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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN OF THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142 **STAFF'S NOTICE OF FILING SURREBUTTAL TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Surrebuttal Testimony of Thomas M. Broderick, Howard Solganick, Donna Mullinax, Barbara Keene, Eric Van Epps, and Candrea Allen in the above docket.

RESPECTFULLY SUBMITTED this 23rd day of February 2016.

Arizona Corporation Commission
DOCKETED
FEB 23 2016
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BEFORE THE ARIZONA CORPORATION COMMISSION

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SURREBUTTAL

RATE DESIGN TESTIMONY

OF

THOMAS M. BRODERICK

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

Mr. Broderick's surrebuttal testimony continues the discussion regarding Staff's proposed full transition from two-part to three-part rates for all of UNS Electric, Inc.'s ("UNSE") residential and small general service customers.

Staff proposes two additional mitigation measures for residential and small general service customers: A 15 percent bill credit to customers who adopted DG solar on or before June 1, 2015, and a temporary 15 percent incentive for new DG solar adopters during the six month period following full rate migration.

Based on UNSE's acceptance of a full migration to three-part rates in its rebuttal testimony, Staff now recommends continuing net metering without change in this case.

The primary reason Staff wants the record to remain open in this case is to be able to address any significant discrepancies between estimated and actual kW demands.

Staff further develops the concept of a ceiling on kW demand with aspirations for an eventual phase-out and post-case compliance filings.

As a component of its rate migration education program, UNSE should be required to provide customers with materials that list the major electrical appliances and end-uses over an estimated range of kW demands based on a review of appliance usage and saturation data relevant to UNSE's service territory.

Staff accepts UNSE's recommendation to transition all residential and small general service customers to three-part time-of use rates during one month, but Staff does not want UNSE to be required to do that.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas M. Broderick. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as Director of the Utilities Division ("Staff"). I submitted direct rate design related testimony on December 9, 2015, in this docket.

Q. What is the subject matter of your surrebuttal testimony?

A. The topics are listed in my Table of Contents. My surrebuttal testimony continues the discussion regarding Staff's proposed full transition from two-part to three-part rates for UNS Electric, Inc.'s ("UNSE") residential and small general service customers. UNSE has embraced Staff's long-term concept for such a rate migration. Staff encourages UNSE to continue to specify the transition details for its unique circumstances. Staff intends to be active throughout the entire implementation process to ensure a successful transition.

As UNSE has indicated, the transition from two-part to three-part rates is class revenue neutral for residential and small general service customers. Therefore, many of the Company's customers will save on their electric bills after the transition is completed without doing anything differently. For other customers, Staff (and UNSE for that matter) are working hard to listen, understand, and address specific identified and reasonable concerns.

Thus far, mitigation measures proposed or accepted by Staff and/or UNSE to assist residential and small general service customers include: 1) Gradualism in class allocations of increased costs to serve; 2) Gradualism in class allocations of demand costs which reduce the kW demand charge in this case; 3) A ceiling on kW demand incorporated into tariffs at a 15 percent load factor; 4) A thorough, widely available and thoughtful customer education program; 5) A carefully designed rate migration implementation process; 6) A case left open for 18 months; 7) A kW demand measurement period not shorter than one hour and measured only during on-peak periods; 8) Various useful post-case compliance requirements; and 9) Disclosure of intentions and general aspirations of how rate design may evolve in the future under three-part time-of-use rates.

Staff proposes two additional mitigation measures for residential and small general service in my surrebuttal testimony: A bill credit to customers who adopted DG solar on or before June 1, 2015, and a temporary 15 percent incentive for new DG solar adopters during the six month period following full rate migration.

STAFF'S PROPOSED MITIGATION MEASURE FOR EXISTING DG CUSTOMERS

Q. Please summarize Staff's rate design proposal, as set forth in Staff's direct testimony.

A. In its rate design testimony, Staff proposed a mandatory transition from two-part to three-part rates for all UNSE residential and small general service customers, unless a particular category of customers could somehow establish that it is "vulnerable" in some manner to the three-part rate. Staff's initial conclusion was that DG customers were unlikely to be vulnerable.

Q. Is Staff revising its position stated on December 9, 2015, regarding "grandfathering" of existing DG solar customers' tariffs?

A. No. Staff maintains that demand charges are a reasonable way to allocate costs for recovery. My earlier testimony stated "...all existing DG customers should participate in the migration to a three-part tariff under Staff's proposal like everyone else." (Broderick Direct, Page 10, Lines 6-7). Although Staff continues to support this statement, based on subsequent input from parties, further independent review, discussion, and reflection, Staff now augments its original position in order to mitigate a portion of the estimated impact of the transition from two-part to three-part rates for existing DG customers.

Q. What input has Staff received from other parties in this case about Staff's original proposal, particularly as to how it could affect existing DG customers?

A. Some parties believe that demand charges will unfairly impact existing DG customers. In particular, it has been suggested that "net-zero" customers will receive a significant bill increase as a result of the transition to three-part rates. A net-zero customer is one who is able to offset all kWh charges through the output of his solar panels. As a result, a net-zero customer pays the monthly customer charge, but avoids all kWh charges. As these customers transition to three-part rates, they would see a new demand charge (that cannot be offset by kWh production) in addition to the higher monthly customer charge. Because these customers are currently avoiding kWh charges, the impact of the transition to three-part rates will be more significant for them than for other customers.

Q. Do these comments raise valid concerns?

A. These comments raise concerns about gradualism. While I do not know the exact number of existing DG customers who would face significant impacts, UNSE stated in discovery that approximately 57 percent of existing DG solar customers are net-zero customers. In sum, according to UNSE, the majority of its existing residential DG customers are likely to be net-zero customers, and the balance of the Company's remaining DG customers are close to net-zero.

Q. Has Staff attempted to develop a quantitative approach for helping evaluate this issue?

A. Yes. In surrebuttal testimony filed contemporaneously herewith, Staff witness Yue Liu has evaluated the relevant financial, technical, and usage parameters associated with the adoption of DG by residential customers.

Q. **Please discuss the context of the surrebuttal testimony of Staff witness Liu.**

A. Staff is, as always, tasked with finding and recommending a balanced solution. For the most part, the utilities have been predicting severe consequences from the failure to immediately address technology-related cost shifts. Yet, technology vendors have been predicting that customers will no longer select solar if there is any change in the status quo for rate design and net metering. This large gap in positions, in Staff's opinion, has not yet been filled with evidence relating to customer response to changes in rate design.

As a result, Mr. Liu was tasked with reviewing discovery responses provided by several parties in order to develop financial, usage, and operational spreadsheet models that can be used to analyze the decision to purchase DG solar from the customer's perspective. In order to provide the complete investment picture, the customer's perspective includes not only savings on electric bills and compensation for electricity export, but also the cost of purchasing or leasing DG solar.

Mr. Liu was also tasked with evaluating, on behalf of Staff, the various inputs, assumptions, and calculations received from the parties and modifying those inputs as appropriate. Given that Staff has already proposed a long-term plan for reducing/eliminating cost shifts (i.e., three-part rates), the primary purpose of his effort is to assess the impact of various rate design proposals on the customer's pay-back period and internal rate of return. A longer pay-back and a lower rate of return discourage adoption of solar; a shorter pay-back and higher rate of return encourage it.

Q. What were the results of this analysis relating to migration of existing DG solar customers from a two-part to a three-part rate design?

A. His testimony indicates lower (but still positive) rates of return on DG solar after migration to UNSE's revised proposed three-part TOU Demand tariff. However, he estimates that average DG residential customers will experience an increase of $10.06 under three-part as compared to two-part or an additional 20.28 percent, excluding any increase in the monthly basic minimum charge. For large DG residential customers, the increase is $20.44 and 31.82 percent. These increases are in addition to the revenue requirement increase assigned to the residential class.

Q. In light of the higher monthly bills and lower rates of return on DG solar that are likely to result from a migration to a three-part tariff, should the Commission consider additional mitigation measures for existing DG solar customers?

A. Yes. Additional mitigation measures for these customers would be consistent with principles of gradualism. Because the effects of the transition to three-part rates are likely to be greater for existing DG customers than for other customers, some further mitigation is appropriate. Furthermore, Staff recognizes that many early adopters of solar took a risk in their decision to install solar systems. Over the years, solar system purchase prices have decreased substantially, but many of the early adopters paid substantial amounts to install their systems.

Q. What specific mitigation measures does Staff now recommend?

A. Staff recommends that the Commission require UNSE to offer a 15 percent bill credit to customers who adopted DG on or before June 1, 2015. The dollars needed to offset the bill credit should be collected through a surcharge that is assessed to all of UNSE's customers. Staff requests UNSE to calculate and propose the details for this new surcharge. UNSE's proposed rate design would need to migrate existing DG solar customers from two-part to three-part rates and also apply a 15 percent discount. Based on Staff's estimates, that result would be less costly to non-DG solar customers than the Company's original proposal to grandfather.

Q. What is the basis for a 15 percent bill credit?

A. As previously discussed, the bill impacts related to rate migration for existing DG customers will likely fall within a range of approximately 20 to 30 percent. A 15 percent bill credit represents mitigation of a significant portion of the estimated impact. By way of comparison, the UNSE CARES discount supported by Staff and UNSE is 18 percent with a $16/month cap. Staff believes that partial rather than full mitigation is the more appropriate goal.

Q. Why has Staff recommended June 1, 2015 as a cutoff date for eligibility for the bill credit?

A. Staff concludes that the cut-off date of June 1, 2015, or any other date through the date of a decision in this case, is reasonable and acceptable to Staff for determining customer eligibility for its proposed mitigation. It is much less likely that applicants processed after June 1, 2015 will be comparably financially harmed, as DG solar costs per kW have been declining.

Q. How long should this mitigation measure remain in place?

A. The need for continuing the 15 percent bill credit should be evaluated again in the Company's next rate case. Staff recognizes that some parties believe that various mitigation measures should be "grandfathered." For example, UNSE has suggested a twenty-year horizon, with an end date of May 31, 2035. Staff prefers instead to revisit these issues in UNSE's future rate cases.

Q. Why has Staff recommended a surcharge to recover the costs of the bill credit?

A. A surcharge provides simplicity and transparency.

Q. Are Staff's proposed mitigation measures independent of its rate design recommendations?

A. No. This augmented Staff position assumes (and is dependent upon) the Commission ultimately approving Staff's proposed migration to three-part tariffs. The rate design proposals recommended by the other parties to this case may not create any special need for mitigation, or may require different types of mitigation.

Q. Should future DG customers be eligible for mitigation-type discounts in future rate cases?

A. The need for continuing and expanding the bill credit will likely be evaluated again in the Company's next rate case. However, Staff wants to make it clear that it is likely to be opposed to extending special mitigation discounts to any *future* DG customers.[1] Future DG customers should be on notice that Staff is unlikely to support mitigation measures for the effects of future rate changes or other terms-of-service changes.

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[1] A future customer is any application submitted on or after June 1, 2015, under Staff's proposal or by another eligibility cut-off date established by the Commission in its decision. A future customer should include previously eligible customers that install a replacement solar system after May 31, 2015.

Q. Does Staff have any other considerations regarding future UNSE rate cases?

A. Yes. To-date, Staff has evaluated the need for mitigation measures largely in reliance upon statements from the solar industry and upon the Staff analyses conducted by Mr. Liu. In UNSE's next rate case, the degree to which actual, existing DG customers provide public comment or otherwise participate in the case is likely to be relevant to whether Staff will continue to support continuing the bill credit for existing DG customers. Additionally, Staff may ask the solar industry to consider sharing a portion of the burden of continuing mitigation for existing DG customers.

STAFF'S RECOMMENDATION ON NET METERING AND VALUE OF SOLAR

Q. UNSE accepted Staff's proposal for a full migration to three-part rates for residential and small general service customers. Does Staff now have an associated recommendation on net metering as an appropriate reflection of the net value of DG solar?

A. Yes. In my December 9, 2015 direct testimony, I stated "for the time being, Staff does not propose any changes to existing net metering, but it may update its position in its surrebuttal testimony or later at the hearing in this case." (Broderick Direct, Page 11, Lines 10-12). Further, I made reference to the Commission's on-going generic Value and Cost of Solar docket (No. 14-0023). Some parties interpreted these statements as implying that Staff would not make a recommendation in this case regarding net metering and the net value of solar until a decision had been reached in *that* case. However, based on UNSE's acceptance of a full migration to three-part rates in its rebuttal testimony, Staff now recommends continuing net metering without change in this case.

Staff believes that UNSE either supported or hinted at its likely support for continuing net metering without change in its rebuttal testimony.[2] Staff understands that UNSE may be unwilling to continue net metering if specific parameters of a three-part rate design later become unacceptable. However, it would be helpful if UNSE would confirm Staff's understanding of its acceptance of continuing net metering unchanged (at least until its next rate case) in rejoinder or at hearing.

Q. How do the energy kWh rates proposed by UNSE in its rebuttal testimony for a three-part residential time-of-use rate compare to its earlier proposal to compensate exports at a 5.84 cents per kWh renewable energy credit?

A. Energy kWh rates are significant because they form the basis for compensation for exports under net metering. The rates proposed by UNSE in its rebuttal testimony are higher for all periods except Winter Off-Peak. UNSE proposed the following energy charges in its residential three-part time-of-use rate proposal:[3]

Energy Charge (kWh's), Applicable on all kWh's	1.6760 cents/kWh
Base Power Supply Charge, Summer On-Peak all kWh's	10.2251 cents/kWh
Base Power Supply Charge, Summer Off-Peak all kWh's	4.2830 cents/kWh
Base Power Supply Charge, Winter On-Peak all kWh's	8.2000 cents/kWh
Base Power Supply Charge, Winter Off-Peak all kWh's	3.8610 cents/kWh

The Summer On-Peak (1.6760 plus 10.2251 cents/kWh), Summer Off-Peak (1.6760+4.2830 cents/kWh) and Winter On-Peak (1.6760 plus 8.2000 cents/kWh) rates are each higher than 5.84 cents per kilowatt-hour. Only the Winter Off-Peak proposed rate (1.6760 plus 3.8610 cents/kWh) is lower than the original UNSE proposed renewable energy credit of 5.84 cents

[2] Tilghman Rebuttal, Page 3, Lines 17-18.
[3] Jones, Rebuttal Exhibit CAJ-R-4, page 4 of 7.

per kilowatt-hour. These proposed rates are, of course, subject to further revision as this case progresses.

Staff believes that compensation to DG solar customers will be higher per kWh under UNSE's revised proposal versus its original rate design proposal. It is noteworthy that the existing banking provision of net metering allows kWhs, which are often generated in winter, to carry over into summer at the respective On- and Off-Peak summer rates.

Again, Staff's recommendation for net metering assumes (and is dependent upon) acceptance of the proposed full migration from two-part to three-part rates. Staff is comfortable continuing net metering for UNSE with that assumption without concluding on-going Docket No. E-00000J-14-0023.

STAFF'S RECOMMENDATION ON LOST FIXED COST RECOVERY ("LFCR")

Q. Is Staff suggesting that UNSE should be required in this case to accept the elimination of the DG component of the LFCR by the conclusion of UNSE's next rate case?

A. No. UNSE witness Mr. Jones expressed a concern that Staff was making this a requirement in the instant docket.[4] To clarify, Staff has identified, as an appropriate aspirational goal, that the DG component of the LFCR would be eliminated in a subsequent UNSE rate case. This elimination would occur only upon a successful migration to three-part rates and a continuing evolution of rate designs, as appropriate, based on then existent facts. Both Staff and UNSE agree on the principle of gradualism in rate design, and both acknowledge that the proposed kW demand charge does not fully address UNSE's fixed cost recovery.

[4] Jones Rebuttal, Page 4, Lines 25-27.

To avoid any misunderstanding in post-case compliance, Staff recommends that UNSE submit a specific updated LFCR plan of administration ("POA") not later than the time of hearing. The updated POA would apply through the conclusion of UNSE's next rate case and include the proposed impact on the LFCR given UNSE's proposal regarding the percentage of functionalized (i.e., G, T, D) fixed costs recovered in the kW demand charge, the monthly minimum charge, and the energy charges.

As a result, Staff concludes that the parties do not need to fully address in this docket the issue of further recovery of fixed distribution and generation costs as rate designs become more cost-based in subsequent cases.

STAFF'S RECOMMENDATION TO HOLD OPEN THE RATE CASE TO ADDRESS POTENTIAL UNINTENDED CONSEQUENCES

Q. Why does Staff recommend that the Commission hold open the rate case?

A. Staff wants to be able to address any discrepancies between estimated and actual kW demands. As UNSE witness Mr. Jones indicates, UNSE is relying upon estimates of kW demand from its load research data.[5] Should its kW estimates used in designing rates ultimately prove too low, then the kW charge should be decreased. Should kW estimates ultimately prove too high, then the kW charge should be increased. The concern is not over a minor discrepancy; however, a significant difference could create serious unintended consequences that should be timely addressed. The purpose of holding the case open for 18 months is to allow for the passage of enough time to fairly and accurately determine if significant discrepancies exist.

Although not the primary focus, other unanticipated consequences, if any, could also be addressed.

[5] Jones Rebuttal, Page 6, Lines 19-21.

STAFF'S PROPOSED KW DEMAND CEILING

Q. Does a ceiling on kW demand protect customers from unexpectedly high bills?

A. Yes. From a review of the testimony in this case, Staff concluded that no new vulnerable *groups* are created per se as a result of a full migration to three-part rates; instead, there is a broad based concern that individual customers will experience unexpectedly high kW demands, at least for a period until customers become accustomed to three-part rates. Some parties believe that it will be challenging not only to educate customers about the reasons for unexpectedly high kW, but also to teach them how to avoid such surprises. Some parties highlighted various lifestyle situations and events for which it may be difficult to manage kW demand.

