electric is proposing a Residential three-part TOU DG Rate option with the following elements (all changes from rates proposed previously in Rebuttal Testimony are noted):

[8] Huber Phase 2 Surrebuttal Testimony, 21:12-20 and Huber Phase 2 Direct Testimony, 14:5-6.

- A monthly Basic Service Charge of $12.00.
- A monthly DG Meter Charge of $3.00 (previously $3.92).
- An Energy Delivery Charge of $0.01187/kWh for all billing kWh.
- Demand charges of $5.50/kW for the first 5 kW of billing demand and $7.75/kW for all billing demand greater than 5 kW with billing demand defined as the maximum one-hour average kW during on-peak periods in the billing month.
- Base Power Charges ($/kWh):
    - Summer On-Peak $0.111000
    - Summer Off-Peak $0.042500
    - Winter On-Peak $0.091550
    - Winter Off-Peak $0.038570
- Summer months are May through October; the Summer On-Peak period is 3:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are November through April; the Winter On-Peak periods are 6:00 a.m. to 9:00 a.m. and 6:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has UNS Electric calculated bill impacts for the proposed Residential Demand TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 6 below.

Table 6: UNSE Residential Demand TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	UNSE RES Basic: Full Require-ments	UNSE Residential DG Option 2: Demand TOU Rate				
		RES-DEM-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 797 kWh	$94.58	$25.15	($69.43)	$0.0587	$0.0871	10.5
Medium: 1,112 kWh	$126.46	$24.87	($101.59)	$0.0688	$0.0914	9.5
Large: 1,615 kWh	$177.41	$24.10	($153.31)	$0.0777	$0.0949	9.0
Extra Large: 1,992 kWh	$215.70	$21.88	($193.82)	$0.0828	$0.0973	8.8

The results in Table 6 show that a typical medium usage UNS Electric residential DG customer taking service on the proposed Demand TOU DG rate would save $101.59 per month, or about 80 percent, when compared to a customer with the same usage profile taking full-requirements service under UNS Electric's Residential basic two-part rate.

B. UNS Electric SGS DG Rate Design

Q. Please summarize the rates and charges UNS Electric is proposing for the SGS two-part TOU DG Rate.

A. UNS Electric is proposing a SGS two-part TOU DG Rate option with the following elements:

- A monthly Basic Service Charge of $20.00.
- A monthly DG Meter Charge of $4.60.
- Energy Delivery Charge of $0.04128/kWh for all billing kWh.
- A Grid Access Charge of $1.00/kW-DC based on the DC-rated installed capacity of the customer's DG system.
- Base Power Charges ($/kWh):
  - Summer On-Peak $0.109800
  - Summer Off-Peak $0.045700
  - Winter On-Peak $0.108800
  - Winter Off-Peak $0.040036
- Summer months are May through October; the Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are November through April; the Winter On-Peak periods are 5:00 a.m. to 9:00 a.m. and 5:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has UNS Electric calculated bill impacts for the proposed SGS two-part TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 7 below.

Table 7: UNSE SGS Two-Part TOU DG Rate Option Bill Average Bill & Impacts

Monthly Usage	UNSE SGS Basic: Full Requirements	UNSE SGS DG Option 1: Two-Part TOU Rate				
		SGS-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 649 kWh	$89.42	$31.09	($58.33)	$0.0680	$0.0899	10.3
Medium: 792 kWh	$103.70	$31.58	($72.12)	$0.0711	$0.0911	9.6
Large: 1,591 kWh	$183.55	$36.70	($146.85)	$0.0767	$0.0923	9.2
Extra Large: 2,307 kWh	$255.09	$41.19	($213.90)	$0.0780	$0.0927	9.3

The results in Table 7 show that a typical medium usage UNS Electric SGS DG customer would save $72.12 per month and a large usage customer $146.85 per month under the proposed two-part TOU DG rate when compared to customers with the same usage profiles taking full-requirements service under UNS Electric's SGS basic two-part rate. These correspond to monthly bill savings of about 70 percent and 80 percent, respectively. Finally, this DG rate option yields a class rate of return of negative 6.17 percent, compared to a return of positive 13.31 percent for the UNS SGS class as a whole.

Q. Please summarize the rates and charges UNS Electric is proposing for the SGS three-part TOU DG Rate with a Demand Charge.

A. UNS Electric is proposing a SGS three-part TOU DG Rate option with the following elements:

- A monthly Basic Service Charge of $20.00.
- A monthly DG Meter Charge of $4.60.
- An Energy Delivery Charge of $0.01295/kWh for all billing kWh.

- Demand charges of $8.25/kw for the first 5 kW of billing demand and $11.00/kW for all billing demand greater than 5 kW with billing demand defined as the maximum one-hour average kW during on-peak periods in the billing month.
- Base Power Charges ($/kWh):
  - Summer On-Peak $0.109800
  - Summer Off-Peak $0.045700
  - Winter On-Peak $0.108800
  - Winter Off-Peak $0.040036
- Summer months are May through October; the Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day and Labor Day).
- Winter months are November through April; the Winter On-Peak periods are 5:00 a.m. to 9:00 a.m. and 5:00 p.m. to 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

Q. Has UNS Electric calculated bill impacts for the proposed SGS Demand TOU DG rate option?

A. Yes. Average monthly bills and bill impacts are presented in Table 8 below.

Table 8: UNSE SGS Demand TOU DG Rate Option Average Bill & Bill Impacts

Monthly Usage	UNSE SGS Basic: Full Require-ments	UNSE SGS DG Option 2: Demand TOU Rate				
		SGS-DEM-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 649 kWh	$89.42	$38.15	($51.27)	$0.0462	$0.0790	11.8
Medium: 792 kWh	$103.70	$39.30	($64.40)	$0.0518	$0.0813	10.9
Large: 1,591 kWh	$183.55	$47.64	($135.91)	$0.0641	$0.0854	9.9
Extra Large: 2,307 kWh	$255.09	$51.00	($204.09)	$0.0704	$0.0885	9.8

The results in Table 8 show that a typical medium usage UNS Electric SGS DG customer would save $64.40 per month and a large usage customer $135.91 per month under the proposed Demand TOU DG rate when compared to customers with the same usage profiles taking full-requirements service under UNS Electric's SGS basic two-part rate. These correspond to monthly bill savings of about 62 percent and 74 percent, respectively.