As a mitigation measure, Staff and UNSE have discussed the concept of placing a ceiling on kW demand for each customer through the use of a minimum load factor. UNSE later responded with a detailed specific proposal for a minimum load factor of 15 percent for each customer. This proposal was fully developed by UNSE witness Mr. Jones.[6]

Simply put, with this ceiling on kW demand, no customer can experience a significant kW billing surprise. All residential and small general service customers, including DG solar customers, would be eligible for the ceiling on kW demand. For DG solar customers, their calculation would be based on their "site" energy consumption.[7] For DG solar customers, site load equals kWh self-consumption plus kWh purchases from UNSE, which therefore excludes kWh produced and exported to the grid.

Staff recommends that UNSE include the specifics of the proposed ceiling on kW demand in its revised proposed tariffs in rejoinder or at hearing.

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[6] Jones Rebuttal, Page 13, Line 8 to Page 15, Line 23.
[7] Jones Rebuttal, Page 14, Line 5.

Q. Should the kW ceiling be phased-out in time?

A. Yes. UNSE has expressed a preference for phasing out a ceiling on kW demand in the decision in its next rate case.[8] Staff agrees with UNSE that a ceiling on kW demand is a transitional mechanism that should ultimately be phased-out. However, Staff is presently unable to support its elimination in UNSE's next rate case. Staff would expect, at a minimum, that the ceiling on kW demand would be increased, perhaps based on a 10 percent or 5 percent load factor. The kW ceiling would increase as the load factor decreases. To facilitate this decision in the next UNSE rate case, Staff recommends that the Commission require UNSE to report at least annually the following compliance items, beginning one year after the effective date of the decision in this case:

1) The annual and monthly total number of customer bills exceeding the kW ceiling on demand by residential and small general service customer classes;
2) The annual and monthly total amount of unbilled kW demand and associated revenue savings by residential and small general service customer classes; and
3) The same statistics as 1) and 2), provided separately for CARES customers and DG solar customers.

STAFF'S RECOMMENDATION ON MITIGATION FOR FUTURE DG SOLAR

Q. Is Staff concerned about the potential for a temporary reduction in DG solar installations in the period immediately following customer migration to a three-part rate?

A. Yes. In the months after the transition from two-part to three-part rates, residential and small general service customers may not have adequate (i.e., 12 months) kW billing history upon which to base a sound DG solar decision. Additionally, there may be a brief period of customer

[8] Jones Rebuttal, Page 15, Lines 21-23.

confusion or hesitation in the aftermath of rate migration. For that reason, Staff recommends that UNSE establish a 15 percent cost per kW incentive for DG solar installations, effective for the first six months following the completion of the full transition from two-part to three-part rates in early 2017. Please refer to Mr. Liu's testimony for the basis of a 15 percent incentive.

Staff requests that UNSE identify at hearing a method to fund this incentive using REST funds either from a 2015 or 2016 carryover or in the 2017 program.

STAFF'S RECOMMENDATION ON CUSTOMER EDUCATION

Q. Is it important that customers have information on the estimated range of kW demand for individual appliances and other electrical end uses prior to the transition to three-part rates?

A. Yes. UNSE should be required to provide customers with materials that list the major electrical appliances and end-uses over an estimated range of kW demands based on a review of appliance usage and saturation data relevant to UNSE's service territory. It would also be helpful for UNSE to differentiate significant kW demands for select end-uses by on and off-peak time-of-use, if available. Air conditioning kW demand comes to mind as its use is typically more intensive on-peak than off-peak, but there may be other end-uses that vary with intensity by time-of-use.

Armed with this information, a customer can scan the list, become familiar with common electrical end-uses, and get an early indication of what causes kW demand usage and how to control it. As time passes and electric bills based on three-part rates are being experienced, customers can continue to refer to this list and begin to further refine kW demand experience.

Given some of the general concerns expressed by some parties, Staff wants customers to know how to successfully control kW demand in order to impact their bills. Staff wants customers to understand that significant kW demand appliances include such end-uses as air conditioners and electric clothes dryers. Likewise, Staff wants customers to understand that charging cell phones and using LED large screen TVs are low kW demands and are either not a concern or a relatively minor concern. Staff wants customers to be able to avoid needlessly trimming their lifestyles through limiting their low kW demand end-uses, which are unlikely to significantly impact bills.

Staff recommends that UNSE estimate a kW demand range for each identified end-use over a range of efficiency in its territory from less efficient models to new and highly efficient models.

Such materials should remind customers to confirm which appliances, if any, are supplied by natural gas and are thus nearly irrelevant to electrical kW demand, except for internal lighting or incidental electrical use.

Materials should also attempt to provide information on whole house kW demand ranges, perhaps based on home vintage as some older properties have less insulation. By contrast, new construction will likely already have a high energy efficiency designation.

Staff recommends that these materials be provided in various forms and/or media (e.g., internet) and at regular, appropriate time intervals to customers.

Staff recommends that UNSE provide, as a compliance item in the Commission's decision in this case, the above discussed materials and process descriptions 60 days prior to commencing the transition to three-part rates.

Staff also recommends that UNSE review its existing Energy Efficiency ("EE") programs and related educational materials, and revise them as appropriate at its earliest opportunity to support customer understanding of kW demand. Demand reducing programs should be considered in its next annual submittal.

STAFF'S RECOMMENDATION ON RATE MIGRATION TIMING

Q. Does Staff accept UNSE's recommendation to transition all residential and small general service customers to three-part time-of use rates during one month, billing cycle by billing cycle?

A. Yes, subject to UNSE's fulfilling the various obligations and responsibilities that Staff and other parties are discussing and that are ultimately incorporated by this Commission in its decision in this case.

UNSE should not be required to complete the transition in one billing month; rather, it should be permitted to do so. UNSE should be required to complete the transition within the 18 month period during which the case will remain open.

Q. Does this conclude your Surrebuttal testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC CORPORATION
DOCKET NO. E-04204A-15-0142

Mr. Solganick's surrebuttal testimony reviews the Company's revenue allocation proposal, compares it to Staff's recommendation and discusses the relationship between Staff's recommendation and the protections envisioned during the transition to three-part TOU rates recommended by the Staff.

The testimony also discusses Staff's recommended rate design and the relationship to the protections envisioned during the transition to three-part TOU rates recommended by the Staff.

The testimony also discusses CARES, Buy-Through and the LFCR proposal by the Company and Staff's arguments against that proposal.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, Pennsylvania 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously provided direct testimony relating to the engineering analysis of the UNS Electric, Inc.'s ("UNSE" or "Company") rate base items, service reliability, and planning process on November 6, 2015, and cost of service, revenue allocation, rate design, and the Lost Fixed Cost Recovery mechanism ("LFCR") on December 9, 2015. My initial testimony in this case includes a summary of my background, qualifications, and experience.

Q. What is the purpose of your surrebuttal testimony?

A. My testimony provides a portion of Staff's response to rebuttal testimony filed by the Company along with direct testimony filed by some of the interveners.

SURREBUTTAL TESTIMONY

Q. Please summarize Staff's positions.

A. Staff recommended that rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU"). When changes are made, gradualism should be recognized. This long-term rate design plan was placed into the context of evolving metering and customer information capabilities.

Staff recommended a revenue allocation among the customer classes based on moving all classes to cost of service but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of its portion of the new Gila River Unit #3.

Staff recommended, consistent with the long-term rate design plan, the mandatory transition of residential and small general service rates to Three Part-TOU rates.

Staff highlighted that, due to the changes proposed, the Commission should keep the rate design portion of the rate case open to resolve significant unanticipated customer rate impacts.

Staff recommended that the level of the CARES discount not be reduced and that a CARES provision for the new Three Part-TOU rate should be developed.

Staff did not propose changes to the existing net metering tariff or waivers of the net metering rules in its December 9th testimony.

Q. What was Staff's revenue allocation proposal?

A. Staff recommended a revenue allocation that moved all classes gradually toward parity of return over this and the next rate case. Staff also recognized that the purchase of a combined cycle generating unit provides benefits to all customers during many hours of the year and, thus, it would be inappropriate to reduce rates for any customer class.

In the Company's filing it proposed a change in cost allocation methodology from Peaks and Average to Average and Excess.[1] The Company's proposed change reduced the class rate of return for the Residential, Small General Service and Lighting classes and raised the class rate of return for the Medium/Large General Service and Large Power Service classes.[2]

Staff's revenue allocation proposal is detailed in Exhibit HS-4 (previously submitted) and suggested that the Residential class receive 58.3 percent of the total increase ($10.5 million). This revenue increase of 14.3 percent for the Residential class and 11.16 percent for the Small

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[1] Jones Direct 25:3
[2] Jones Direct 25:11

General Service class contrasts with a proposed 10.1 percent increase for all other classes.[3] The effect of Staff's recommended revenue allocation was intended to move to cost-based rates in this and the next rate case while providing protection during the transition to Three-Part TOU rates. Staff's recommended revenue allocation also acts to buffer the Residential, Small General Service and Lighting classes from the full effects of the Company's proposed change in cost allocation methodology.

Q. What revenue allocation does the Company propose in its rebuttal testimony?

A. While the Company states "… the Company is willing to adjust the allocation of revenue between the rate classes using Staff's suggestion as a guide,"[4] the Company's proposed increase for the Residential class is $15.9 million or 86 percent of the proposed $18.4 million increase.[5]

Q. What is the impact of the Company's new revenue allocation proposal?

A. The Company's new revenue allocation proposal is only a small decrease from its original proposal to assign over 91 percent of the increase to residential customers, almost 12 percent to small general service customers and decrease rates for large power customers and have rates even for medium and large service customers.[6] While the Company characterized its rebuttal revenue allocation as using Staff's suggestion as a guide, the Company has failed to remember that its change in cost allocation methodology, the purchase of Gila River Power Plant Unit #3 and other actions should be recognized and the affected classes see the temporary protection of gradualism.

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[3] Exhibit HS-4 line 29
[4] Jones Rebuttal 2:26
[5] Exhibit CAJ-R-1
[6] Exhibit HS-4 lines 50, 54

Even under the Company's latest revenue allocation proposal it still will take two cases (the present and the next one) to move to cost-based rates. Further, the Company's proposed revenue allocation has not recognized the disproportionate impacts between the present Class Cost of Service Study ("CCoSS") and the prior one.[7]

The impact of the Company's use of Staff's suggestion as a guide can be easily seen by comparing the original Schedule G-2 and the Company's revised Schedule G-2[8] for the Large Power Service class' Proposed Sales Revenue (line 20) which moved from $6.604 million (original filing) to $6.777 million, an increase of less than 3 percent, while the Residential class moved from $94.209 to $94.098, a decrease of less than 0.2 percent. Under either Company proposal, the difference is more pronounced when Base Revenues Present Rates[9] are $7.376 million for Large Power Service resulting in a significant decrease (8.1 percent) and $73.653 million for Residential resulting in a significant increase (27.7 percent). NOTE: The Large Power Service class was used for this comparison because it retains the same number of customers and kWh sales while the Medium/Large General Service class is subject to a rate redesign.

Q. Why is the magnitude of the Residential increase important outside of the issue of revenue allocation?

A. Staff has always been cognizant of the impact of a rate design change both on a class level and the individual customer impact. That is why Staff has worked with the Company to analyze the impact of Staff's proposed rate design across a range of usage and supports the proposed 15 percent load factor floor. However, the Company's additional Residential class revenue allocation is layered on top of the rate design change. While it may not have been

[7] Solganick Direct 19:19
[8] UDR 3.1
[9] UNS Schedule G-1, line 20

apparent to the Company, Staff's suggested revenue allocation is part of the protection that Staff recommends as part of its rate design.

Q. Please describe Staff's rate design recommendation?

A. Staff has recommended the mandatory transition of all Residential and Small General Service customers from the present two-part rates to Three-Part TOU rates which offer all customers more opportunities to react to clearer costs and control their bills. Staff conditioned its recommendation on the requirement that the Company would develop and implement a transition plan that offers Residential and Small General Service customers both information AND education BEFORE the transition takes place.

Q. Where will the customer information come from?

A. The Company expects to complete its conversion to advanced metering capable of supporting three-part rates by the end of 2016[10] and has committed to providing consumption information to customers before the transition.[11] Customers will have a view into how and when they use electricity before the transition begins.

Q. How will customers know how to react to Three-Part TOU rates and decide if they wish to change the amount of energy they use and when they use it?

A. The Company has committed to an education program to inform customers of the impacts and benefits of the new rate design before the transition begins.[12] While the parties are still defining what information and education will be provided, Staff notes that the Company is planning web portal capabilities that will allow customers to access historical energy and demand interval data in multiple formats with about a one-day lag.[13] Further, the Company

[10] Dukes Rebuttal 7:3
[11] Dukes Rebuttal 9:21
[12] Dukes Rebuttal 9:1
[13] UNS Response to RUCO 11.4

and Staff have discussed including information on the demands that various appliances and uses will place on the system and how they can impact a customer's bill.

Q. Will customers need to purchase demand control equipment or make expensive changes to avoid a higher bill under the new rate design?

A. No. Many customers, such as high load factor customers, will experience lower bills. For others, the focus of the Company's education program should be to assist customers to make usage and time-of-use decisions based on their own lifestyles. Simple actions such as not performing multiple electrical activities simultaneously (e.g., cooking, clothes drying and cooling) can be implemented by customers without any control equipment. Customers may decide to install a programmable thermostat (which should cost less than $75) for greater control.

Q. What protections has Staff sought to have in place before the transition takes place?

A. In part due to gradualism, Staff recommended that the demand charge established at the conclusion of the case be set at a partial cost level and apply only during the On-Peak time period to allow some load shifting. Also, Staff recommended that a mechanism be developed to determine if adverse effects are taking place and to keep the rate design portion of the case open to address any issues that may develop.

Besides these regulatory steps, Staff has requested a transition plan, which should be documented as a Plan of Action, well before the transition date. Staff expects that this Plan of Action will cover not only the items that the Company has suggested[14] but also milestones that may include meter data management testing, providing usage information to customers on pre-transition bills, the education and communications program, billing system stress

[14] Exhibit DJD-R-1

testing, customer information systems stress testing, customer service training and on-going monitoring for adverse effects and regular reporting to Staff, Residential Utility Consumer Office ("RUCO") and other interested parties.

Q. The Company has proposed that all Residential and Small General Service customers would transition to Three-Part TOU rates in February or March 2017.[15] How does this compare to Staff's phased transition?

A. This is a more rapid transition than Staff proposed; however, a quicker transition is acceptable if the Company is able to successfully manage the transition as described above. The Company's proposal allows for two or three additional months of communications and education before customers begin a transition, which is positive since all customers are to be migrated at that time. Transitioning all customers during a single month of billing cycles can result in stressing various systems such as customer service. This is why Staff recommends that stress testing be included in the transition planning.

Q. What protections has Staff sought to include within the Three-Part TOU rate design?

A. In Staff's testimony of December 9th, Staff highlighted that there could be inadvertent effects from the transition. Subsequent to that testimony Staff continued the discussion, including the concept of a load factor floor, which the Company explored in detail and included in its rebuttal testimony.[16] The detailed analysis informally provided to Staff by the Company demonstrates that this concept prevents significant adverse effects and should be included in the Three-Part TOU rate design at implementation.

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[15] Dukes Rebuttal 11:7
[16] Dukes Rebuttal 7:22 and Jones Rebuttal 14:1

Q. Do you foresee any customer subgroups that should not be subject to mandatory transition?

A. Not beyond Staff witness Mr. Broderick's surrebuttal discussion concerning the provision of bill credits. Assuming all of the elements of the pre-transition Plan of Action are properly executed, specifically the education and information requirements, all customers will be given the knowledge to control their usage, time of usage and overlap of usage.

Q. How does Staff's recommended Three-Part TOU rate accommodate lifestyle and other situations?

A. Staff recognized (as did other parties[17]) that a "pure or perfect" Three-Part TOU rate would have multiple demand charges to perfectly price distribution, transmission and generation demand. Staff also recognized that implementation of the "pure or perfect" rate would have significant impacts (as did other parties) while customers learned to deal with the new rate and potentially change their electric controls. To avoid being trapped by the perfect, Staff recommended applying a single demand charge only to the existing On-Peak period. This decision eliminates the impact of holidays, weekend entertaining, the use of short-term high demand loads such as electric oven cleaning and hobbies.

Q. The Arizona Community Action Association ("ACAA") has argued that CARES and other low-income customers have limited opportunities to control their usage to avoid adverse impacts from a Three-Part TOU rate and should be exempt.

A. Staff's recommendation for a Three-Part TOU rate design recognizes that it provides an additional dimension (demand) for customers to make changes to lower their bills. Certain electrical usage such as food refrigeration is a 24 hour usage that is fairly level, but space and

[17] Overcast Rebuttal 33:14

water heating can be shifted if desired or controlled. More efficient lighting can be offered to rental tenants.

Staff recognizes that there is a learning curve and that is why they have worked with the Company to develop the load factor floor to protect against high demand readings. Staff insists that the Company's education program provide tools to help all customers identify and manage demand without devices and computers.

Staff's suggested Residential demand rate of $4.78[18] per kW applies only during On-Peak periods to minimize the impact on all customers and create windows that may work for them. The Company's updated proposed rate design recommends a demand rate of $5.15 per kW.[19]

ACAA has proposed a shadow billing service to show low-income customers how much they would have been billed under two-part rates and then credit them for the difference between the two- and three-part rate design.[20] The shadow billing concept proposed by ACAA results in maintaining the two-part rate for those months when a customer benefits and may require a customer to learn, and react to, two rates rather than one in order to minimize their bills. A clear transition with education, communications and protections as discussed will minimize complexity for low income and all other customers and is preferable. Therefore, Staff recommends that the "shadow bill" be rejected.