VI. TEP AND UNS ELECTRIC RESIDENTIAL DG CUSTOMER BILLS AFTER JULY 1, 2018

Q. Tables 1 through 8 above present estimated bill impacts and simple payback periods for new TEP and UNS Electric DG customers using the Companies' proposed initial RCP rate of $0.1070/kWh. What are the Companies proposing for the period immediately after the initial RCP rate is effective?

A. For TEP, the Companies are proposing that the initial combined RCP rate of $0.1070/kWh be reset to $0.0963/kWh, a 10 percent reduction, on July 1, 2018. For UNS Electric, the Companies are proposing that the initial RCP rate be reset to $0.0920/kWh, which is the weighted average of the retail rates for the UNS Electric Residential and SGS rate classes, on July 1, 2018.[9]

Q. Have you calculated monthly bills and simple payback periods for new residential DG customers who install rooftop PV systems after July 1, 2018?

A. Yes. Tables 9 and 10 below present monthly bill calculations and simple payback periods for new TEP and UNS Electric residential DG customers, respectively, who install PV systems after July 1, 2018, but before the next reset of RCP rates is effective. All other assumptions used for Tables 1 through 8 above are unchanged.

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[9] See Rejoinder Testimony of Companies' witness Dallas Dukes.

Table 9: TEP Residential Two-Part TOU DG Rate Option; $0.0963/kWh RCP Rate

Monthly Usage	TEP RES Basic: Full Require-ments	TEP Residential DG Option 1: Two-Part TOU Rate				
		RES-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 737 kWh	$97.39	$34.47	($62.92)	$0.0664	$0.0854	10.5
Medium: 964 kWh	$124.95	$39.72	($85.23)	$0.0736	$0.0884	9.6
Large: 1,366 kWh	$173.41	$48.14	($125.27)	$0.0816	$0.0917	9.3
Extra Large: 1,667 kWh	$210.28	$54.44	($155.84)	$0.0857	$0.0935	8.8

Q. Please comment on the results presented in Table 9.

A. Table 9 shows that a new medium usage TEP residential DG customer taking service on the proposed two-part TOU DG rate option, who installs a net-zero PV system on or after July 1, 2018, but before the next RCP reset, will save $85.23 per month before taxes when compared to a customer with the same usage profile taking full-requirements service under TEP's basic two-part rate. This represents monthly bill savings of about 68 percent. Also, this customer would face a simple payback period on the PV system investment of about 9.6 years, compared with 8.9 years for a pre-July 1, 2018 investment.

Table 10: UNSE Residential Two-Part TOU DG Rate Option; $0.0920/kWh RCP Rate

Monthly Usage	UNSE RES Basic: Full Require-ments	UNSE Residential DG Option 1: Two-Part TOU Rate				
		RES-TOU-DG	Difference from Full Reqts.	Offset Rate ($/kWh)	Blended Value of PV ($/kWh)	Simple Payback (years)
Mean: 797 kWh	$94.58	$25.15	($69.43)	$0.0772	$0.0871	10.4
Medium: 1,112 kWh	$126.46	$28.27	($98.19)	$0.0803	$0.0883	9.8
Large: 1,615 kWh	$177.41	$32.11	($145.30)	$0.0844	$0.0900	9.4
Extra Large: 1,992 kWh	$215.70	$34.90	($180.80)	$0.0861	$0.0907	9.5

Q. Please comment on the results presented in Table 10.

A. Table 10 shows that a new medium usage UNS Electric residential DG customer taking service on the proposed two-part TOU DG rate option, who installs a net-zero PV system on or after July 1, 2018, but before the next RCP reset, will save $98.19 per month before taxes, or about 78 percent, when compared to a customer with the same usage profile taking full-requirements service under UNS Electric's basic two-part rate. Also, this customer would face a simple payback period on the PV system investment of about 9.8 years, compared with 8.9 years for a pre-July 1, 2018 investment.

VII. OVERVIEW OF STAFF AND INTERVENOR DG RATE DESIGN PROPOSALS

Q. Please summarize the DG rate design proposals submitted by Staff and Intervenors in Surrebuttal Testimony.

A. Staff witness Smith is proposing rate design options for new residential and SGS DG customers that are essentially the same as those proposed by the Companies in Rejoinder Testimony. The one exception is that Staff recommends separate RCP rates of \$0.1050/kWh for TEP and \$0.1280/kWh for UNS Electric.[10] However, if the Commission finds that a single RCP rate for both TEP and UNS Electric is appropriate, Staff recommends a single rate of \$0.1070/kWh.[11] This recommendation is unchanged from Staff's Direct Testimony. The Companies are recommending (i) the single RCP rate of \$0.1070/kWh in Rejoinder Testimony compared to the \$0.0973/kWh the Companies recommended in Direct and Rebuttal Testimony, and (ii) a reset of the TEP RCP on July 1, 2018 to \$0.0963/kWh and \$0.0920/kWh for UNS Electric. Staff also supports resetting the initial RCP on July 1, 2018.[12]

Vote Solar and TASC/EFCA recommend that new residential and SGS DG customers be allowed to take service under any of the Companies' currently available tariffs, including basic non-TOU two-part rates and both oppose the adoption of any Grid Access Charge. Vote Solar recommends incremental DG Meter Charges of \$2.23/month for new TEP and

[10] Smith Phase 2 Surrebuttal Testimony, 10:3-4.
[11] Smith Phase 2 Surrebuttal Testimony, 13:14-17.
[12] Smith Phase 2 Surrebuttal Testimony, 12:17-21.

UNS Electric residential DG customers and \$0.90/month for new SGS DG customers. TASC/EFCA witness Beach recommends that any incremental DG Meter charges be kept at the levels approved in Phase 1, which are \$2.05/month for TEP residential, \$0.35/month for TEP SGS, and \$1.58 for UNS Electric residential and SGS.[13] Vote Solar[14] and TASC/EFCA[15] recommend respective first-year RCP rates of \$0.1240/kWh and \$0.1250/kWh for both TEP and UNS Electric.

Q. Have you evaluated the residential DG rate design proposals put forth by the Companies, Staff, Vote Solar, and TASC/EFCA?