Q. Are Staff's recommendations interrelated?

A. Yes. As explained above, Staff's recommendation for a mandatory transition to a Three-Part TOU rate design is interrelated with a number of items:

[18] $4.78 = 75 percent of ($5.65 and $ 0.73) UNSE Schedule G-6-1, lines 19 and 20 (Demand Distribution Primary and Secondary)
[19] Jones Rebuttal 13:5 and Exhibit CAJ-R-4, Schedule H-3 page 4
[20] Zwick Rebuttal 11:24

- Class revenue allocation that recognizes gradualism and the impacts of a new methodology and Gila River Unit #3
- Customer information and education
- An appropriate Basic Service Charge ("BSC")
- A demand charge that recognizes gradualism
- On-Peak demand only
- On-Peak periods as in effect now
- Significant protections against adverse effects
- Keeping the rate design portion of the case open

Q. Has the Company accepted Staff's interrelated items?

A. For the most part, the Company has accepted Staff's recommendations. The Company has not accepted Staff's revenue allocation as discussed above. The Company supports and has proposed further details relating to Staff's suggestions on information and education.[21] The Company has accepted Staff's proposed $15 BSC if the Commission adopts an acceptable three-part rate structure for all Residential and Small General Service customers.[22] While the Company has proposed a different basis for the On-Peak[23] demand charge, their $5.15/kW value is similar to Staff's $4.78/kW proposal. Working with Staff, the Company developed the 15 percent load factor floor to protect customers against adverse effects.[24] The Company also supports keeping the rate design portion of the case open to address issues that may develop.[25]

[21] Dukes Rebuttal 9:14
[22] Dukes Rebuttal 7:10 and Hutchens Rebuttal 8:5
[23] Dukes Rebuttal 8:19
[24] Dukes Rebuttal 7:22 and Hutchens Rebuttal 8:25
[25] Dukes Rebuttal 10:18

Q. Why are these interrelationships important to Staff?

A. Subsequent to the submission on December 9th, Staff has worked with the Company to explore the detailed interrelationships to minimize the impact on customers. If any party seeks to reject Staff's Three-Part TOU rate design and the other interrelated items, then Staff may have to reconsider or shift some or all of its positions.

Q. Are there other interrelations in Staff's recommendation of a mandatory transition to Three-Part TOU rate design?

A. Yes. Staff considered other solutions to the problem caused by shifting fixed costs from vacant, seasonal and distributed generation ("DG") customers. While other solutions would require carving out subclasses and applying measurements to define inclusion or exclusion, Staff's long-term rate design proposal sets the foundation to deal with these concerns without arguing over whether one or more subclasses exist and which customers should be selected for different rates. As recommended by Staff, the Three-Part TOU rate does not cure every problem at the onset but provides the foundation for now and the future.

Q. Do the interrelationships apply to distributed generation?

A. Yes. The use of a Three-Part TOU rate will ensure that DG customers contribute to the recovery of the fixed costs of infrastructure that they continue to use even after their decision to connect to the Company's system, their use of the system as "storage" for their excess banked energy, their use of the system to provide frequency for their inverters and the use of the system to sell excess energy.

The addition of a demand charge and its resulting revenue stream reduces the required energy charge within any rate structure (for the same revenue requirement). If the Commission decides to retain net metering and/or banking of energy as Staff continues to recommend, the use of the Three-Part TOU rate has an impact on the compensation under net metering due to a reduced energy charge. Any decision to not implement Three-Part TOU rates must then reconsider whether net metering is overcompensating DG customers.

CARES

Q. Does Staff support the Company's proposal for CARES?

A. The Company is proposing to change the CARES program to be based upon the new Three-Part TOU rate and provide an 18 percent discount with a flat $16 discount applied for bills above 1,000 kWh.[26] CARES-Medical customers would receive a 24 percent discount with a flat $16 discount applied for bills above 2,000 kWh.[27]

The Company agrees with Staff that the total value of the CARES discount must be preserved.[28] Subject to a review of the impact as the final rates are finalized, Staff supports the Company's revised proposal.

BUY-THROUGH

Q. Several parties have proposed changes to the "Buy-Through" proposal submitted by the Company, does Staff support those changes?

A. Staff reiterates its position that the Buy-Through proposal should not impact any other customers. Care must be taken to ensure that if a customer is permitted to seek savings on its own and then later decides to return (for example when the power market tightens) all other customers must be protected from this return as well, which could have adverse effects on other regulated customers, and could be magnified if the volume cap of 10 MW is increased. Therefore, if the Buy-Through is approved on a permanent basis, then Staff recommends the

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[26] Jones Rebuttal 39:12
[27] Jones Rebuttal 39:15
[28] Jones Rebuttal 21:14

Company propose a market price for any customers that return. However, if the proposal is approved on a temporary basis until the next rate case, the Company may be amenable to addressing this issue in its next case.

LOST FIXED COST RECOVERY

Q. Why is only 50 percent of the non-generation related portion of the demand charge included in the LFCR?

A. The 50 percent mechanism, as approved by the Commission, recognizes that while some energy efficiency measures will reduce the energy consumption, they do not always reduce the demand component proportionally. For example, if a customer installs a setback thermostat for electrical space heating, during the setback period energy consumption will be reduced. Since thermostats are on-off devices, when the thermostat calls for heat at the end of the setback period the full load of the heating system will occur and therefore the demand measurement will not decrease in proportion to the energy decrease. That is why the 50 percent demand provision was proposed. It would be inappropriate to compensate for the entire demand amount when it is unlikely that all of the demand will disappear.

Q. The Company argues that fixed generation costs should be included in the LFCR.[29] Why are generation costs not included?

A. The Company's generation can be sold to all of its customers and neighboring utilities because it is connected through the transmission system as opposed to distribution facilities that cannot serve customers on a different feeder or substation.

The Company states that it must realize the approved level of billing determinants in future years to fully recover its fixed costs.[30] The Company also states that sales have decreased 8

[29] Jones Rebuttal 23:22
[30] Jones Rebuttal 24:12

percent between this test year and the last test year and categorizes "...this reduction is more than DG and EE related reductions..."[31].

For periods after the Test Year, the Company's Integrated Resource Plan shows a trend of increasing total numbers of customers[32] and the reference case shows increasing retail energy sales[33] and increasing peak demand.[34]

The LFCR is not designed to compensate for non-specific sales losses or business climate changes as it is not a full revenue decoupling mechanism, nor was the adoption of the LFCR accompanied by a reduction in the rate of return to reflect the shift of sales risk to customers. Adding generation to the LFCR due to the declining sales circumstances (in the recent past) noted by the Company would unacceptably shift risk to customers.

Q. The Company has expressed concern that "as long as solar production reduces overall retail volumes sold, the recovery of fixed costs is avoided."[35] Does this imply a difference in perspective between the Company and Staff?

A. Staff views anything that occurs behind the meter as the customer's private matter and an opportunity to control electricity usage. Therefore, a reduction in sales due to the addition of insulation, installation of higher efficiency HVAC equipment, and/or conservation due to customer lifestyle changes will affect the customer's energy consumption in a manner similar to a customer installing solar DG (absent the impact of excess production). Since the LFCR is reset after the end of a rate case, any lost sales due to installed solar DG or EE have already been accounted for in the Test Year billing determinants. From this perspective, Staff

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[31] Jones rebuttal 24:22
[32] UNSE 2014 Integrated Resource Plan Chart 6 (page 39)
[33] UNSE 2014 Integrated Resource Plan Chart 8 (page 42)
[34] UNSE 2014 Integrated Resource Plan Chart 10 (page 44)
[35] Jones Rebuttal 28:17

envisions that the DG portion of the LFCR can be eliminated once Three-Part TOU rates are in place and charges fully reflect cost as anticipated upon conclusion of the next rate case.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

YUE LIU

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

My Surrebuttal Testimony will address the estimated financial net savings or net costs in purchasing or leasing a rooftop solar system from a typical UNS Electric, Inc. ("UNSE" or "Company") residential customer's perspective. I provide a comparison of the net savings and net costs for a customer considering solar based on four different rate designs, namely, the Company's current effective Residential Service rate schedule ("Existing RES-01"), the Company's proposed Residential Service Demand rate schedule in its Application ("Company Original Proposed RES-01 Demand"), the Company's proposed Residential Service Demand Time-of-Use rate schedule in its Application ("Company Original Proposed RES-01 TOU Demand"), and the revised Residential Service Demand Time-of-Use rate schedule in the Company's Rebuttal Testimony ("Company Rebuttal RES-01 TOU Demand").

By modeling the bill savings under four different rate designs, Staff intends to demonstrate that with the Company Rebuttal RES-01 TOU Demand customers can achieve a reasonable Internal Rate of Return ("IRR") when purchasing a rooftop solar system, which makes it a financially feasible investment. With an annual future utility rate escalation of 2.5 percent, the IRRs can reach 8.10 percent and 7.64 percent, respectively, for an Average Customer and a Large Customer. This level of IRR is higher than the annual return on a 10-year Treasury Bond ("10-year T-Bond"), which is generally accepted as the discount rate for long-term investment. The IRRs are slightly higher than the recent 10-year (2006-2015) average annual return on the Standard & Poor's 500 ("S&P 500"). In addition, the IRRs are higher than mortgage rates for all three electric escalation scenarios shown in this testimony. My preliminary analysis shows that purchasing a rooftop solar system would still be an economically viable choice with the adoption of the Company Rebuttal RES-01 TOU Demand rate schedule. Nevertheless, the pace of rooftop solar installations would be expected to be reduced, at least temporarily, if Company Rebuttal RES-01 TOU Demand is adopted, all else being constant.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Yue Liu. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background and professional experience.

A. In 2013, I graduated with high distinction from the University of Minnesota, receiving a Bachelor of Arts degree in economics, mathematics and statistics. In 2014, after working as an investment-banking analyst for one year, I enrolled in the graduate program in statistics at the University of California Berkeley and received a Master of Arts degree in 2015. Before joining the Commission in December 2015, I worked on several research projects of various disciplines as a statistical consultant, offering clients advisory services on experimental designs, sampling methodologies, data analytics and statistical inferences.

Q. Briefly describe your responsibilities as a Public Utilities Analyst III.

A. In my capacity as a Public Utilities Analyst III, I have been assigned to analyze and provide recommendations to the Commission on assigned cases. This is my first proceeding as a Public Utilities Analyst with the Commission.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. What is the scope of your testimony in this case?

A. I provide estimates of financial net savings and net costs in purchasing or leasing a rooftop solar system from the perspective of a typical UNS Electric, Inc. ("UNSE" or "Company") residential customer using a bill and solar cost estimation model I sponsor herein. Among other things, I provide a comparison of the net savings and net costs for a customer considering solar based on four different rate designs, namely, the Company's current effective Residential Service rate schedule ("Existing RES-01"), the Company's proposed Residential Service Demand rate schedule in its Application ("Company Original Proposed RES-01 Demand"), the Company's proposed Residential Service Demand Time-of-Use rate schedule in its Application ("Company Original Proposed RES-01 TOU Demand"), and the revised Residential Service Demand Time-of-Use rate schedule in the Company's Rebuttal Testimony[1] ("Company Rebuttal RES-01 TOU Demand"). I also performed a sensitivity analysis to examine the impacts of potential new solar incentives on the cost effectiveness of Distributed Generation ("DG") solar for residential customers.

Q. Have you reviewed direct and rebuttal testimony submitted by the various parties in this case as it relates to the subject matter of your Surrebuttal Testimony?

A. Yes. My reviews included testimony from DG solar industry representatives and associations which intervened in this case.

The DG solar industry interveners are opposed to demand kW rates due, in part, to concern for the future viability of their DG solar business model(s) which appear to now be at a crossroads as electric utilities such as UNSE propose significant rate design changes to address their various concerns. However, the DG solar industry has not introduced into this case any of its business models, yet it is well-known that residential customers are provided with a detailed electric rate savings analysis that is compared to the various cost of purchase or leasing DG solar at the time a customer considers a DG solar purchase. To address these concerns,

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[1] Jones, Rebuttal Exhibit CAJ-R-4, page 4 of 7.

Staff witness, Mr. Broderick, tasked me with preparation of the analysis I discuss in my testimony.

BILL ESTIMATION AND SOLAR COST MODEL AND ASSUMPTIONS

Q. How was the bill estimation and solar cost model established?

A. On January 6, 2016, Staff issued a data request to Arizona Public Service Company ("APS") and The Alliance for Solar Choice ("TASC") requesting a spreadsheet template which quantitatively captures from a residential customer's perspective the typical financial net savings or net costs of purchasing or leasing a rooftop solar system. APS responded with an initial model including relevant inputs and assumptions. TASC objected and did not provide any analysis at that time. Staff then forwarded the APS model to both UNSE and TASC requested their reactions and suggestions for improving the model.

The final model used in Staff's surrebuttal testimony was based on the initial APS model and augmented by relevant revisions and improvements from incorporation of UNSE and TASC input and Staff's internal review and best judgement. Staff is grateful to APS, UNSE and TASC for their thoughtful and useful assistance. The raw information regarding implementation of three part rates provided by APS and UNSE generally showed DG solar as cost effective for customers; whereas, TASC estimated DG solar as less cost effective. UNSE provided its input on February 1, 2016 and TASC on February 5, 2016.

The model used here should be viewed as Staff's model for which it is responsible. Staff is confident in the relative DG solar cost effectiveness demonstrated under the various rate options presented herein. Staff acknowledges there is uncertainty concerning the input assumptions and, therefore, in the absolute values of the resulting estimations.

Q. Has Staff used such an approach or model before?

A. No. And, we are not aware of it being used by any other state. However, we believe it adds an important new dimension to the analysis of rooftop solar and financial considerations of customers who are or may become DG customers. We are continuing to evaluate the model and will on an ongoing basis look for any ways the model can be improved.

Q. What are the key assumptions used in modeling the net savings or net costs in purchasing or leasing a rooftop solar system?

A. The initial assumptions include the 1) solar system size (kW-DC); 2) solar system conversion factor (kWh-AC/kW-DC); 3) seasonal shaping of solar generation; 4) solar off-setting load at time of generation; 5) a typical residential customer kWh and kW before solar by season; 6) related taxes and fees; 7) solar purchase cost ($/kW-DC); and 8) applicable federal and state investment credits. The numerical values of those assumptions are listed in Schedule YL-1.

Q. Please discuss each key necessary assumption starting with the customer's solar system size (kW-DC).

A. For this assumption, Staff utilized UNSE's response to Staff data requests[2] for the average residential customer and Schedule H-4, Page 1 of 22, data for the large residential customer assuming a 90 percent offset of a customer's energy. This means the customer's DG solar system generates 90 percent of its energy requirement. UNSE assumed 100 percent and TASC assumed 80 percent. Staff selected the midpoint of 90 percent, resulting in 4.77 kW and 6.86 kW system sizes, respectively, for average and large customers.

[2] Staff to UNSE 29.1

Q. What is the solar system conversion factor (kWh-AC/kW-DC)?

A. That assumption represents the energy kWh generation estimate per kW. UNSE provided 1,800 kWh annually per one kW. UNSE provided 1,800 based on Tucson and TASC provided 1,698 based on Flagstaff using the National Renewable Energy Laboratory's ("NREL") System Advisor Model. This assumption is also used in the formula for the customer's solar system size as described above. Staff selected the UNSE provided amount based on the NREL Tucson area data.

Q. Why did you use NREL's Tucson area data?

A. NREL has data covering several areas in Arizona. In responses to Staff data requests, the Company (Staff to UNSE 29.1) and TASC (email response) used Tucson and Flagstaff area data, respectively. Flagstaff is on a similar latitude as the Company's major service territory (Kingman and Lake Havasu City). However, Flagstaff has a much higher elevation (6,910 feet) compared to Kingman (3,333 feet), Lake Havasu City (735 feet) and Nogales (3,832 feet). Thus, the electricity consumption and weather characteristics are quite different in Flagstaff compared to the Company's service territory. Flagstaff would have higher winter electricity consumption (for customers with electric heating) and lower summer consumption (little to no air conditioning requirement) as compared to Tucson which Staff concluded would introduce a potential for bias as a key characteristic of DG solar is the carryover of banked electricity into higher tariff summer periods, at least under Staff's analyses of scenarios which continue the existing net metering. Staff concluded the bias would be in the direction of reducing the financial attractiveness of DG solar to residential customers. Tucson has an elevation of 2,643 feet and its latitude is between Nogales and Mohave County, which makes it a better proxy for the Company's service territory than Flagstaff. Recently, Staff became aware that NREL has useful data for other Arizona communities[3], but time did not permit its use in this surrebuttal testimony.

Q. What did you assume for seasonal shaping of solar generation?

A. Seasonal shaping is each season's average monthly DG solar generation as a percentage of the monthly average DG solar generation. UNSE provided a 105 percent summer to annual solar generation percentage and a 95 percent winter to annual solar generation percentage. TASC provided 110 percent and 90 percent, respectively, for summer and winter. Staff selected the UNSE provided percentages.

Q. What is solar off-setting load at time of generation?

A. Solar off-setting load at time of generation represents the percentage of a customer's solar production which is self-consumed at the time of generation. The balance, then, is exported. UNSE provided a summer percentage of 44 percent and winter percentage of 37 percent. TASC provided 44 percent and 34 percent, respectively. Staff selected UNSE's assumption. Stated alternatively, UNSE assumed that 56 percent of solar generation in summer is exported and 63 percent is exported in winter. This assumption is obviously important to the estimated value of solar exports in the various tariff scenarios.

Q. What is customer load before solar by season?

A. This is the UNSE provided customer load profile data for the average customer. Staff pro-rata scaled this data for the large customer.