A. Yes. Table 11 and Figure 1 present monthly bill calculations for new medium usage TEP residential DG customers subject to the parties' rate design proposals. Table 12 and Figure 2 present the same information for new medium usage UNS Electric residential DG customers. Included in these bill calculations are the Companies' Direct and Rejoinder DG rate design proposals and those put forth by Staff, Vote Solar, and TASC/EFCA in Surrebuttal. All comparisons are based on a new residential DG customer taking service on a two-part DG rate using an average of 964 kWh per month for TEP and 1,112 kWh per month for UNS Electric, which correspond to the 75th percentile of the respective residential customer samples. These DG customers are assumed to have south-facing PV systems sized to offset 100% of annual consumption (i.e., net-zero customers).

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[13] TASC/EFCA Phase 2 Surrebuttal Testimony of R. Thomas Beach ("Beach"),

[14] Kobor Phase 2 Surrebuttal Testimony, 6:9-10.

[15] Beach Phase 2 Surrebuttal Testimony, 13:11-12.

Table 11: Summary of Phase 2 TEP Residential DG Rate Design Positions

TEP Residential Customer with 964 kWh Average Monthly Usage	TEP RES Basic				TEP RES TOU DG		
	Full Require-ments	Current Net Metering	Vote Solar	TASC / EFCA	TEP Rejoinder	Staff Surrebuttal	TEP Direct
RCP Rate ($/kWh)	NA	NA	$0.1240	$0.1250	$0.1070	$0.1070	$0.0973
Grid Access Charge ($/kW-DC)	NA	NA	$0.00	$0.00	$2.50	$2.50	$3.50
Basic Service Charge	$13.00	$13.00	$13.00	$13.00	$10.00	$10.00	$13.00
DG Meter Charge	$0.00	$2.05	$2.23	$2.05	$3.50	$3.50	$4.32
Energy Delivery Charges	$71.47	$0.02	$36.47	$36.47	$39.67	$39.67	$38.50
Grid Access Charges	$0.00	$0.00	$0.00	$0.00	$15.75	$15.75	$22.05
Base Power/PPFAC Charges	$31.30	$0.36	$17.25	$17.25	$15.16	$15.16	$15.16
Statement of Charges[16]	$9.18	$4.67	$6.76	$6.75	$7.01	$7.01	$15.03
Subtotal before PV Credits	$124.95	$20.10	$75.71	$75.53	$91.09	$91.09	$108.06
PV Export Credits	$0.00	$0.00	($66.13)	($66.67)	($57.07)	($57.07)	($51.90)
Monthly Bill before Taxes	**$124.95**	**$20.10**	**$9.58**	**$8.86**	**$34.02**	**$34.02**	**$56.16**
Savings from Full Requirements.	NA	($104.84)	($115.36)	($116.09)	($90.93)	($90.93)	($68.78)
Simple Payback (years)	NA	7.1	7.0	6.9	8.9	8.9	10.8
Offset Rate ($/kWh)	NA	$0.1041	$0.1087	$0.1091	$0.0736	$0.0736	$0.0528
Blended Value of PV ($/kWh)	NA	$0.1088	$0.1197	$0.1204	$0.0943	$0.0943	$0.0795

16 Statement of Charges includes Demand Side Management Surcharge (DSMS), Renewable Energy Standard and Tariff Surcharge (REST), Lost Fixed Cost Recovery Mechanism (LFCR), and Environmental Compliance Adjustor (ECA).

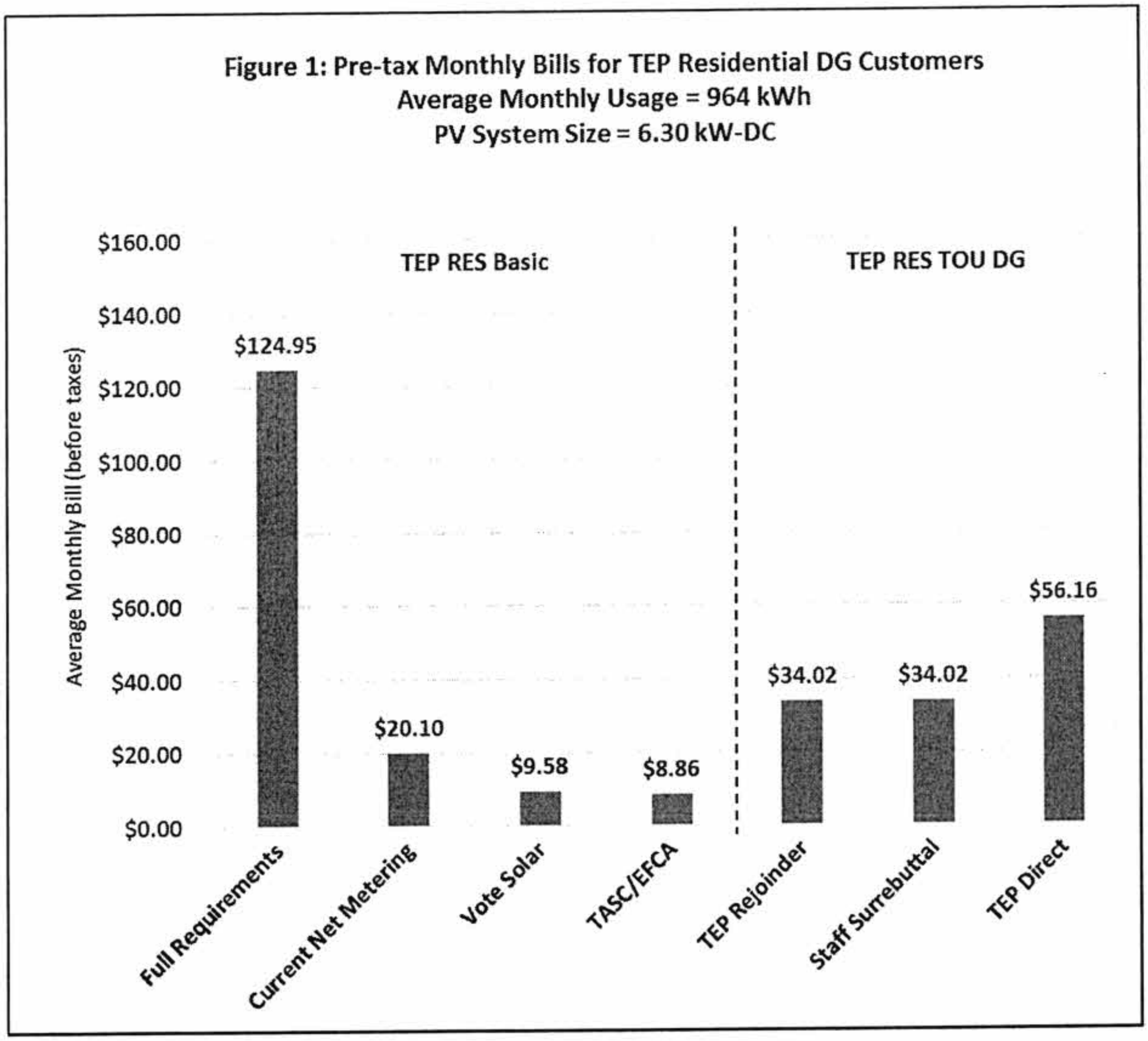
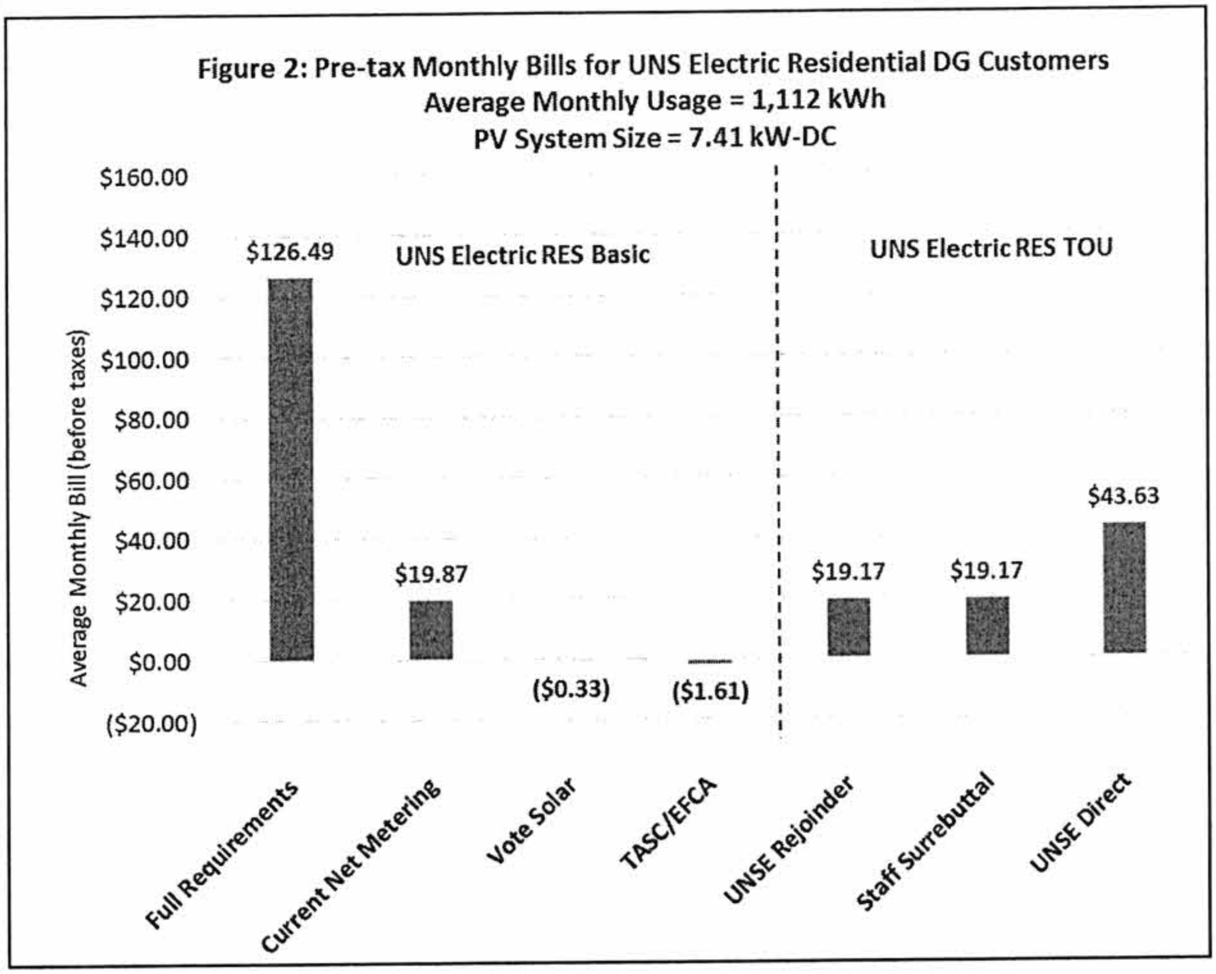


Figure 1: Pre-tax Monthly Bills for TEP Residential DG Customers
Average Monthly Usage = 964 kWh
PV System Size = 6.30 kW-DC
TEP RES Basic
TEP RES TOU DG
Average Monthly Bill (before taxes)
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
$124.95
$20.10
$9.58
$8.86
$34.02
$34.02
$56.16
Full Requirements
Current Net Metering
Vote Solar
TASC/EFCA
TEP Rejoinder
Staff Surrebuttal
TEP Direct