[3] Others include Phoenix, Scottsdale, Kingman, Prescott, and etc.

Q. What is On-peak solar generation?

A. Of the total solar generation, this assumption represents the percentage occurring by season for the On-peak tariff periods in the tariff analyses. UNSE provided 22 percent On-peak and 5 percent On-peak for summer and winter, respectively. TASC provided similar figures, which are 20 percent and 7 percent, respectively. Staff selected the UNSE provided percentages.

Q. What is the solar purchase cost assumption ($/kW-DC)?

A. This assumption is the installed purchase price to the customer. UNSE provided a cost of $2,500 per kW and TASC provided $3,000 per kW. Staff selected $2,750 as a midpoint assumption.

Q. What are the taxes, fees and investment tax credit assumptions?

A. These assumptions relate to applicable avoidable taxes on electric bills and applicable investment tax credits. UNSE provided 10 percent as the percentage of taxes and government fees. TASC provided 0.87 percent. Staff selected the UNSE provided percentage. All parties agreed on the assumptions on federal investment tax credit and Arizona residential solar tax credit provided in Schedule YL-1.

Q. Please provide more information on the two types of residential customers examined in your analyses as depicted in YL-2.

A. Two types of customers are used in the bill saving model, an Average Customer and a Large Customer. An Average Customer has a pre-DG solar monthly kWh usage of 795, which is the mean monthly kWh usage based on a sample of 2,309 UNSE non-DG residential customers. A Large Customer has a pre-DG solar monthly kWh usage of 1,144, which is the "Large Customer" monthly kWh defined in Schedule H-4 of the Company's Application for customers under the existing RES-01. Other characteristics of a Large Customer are adjusted proportionally to those of an Average Customer in the model. The list of the numeric values is shown in Schedule YL-2. Large Customers are modeled because the Company indicated that customers who installed DG tend to have higher consumption on average.

Q. Lastly, what assumptions are made on Net Energy Metering (NEM)?

A. Under the Existing RES-01 and Company Rebuttal RES-01 TOU Demand, the current effective NEM is assumed, with banking and rollover for excess generation. For modeling purposes, the accumulated excess generation is represented as an average credit spread over all months, and the excess generation banked during the winter months is assumed to evenly offset summer months' energy usage. The year-end balance of excess generation is paid out to customers at the Company's current effective Market Cost of Comparable Conventional Generation ("MCCCG") of $0.03003 per kWh used in Existing RES-01 and $0.03697 per kWh used in Company Rebuttal RES-01 TOU Demand.

Under the Company Original Proposed RES-01 Demand and Company Original Proposed RES-01 TOU Demand, the proposed NEM alternative in the Company's Application is assumed. With the proposed NEM alternative, no banking or rollover for excess generation is allowed, and all exported electricity from a customer to the Company is paid out each month to the customer at a rate of $0.00584 per kWh.

RESULTS AND COMPARISON

Q. What evaluation measures did you select for purchasing a rooftop solar system?

A. In order to evaluate the purchasing option, the simple payback and the Internal Rate of Return ("IRR") measures were selected. The purpose of using those two measures is to capture the total financial impact of purchasing a rooftop solar system, by evaluating bill savings together with system capital cost recovery.

Q. What are the resulting simple paybacks?

A. Simple payback is a straightforward measure of how many years a customer needs to recover the initial cost of purchasing a rooftop solar system through bill savings. Table 1 below summarizes the resulting simple paybacks for an Average Customer and a Large Customer.

	Simple Payback (Years)	
	Average Customer	Large Customer
Existing RES-01	9.2	9.2
Company Original Proposed RES-01 Demand	14.4	14.9
Company Original Proposed RES-01 TOU Demand	15.0	15.5
Company Rebuttal RES-01 TOU Demand	**11.5**	**11.9**

Table 1: Resulting Simple Paybacks

The results suggest that, under the Existing RES-01, both the Average Customer and Large Customer can achieve a better simple payback. However, with the Company Rebuttal RES-01 TOU Demand, both customers have effective improvement in terms of simple payback, as compared to the Company Original Proposed RES-01 Demand and Company Original Proposed RES-01 Demand.

Q. What is the formula of the IRR?

A. The IRR is a financial metric used to evaluate the profitability of any potential investments. The IRR is a discount rate that makes the net present value ("NPV") of all cash flows from a particular investment equal to zero. In the bill saving model, the IRR is calculated based on the formula below:

$$NPV = 0 = -C_0 + \frac{S_1}{1+IRR} + \frac{S_2}{(1+IRR)^2} + \cdots + \frac{S_{20}}{(1+IRR)^{20}},$$

where C_0 is the total initial cost of purchasing the rooftop solar system, and S_1, S_2, …, S_{20} are the annual bill savings during the period of year 1, 2, …, 20 after the rooftop solar system is installed.

Q. Why is the IRR used to evaluate a customer's investment decision in purchasing the rooftop solar system?

A. Staff is using the IRR because, unlike the NPV, it does not make a numerical assumption regarding discount rate. Given different perspectives on discount rates for various customers, using the IRR simplifies the evaluation. Generally speaking, the higher an investment's IRR, the more desirable it is to undertake the investment from the customer's perspective. Thus, the IRR can be used to rank multiple potential investments. In the bill saving model, the IRR provides an effective comparison for the financial feasibility of investing in a rooftop solar system under the four rate designs. Moreover, the IRR can also be compared against the prevailing rate of return in the securities market or accepted discount rate which are reference points for customers. For a customer considering an investment in a rooftop solar system, if the IRR for the investment is higher than his/her (publicly unknown) but accepted discount rate, the investment is economically viable.

Q. Are there additional assumptions in calculating the IRR?

A. Yes. An annual DG solar degradation rate of 0.25 percent and a lifespan of 20 years are assumed for the solar system. Moreover, in order to perform a sensitivity analysis, three levels of annual future utility rate escalation are assumed: 0 percent, 1.5 percent and 2.5 percent.

Q. How does the change of those assumptions affect the resulting IRRs?

A. The change of assumptions on annual degradation rate and annual future utility rate escalation will affect the numeric values of the resulting IRRs. However, the relative ranking among the four rate designs should be unchanged and accurate, which is the reason why the IRR is used here as an evaluation measure. Table 2 and Table 3 illustrate the unchanged rankings among the four rate designs with the various assumptions of utility rate escalation.

Q. What are the resulting IRRs for an Average Customer?

A. The resulting IRRs for an Average Customer under the four rate designs with three levels of utility rate escalation are summarized in Table 2 below:

	IRR (%)		
Utility Rate Escalation	0.00%	1.50%	2.50%
Existing RES-01	8.72%	10.14%	11.09%
Company Original Proposed RES-01 Demand	3.13%	4.52%	5.44%
Company Original Proposed RES-01 TOU Demand	2.71%	4.09%	5.01%
Company Rebuttal RES-01 TOU Demand	**5.76%**	**7.16%**	**8.10%**

Table 2: Resulting IRRs for an Average Customer

From the table above, it can be observed that an Average Customer is better off under the Company Rebuttal RES-01 TOU Demand compared to the Company Original Proposed RES-01 Demand and Company Original Proposed RES-01 TOU Demand. Even though the IRR is lower compared to the IRR under the Existing RES-01, with the Company Rebuttal RES-01 TOU Demand purchasing a rooftop solar system is still an economically viable investment, especially when a high utility rate escalation is expected.

Q. What are the resulting IRRs for a Large Customer?

A. The resulting IRRs for a Large Customer under the four rate designs with three levels of utility rate escalation are summarized in Table 3 below:

	IRR (%)		
Utility Rate Escalation	0.00%	1.50%	2.50%
Existing RES-01	8.69%	10.11%	11.06%
Company Original Proposed RES-01 Demand	2.74%	4.12%	5.03%

Company Original Proposed RES-01 TOU Demand	2.32%	3.70%	4.61%
Company Rebuttal RES-01 TOU Demand	5.31%	6.71%	7.64%

Table 3: Resulting IRRs for a Large Customer

The results illustrated in the above table for a Large Customer are similar to the results shown in Table 2 for an Average Customer.

Q. Can you provide a prevailing rate of return in the securities market or a generally accepted discount rate for comparison purposes?

A. Yes. The Standard & Poor's 500 ("S&P 500") is an American stock market index based on the market capitalizations of 500 large companies with common stock listed on the NYSE or NASDAQ. The S&P 500 has a diverse constituency and is widely considered as one of the best representations of the U.S. stock market and the U.S. economy. Therefore, the return on the S&P 500 can be used as a prevailing rate of return in the securities market. In addition, the returns on a 3-month Treasury Bill ("3-month T-Bill") and a 10-year Treasury Bond ("10-year T-Bond") are generally accepted discount rates for long term and short term investments, respectively. Table 4 below summarizes the geometric averages of the annual returns on the S&P 500, the 3-month T-Bill and the 10-year T-Bond for three different time periods. The raw data of annual returns during 1928 - 2015 was retrieved from Dr. Aswath Damodaran's online database (http://pages.stern.nyu.edu/~adamodar/). Dr. Damodaran is a Professor of Finance at the Stern School of Business at New York University. The raw data is listed in Schedule YL-2.

	S&P 500	3-month T-Bill	10-year T-Bond
1928-2015	9.50%	3.45%	4.96%
1966-2015	9.61%	4.92%	6.71%
2006-2015	7.25%	1.14%	4.71%

Table 4: Geometric Averages of the Annual Returns

Q. Are there any other prevailing discount rates that can be used for comparison purposes?

A. Mortgage rate is another widely used prevailing discount rate. The Primary Mortgage Market Survey ("PMMS") results provided by Freddie Mac are presented in this surrebuttal testimony. Through the PMMS, Freddie Mac surveys lenders each week on the rates, fees and points for the most popular mortgage products. Three types of mortgage products will be shown, namely 30-Year Fixed-Rate Mortgages ("30-Yr FRM"), 15-Year Fixed-Rate Mortgages ("15-Yr FRM") and 5-Year Adjustable-Rate Mortgages ("5/1-Yr ARM"). Table 5 below lists the average rates of these three mortgage products for 2005-2015.

	Mortgage Products		
	30-Yr FRM	15-Yr FRM	5/1-Yr ARM
Average Rate (2005-2015)	4.95%	4.35%	4.25%

Table 5: Average Rates of Three Mortgage Products

Q. Please summarize your findings from your analysis.

A. With an annual future utility rate escalation of 2.5 percent, the IRRs can reach 8.10 percent and 7.64 percent, respectively, for an Average Customer and a Large Customer. This level of IRR is relatively higher than the annual return on a 10-year T-Bond, which is generally accepted as the discount rate for long-term investment. The IRRs are slightly higher than the recent 10-year (2006-2015) average annual return on the S&P 500. In addition, the IRRs are higher than mortgage rates for all three electric escalation scenarios. Therefore, purchasing a rooftop solar system would still be an economically viable choice even with the adoption of Company Rebuttal RES-01 TOU Demand. Nevertheless, the pace of rooftop solar installations would be expected to be reduced, at least temporarily, if Company Rebuttal RES-01 TOU Demand is adopted, all else being constant.

Q. Please explain the difference in the resulting IRRs under the Existing RES-01 and the Company Rebuttal RES-01 TOU Demand.

A. With the same assumptions of rooftop solar system cost, degradation rate and annual future utility rate escalation, the difference in the resulting IRRs under the above-mentioned two rate designs is mainly due to the variation in the annual bill savings. Table 6 below summarizes the monthly average saving results under the two rate designs for both an Average Customer and a Large Customer.

		Monthly Average Bills			
		Before Solar	After Solar	Credit for Excess Generation	Savings
Average Customer	Existing RES-01	$93.13	$18.64	$0	$74.49
	Company Rebuttal RES-01 TOU Demand	$108.37	$49.61	$0.67	$59.43
Large Customer	Existing RES-01	$132.88	$21.96	$0	$110.92
	Company Rebuttal RES-01 TOU Demand	$148.74	$64.24	$0.98	$85.48

Table 6: Monthly Average Savings Summary

From Table 6, we can observe that, for an Average Customer, the amount of monthly average savings under the Company Rebuttal RES-01 TOU Demand is $15.06 lower than that under the Existing RES-01. Moreover, the reduction in monthly average savings is $25.44 for a Large Customer. In addition, the monthly Basic Service Charge is $10 and $15 under the Existing RES-01 and the Company Rebuttal RES-01 TOU Demand, respectively. This $5 increase in

Basic Service Charge would be applied to all residential customers, so it has been excluded from the reduction in monthly average savings. Therefore, the reduction in monthly average savings is $10.06 and $20.44, respectively, for an Average Customer and a Large Customer. The reduction represents 20.28 percent and 31.82 percent of the monthly after-solar average bill under the Company Rebuttal RES-01 TOU Demand for an Average and a Large Customer, respectively.

Q. What is the impact on the resulting simple paybacks or IRRs under the Company Rebuttal RES-01 TOU Demand if new solar incentives are temporarily offered to residential customers?

A. With solar incentives, the initial cost of purchasing a rooftop solar system will be reduced for a residential customer. The initial cost plays a very critical role in calculating simple payback and the IRR as suggested by the formulas. Thus with lower initial cost, the resulting simple paybacks and the IRRs will improve significantly. In order to evaluate those impacts quantitatively, a sensitivity analysis is performed to capture the impacts with different levels of solar incentives. With the assumptions of 0.25 percent annual degradation rate and 2.5 percent annual future utility rate escalation, the resulting simple paybacks and IRRs under the Company Rebuttal RES-01 TOU Demand for different levels of solar incentives are summarized in Table 7 below.

		Solar Incentives				
		5%	10%	15%	20%	25%
Average Customer	Simple Paybacks (Years)	10.6	9.6	8.7	7.8	6.9
	IRR	9.16%	10.38%	11.80%	13.48%	15.52%
Large Customer	Simple Paybacks (Years)	11.0	10.1	9.1	8.2	7.3
	IRR	8.64%	9.78%	11.10%	12.65%	14.51%

Table 7: Resulting Simple Paybacks and IRRs with Different Levels of Solar Incentives

It can be observed from Table 7 that the solar incentives offer both Average Customer and Large Customer with shorter simple paybacks and greater IRRs. Moreover, with 15 percent solar incentives, both customers can achieve slightly better simple payback and IRR compared to those under the Existing RES-01.

Q. What are the net payoffs under the four rate designs if a customer chooses to lease a rooftop solar system?

A. $0.09/kWh is assumed as the rooftop solar system lease rate, and all parties agreed on this assumption. The monthly average net payoffs under the four rate designs for both an Average Customer and a Large Customer are summarized in Table 8 below. The parentheses in the table indicate a net loss.

	Monthly Average Net Payoff	
	Average Customer	Large Customer
Existing RES-01	$ 10.10	$ 18.26
Company Original Proposed RES-01 Demand	$ (17.00)	$ (24.45)
Company Original Proposed RES-01 TOU Demand	$ (18.80)	$ (27.07)
Company Rebuttal RES-01 TOU Demand	$ (4.97)	$ (7.18)

Table 8: Monthly Average Net Payoffs for Leasing

Q. Please summarize your findings from the modeling of the net payoffs for leasing a rooftop solar system.

A. As Table 8 suggests, leasing a rooftop solar system is an economically viable option only under the Existing RES-01 for both customers. However, those resulting net payoffs are based on the assumption of zero utility rate escalation. With an assumption of 2.5 percent annual future utility rate escalation, under the Company Rebuttal RES-01 TOU Demand, both customers would start to have positive net payoffs in the fifth year after they lease a rooftop solar system. In order to further evaluate the leasing option for a residential customer under the Company Rebuttal RES-01 TOU Demand, the NPV is analyzed to reflect the overall payoffs. In these calculations a 20-year leasing term is assumed and, moreover, a sensitivity analysis is performed to illustrate the NPVs under different assumptions of discount rate. Table 9 below shows the resulting NPVs.