Table 12: Summary of Phase 2 UNS Electric Residential DG Rate Design Positions

UNSE Residential Customer with 1,112 kWh Average Monthly Usage	UNS Electric RES Basic				UNS Electric RES TOU DG		
	Full Require ments	Current Net Metering	Vote Solar	TASC / EFCA	UNSE Rejoinder	Staff Surrebuttal	UNSE Direct
RCP Rate ($/kWh)	NA	NA	$0.1240	$0.1250	$0.1070	$0.1070	$0.0973
Grid Access Charge ($/kW-DC)	NA	NA	$0.00	$0.00	$1.00	$1.00	$2.00
Basic Service Charge	$15.00	$15.00	$13.00	$13.00	$12.00	$12.00	$13.00
DG Meter Charge	$0.00	$1.58	$2.23	$1.58	$3.00	$3.00	$3.92
Energy Delivery Charges	$42.73	$0.00	$21.36	$21.36	$24.79	$24.79	$24.79
Grid Access Charges	$0.00	$0.00	$0.00	$0.00	$7.41	$7.41	$14.82
Base Power/PPFAC Charges	$62.08	$0.00	$34.25	$34.25	$32.63	$32.63	$32.63
Statement of Charges[17]	$6.69	$3.29	$4.85	$4.84	$4.95	$4.95	$14.13
Subtotal before PV Credits	$126.49	$19.87	$75.68	$75.02	$84.77	$84.77	$103.28
PV Export Credits	$0.00	$0.00	($76.01)	($76.63)	($65.60)	($65.60)	($59.65)
Monthly Bill before Taxes	**$126.49**	**$19.87**	**($0.33)**	**($1.61)**	**$19.17**	**$19.17**	**$43.63**
Savings from Full Requirements.	NA	($106.62)	($126.82)	($128.10)	($107.32)	($107.32)	($82.86)
Simple Payback (years)	NA	8.3	7.5	7.4	8.9	8.9	10.5
Offset Rate ($/kWh)	NA	$0.0928	$0.0981	$0.0994	$0.0801	$0.0801	$0.0614
Blended Value of PV ($/kWh)	NA	$0.0959	$0.1140	$0.1152	$0.0965	$0.0965	$0.0827

[17] Statement of Charges includes Demand Side Management Surcharge (DSMS), Renewable Energy Standard and Tariff Surcharge (REST), and Lost Fixed Cost Recovery Mechanism (LFCR. The Transmission Cost Adjustor (TCA) is included in Energy Delivery Charges.



Q. What can one conclude from the results in Tables 11 and 12 and Figures 1 and 2?

A. The results above show that the Companies have moved significantly from their proposals submitted in Direct Testimony, and are now proposing DG rate design options identical to those proposed by Staff, assuming a single RCP rate for both Companies. Compared to the Companies' Direct Testimony, TEP's two-part TOU DG rates proposed in Rejoinder result in monthly bills to medium usage residential DG customers reduced by $22.15 and the simple payback period decreased by almost two years. For UNS Electric, the Companies' Rejoinder Testimony results in monthly bills for medium usage residential DG customers that are $24.46 lower than the Companies' Direct case and the simple payback period is reduced by over one and one-half years.

Also, the results show that for a typical new TEP residential DG customer with the usage profile modeled in this exercise, Vote Solar and TASC/EFCA are proposing DG rate design options for residential DG customers that would result in lower monthly bills than a similar customer currently realizes under net metering and would actually result in bill credits, i.e., negative bills for UNS Electric residential DG customers.

VIII. RESPONSE TO STAFF SURREBUTTAL TESTIMONY

Q. On page 15 of his Surrebuttal Testimony, Staff witness Smith recommends that payback period information should be considered by the Commission, in conjunction with other information, in making its decision on the RCP rate and the components of the new rates.[18] Please comment.

A. I agree with Staff witness Smith, but with reservations, that payback analysis should be considered as one element among many when making decisions on DG rate design. However, while the simple payback period calculations presented by the Companies and other parties provide some information with respect to the economics of investing in rooftop PV, I caution against placing too much stock in them. As the experience in this case demonstrates, there are multiple variables and assumptions that can enter into the decision to invest in rooftop PV and an overemphasis on calculated payback periods may serve to shed more heat than light on the evaluation of DG rate design proposals.

[18] Smith Phase 2 Surrebuttal Testimony, 15:9-13.

Q. Staff witness Smith identifies several concerns related to the payback calculations presented in your Rebuttal Testimony.[19] What are they?

A. Mr. Smith identifies several concerns about the Companies' calculation of payback periods. These include:

1. Modeling of the TOU peak periods
2. Modeling of the 15% revenue-based tax component
3. Omission of PV system financing costs
4. No consideration of future decreases in RCP rates
5. No consideration of future increases in DG customer meter charges

Q. Do you have any thoughts on Staff witness Smith's concerns?

A. Yes. First, the concerns that Mr. Smith identifies regarding the Companies' payback period calculations are accurate. Second, Staff witness Smith is not alone in expressing concerns about the Companies' estimated PV system payback periods as other parties have voiced similar concerns with the calculations presented.[20] Therefore, I will address Mr. Smith's concerns specifically and the usefulness of estimated payback periods in general.

The first two concerns identified by Mr. Smith are modeling issues and I addressed them earlier in my testimony. They have been corrected, and as Mr. Smith states, both changes had the impact of lengthening calculated payback periods.

With respect to the omission of PV system financing costs, the Companies' do not wish, for the purposes of this proceeding, to either speculate or enter into debate about the terms and conditions of possible PV system financing options available to prospective

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[19] Smith Phase 2 Surrebuttal Testimony, 15:16-23:26.

[20] See Phase 2 Surrebuttal Testimony of Kevin Koch ("Koch"), Bruce Plenk Phase 2 Surrebuttal Testimony of Louis Woofenden ("Woofenden"), 17:244-23:305, and Beach Phase 2 Rebuttal; 11:20-13:18.

DG customers. If other parties are interested in modeling PV system financing costs and including them in payback period calculations, they are welcome to it.

Concerning the fact that the Companies did not consider future decreases in RCP rates and future increases in DG customer meter charges, my presentation of payback period calculations was only meant to give some notion of PV investment returns given the conditions present immediately following a decision in this proceeding.[21] Also, although it is most likely that future changes in RCP rates will be decreases and are somewhat knowable, Mr. Smith implicitly assumes that all future changes in DG customer meter charges will be increases without entertaining the possibility that they could decrease. With respect to future DG customer meter charges, the Companies stand by their position that no current basis exists for speculation on them. Finally, the models provided in the Companies' workpapers provide a framework for the analysis of payback periods under any assumed future values for most of the variables cited above. Other parties are welcome to use those models and manipulate assumptions as they see fit.

Finally, Mr. Smith's concerns identify only variables whose omissions most likely understate estimated PV system payback periods. However, there are other variables that impact PV system payback periods whose omission may overstate them.

Q. What variables, if included, may result in reducing estimated payback periods?

A. Most notably, recent trends in PV system costs and PV panel efficiency, and increases in future electric rates would all result in reduced payback periods. The cost of PV systems has been decreasing and their efficiency increasing, trends which are likely to continue in

[21] It should be noted that Companies' witness Dallas Dukes presents estimated payback periods for two years of future RCP reductions in his Phase 2 Rebuttal and Rejoinder testimonies.

the absence of market interference. Obviously, if continued, the trends in these two variables would result in shorter payback periods.