	NPV	
Discount Rate	4.71%	7.20%
Average Customer	$1,335.07	$922.52
Large Customer	$1,915.60	$1,323.05

Table 9: Resulting NPVs under the Company Rebuttal RES-01 TOU Demand

The resulting NPVs in Table 9 suggest both Average Customer and Large Customer can achieve positive NPVs under different assumptions of discount rate. Thus, leasing a rooftop solar system could still be economically viable under the Company Rebuttal RES-01 TOU Demand in the long haul for residential customers.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Key Assumptions

Solar system Size (kW-DC)	
Average Customer	4.77
Large Customer	6.86
Solar system conversion factor (kWh-AC/kW-DC)	1800 (south orientation)
Seasonal shaping of solar generation	
Summer	105% of monthly average
Winter	95% of monthly average
Solar off-setting load at time of generation	
Summer	44% of total solar kWh
Winter	37% of total solar kWh
Customer load before solar by season	See Schedule YL-2
On-peak solar generation	
Summer	22% of total solar kWh
Winter	5% of total solar kWh
Customer on-peak load before solar	
Summer	24% of total kWh
Winter	26% of total kWh
Taxes and government fees	10%
Solar purchase cost ($/kW-DC)	2,750
Federal investment tax credit	30%
Arizona residential solar tax credit	$1,000

Customer Profiles

	Average Customer	Large Customer
Monthly kWh	795	1,144
Solar system size kW-DC	4.77	6.86
Monthly kWh - Summer	935	1,345
Monthly kWh - Winter	665	943
On-peak kW - Summer	4.13	6
On-peak kW - Winter	3.34	4.81
On-peak kW offset - Summer	0.13	0.19
On-peak kW offset - Winter	0	0

Raw Data of Annual Returns

	Annual Returns on Investments in		
Year	*S&P 500*	*3-month T-Bill*	*10-year T-Bond*
1928	43.81%	3.08%	0.84%
1929	-8.30%	3.16%	4.20%
1930	-25.12%	4.55%	4.54%
1931	-43.84%	2.31%	-2.56%
1932	-8.64%	1.07%	8.79%
1933	49.98%	0.96%	1.86%
1934	-1.19%	0.32%	7.96%
1935	46.74%	0.18%	4.47%
1936	31.94%	0.17%	5.02%
1937	-35.34%	0.30%	1.38%
1938	29.28%	0.08%	4.21%
1939	-1.10%	0.04%	4.41%
1940	-10.67%	0.03%	5.40%
1941	-12.77%	0.08%	-2.02%
1942	19.17%	0.34%	2.29%
1943	25.06%	0.38%	2.49%
1944	19.03%	0.38%	2.58%
1945	35.82%	0.38%	3.80%
1946	-8.43%	0.38%	3.13%
1947	5.20%	0.57%	0.92%
1948	5.70%	1.02%	1.95%
1949	18.30%	1.10%	4.66%
1950	30.81%	1.17%	0.43%
1951	23.68%	1.48%	-0.30%
1952	18.15%	1.67%	2.27%
1953	-1.21%	1.89%	4.14%
1954	52.56%	0.96%	3.29%
1955	32.60%	1.66%	-1.34%
1956	7.44%	2.56%	-2.26%
1957	-10.46%	3.23%	6.80%
1958	43.72%	1.78%	-2.10%
1959	12.06%	3.26%	-2.65%

1960	0.34%	3.05%	11.64%
1961	26.64%	2.27%	2.06%
1962	-8.81%	2.78%	5.69%
1963	22.61%	3.11%	1.68%
1964	16.42%	3.51%	3.73%
1965	12.40%	3.90%	0.72%
1966	-9.97%	4.84%	2.91%
1967	23.80%	4.33%	-1.58%
1968	10.81%	5.26%	3.27%
1969	-8.24%	6.56%	-5.01%
1970	3.56%	6.69%	16.75%
1971	14.22%	4.54%	9.79%
1972	18.76%	3.95%	2.82%
1973	-14.31%	6.73%	3.66%
1974	-25.90%	7.78%	1.99%
1975	37.00%	5.99%	3.61%
1976	23.83%	4.97%	15.98%
1977	-6.98%	5.13%	1.29%
1978	6.51%	6.93%	-0.78%
1979	18.52%	9.94%	0.67%
1980	31.74%	11.22%	-2.99%
1981	-4.70%	14.30%	8.20%
1982	20.42%	11.01%	32.81%
1983	22.34%	8.45%	3.20%
1984	6.15%	9.61%	13.73%
1985	31.24%	7.49%	25.71%
1986	18.49%	6.04%	24.28%
1987	5.81%	5.72%	-4.96%
1988	16.54%	6.45%	8.22%
1989	31.48%	8.11%	17.69%
1990	-3.06%	7.55%	6.24%
1991	30.23%	5.61%	15.00%
1992	7.49%	3.41%	9.36%
1993	9.97%	2.98%	14.21%
1994	1.33%	3.99%	-8.04%
1995	37.20%	5.52%	23.48%
1996	22.68%	5.02%	1.43%
1997	33.10%	5.05%	9.94%

1998	28. 34%	4. 73%	14. 92%
1999	20. 89%	4. 51%	-8. 25%
2000	-9. 03%	5. 76%	16. 66%
2001	-11. 85%	3. 67%	5. 57%
2002	-21. 97%	1. 66%	15. 12%
2003	28. 36%	1. 03%	0. 38%
2004	10. 74%	1. 23%	4. 49%
2005	4. 83%	3. 01%	2. 87%
2006	15. 61%	4. 68%	1. 96%
2007	5. 48%	4. 64%	10. 21%
2008	-36. 55%	1. 59%	20. 10%
2009	25. 94%	0. 14%	-11. 12%
2010	14. 82%	0. 13%	8. 46%
2011	2. 10%	0. 03%	16. 04%
2012	15. 89%	0. 05%	2. 97%
2013	32. 15%	0. 07%	-9. 10%
2014	13. 52%	0. 05%	10. 75%
2015	1. 36%	0. 21%	1. 28%

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

DONNA H. MULLINAX

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

The Surrebuttal Testimony of Donna Mullinax responds to the Rebuttal Testimony of UNS Electric, Inc. ("UNSE" or "Company") witnesses Kentton C. Grant, David J. Lewis, and David G. Hutchens as summarized below:

- Modification to Capital Structure calculation changing Staff's original Fair Value Rate of Return of 5.60 percent to 5.63 percent.

- Adjustment to Injuries and Damages for Arizona Corporation Commission Jurisdiction, which changes from Staff's initial increase to Operating Income of $207,954 to an increase of $199,699, a reduction of $8,255.

- Adjustment to Incentive Compensation for Arizona Corporation Commission Jurisdiction, which changes from Staff's initial increase to Operating Income of $100,178 to an increase of $96,920, a reduction of $3,258.

- Elimination of Payroll Expense and Tax Adjustment that were initially proposed for what appeared to be a double inclusion of Incentive Compensation. The modification changes from Staff's initial increase to Operating Income of $91,068 (including Payroll Taxes) to no increase, a reduction of $91,068.

- Modification to Gila River Deferred Cost that removes the Regulatory Asset Amortization of the deferred cost. The modification increases operating income by $1,933,981.

- Flow-through adjustment to Working Capital, which changes from an increase to rate base of $192,930 to an increase of $296,489, or an increase to rate base of $103,559.

- Flow-through adjustment to Interest Synchronization, which changes from a reduction to Operating Income of $15,085 to a reduction of $14,229, or an increase of $856.

- The impact of these modifications increased Staff's initial recommended Fair Value Rate Base by $103,558 to $353.999 million.

- The impact of these modifications changes Staff's recommended increase to base rates from $18.128 million on Fair Value Rate Base to $15.360 million, or a reduction of $2,768,000.

- Comments on Company's Incentive Compensation argument

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Donna H. Mullinax. I am employed as Vice President and Chief Financial Officer by Blue Ridge Consulting Services, Inc. ("Blue Ridge"). My business address is 114 Knightsridge Road, Travelers Rest, South Carolina 29690.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Surrebuttal Testimony in this proceeding?

A. My Surrebuttal Testimony is filed on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission").

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my Surrebuttal Testimony is to respond to portions of the Rebuttal Testimony of UNS Electric, Inc. ("UNSE" or "Company") witnesses Kentton C. Grant, David J. Lewis, and David G. Hutchens and to make several adjustments to my Direct Testimony and Exhibits.

Q. Did you revise your Schedules as a result of your analysis and review of information provided by the Company?

Yes. I have revised Schedules A, B, C, D, D.1, E, E-1, E-3, E-4, E-5, E-7, and E10. For ease of reference, Attachment DHM-1 contains Schedule A through Schedule E-10, which also includes those that were not modified.

MODIFICATIONS TO STAFF'S ADJUSTMENTS

Capital Structure – Fair Value Rate of Return

Q. Please explain the change that needs to be made to your proposed Capital Structure – Fair Value Rate of Return ("FVROR") calculation.

A. As noted in Company witness Grant's Rebuttal Testimony,[1] I inadvertently included in my FVROR calculation the Company's original filed position instead of using Staff's recommended position in the weighting calculation. My original FVROR of 5.60 percent should be 5.63 percent.

Injuries and Damages

Q. Please explain the change that needs to be made to your Injuries and Damages Adjustment.

A. As noted in Company witness Lewis's Rebuttal Testimony,[2] my original calculation for Staff Adjustment E-3 Injuries and Damages did not apply the ACC Jurisdictional factor. Staff's adjustment E-3 Injuries and Damages should change from an increase to Operating Income of $207,954 to an increase to Operating Income of $199,699, a change of $8,255.

Incentive Compensation

Q. Please explain the change that needs to be made to your Incentive Compensation adjustment.

A. As noted in Company witness Lewis's Rebuttal Testimony,[3] my original calculation for Staff Adjustment E-5 Incentive Compensation did not apply the ACC Jurisdictional factor. Staff's adjustment E-5 Incentive Compensation should change from an increase to Operating Income of $100,178 to an increase to Operating Income of $96,920, a change of $3,258.

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[1] Rebuttal Testimony of Kentton C. Grant, page 8, lines 8-17.
[2] Rebuttal Testimony of David J. Lewis, page 2, lines 11-12.
[3] Rebuttal Testimony of David J. Lewis, page 2, lines 24-25.

Payroll Expense and Payroll Taxes

Q. Please explain the change that needs to be made to Staff Adjustment E-4 Payroll Expense and Payroll Taxes.

A. As noted in Company witness Lewis's Rebuttal Testimony,[4] there was a misunderstanding between what was requested and what was provided within a data request. I interpreted the information provided to mean that Incentive Compensation was included within Payroll Expense and Payroll Taxes. After discussions with Company witness David Lewis and a detailed review of the Company's Payroll Expense and Payroll Tax work papers, I am confident that the Company has not included Incentive Compensation in both Operations & Maintenance ("O&M") Payroll and the Company's Incentive Compensation adjustments. Staff's adjustment E-4 Payroll Expense should change from an increase to Operating Income of $91,068 (including Payroll Taxes) to no increase to Operating Income, a change of $91,068.

Gila River Deferred Cost

Q. Please explain the additional adjustment made to Staff Adjustment E-10 Gila River Deferred Cost.

A. Staff witness Barbara Keene presents the addition to Staff's Gila River Deferred Cost Adjustment. In addition to the rate base adjustment included in my Direct Testimony that reduces rate base by $2,000,000, the additional adjustment increases operating income by $1,933,981.

[4] Rebuttal Testimony of David J. Lewis, page 2, lines 13-23.

FLOW-THROUGH ADJUSTMENTS

Q. Please explain what other adjustments should be made to your revenue requirements calculations as a result of your modifications?

A. There are two flow-through adjustments that need to be made: Cash Working Capital and Interest Synchronization.

Cash Working Capital

Q. Please explain the modification to Staff Adjustment E-1 – Cash Working Capital.

A. The Company's proposed rate base includes Cash Working Capital, which was developed through the preparation of a lead-lag study. With Staff's modified adjustments noted above, the expense components of the Company's lead-lag study need to be updated. Staff Adjustment E-1 Cash Working Capital changes from an increase to jurisdictional rate base of $192,930 to an increase of $296,489, or an increase to rate base of $103,559.

Interest Synchronization

Q. Please explain the modification to Staff Adjustment E-7 – Interest Synchronization.

A. The interest synchronization adjustment is a flow-through adjustment that synchronizes the rate base and cost of capital with the tax calculation. The adjustment applies the weighted cost of debt to the calculation of test year income tax expense. If any of these components are modified, the interest synchronization calculation should be updated to reflect the correct amount of synchronized interest to be included in the tax calculation. Staff Adjustment E-7 Interest Synchronization changes from a reduction to Operating Income of $15,085 to a reduction of $14,229, or a change of $856.

IMPACT OF MODIFIED ADJUSTMENTS

Q. How did your modifications impact Staff's recommended rate base?

A. Staff's recommended rate base was increased by $103,558.

Q. What is the overall impact of your modifications to Staff's recommended base rate increase?

A. The overall impact of the modifications to Staff's adjustments changes Staff's recommended base rate increase from $18.128 million on FVRB to $15.360 million, or a reduction of $2,768,000.

Q. Has the Company agreed with your recommended base rate increase?

A. Yes. Company witness Hutchens's Rebuttal Testimony stated that the Company will agree to stipulate to an $18.5 million increase to adjusted test-year non-fuel revenues.[5] This agreed to stipulation was later modified by the Gila River Deferred Cost Adjustment as addressed in Staff witness Barbara Keene's Surrebuttal Testimony.

SURREBUTTAL TO INCENTIVE COMPENSATION REBUTTAL

Q. What was the Company rebuttal in regard to Staff's adjustment to Incentive Compensation?

A. Staff Adjustment E-5 Incentive Compensation included three parts: (1) normalization using a two-year average similar to the Payroll Expense instead of the three-year average used by the Company; (2) excluding the 2017 merit increase as not known and measureable; and (3) sharing the Incentive Compensation 50/50 between ratepayers and shareholders.

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[5] Rebuttal Testimony of David G. Hutchens, page 15, lines 5-7.

The Company rebutted the third part of Staff's adjustment, sharing the Incentive Compensation 50/50 between ratepayers and shareholders, stating that it strongly disagreed with the "who benefits" analysis as a tool for what percentage of recovery should be afforded to the Company. The Company argued, "[A]lmost any expense could be seen to 'benefit' both ratepayers and shareholders."[6] Therefore, the Company is maintaining its position that 100 percent of incentive compensation should be allowed and recovered from ratepayers.

Q. Why is incentive compensation different from "almost any expense?"

A. Incentive compensation is very different from "almost any expense." Unlike incentive compensation, there is less incentive to manipulate other expenses.

Q. Please elaborate.

A. Achieving Net Income or profitability goals is a major component of the Company's incentive compensation program. As pointed out in my Direct Testimony, Financial goals are weighted 50 percent of the total incentive compensation metric, with Net Income equal to 40 percent and O&M Cost Containment equal to 10 percent.

Net Income or profitability increases as expenses are reduced. Reducing expenses drives up Net Income or profitability, increasing Incentive Compensation payouts to management and benefitting shareholders at the expense of ratepayers. For example, taken to an extreme, expenses can be reduced by deferring maintenance (resulting in increased outages) and failing to adequately staff Customer Services to address customer reported outages, inquiries, or complaints.

[6] Rebuttal Testimony of David J. Lewis, page 4, lines 13-20.

As the Commission has recognized in the past, ensuring that the competing interests are balanced is important. This balance has been achieved by requiring the sharing of incentive compensation 50/50 between ratepayers and shareholders.

Q. Does this conclude your Surrebuttal testimony?

A. Yes.

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
List of Schedules

Line #	Schedule	Description
1	**Schedule A**	**Computation of Increase in Gross Revenue Requirement - Modified**
2	Schedule A.1	Computation of Revenue Conversion Factor
3	**Schedule B**	**Original Cost and RCND Adjusted Rate Base - Modified**
4	**Schedule C**	**Adjusted Net Operating Income - Modified**
5	**Schedule D**	**Cost of Capital - Modified for FVROR Calculation Error**
6	**Schedule D.1**	**Impact of Recommended Cost of Captial on Company's Proposed Revenue Requirements - Modified**
7	**Schedule E**	**Summary of Rate Base and Operating Income Adjustments - Modified**
8	**Schedule E-1**	**Adjustment E-1 Cash Working Capital - Modified**
9	**Schedule E-1 WP**	**Adjustment E-1 Cash Working Capital Workpaper - Modified**
10	Schedule E-2	Adjustment E-2 Bad Debt Expense
11	**Schedule E-3**	**Adjustment E-3 Injuries and Damages - Modified for ACC Jurisdictional Allocation**
12	**Schedule E-4**	**Adjustment E-4 Payroll Expense and Payroll Taxes - Withdrawn**
13	**Schedule E-5**	**Adjustment E-5 Incentive Compensation - Modified for ACC Jurisdictional Allocation**
14	**Schedule E-5 WP**	**Adjustment E-5 Incentive Compensation Workpaper - Modified for ACC Jurisdictional Allocation**
15	Schedule E-6	Adjustment E-6 Directors and Officers (D&O) Liability Insurance
16	**Schedule E-7**	**Adjustment E-7 Interest Synchronization - Modified Due Change in Working Capital - Rate Base**
17	Schedule E-8	Adjustment E-8 Purchased Power and Fuel Adjustment Clause (PPFAC)
18	Schedule E-9	Adjustment E-9 OATT
19	**Schedule E-10**	**Adjustment E-10 Gila River Deferred Cost - Modified**

ARIZONA CORPORATION COMMISSION

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Schedule A
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UNS Electric, Inc.
Computation of Increase in Gross Revenue Requirement - **Modified**
ACC Jurisdictional
Test Year Ended December 31, 2014

(Thousands of Dollars)

			UNSE Proposed			Staff Calculated			Difference		
Line	Description	Reference	Original Cost (A)	RCND (B)	Fair Value (B)	Original Cost (C)	RCND (E)	Fair Value (D)	Original Cost (E)	RCND (E)	Fair Value (F)
1	Adjusted Rate Base	Sch. B (ACC)	$ 272,013	$ 439,427	$ 355,720	$ 270,293	$ 437,706	$ 353,999	$ (1,720)	$ (1,720)	$ (1,721)
2	Required Operating Income (a)		$ 22,108	$ 22,108	$ 22,108	$ 19,927	$ 19,927	$ 19,927	$ (2,181)	$ (2,181)	$ (2,181)
3	Adjusted Orperating Income	Sch. C (ACC)	$ 8,045	$ 8,045	$ 8,045	$ 10,369	$ 10,369	$ 10,369	$ 2,324	$ 2,324	$ 2,324
4	Operating Income Deficiency		$ 14,064	$ 14,064	$ 14,064	$ 9,558	$ 9,558	$ 9,558	$ (4,505)	$ (4,505)	$ (4,505)
5	Gross Revenue Conversion Factor		1.6084	1.6084	1.6084	1.6070	1.6070	1.6070			
6	Increase in Gross Revenue Requirement		$ 22,621	$ 22,621	$ 22,621	$ 15,360	$ 15,360	$ 15,360	$ (7,261)	$ (7,261)	$ (7,261)
7	Original DH Mullinax Testimony					$ 18,128	$ 18,128	$ 18,128			
8	Change from Original Filed Testimony					$ 2,768	$ 2,768	$ 2,768			
9	Weighted Average Cost of Captial	Schedule D	7.67%	7.67%	7.67%	7.22%	7.22%	7.22%			
10	Fair Value Adjustment		0.46%	-2.64%	-1.45%	0.15%	-2.66%	-1.59%			
11	Required Rate of Return	Schedule D	8.13%	5.03%	6.22%	7.37%	4.55%	5.63%			
12	Return on Equity		10.35%			9.50%					
	Revenue Increase and Estimated Percentage Rate Increase (Decrease)										
13	Electric Retail Revenues - Current Rates	Sch. C (ACC)	$ 147,107		$ 147,107	$ 154,888		$ 154,888	Staff Revenue from Schedule C		
14	With Proposed Base Rate Increase	Line 6 + Line 10	$ 169,728		$ 169,728	$ 170,248		$ 170,248			
15	Percent Retail Revenue Increase		15.4%		15.4%	9.9%		9.9%			