The Companies chose to assume no changes in future electric rates in the estimation of payback periods. However, future electric rate increases would increase the savings from a rooftop PV investment and shorten estimated payback periods. In fact, for the medium usage TEP residential DG customer examined earlier, future rate increases of 0.8 percent per year, which represents the historical 20-year annual change in TEP residential electric rates, would decrease the estimated payback period by three months. A 3.0 percent annual increase in TEP electric rates, a number often cited by solar PV vendors in promotional literature, would shorten the payback period by about ten months.

Q. You earlier urged caution in placing too much emphasis on PV system payback analysis to evaluate RCP and DG rate design proposals. Please comment.

A. My reservations concerning an overemphasis on PV system payback analysis in evaluating DG rate design options relate to the fact that each prospective investment in solar PV is unique. Vote Solar witness Briana Kobor agrees and says it best:

> "I recommend the focus remain on 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."[22]

Ms. Kobor concludes her discussion of the usefulness of payback analysis with:

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[22] Kobor Phase 2 Surrebuttal Testimony, 68:16-22.

> "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."[23]

I agree with witness Kobor on this issue, although I would not limit the focus to only the rate metrics identified by Ms. Kobor. Obviously, among the criteria the Commission should also consider are the impacts of the proposed DG rate options on utility cost recovery, cost shifts to other customers, and whether the proposed rates are consistent with the intent of the VOS Order. The PV system payback period may be a useful tool for a prospective individual customer or PV vendor to evaluate a unique investment situation, but it is of very limited use in the evaluation of DG rate options without taking into account other rate design criteria.

Q. If you believe that PV system payback periods are of limited use for evaluating DG rate proposals, why did the Companies provide them?

A. The Companies actually did not provide PV system payback period calculations in either Phase 1 of this proceeding or Phase 2 Direct Testimony. However, some parties showed interest in PV system payback periods and actually provided their own calculations in Direct Testimony.[24] Therefore, the Companies decided to provide simple PV system payback calculations for each of the proposed DG rate options beginning with Phase 2 Rebuttal Testimony. Regrettably, the introduction of payback analysis in this proceeding

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[23] Kobor Phase 2 Surrebuttal Testimony, 69:17-19.

[24] See Koch Phase 2 Direct Testimony.

has led many parties to chase a shiny object rather than concentrate on the rate design criteria that are useful for the determination of just and reasonable electric rates.

Q. How do you recommend estimated PV system payback periods should be used to evaluate DG rate options?

A. As I stated earlier, PV system payback periods can be a useful evaluation tool when used in combination with other rate design metrics. Given each prospective DG customer's unique situation, the probability that any prospective DG customer will realized the payback periods presented in the above tables approaches zero. However, if one deemphasizes the absolute value of the estimated PV system payback period and looks at how the payback periods differ among alternative rate options under identical assumptions, some useful information can be obtained. For example, in Table 11 above the estimated payback period for a new medium usage TEP residential DG customer under the Phase 2 DG rate design options recommended by TEP and Staff is about 22 months longer than the same customer would see under current net metering using identical assumptions. In Table 12 above, a new medium usage UNS Electric residential DG customer would see an 8-month longer estimated payback period than current net metering under the DG rate design options recommended by UNS Electric and Staff. In all cases for both TEP and UNS Electric, new DG customers subject to the residential DG rate design options recommended by Vote Solar and TASC/EFCA would see estimated payback periods shorter than those calculated for the same customers under current net metering. These comparisons give the Commission and parties to the proceeding a useful metric, albeit one of many, for comparing the DG rate proposals relative to the status quo.

IX. RESPONSE TO RUCO SURREBUTTAL TESTIMONY

Q. Do you have any comments on the Surrebuttal Testimony of RUCO witness Lon Huber?

A. Yes. Concerning Mr. Huber's evaluation and comments on the Companies' rate proposals for new residential and SGS DG customer, I largely agree and have no comments.

The only issue in Mr. Huber's Surrebuttal Testimony on which I have comments is the "All Production TOU RCP" rate proposal. I have modeled the proposal for new TEP residential DG customers with the same methodology used in the results presented above and have some results and comments.

Q. Please briefly describe RUCO's proposed All Production TOU RCP proposal.

A. RUCO's All Production TOU RCP proposal is essentially a buy-all/sell-all arrangement between the utility and DG customers with a time-varying RCP. Also, RUCO's proposal would allow the DG customer to access any of the Companies' full-requirements rate plans.

Q. What is a buy-all/sell-all arrangement between a utility and a DG customer?

A. Under a buy-all/sell-all arrangement, the utility bills the customer for all electricity usage on site regardless of whether the DG customer is consuming utility delivered energy or output from his or her own PV system. In return, the utility pays or credits the DG customer for all kWh produced by the PV system at a $/kWh price.

Q. Are the Companies in favor of such a proposal?

A. Companies' witness Dallas Dukes discusses the merits of RUCO's proposed All Production TOU RCP proposal. I will confine my comments to a preliminary analysis of some of the rate design metrics (i.e., bill savings, payback periods, etc.) that I have analyzed earlier in my testimony.

Q. What RCP is RUCO proposing for the All Production TOU RCP rate plan?

A. Mr. Huber proposes an RCP rate of $0.097/kWh for the DG rate options other than the All Production TOU RCP rate plan. For the All Production TOU RCP rate plan, Mr. Huber proposes the following RCP schedule for TEP[25]:

Period	TEP RCP ($/kWh)
Peak (3 PM – 7 PM)	$0.2400
Shoulder (7 PM – 11 AM)	$0.0120
Off-Peak (11 AM – 3 PM)	$0.0300

The RCP periods in this schedule are effective year-round. In other words, unlike the TOU periods that apply to TEP and UNS Electric rates, these periods do not differ by season and are effective for weekends and holidays. Also, Mr. Huber proposes a separate RCP for UNS Electric and a combined RCP for both Companies. For UNS Electric, Mr. Huber proposes the same RCP periods as above but with a $0.2100/kWh peak RCP and $0.0500/kWh shoulder RCP. For a combined RCP, Mr. Huber recommends substituting the peak RCP in the table above with $0.2100/kWh.

Q. Have you analyzed the RCP rate schedule against PV production profiles?

A. Yes. I confine my analysis to TEP using the RCP schedule in the above table. When analyzed against the NREL SAM profile described earlier for a 90-degree, south-facing PV system, the system yields an annual RCP of $0.937/kWh. When analyzed against a

[25] Huber Phase 2 Surrebuttal Testimony, 25:5-11.

270-degree west-facing system, the annual RCP is \$0.1043/kWh. This result is unsurprising given that a major objective of the RUCO proposal is to encourage the installation of more west-facing PV systems.[26] Although a south-facing system generates more kWh per year than the same sized west-facing system, the west-facing system will produce more output later in the day during the peak hours.

Q. Why do your average annual RCP estimates differ from Mr. Huber's estimates of \$0.0970/kWh for a south-facing system and \$0.1185 for west-facing.[27]?

A. I suspect that the differences are because of the Excel coding error I discussed earlier concerning TOU periods. Mr. Huber likely modified the Companies' Rebuttal workpapers for his analysis and therefore may not have used the correct periods. I therefore have adjusted Mr. Huber's time-varying RCP rates as follows:

Period	TEP RCP (\$/kWh)
Peak (3 PM – 7 PM)	\$0.2600
Shoulder (7 PM – 11 AM)	\$0.0120
Off-Peak (11 AM – 3 PM)	\$0.0300

This adjustment yields annual average RCP rates of \$0.097/kWh for a south-facing system and \$0.1096 for west-facing. This should put my analysis on similar footing with Mr. Huber's.

Q. Please summarize your results.

A. My results incorporate the following assumptions. First, I analyze a medium usage, 964 kWh/month, TEP residential DG customer taking service on TEP's Residential two-part non-TOU rate, also known as RES Basic. Second, I assume the DG customer is subject to the \$3.50/month DG meter charge, since a bi-directional meter will still be required.

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[26] Huber Phase 2 Surrebuttal Testimony, 29:4-31:2.

[27] Huber Phase 2 Surrebuttal Testimony, 26:6-8.

There is a temptation, because this is a buy-all/sell-all arrangement, to look only at the PV RCP credits in the calculation of a payback period. However, the additional DG meter charge is an additional cost that must be included, unless the charge is waived. Third, I assume no Grid Access Charge. One purpose of a Grid Access Charge is to mitigate utility fixed cost under-recovery. In a buy-all/sell-all arrangement, the utility is compensated for all kWh consumed and fixed cost recovery is equal to that of a similar full-requirements customer. Therefore, no further mitigation is necessary. Finally, I assume a PV system size of 6.3 kW-DC, without storage, which makes the south-facing system net-zero. However, the west-facing system produces about 14 percent less kWh on an annual basis. The question to be answered by this analysis is whether RUCO's proposed RCP pricing scheme results in sufficient incentive to install a west-facing PV system.

Table 13 below summarizes the results. A new medium usage TEP residential DG customer taking service on this rate plan would definitely benefit from installing a west-facing PV system over a south-facing system. In fact, a DG customer on this rate plan with a west-facing system would fare better than the same customer with a south-facing system under the TEP's proposed Residential TOU DG rate proposal. Average monthly savings increase from $90.93 under the TEP proposal to $102.82 under RUCO's and the estimated simple payback period is reduced from 8.9 to 8.4 years.

Table 13: Summary of RUCO All Production TOU RCP Rate Proposal

Rate Element	RUCO All Production: South	RUCO All Production: West
RCP Rate (annual average $/kWh)	$0.0970	$0.1096
Basic Service Charge	$13.00	$13.00
DG Meter Charge	$3.50	$3.50
Energy Delivery Charges	$71.47	$71.47
Base Power/PPFAC Charges	$31.30	$31.30
Statement of Charges	$8.56	$8.56
Subtotal before PV Credits	$127.83	$127.83
PV Export Credits	($93.53)	($105.70)
Total Bill before Taxes	$34.30	$22.12
Difference from RES Basic Full Reqts.	($90.65)	($102.82)
Simple Payback (years)	9.6	8.4

X. RESPONSE TO VOTE SOLAR SURREBUTTAL TESTIMONY

Q. On page 58 of her Surrebuttal Testimony, Vote Solar witness Kobor states that "the Companies' COSSs and Proofs of Revenue should not be relied on for ratemaking."[28] Please comment.

A. Companies' witness Craig Jones is sponsoring the Class Cost of Service Study ("CCOSS") that underlies the allocation of costs among rate classes and I will not address CCOSS issues here. I am sponsoring the Companies' Proofs of Revenue and will comment on that portion of Ms. Kobor's statement. First, I don't quite understand Ms. Kobor's statement because the Companies never relied on the Proofs of Revenue submitted in Phase 2 of this proceeding for ratemaking, if by ratemaking she means setting the individual charges for each rate option. Typically, a Proof of Revenue is a schedule that uses test-year adjusted billing determinants, i.e., number of customers, billing kWh, and billing kW, along with proposed test-year revenues to assure that proposed rates recover the proposed test-year revenues allocated to each rate class by the

[28] Kobor Phase 2 Surrebuttal Testimony, 58:3-4.

CCOSS. Individual charges within the different rate options are adjusted until the proposed test-year revenue targets are achieved. Also, once rates are determined, a Proof of Revenue is used in combination with the CCOSS to calculate relative rates of return by customer class.

Q. What issues arise in developing Proofs of Revenue for the DG rate options proposed in Phase 2?

Typically, developing a Proof of Revenue requires the availability test-year billing data for the rates in question. However, because the DG rate options being proposed in this case are new rate options that will apply only to new DG customers, test-year billing determinants for these rate options do not exist. This is not a problem for test-year number of customers and billing kWh because these are billing determinants that have applied historically to the Companies' residential and SGS customers and for which there is available data. However, the test-year billing kW data needed to prove revenues for the proposed three-part TOU DG rate options are incomplete. Therefore, the test-year billing kW used in the Proofs of Revenue submitted in Phase 2 must be estimated from load research or customer sample data.

Q. Without test-year billing determinants, how did the Companies calculate the rates and charges for the new DG rate options?