Notes and Source
Column A and B: UNSE filing, Schedule A-1

		UNSE Proposed	
[a]	Required Operating Income		
	Adjusted OCRB Rate Base	$ 272,013	
	Weighted Average Cost of Captial	7.67%	
	Required Income Before FV Adjustment	$ 20,854	$ 20,854
	Adjusted FV Rate Base	$ 355,720	
	Adjusted OCRB Rae Base	$ 272,013	
	Difference	$ 83,707	
	Return on FV Increment (b)	1.50%	
	Required Income on FV Increment	$ 1,256	$ 1,256
	Required Operating Income		$ 22,108

(b) From 2015 UNSE Rev Req Model.xlsm; Cover; Line 31

ARIZONA CORPORATION COMMISSION

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Schedule A.1
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UNS Electric, Inc.
Computation of Revenue Conversion Factor

Test Year Ended December 31, 2014

Line	Description	Company Proposed (A)	Staff Adjustment (B)	Staff Proposed (C)
1	Gross Revenue	100.00%		100.00%
2	Less: Uncollectible Revenue (a)	0.3438%	-0.0895%	0.2543%
3	Taxable Income as a Percent	99.66%		99.75%
4	State Income Tax Rate	5.48%		5.48%
5	Federal Effective Income Tax Rate [b]	32.14%		32.14%
6	Total Effective Tax Rate	37.61%		37.613%
7	Total Effective Tax Rate Adjusted for Uncollectibles	37.48%		37.52%
8	Change in Net Operating Income	62.17%		62.23%
9	Gross Revenue Conversion Factor	1.6084	(0.0014)	1.6070

Notes and Sources
Column A: UNSE filing, Schedule C-3

(a) Average Retail Expense Ratio from Bad Debt Adjustment
(b)

Federal Effective Income Tax Rate (1-State Rate*Federal Rate)	Company Proposed (A)	Staff Proposed (C)
1-State Income Tax Rate	94.53%	94.53%
Federal Income Tax Rate	34.0%	34.0%
Federal Effective Inocme Tax Rate	32.14%	32.14%

ARIZONA CORPORATION COMMISSION

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Schedule B
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UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base - **Modified**
ACC Jurisdictional
Test Year Ended December 31, 2014

(Thousands of Dollars)

		Original Cost			RCND		
Line	Description	As Adjusted by UNSE (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	As Adjusted by UNSE (D)	Staff Adjustments (E)	As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 664,701		$ 664,701	$ 1,169,067		$ 1,169,067
2	Less: Accumulated Depreciation	296,961	2,000	298,961	561,911	2,000	563,911
3	Net Utility Plant in Service	367,740	(2,000)	365,740	607,156	(2,000)	605,156
4	Citizens Acquisition Discount	(95,156)		(95,156)	(170,847)		(170,847)
5	Less: Accum. Amort. - Citizens Acq. Discount	(36,098)		(36,098)	(69,678)		(69,678)
6	Net Citizens Acquisition Discount	(59,058)	-	(59,058)	(101,169)	-	(101,169)
7	Total Net Utility Plant	308,682	(2,000)	306,682	505,987	(2,000)	503,987
8	Customer Advances for Construction	(3,833)		(3,833)	(4,268)		(4,268)
9	Customer Deposits	(4,428)		(4,428)	(4,428)		(4,428)
10	Other (ITC)	(422)		(422)	(422)		(422)
11	Accumulated Deferred Income Taxes	(35,161)		(35,161)	(64,617)		(64,617)
12	Total Deductions	(43,844)	-	(43,844)	(73,735)	-	(73,735)
13	Allowance for Working Capital	7,175	280	7,455	7,175	280	7,455
14	Regulatory Assets	-		-	-		-
15	Regulatory Liabilities	-		-	-		-
16	Total Rate Base	$ 272,013	$ (1,720)	$ 270,293	$ 439,427	$ (1,720)	$ 437,706

Notes and Source

Columns A and D: UNSE filing, Schedule B-1
Columns B and E: See Schedule E

	Fair Value Calculation (Per Company)		
17	Original Cost	$ 272,013	
18	RCND	$ 439,427	
19	Total	$ 711,440	
20	Average (Fair Value)	$ 355,720	Used in Schedule A
	Fair Value Calculation (Per Staff)		
21	Original Cost	$ 270,293	
22	RCND	$ 437,706	
23	Total	$ 707,999	
24	Average (Fair Value)	$ 353,999	Used in Schedule A

ARIZONA CORPORATION COMMISSION

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Schedule C
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UNS Electric, Inc.
Adjusted Net Operating Income - **Modified**
ACC Jurisdictional

Test Year Ended December 31, 2014
(Thousands of Dollars)

Line	Description	As Adjusted by UNSE (A)	Staff Adjustment (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 147,107	$ 7,782	$ 154,888
2	Sales for Resale	(0)	-	(0)
3	Other Operating Revenues	1,828	-	1,828
4	Total Operating Revnues	$ 148,935	$ 7,782	$ 156,716
	Operating Expenses			
5	Fuel, Purchased Power, and Transmission	$ 77,522	$ 7,762	$ 85,284
6	Other Operations and Maintenance Expense	42,868	(3,718)	39,149
7	Depreciation and Amortization	13,060	-	13,060
8	Taxes Other than Inocme Taxes	6,149	(9)	6,140
9	Income Taxes	1,291	1,424	2,715
10	Total Operating Expenses	$ 140,889	$ 5,458	$ 146,348
11	Operating Income	$ 8,045	$ 2,323	$ 10,369

Notes and Sources
Column A: UNSE filing, Schedule C-1
Column B: Staff Schedule E

ARIZONA CORPORATION COMMISSION

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Schedule D
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UNS Electric, Inc.
Cost of Capital - **Modified for FVROR Calculation Error**
Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description (A)	Reference (B)	Amount (B)	Percent (C)	Cost Rate (E)	Rate of Return (F)
	UNSE'S PROPOSED					
	UNSE Proposed Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Schedule B	272,013			
2	Reconstructed Cost New Depreciation (RCND)	Schedule B	439,427			
3	Fair Value Rate Base (FVRB)	Average Lines 1 & 2	355,720			
4	FVRB/OCRB Multiple	Line 3/Line 1	1.30773			
	UNSE Proposed Adjusted Captial Structure for OCRB					**WACC**
5	Short-Term Debt		$ -	0.00%	0.00%	0.00%
6	Long-Term Bond Debt, Net	UNSE Schedule D-1	169,590	47.17%	4.66%	2.20%
7	Common Stock Equity	UNSE Schedule D-1	189,932	52.83%	10.35%	5.47%
8	Total Capital		$ 359,522	100.00%		7.67%
	UNSE Proposed Fair Value Rate of Return					**FVROR**
9	Short-Term Debt		$ -	0.00%	0.00%	0.00%
10	Long-Term Bond Debt, Net	Line 1 x Line 6 (Debt %	128,311	36.07%	4.66%	1.68%
11	Common Stock Equity	Line 1 x Line 7 (Equity %)	143,702	40.40%	10.35%	4.18%
12	FVRB Increment Above Original Cost	Line 3 - Line 1	83,707	23.53%	1.50%	0.35%
13	Total Capital		$ 355,720	100.00%		6.22%
	STAFF'S RECOMMENDATION					
	Staff Proposed Adjusted Fair Value Rate Base					
14	Original Cost Rate Base (OCRB)	Schedule B	270,293			
15	Reconstructed Cost New Depreciation (RCND)	Schedule B	437,706			
16	Fair Value Rate Base (FVRB)	Average Lines 14 and 15	353,999			
17	FVRB/OCRB Multiple	Line 16/Line 14	1.30969			
	Staff Proposed Adjusted Captial Structure for OCRB					**WACC**
18	Short-Term Debt		$ -	0.00%	0.00%	0.00%
19	Long-Term Bond Debt, Net	UNSE Schedule D-1	169,590	47.17%	4.66%	2.20%
20	Common Stock Equity	UNSE Schedule D-1	189,932	52.83%	9.50%	5.02%
21	Total Capital		$ 359,522	100.00%		7.22%
	Staff Proposed Fair Value Rate of Return			**Modified**		**FVROR**
22	Short-Term Debt		$ -	0.00%	0.00%	0.00%
23	Long-Term Bond Debt, Net	Line 14 x Line 19 (Debt %	127,500	36.02%	4.66%	1.68%
24	Common Stock Equity	Line 14 x Line 20 (Equity	142,793	40.34%	9.50%	3.83%
25	FVRB Increment Above Original Cost	Line 14 - Line 16	83,707	23.65%	0.50%	0.12%
26	Total Capital		$ 353,999	100.00%		5.63% **Modified**

Notes and Sources

Line 21 and 24 Staff's recommended Cost of Common Stock Equity - see Staff Witness Elijah Abinah
Line 25 Staff's recommended FVRB ROR - see Staff Witness Elijah Abinah

ARIZONA CORPORATION COMMISSION

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Schedule D.1
Page 1 of 1

UNS Electric, Inc.
Impact of Recommended **Cost of Captial** on Company's Proposed Revenue Requirements - **Modified**

(Thousands of Dollars)

Line	Description (A)	UNSE Fair Value (B)	Staff Adjustment (C)	Staff's Position (D)
1	**Adjusted Rate Base**	$ 355,720		$ 355,720
2	Weighted Average Cost of Capital	7.67%	-0.45%	7.22%
3	Fair Value Adjustment	-1.45%	-0.14%	-1.59%
4	Required Rate of Return	6.22%	-0.59%	5.63%
5	**Return Requirement**	$ 22,097	$ (2,073)	$ 20,024
6	Operating Revenues	$ 148,935		$ 148,935
7	Operating Expenses	$ 140,889		$ 140,889
8	**Net Operating Income**	$ 8,045		$ 8,045
9	**Income Deficiency**	$ 14,053		$ 11,980
10	Revenue Conversion Factor	1.6084		1.6084
11	**Revenue Deficiency**	$ 22,603	$ (3,334)	$ 19,269
12	Revenue Deficiency Percent Change		-14.75%	

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Summary of Rate Base and Operating Income Adjustments - **Modified**
ACC Jurisdictional
Test Year Ended December 31, 2014

Line	Description	Total Staff Adjustments	Modified E-1 Working Capital - Modified	E-2 Bad Debt Expense	Modified E-3 Injuries & Damages	Withdrawn E-4 Payroll Expense & Payroll Taxes	Modified E-5 Incentive Compensation	E-6 D&O Liability Insurance	Modified E-7 Interest Synchronization	E-8 Purchased Power & Fuel	E-9 OATT	Modified E-10 Gila River Deferred Costs
		(A)	(B)	(C)	(D)	(E)	(F)	(F)	(F)	(G)	(H)	(H)
	Rate Base											
1	Gross Utility Plant in Service	$ -										
2	Less: Accumulated Depreciation	2,000,000										2,000,000
3	Net Utility Plant in Service	(2,000,000)	-	-	-	-	-	-	-	-	-	(2,000,000)
4	Citizens Acquisition Discount	-										
5	Less: Accum. Amort. - Citizens Acq. Discount	-										
6	Net Citizens Acquisition Discount	-	-	-	-	-	-	-	-	-	-	-
7	Total Net Utility Plant	$ (2,000,000)	-	-	-	-	-	-	-	-	-	(2,000,000)
8	Customer Advances for Construction	$ -										
9	Customer Deposits	-										
10	Other (ITC)	-										
11	Accumulated Deferred Income Taxes	-										
12	Total Deductions	$ -	-	-	-	-	-	-	-	-	-	-
13	Allowance for Working Capital	$ 279,710	296,489					(16,778)				
14	Regulatory Assets	-										
15	Regulatory Liabilities	-										
16	Total Rate Base	$ (1,720,290)	$ 296,489	$ -	$ -	$ -	$ -	$ (16,778)	$ -	$ -	$ -	$ (2,000,000)
	Operating Revenues											
17	Electric Retail Revenues	$ 7,781,533								$ 7,781,533		
18	Sales for Resale	-										
19	Other Operating Revenues	-										
20	Total Operating Revenues	$ 7,781,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,781,533	$ -	$ -
	Operating Expenses											
21	Fuel, Purchased Power, and Transmission	$ 7,761,608								$ 7,781,533	$ (19,925)	
22	Other Operations and Maintenance Expense	(3,718,384)		(131,640)	(320,100)		(146,616)	(20,028)				(3,100,000)
23	Depreciation and Amortization	-										
24	Taxes Other than Income Taxes	(8,738)					(8,738)					
25	Income Taxes	1,423,625		49,514	120,401		58,435	7,533	14,229		7,494	1,166,019
26	Total Operating Expenses	$ 5,458,111	$ -	$ (82,126)	$ (199,699)	$ -	$ (96,920)	$ (12,495)	$ 14,229	$ 7,781,533	$ (12,431)	$ (1,933,981)
27	Operating Income	$ 2,323,422	$ -	$ 82,126	$ 199,699	$ -	$ 96,920	$ 12,495	$ (14,229)	$ -	$ 12,431	$ 1,933,981

Notes and Sources

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Cash Working Capital - **Modified**

Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Cash Working Capital	$ (5,197,996)	$ 296,489	$ (4,901,507)
2	**Impact to Rate Base**	$ (5,197,996)	$ 296,489	$ (4,901,507)

Notes and Sources

See CWC Workpaper

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Cash Working Capital Workpaper - **Modified**

Test Year Ended December 31, 2014

(Thousands of Dollars)

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		UNSE Proposed						Staff Recommendation	
Line	Description	Pro Forma Test Year Amount	Revenue Lag Days	Expense Lag Days	Net Lag Days (C - D)	Lead/Lag Factor (E/365)	Cash Working Capital (F x B)	Adjuatments	Cash Working Capital
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Operating Expenses								
	Non-Cash Expenses								
1	Bad Debts Expense	$ 506						$ (132)	
2	Depreciation	11,406							
3	Amortization	(3,629)							
4	Deferred Income Taxes	4,627							
	Other Operating Expenses								
5	Salaries and Wages (UNSE Direct Employees)	4,616	35.59	23.33	12.26	0.0336	$ 155	-	-
6	Incentive Pay (UNSE Direct Employees)	329	35.59	267.00	(231.41)	(0.6340)	(209)	(147)	93
7	Purchased Power	62,965	35.59	33.79	1.80	0.0049	311	7,782	38
8	Transmission Other	9,014	35.59	40.67	(5.08)	(0.0139)	(125)	(20)	0
9	Meter Reading	574	35.59	33.67	1.92	0.0053	3		-
10	Customer Records & Collection Expenses (excluding allocati	1,169	35.59	34.94	0.65	0.0018	2		-
11	Office Supplies and Expenses	1,005	35.59	50.89	(15.30)	(0.0419)	(42)		-
12	Injuries and Damages	750	35.59	70.52	(34.93)	(0.0957)	(72)	(340)	33
13	Pensions and Benefits	1,960	35.59	51.37	(15.78)	(0.0432)	(85)		-
14	Support Services - TEP (Direct Labor, Burdens, System Alloc	6,059	35.59	44.77	(9.18)	(0.0252)	(152)		-
15	Property Taxes	6,733	35.59	212.00	(176.41)	(0.4833)	(3,254)		-
16	Payroll Taxes	376	35.59	12.00	23.59	0.0646	24	(9)	(1)
17	Current Income Taxes	-	35.59	0.00	35.59	0.0975	-	1,424	139
18	Interest on Customer Deposits	7	35.59	182.50	(146.91)	(0.4025)	(3)		-
19	Other Operations and Maintenance	25,050	35.59	41.21	(5.62)	(0.0154)	(386)		-
						-			
20	Total Operating Expenses	133,517						$ 8,558	
	Other Cash Working Capital Elements:								
21	Interest On Long-Term Debt	7,859	35.59	89.50	(53.91)	(0.1477)	(1,161)		
22	Revenue Taxes and Assessments	11,717	35.59	49.43	(13.84)	(0.0379)	(444)		
23	Total Cash Working Capital					Total Company	$ (5,438)		$ 302
24						ACC Jurisdiction Ratio	96%		96%
25						ACC Jurisdiction	(5,198)		$ 296
		w/o Int Synch	w/ Int Synch	Int Synch					
26.00	Current Income Taxe	1,409	1,424	14					

Notes and Sources

Lead/Lag Study from UNSE Schedule B-5, page 3 of 3

Line 24 - ACC Jurisdiction Ratio - 2015 UNSE Rev Req Model, Tab Rate Base, Cell AD 279

ARIZONA CORPORATION COMMISSION

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Schedule E-2
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UNS Electric, Inc.
Bad Debt Expense

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Adjusted Retail Revenue	##########		##########
2	Three-Year Average Retail Expense Ratio	0.34375%		0.25426%
3	Pro Forma Bad Debt Expense	505,677		374,037
4	Recorded Test Year Bad Debt Expense	863,828		863,828
5	Adjust Recorded to Normalized Bad Debt	$ (358,151)	$ (131,640)	$ (489,791)
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ 19,609	$ 7,207	$ 26,816
8	Federal Taxable	$ (338,542)		$ (462,975)
9	Federal Income Tax Rate	34.00%		34.00%
10	Effect on Federal income tax expense	$ 115,104	$ 42,307	$ 157,411
11	Total Income Tax		$ 49,514	
12	Total Expense	$ (223,438)	$ (82,126)	$ (305,564)
13	**Impact to Operating Income**	$ 223,438	$ 82,126	$ 305,564

Notes and Sources

Line 1 - UNSE response to UDR 1.001 Income-Bad Debt Expense

UNSE response to UDR 1.001 Income-Bad Debt Expense

	Unadjusted Retail Revenue			
14	2012	##########		##########
15	2013	160,650,785		160,650,785
16	2014	167,998,569		167,998,569
	Bad Debt Expense			
17	2012	$ 518,681		$ 518,681
18	2013	310,216		310,216
19	2014	863,828	$ (450,000)	413,828
				$ 1,242,724
	% Retail Expense to Retail Revenue			
20	2012	0.32396%		0.32396%
21	2013	0.19310%		0.19310%
22	2014	0.51419%		0.24633%
23	Average of Average Retail Expense Ratio	0.34375%		0.25446%
24	Total Unadjusted Retail Revenue	##########		##########
25	Total Bad Debt Expense	$ 1,692,724		$ 1,242,724
26	Three-Year Average Retail Expense Ratio	0.34633%		0.25426%
27	Uncollected Revenues Ratio - Schedule A.1	0.34375%		0.25426%

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

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Schedule E-3
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UNS Electric, Inc.
Injuries and Damages - **Modified for ACC Jurisdictional Allocation**

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	FERC 925 Injuries and Damages			
2	Year Ended 2012	$ 32,670		$ 32,670
3	Year Ended 2013	1,133,687	$ (1,000,000)	133,687
4	Year Ended 2014	27,797		27,797
5	Total Company FERC 925 Injuries and Damages	1,194,153		194,153
6	ACC Jurisdictional Allocation	96.03%		96.03%
7	Total ACC Jurisdiction FERC 925 Injuries and Damag	1,146,745		186,445
8	Three-Year Average	$ 382,248	$ (320,100)	$ 62,148
9	State Income Tax Rate	5.475%		5.475%
10	Effect on State income tax expense	$ (20,928)	$ 17,525	$ (3,403)
11	Federal Taxable	$ 361,320		$ 58,745
12	Federal Income Tax Rate	34%		34%
13	Effect on Federal income tax expense	$ (122,849)	$ 102,876	$ (19,973)
14	Total Income Tax		$ 120,401	
15	Total Expense	$ 238,471	$ (199,699)	$ 38,772
16	**Impact to Operating Income**	$ (238,471)	$ 199,699	$ (38,772)

Notes and Sources

Lines 2-4 - UNSE response to UDR 1.001 Income-Injuries & Damages

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

UNS Electric, Inc.
Payroll Expense and Payroll Taxes - **Withdrawn**

Test Year Ended December 31, 2014

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Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	Adjustment withdrawn.			

Notes and Sources

Lines 2-11 Column A - UNSE response to UDR 1.001 Income - Payroll Expense
Line 2-3 Column B - UNSE response to UDR STF 6.12

Line 13 UNSE response to UDR 1.001 Income-Payroll Tax Expense - Effective Tax Rate = 7.8%

State and Federal Income Tax Rate - UNSE response to UDR 1.068

ARIZONA CORPORATION COMMISSION

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Schedule E-5
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UNS Electric, Inc.
Incentive Compensation - **Modified for ACC Jurisdictional Allocation**

Test Year Ended December 31, 2014

Line	Description	ACC Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Incentive Compensation	$ 302,790	$ (146,616)	$ 156,173
2	Payroll Taxes	$ 13,293	$ (8,738)	$ 4,554
3	Total Payroll Expense and Payroll Taxes	$ 316,082		$ 160,728
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (17,306)		$ (8,800)
6	Federal Taxable	$ 298,776		$ 151,928
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (101,584)		$ (51,655)
9	Total Income Tax	$ (118,890)	$ 58,435	$ (60,455)
10	Total Expense	$ 197,192	$ (96,920)	$ 100,273
11	**Impact to Operating Income**	$ (197,192)	$ 96,920	$ (100,273)

Notes and Sources

See Workpaper

ARIZONA CORPORATION COMMISSION

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Schedule E-5 WP
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UNS Electric, Inc.
Incentive Compensation Workpaper - **Modified for ACC Jurisdictional Allocation**

Test Year Ended December 31, 2014

Line	Description	2012 (A)	2013 (B)	2014 (C)	Average (D)	Pay Increase (E)	Total Company (F)	ACC Jurisdictional Allocation (G)	Total ACC (H)
	As Filed by UNSE								
1	Incentive Compensation by FERC Account								
2	0581	$ -	$ 10,996	$ 11,558	$ 7,518	$ 595	$ 8,113	100%	$ 8,113
3	0583	12,228	36	-	4,088	324	4,412	100%	4,412
4	0592	11,774	32	-	3,935	311	4,247	100%	4,247
5	0593	10,754	7,952	7,154	8,620	682	9,302	100%	9,302
6	0901	16,458	20,650	25,967	21,025	1,664	22,689	100%	22,689
7	0908	(1,090)	8,238	11,652	6,267	496	6,763	100%	6,763
8	0920	221,542	241,707	252,559	238,603	18,884	257,487	96.03%	247,264
9	O&M	$ 271,666	$ 289,610	$ 308,890	$ 290,056	$ 22,956	$ 313,012		$ 302,790
10	Non-Taxable	(118,215)	(130,669)	(131,471)					
11	Taxable	153,451	158,942	177,419					
12	Effective Payroll Tax Rate	7.8%	7.8%	7.8%				Prorated	
13		$ 11,969	$ 12,397	$ 13,839	$ 12,735	$ 1,006	$ 13,741	96.73%	$ 13,293
14	Total	$ 165,420	$ 171,339	$ 191,258	$ 302,791	$ 23,963	$ 326,753		$ 316,082
	Pay Increase - 2%								
15	2012								
16	2013	$ 5,433							
17	2014	5,433	$ 5,792						
18	2014	5,433	5,792	$ 6,178					
19	2016	5,433	5,792	6,178					
20	2017	5,433	5,792	6,178					
21	Total	$ 27,167	$ 23,169	$ 18,533	$ 22,956				
	Payroll Taxes - 2% Increase								
22	2012								
23	2013	$ 239							
24	2014	239	$ 248						
25	2014	239	248	$ 277					
26	2016	239	248	277					
27	2017	239	248	277					
28	Total	$ 1,197	$ 992	$ 830	$ 1,006				

Line	Description	2012 (A)	2013 (B)	2014 (C)	Average (D)	Pay Increase (E)	Total (F)	50/50 Sharing (G)	ACC Jurisdictional Allocation (H)	Total ACC (I)
	Staff's Adjustment									
29	Incentive Compensation by FERC Account									
30	0581		$ 10,996	$ 11,558	$ 11,277	$ 893	$ 12,170	$ 6,085	100%	$ 6,085
31	0583		36	-	18	1	19	10	100%	10
32	0592		32	-	16	1	17	9	100%	9
33	0593		7,952	7,154	7,553	598	8,151	4,075	100%	4,075
34	0901		20,650	25,967	23,308	1,845	25,153	12,576	100%	12,576
35	0908		8,238	11,652	9,945	787	10,732	5,366	100%	5,366
36	0920		241,707	252,559	247,133	19,559	266,692	133,346	96.03%	128,052
37	O&M	$ -	$ 289,610	$ 308,890	$ 299,250	$ 23,684	$ 322,934	$ 161,467		######
38	Non-Taxable		(130,669)	(131,471)						
39	Taxable	-	158,942	177,419						
40	Effective Payroll Tax Rate	7.8%	7.8%	7.8%					Prorated	
41		$ -	$ 12,397	$ 13,839	$ 8,745	$ 672	$ 9,417	$ 4,709	96.72%	$ 4,554
42	Total	$ -	$ 171,339	$ 191,258	$ 307,996	$ 24,356	$ 332,352	$ 166,176		######
	Pay Increase - 2%									
43	2012									
44	2013	$ -								
45	2014	5,433	$ 5,792							
46	2015	5,433	5,792	$ 6,178						
47	2016	5,433	5,792	6,178						
48	2017									
49	Total	$ 16,300	$ 17,377	$ 12,356	$ 15,344					
	Payroll Taxes - 2% Increase									
50	2012									
51	2013	$ -								
52	2014	239	$ 248							
53	2015	239	248	$ 277						
54	2016	239	248	277						
55	2017									
56	Total	$ 718	$ 744	$ 554	$ 672					

Notes and Sources

Lines 1-28 UNSE response to UDR 1.001 Income-Incentive Compensation

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
Directors and Officers (D&O) Liability Insurance

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	FERC 165 D&O Liability Insurance Prepaid	$ 33,557	$ (16,778)	$ 16,778
2	**Impact to Rate Base**	$ 33,557	$ (16,778)	$ 16,778
3	FERC 925 Officers & Directors Liability	$ 145,954		
4	Amount excluded by UNSE in Fortis	(105,899)		
5	D&O Liability Insurance in Test Year	40,055	$ (20,028)	20,028
6	State Income Tax Rate	5.475%		5.475%
7	Effect on State income tax expense	$ (2,193)	$ 1,096	$ (1,097)
8	Federal Taxable	$ 37,862		$ 18,931
9	Federal Income Tax Rate	34%		34%
10	Effect on Federal income tax expense	$ (12,873)	$ 6,437	$ (6,436)
11	Total Income Tax		$ 7,533	
12	Total Expense	$ 24,989	$ (12,495)	$ 12,495
13	**Impact to Operating Income**	$ (24,989)	$ 12,495	$ (12,495)

Notes and Sources

Line 1 - UNSE response to STF 10.14
Line 3 - UNSE supplemental response to UDR 1.59
Line 4 - UNSE response to STF 16.05

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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Schedule E-7
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UNS Electric, Inc.
Interest Synchronization - **Modified Due Change in Working Capital - Rate Base**

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Rate Base	$ 272,013,000	$ (1,720,290)	$ 270,292,710
2	Interest Component of Rate of Return	2.20%		2.20%
3	Interest Attributable to Rate Base	5,981,248	(37,827)	5,943,421
4	State Income Tax Rate	5.475%		5.475%
5	Effect on State income tax expense	$ (327,473)	$ 2,071	$ (325,402)
6	Federal Taxable	$ 5,653,775		$ 5,618,019
7	Federal Income Tax Rate	34%		34%
8	Effect on Federal income tax expense	$ (1,922,284)	$ 12,158	$ (1,910,126)
9	Total Income Tax		$ 14,229	
10	Total Expense	$ (2,249,757)	$ 14,229	$ (2,235,528)
11	**Impact to Operating Income**	$ 2,249,757	$ (14,229)	$ 2,235,528

Notes and Sources

Line 1 Original Cost Rate Base from Schedule B
Line 2 Interest Component of Rate of Return - OCRB Weighted Cost of Long Term Debt on Schedule D

ARIZONA CORPORATION COMMISSION

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Schedule E-8
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UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause (PPFAC)

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	Test Year Adjusted Billing Detemrinants (kWh)	1,600,809,167		1,600,809,167
2	Proposed Base Cost Rate ($ per kWh)	0.048427	0.004861	0.053288
3	Base Cost of Fuel and Purchased Power	$ 77,522,386	$ 7,781,533	$ 85,303,919
4	**Electric Retail Revenues**		$ 7,781,533	
5	**Expense: Fuel, Purchased Power and Transmission**		$ 7,781,533	
6	**Impact to Operating Income**		$ -	

Notes and Sources

See Direct Testimony of Barbara Keene

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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UNS Electric, Inc.
OATT

Test Year Ended December 31, 2014

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
1	OATT	14,531,456	$ (19,925)	14,511,531
2	State Income Tax Rate	5.475%		5.475%
3	Effect on State income tax expense	$ (795,597)	$ 1,091	$ (794,506)
4		$ 13,735,859		$ 13,717,025
5	Federal Income Tax Rate	34%		34%
6	Effect on Federal income tax expense	$ (4,670,192)	$ 6,403	$ (4,663,789)
7	Total Income Tax		$ 7,494	
8	Total Expense	$ 9,065,667	$ (12,431)	$ 9,053,236
9	**Impact to Operating Income**	$ (9,065,667)	$ 12,431	$ (9,053,236)

Notes and Sources

See Direct Testimony of Eric Van Epps

State Income Tax Rate - UNSE response to RUCO 1.03

ARIZONA CORPORATION COMMISSION

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Schedule E-10
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UNS Electric, Inc.
Gila River Deferred Cost - **Modified**

Test Year Ended December 31, 2014

(Thousands of Dollars)

Line	Description	Amount Per Company (A)	Staff Adjustment (B)	Amount Per Staff (C)
	Accumlated Depreciation - Gila River			
1	Accumulated Depreciation	$ -	$ 2,000,000	$ 2,000,000
2	**Impact to Rate Base**	$ -	$ (2,000,000)	$ (2,000,000)
3	Regulatory Asset Amoritzation - Gila River Savings			
4	Other Operations and Maintence Expense	$ 3,100,000	$ (3,100,000)	$ -
5	State Income Tax Rate	5.475%		5.475%
6	Effect on State income tax expense	$ (169,725)	$ 169,725	$ -
7	Federal Taxable	$ 2,930,275		$ -
8	Federal Income Tax Rate	34%		34%
9	Effect on Federal income tax expense	$ (996,294)	$ 996,294	$ -
10	Total Income Tax		$ 1,166,019	
11	Total Expense	$ 1,933,981	$ (1,933,981)	$ -
12	**Impact to Operating Income**	$ (1,933,981)	$ 1,933,981	$ -

Notes and Sources

See Direct Testimony of Barbara Keene for Accumulated Depreciation
See Surrebuttal Testimony of Barbara Kenne for Regulatory Asset Amortization
Line 4 - UNSE response to UDR 1.001 Income-Gila River Deferred Cost

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2014

ADJUSTMENT NAME:	Gila River Deferred Cost
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 15, 2015
PREPARED BY:	Mike Sheehan
CHECKED BY:	David Lewis
REVIEWED BY:	

		Total Company		ACC Jurisdictional	
FERC ACCT	**FERC ACCOUNT DESCRIPTION**	**DEBIT**	**CREDIT**	**DEBIT**	**CREDIT**
407.1	Regulatory Asset Amortization	$3,100,000		$3,100,000	
	ENTRY TOTAL	**$3,100,000**	**$0**	**$3,100,000**	**$0**
	NET ENTRY	**$3,100,000.00**		**$3,100,000.00**	

Reason for Adjustment

To adjust for cost allowable for recovery per ACC Deferred Accounting Order. Decision No. 74911

UNS Electric, Inc.
Gila River Unit 3

In Decision No. 74911 dated January 22, 2015, the ACC approved UNS Electric's request to defer for future recovery non-fuel costs including: (i) depreciation and amortization costs, (ii) property taxes, (iii) O&M expenses, and (iv) carrying costs calculated at 5% associated with owning, operating, and maintaining the plant for the period January 1, 2015 through the earlier of April 30, 2016 or the date new rates go into effect. The maximum amount of costs subject to deferral is the lesser of $10.5 million or the cumulative deferred savings as of April 30, 2016. The deferred savings will continue to accrue until new rates go into effect. UNS Electric will file monthly reports with Docket Control detailing the calculations related to allowable costs and savings. UNS Electric expects non-fuels costs to approximate $9 million by the end of 2015.

Mike Estimates the total to by 9.1M

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE FO RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This surrebuttal testimony addresses the deferred costs and savings associated with Gila River Power Plant Unit 3. This testimony also responds to UNS Electric rebuttal witness Michael E. Sheehan in regard to the base cost and proposed modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC").

Staff's recommendations are as follows:

1. UNSE should update the base cost, based on most recent actual costs, prior to establishing new rates in this case.
2. Instead of approving the proposed Base Rate Annual Adjustment, the formula used for calculating the monthly PPFAC rate should be modified to include consideration of the bank balance.
3. At the time of implementation of new rates, the deferred non-fuel costs associated with Gila River should be netted against the deferred fuel and purchased power savings, with any remaining savings to flow through the PPFAC. The $3.1 million amortized deferred cost should be removed from the proposed revenue requirement.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning power supply, Gila River Power Plant Unit 3 ("Gila River"), and base cost of fuel and purchased power ("base cost") for UNS Electric, Inc. ("UNSE" or "Company") and direct rate design testimony concerning UNSE's proposed modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC").

Q. What is the subject matter of this surrebuttal testimony?

A. This surrebuttal testimony will further address the deferred costs and savings associated with Gila River. This testimony will also respond to UNSE rebuttal witness Michael E. Sheehan in regard to the base cost and proposed modifications to the PPFAC.

DEFERRED COSTS AND SAVINGS ASSOCIATED WITH GILA RIVER

Q. Did you address deferred costs and savings associated with Gila River in your direct testimony in this case?

A. Yes.

Q. Please summarize Commission Decision No. 74911.

A. Decision No. 74911, (January 22, 2015) authorized UNSE to defer for possible later recovery through rates (1) the non-fuel costs of owning, operating, and maintaining its share of Gila River and (2) the short-term fuel and purchased power savings associated with the purchase of Gila River. Decision No. 74911 approved a Plan of Administration ("POA") that describes how the deferred accounting order would operate.

Q. Please describe the major provisions of the POA.

A. The POA allows UNSE to defer certain defined non-fuel costs[1] for the period of January 1, 2015, through the earlier of April 30, 2016, or the date new rates go into effect. It provides that the cumulative non-fuel costs will not exceed the lower of $10.5 million or the cumulative deferred savings as of April 30, 2016. For purposes of calculating the PPFAC, deferred savings will continue to accrue until new rates become effective; however, cumulative deferred costs will not increase after April 30, 2016.