A. The rates and charges for the new DG rate options are, for the most part, based on rates and charges in existing TEP and UNS Electric rate tariffs, namely the applicable full-requirements Residential and SGS two-part and three-part TOU tariffs. The major exceptions are the proposed incremental DG Meter Charges and the Grid Access Charges, which were developed independent of the submitted Proofs of Revenue. The DG Meter Charge was developed by Companies' witness Jones based on cost of service.

The Grid Access Charge was calculated to obtain a targeted self-consumption offset rate for each Company.[29]

Also, it should be noted that the Companies' did not submit formal Proofs of Revenue for the optional Residential and SGS three-part rate options that were approved in Phase 1 of both the TEP and UNS Electric rate cases. Again, this is because these were new rates with no test-year billing kW data on which to prove revenues. Rates and charges for those new three-part rates were developed using residential and SGS customer samples.[30]

Q. If the Proofs of Revenue submitted in Phase 2 were not used by the Companies to develop the DG rate options, why did the Companies submit them?

A. The Companies Proofs of Revenue were submitted in Phase 2 for the single purpose of presenting calculated relative rates of return for the proposed new DG rate classes, and as such, they should be viewed only for that purpose. While I am confident of the accuracy of calculated rates of return for the two-part TOU DG rate options because residential and SGS customers have always been billed on kWh, the calculated revenues and rates of return for the three-part TOU DG rate options should be viewed as fairly rough estimates because estimated billing kW is the test-year billing determinant with the most uncertainty. In fact, the three-part TOU full-requirements rates, on which the three-part TOU DG options are based, do not yet have a full year of billing kW data to complete a formal Proof of Revenue for them.

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[29] Phase 2 Rebuttal Testimony of Richard D. Bachmeier ("Bachmeier"), 5:23-7:3.

[30] For a discussion of how Phase 1 residential and SGS three-part rates were developed, see Bachmeier TEP Phase 1 Rebuttal Testimony, 14:16-25.

XI. RESPONSE TO TASC/EFCA SURREBUTTAL TESTIMONY

Q. In his Surrebuttal Testimony, TASC/EFCA witness Beach uses your citation of Dr. Alfred Kahn from your Phase Rebuttal Testimony to recommend that the Commission further evaluate the external benefits of renewable generation produced by DG customers.[31] Do you agree?

A. No. First, Mr. Beach ignores Dr. Kahn's conditions for economic efficiency regarding the consideration of external costs and benefits in pricing, specifically that marginal cost pricing that internalizes all external costs and benefits may not necessarily produce optimal results if it is not applied uniformly throughout the economy. Second, the Commission has already considered, and spoken on, the external benefits of renewable generation produced by DG customers in the VOS Order. Mr. Beach's recommendation is nothing more than an attempt to relitigate the VOS proceeding and should be ignored.

XII. RESPONSE TO LOUIS WOOFENDEN SURREBUTTAL TESTIMONY

Q. Beginning on page 17 of his Surrebuttal Testimony, witness Louis Woofenden on behalf of Intervenor Bruce Plenk, has a discussion of why his payback period calculations differ from those presented in your Rebuttal Testimony.[32] Please comment.

A. Mr. Woofenden speculates that the differences may stem from my use of average hourly load data from customer samples while he uses actual individual customer data. He is correct in his observation that I used sample average hourly load data to represent "typical" residential and SGS customer load profiles for the purposes of calculating monthly bills under alternative DG rate design scenarios. I am also fully aware of the

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[31] Beach Phase 2 Surrebuttal Testimony, 35:23-36:9.

[32] Woofenden Phase 2 Surrebuttal Testimony, 17:244-23:305.

pitfalls involved in using average hourly load data for such purposes.[33] Mr. Woodfenden also makes many of the same observations as to the pitfalls of using average hourly loads that I made in TEP Phase 1 testimony.

In contrast to my analysis, Mr. Woofenden presents estimated payback periods for 13 actual TEP commercial customers from 2018 through 2022 subject to TEP's proposed DG rate options. Many of Mr. Woofenden's calculations show longer payback periods than those estimated in my analysis, especially in the years beyond 2020. Because Mr. Woofenden uses different data and, in some cases, different assumptions than I used in my analysis, I am not surprised that the results differ. Furthermore, Mr. Woodfenden's analysis actually strengthens the point I made earlier with respect to the limited usefulness of payback analysis as a DG rate design evaluation tool. While the individual customers in Mr. Woofenden's example would benefit greatly from knowing the approximate period over which they could expect to recover their PV system investments given their unique circumstances, the estimated payback periods for other customers in the example, or for the "typical" customer from my analysis, would be of little use to them.

XIII. RESPONSE TO KEVIN KOCH SURREBUTTAL TESTIMONY

Q. Do you have any comments on the Surrebuttal Testimony of Kevin Koch?

A. Yes. Mr. Koch's disagreements with my Rebuttal Testimony are largely related to the assumptions used to estimate payback periods and the level of the proposed Grid Access Charge. With respect to the payback analysis assumptions, I have commented on this issue at length earlier in my testimony and have nothing more to add here.

[33] Bachmeier TEP Phase 1 Rebuttal Testimony, 34:10-17.

Mr. Koch recommends that the Grid Access Charge be set at a value between \$0.50 to \$0.75 per kW based on peak hourly generation rather than the DC-rated PV system size.[34] Mr. Koch bases this recommendation on two criteria. First, Mr. Koch's recommendation for using actual peak hourly generation for the Grid Access Charge rather than PV system size is based on his desire to not have a DG customer paying a Grid Access Charge for PV system that is underperforming or not performing at all.

I disagree with Mr. Koch's proposal for two reasons. First, the peak hourly generation would be measured in kW-AC while the PV system is rated in kW-DC. The inverters that convert PV system output from kW-DC to kW-AC have losses in the neighborhood of 10%. Therefore, not only is Mr. Koch recommending lower Grid Access Charges than proposed by the Companies, he is also proposing that the billing determinants to which they apply be reduced as well.

Second, Mr. Koch developed his recommended Grid Access Charges to obtain what he estimates, for his business purposes, acceptable payback periods for PV system investments. Utility rates should be set to adequately recover costs; to instead set utility rates with the goal of obtaining a desired payback period on a third-party investment would be a classic example of the tail wagging the dog.

Q. Does this conclude your testimony?

A. Yes it does.

[34] Koch Phase 2 Surrebuttal Testimony, p. 5 (unnumbered).