Q. Has anything recently happened in regard to the POA since the filing of Staff's direct testimony?

A. Yes. On December 18, 2015, UNSE filed a motion in Docket No. E-04204A-13-0476 to amend the POA approved in Decision No. 74911. The motion asks to (1) extend the deferral period for the non-fuel costs from April 30, 2016, until the date that new rates go into effect in the pending rate case and (2) remove the $10.5 million hard cap on deferred costs and allow a deferred cost up to the amount of deferred savings.

Q. What does Staff now recommend in this rate case regarding the deferred costs and savings associated with Gila River?

A. Staff recommends that the deferred costs be netted against the deferred savings at the time of implementation of new rates, with any remaining savings to flow through the PPFAC. Therefore, Staff is removing the $3.1 million amortized deferred cost from the proposed

[1] Allowable deferred costs are limited to depreciation and amortization costs, property taxes, operating and maintenance expenses, and carrying costs (5 percent annual rate) on net book investment.

revenue requirement, as discussed in the surrebuttal testimony of Staff witness Donna Mullinax.

BASE COST OF FUEL AND PURCHASED POWER

Q. What did Staff recommend in direct testimony as the base cost of fuel and purchased power ("base cost") for UNSE?

A. In direct testimony, Staff recommended that the base cost be set at $0.053288 per kWh.

Q. What methodology did Staff use to determine its proposed base cost?

A. Staff used the available actual costs from January through August 2015, and UNSE's forecasted costs for September through December 2015. UNSE had originally proposed a base cost using only forecasted costs.

Q. What did Mr. Sheehan propose in his rebuttal testimony regarding the base cost?

A. Mr. Sheehan has recalculated the base cost as $0.053689 per kWh, using actual costs from January through December of 2015. UNSE proposes to again update the base cost based on actual costs prior to establishing new rates in this case.

Q. Does Staff accept Mr. Sheehan's rebuttal proposals in regard to the base cost?

A. Yes.

Q. In its rebuttal testimony, did UNSE allocate the base cost to the various rate classes?

A. Yes. UNSE rebuttal witness Craig A. Jones included tables in his testimony that indicate the base cost has been allocated among the rate classes.

Q. Is Staff in agreement with the class allocation of the base cost?

A. No. UNSE has not provided its methodology used for the allocation.

Q. What is Staff's recommendation?

A. Until such time as UNSE provides its class allocation methodology for review, Staff recommends that the base cost be used as the same dollar per kWh for all rate classes.

PROPOSED MODIFICATIONS TO PPFAC

Q. What is the purpose of a PPFAC?

A. The purpose of a PPFAC is to track changes in the costs of obtaining power supplies. The costs of obtaining power supplies included in the base rates approved by the Commission in a rate case are compared to actual power supply costs incurred after the rate case. A PPFAC rate is used to bill or refund to customers the difference in costs.

Q. How does UNSE's PPFAC work?

A. The PPFAC POA describes how the PPFAC works. UNSE's PPFAC uses a historical 12-month rolling average of actual fuel, purchased power, and purchased transmission costs to reset the PPFAC rate each month without Commission approval. The actual costs are compared to the Average Base Cost of Fuel and Purchased Power approved in UNSE's last rate case.

The change in the PPFAC rate is banded so that the new monthly PPFAC rate cannot increase or decrease the preceding month's Total Average Retail Fuel and Purchased Power Rate (the average base cost of fuel and purchased power plus the preceding month's PPFAC rate) by more than 0.83 percent.

Any over- or under-recovery of actual costs is recorded in the PPFAC bank balance, with interest. If the bank balance becomes over-collected by more than $10 million, UNSE must file for a PPFAC rate adjustment within 45 days or contact Staff to discuss why a rate adjustment is not necessary at that time. If the bank balance is under-collected, UNSE may file an application with the Commission requesting a surcharge.

The monthly calculation of the PPFAC rate does not consider the bank balance. The only way for over- or under-recovery of funds to be addressed is for UNSE to file for Commission approval of a PPFAC rate adjustment.

Q. Does Mr. Sheehan's rebuttal testimony continue to request a Base Rate Annual Adjustment?

A. Yes.

Q. What is the purpose of the Base Rate Annual Adjustment?

A. Mr. Sheehan states that the purpose of the Base Rate Annual Adjustment is to reduce the difference between the actual and approved collections of the base power supply costs related to changes in customer usage patterns relative to the base year.

Q. Does Staff still oppose the proposed Base Rate Annual Adjustment?

A. Yes. However, Staff proposes an alternative.

Q. What is Staff's alternative?

A. Staff recommends that the formula used for calculating the monthly PPFAC rate be modified to include consideration of the bank balance. This would be much simpler than the very complicated formula of the proposed Base Rate Annual Adjustment and it would maintain the purpose of the PPFAC.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. UNSE should again update the base cost, based on actual costs, prior to establishing new rates in this case.
2. Instead of approving the proposed Base Rate Annual Adjustment, the formula used for calculating the monthly PPFAC rate should be modified to include consideration of the bank balance.
3. At the time of implementation of new rates, the deferred non-fuel costs associated with Gila River should be netted against the deferred fuel and purchased power savings, with any remaining savings to flow through the PPFAC. The $3.1 million amortized deferred cost should be removed from the proposed revenue requirement.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

ERIC VAN EPPS

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This Surrebuttal testimony responds to UNS Electric, Inc. ("UNSE" or "Company") witnesses Jones, Smith and Tilghman as well as to Southwest Energy Efficiency Project ("SWEEP"). These responses focus on the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff adjustment mechanisms.

UNSE is in agreement with Staff's recommendations to create a Plan of Administration ("POA") for each of the aforementioned adjustors.

Staff opposes SWEEP's request for proposing and approving new DSM programs in this rate case as well as the inclusion of DSM funds through base rates. Staff recommends that there be considerations made for new DSM programs in future implementation plans and that the Company include in their education program for three-part rates information on how Energy Efficiency can mitigate the impacts of demand charges.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters in and around the electric utility industry. I have been employed with the Commission for three years.

Q. Have you previously filed testimony in this docket?

A. Yes, I previously provided Direct and Direct Rate Design testimony relating to the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for UNS Electric, Inc. ("UNSE" or "Company").

Q. What is the purpose of your Surrebuttal testimony?

A. My Surrebuttal testimony provides Staff's responses to rebuttal testimony filed by the Company along with direct testimony filed by some of the interveners.

DIRECT RATE DESIGN TESTIMONY RECOMMENDATIONS

Q. Please summarize your Direct Rate Design testimony recommendations.

A. In Direct Rate Design testimony, Staff recommended that UNSE file a Plan of Administration ("POA") for both the DSM and REST adjustors. Further, Staff recommended that UNSE provide draft POAs for both the aforementioned adjustors in rebuttal testimony.

In addition, Staff recommended that UNSE update its TCA POA pursuant to discussions it had with Staff and provide a draft in rebuttal testimony.

TRANSMISSION COST ADJUSTOR

Q. Do you wish to address the rebuttal testimony of Company witness Jones?

A. Yes. I would like to discuss Mr. Jones' testimony as it pertains to the TCA POA.

Q. Has the Company provided an updated TCA POA?

A. Yes. Company witness Mr. Jones provided an updated POA for the TCA in his rebuttal testimony. This was submitted as Exhibit CAJ-R-6.

Q. Does Staff believe the updated POA adequately incorporates the intended changes to the methodology used to calculate the TCA?

A. No. Staff was under the impression that the calculations section of the existing POA would be expanded to include the steps used in calculating the TCA as well as the Company's intended changes in methodology. Staff's intent is to provide clear delineation of the proposed changes in methodology so that there is transparency going forward. Staff does not wish to unduly burden the Company but rather to provide a transparent instrument which could be updated as changes occur in the Company's service territory.

Q. How does Staff recommend the Company proceed?

A. Staff would prefer the Company provide an updated POA before the conclusion of this rate proceeding which can be agreed upon. Staff will continue to work with the Company to develop the TCA POA in the hopes that it can be completed in time for a decision.

DEMAND-SIDE MANAGEMENT

Q. Do you wish to address the rebuttal testimony of Company witness Smith?

A. Yes. I would like to discuss Ms. Smith's testimony as it pertains to the DSM POA.

Q. Has the Company provided a DSM POA?

A. No. Staff would reiterate that it would prefer the Company provide a POA before the conclusion of this rate proceeding. Staff is available to work with the Company to develop a DSM POA that is not only consistent with Arizona Administrative Code ("A.A.C.") R12-2-2401 *et seq.*, but also inclusive of other important methodologies which should be transparent, such as performance incentives and how DSM budget items are allocated and treated with regard to rate proceedings.

Q. Are there any other issues pertaining to the DSM adjustor that Staff wishes to address?

A. Yes. Staff would like to respond to the direct testimony of Southwest Energy Efficiency Project ("SWEEP") witness Mr. Schlegel concerning the recommendation to develop a DSM customer-peak-demand-reduction proposal as part of this rate case and the inclusion of $5 million in energy efficiency program funding expensed through base rates.

Q. Does Staff believe additional DSM programs should be considered in this rate case?

A. No. Staff does not believe that this rate case is the most appropriate place to consider new DSM programs. If the outcome of this rate proceeding warrants new DSM programs, Staff would suggest that these DSM programs be proposed in a separate application or in UNSE's next Implementation Plan so that Staff can determine their cost effectiveness.

Q. Does Staff believe the Company should include in any educational program concerning demand charges information regarding potential Energy Efficiency programs?

A. Yes. Staff believes there is definitely a correlation between implementing Energy Efficiency measures and mitigating demand charges. Staff believes that a primary focus of an educational program involving demand charges should be to educate customers on what a demand charge is and how it affects their bill. Therefore, Staff would recommend that energy efficiency be addressed as an essential part of mitigating fees associated with a transition to a three-part rate.

Q. Does Staff agree with SWEEP's proposal to recover funding for DSM programs through base rates?

A. No. Staff prefers that monies associated with Energy Efficiency continue to be collected solely through the DSM adjustor. Under SWEEP's proposal the Commission would have to wait for the Company to file a rate case before it could make changes to any amount being collected through base rates. Although, the Commission could use the DSM adjustor to apply credits and surcharges if budget allotments for DSM programs grew or fell below an amount being collected through base rates; however, Staff prefers the simplicity of the current DSM funding arrangement and would not recommend adopting SWEEPs proposal. Staff prefers for customers to continue to have visibility into the costs on customer bills.

RENEWABLE ENERGY STANDARD AND TARIFF

Q. Do you wish to address the rebuttal testimony of Company witness Tilghman?

A. Yes. I would like to discuss Mr. Tilghman's testimony as it pertains to the REST POA.

Q. Has the Company provided Staff with a REST POA?

A. No. Staff would reiterate that it would prefer the Company provide a POA before the conclusion of this rate proceeding which can be agreed upon. Staff would add that it is available to work with the Company to develop a REST POA that is not only consistent with A.A.C. R14-02-1813 *et seq.*, but also inclusive of other important methodologies which should be transparent, such as how REST budget items are allocated and treated with regard to rate proceedings.

Q. Does this conclude your Surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	)	DOCKET NO. E-04204A-15-0142

SURREBUTTAL

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2016

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

My surrebuttal testimony addresses the rebuttal testimony of UNS Electric, Inc.'s witness Denise Smith regarding the Company's proposed changes to its Rules and Regulations. Staff makes the following recommendations:

- Staff does not recommend approval of UNSE's proposal to revise Subsection 3.B.1.a. of its Rules and Regulations.
- Staff recommends approval of UNSE's proposed revisions to Staff's initial recommendations regarding Subsections 4.A.6 and 11.L.2.
- Staff recommends approval of UNSE proposed Subsection 12.H except that the language should not apply to customers having a medical device or medical condition. Therefore, Staff recommends that UNSE revise the proposed language in 12.H to specify that customers having a medical device or medical condition would not be eligible to participate in current limitation.
- Staff recommends that UNSE work with Staff to develop a customer agreement for current limitation.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff") as a Public Utilities Analyst.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony regarding the proposed changes to UNS Electric, Inc.'s ("UNSE" or "Company") Rules and Regulations.

Q. What is the scope of your surrebuttal testimony in this case?

A. My surrebuttal testimony addresses the rebuttal testimony of UNSE witness Denise Smith regarding the Company's Rules and Regulations.

SURREBUTTAL TESTIMONY

Q. Are there any items in the UNSE Rate Case application that you did not address in Direct Testimony that you wish to address now?

A. Yes. Staff inadvertently omitted discussion regarding UNSE's proposed changes to Section 3- ***Establishment of Service Subsection B - Deposits*** of its Rules and Regulations. This was an unintentional oversight.

Q. What changes are being proposed to Section 3 of UNSE's Rules and Regulations?

A. UNSE is proposing to delete language regarding customer deposits from Section 3.B.1.a which currently reads:

> **The Applicant has had service of a comparable nature with the Company within the past two (2) years and was not delinquent in payment *more than* twice during the last twelve (12) consecutive months of service or was not disconnected for nonpayment. [Emphasis added.]**

UNSE is proposing to remove the words ***more than*** from the sentence.

Q. Does Staff agree with UNSE's proposed revision?

A. No. The current language in Subsection 3.B.1.a. of UNSE's Rules and Regulations is the precise language from Arizona Administrative Code ("A.A.C.") R14-2-203.B.1.a. Staff believes that removing the words ***more than*** from UNSE's current language would be inconsistent with A.A.C. R14-2-203.B.1.a. Therefore, Staff does not recommend approval of UNSE's proposed revision to Section 3.

Response to UNSE Rebuttal Testimony

Q. Does Staff agree with the modifications UNSE is proposing to Staff's initial recommendations regarding Subsections 4.A.6 and 11.L.2?

A. Yes. Staff believes that UNSE's proposed modifications to Staff's initial recommendations to Subsections 4.A.6 and 11.L.2 are appropriate and add clarity.

Q. What is UNSE's proposal regarding Subsection 12.H?

A. UNSE is proposing to add Subsection 12.H which reads:

> **In the event a Customer provides the Company with documentation certifying that the Customer depends on electricity to power a life-sustaining medical device or if a Customer's medical condition warrants continuous electrical service and the Customer accumulates debt equivalent to a three (3) month bill, in lieu of disconnection of service, the Company may limit the amount of current flowing into the premises to operate medical devices and basic appliances, such as refrigeration, water supply, lighting and small motors in the heating system.**

Q. Does Staff believe its recommendation regarding UNSE's proposed language in Subsection 12.H needs to be modified for clarification?

A. Yes. According to UNSE witness Denise Smith's rebuttal testimony, the proposed language "...would not necessarily be used only for customers with medical device alerts." Staff believes that its initial recommendation should be modified for clarification regarding whom the proposed language should apply.

Q. What was Staff's recommendation regarding the proposed language in Subsection 12.H?

A. Initially, Staff did not recommend approval of UNSE's proposed language. Staff was, and continues to be, concerned that limiting the amount of electricity to a customer that requires electricity to power life-sustaining medical devises or if a customer's medical condition warrants continuous service could potentially have a significant negative impact on the health of a customer. In addition, as stated in my direct testimony, UNSE has stated that of the approximately 560 customers with a life-sustaining medical device or medical condition that warrant continuous electrical service, only nine of the accounts had been delinquent for 90 days or more, as of September 2015. In response to additional data requests, UNSE indicated that, as of February 14, 2016, there was a total of 555 customers with a life-sustaining medical device or medical condition that warrant continuous electrical service and, of those, 14 accounts had been delinquent for 90 or more days. The total amount in arrears and owed by these 14 accounts as of that date was approximately $4,765.

Based on this information, Staff continues to believe that, though the number of accounts in arrears has increased, this represents an insignificant number of UNSE's total customers and does not believe that UNSE has demonstrated a valid need to implement its proposed current limitation for customers having a medical device or medical condition.

Further, the rebuttal testimony of Denise Smith states that customers with a medical device or medical condition would have their current limited in lieu of service disconnection. However, Staff notes that A.A.C. R14-2-211.A.5. specifies the conditions in which a utility shall not terminate service where the customer has the inability to pay and a) "[t]he customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous to the health of a customer or permanent resident residing on the customer's premises, or b) Life supporting equipment used in the home that is dependent on utility service for operation of such apparatus..."

Staff believes that UNSE's proposed language is inconsistent with A.A.C. R14-2-211.A.5 regarding customers having a medical device or medical condition as it pertains to termination of service. Therefore, Staff does not recommend that the proposed language should apply to customers having medical device or medical condition.

Q. What is Staff's recommendation regarding the proposed changes to Subsection 12.H regarding all other UNSE customers?

Staff believes that UNSE's proposed language could apply to all other customers in lieu of disconnection of service. After discussions with UNSE witness Denise Smith, Staff was able to get a more detailed understanding as to how the proposed electricity current limitation would operate. With this additional information, Staff believes that the option to limit the amount of current in lieu of disconnection could be a better option for some customers.

However, Staff believes that UNSE should provide each customer, or customer representative, with a written agreement which details how the current limitation would operate. Staff believes this agreement would ensure that the customer fully understands the specific terms of how the current limitation would operate. The agreement should include, at a minimum, the following information:

- Explanation of what current limitation is;
- Specification that customers or permanent resident at the customer's premises identified as having a medical device or medical condition or are not eligible for current limitation;
- How current limitation operates (i.e., if a device is placed on the meter, a new meter setting on a current meter, etc.);
- The appliance(s) and/or fixture(s) that would and would not continue to operate normally with the current limitation;
- Explanation of what happens to the appliance(s)/fixture(s) should the set current amount be exceeded;
- Actions the customer is required to take should the set current amount be exceeded (i.e., resetting of a breaker box, resetting the device on the meter, etc.);

- Staff recommends that UNSE work with Staff to develop a customer agreement for current limitation.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.